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Optimizing Type Well Construction: A New Approach for Scaling in Multiply Fractured Horizontal Wells

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Abstract: This paper outlines a straightforward method to standardize production histories from analog wells to common reference conditions, including average permeability in the stimulated reservoir volume, fracture half-length, stage spacing, and lateral length. The scaling technique addresses variations among analog wells in a region, crucial for constructing representative type wells and reducing uncertainty in statistical analyses. Grounded in well-established analytical solutions for constant bottom hole pressure production and transient linear flow in multiply fractured horizontal wells, the study introduces the "A-root k" analysis for estimating average fracture length and a depth of investigation equation for average permeability in the stimulated reservoir volume. Scaling involves expressing transient linear flow variables in dimensionless terms, enabling the normalization of rate-time profiles to selected reference conditions. Averaged scaled profiles yield mean, P90, P50, and P10 type wells, which can be further rescaled to design conditions for undrilled wells. The workflow, demonstrated with field examples, facilitates type well construction at desired probability levels from analog wells grouped into a few bins based on scaled production profile similarities. This approach proves effective, typically requiring one or two bins for a given resource play area.

Keywords: Scaling technique, Multiply fractured horizontal wells, Type well construction, Transient linear flow

Introduction

In the petroleum industry, type wells or type-well production profiles (TWPs) play a crucial role in predicting production from undrilled or minimally documented wells in a given region. Traditionally, these type wells are constructed by averaging production rates from existing wells, a process that involves normalizing to a common starting time, often the observed peak rate in every well. However, challenges arise when considering wells with diverse characteristics such as varying lateral lengths, completion designs, geological features, well vintage, and operating companies. The common practice of normalizing for perforated lateral length and creating different "type well areas" may not entirely capture the complexity of these variables, potentially leading to numerous bins with relatively few wells in each.

To overcome this challenge, this paper proposes a novel scaling methodology to reduce the number of bins by scaling wells to common reference conditions. This approach results in a more statistically representative number of wells in each bin, addressing the issue of statistical uncertainty associated with traditional binning methods. The scaling technique presented offers a pragmatic solution for constructing reliable type wells in the context of multiply fractured horizontal wells.

Similarities in Production Profiles

Lemoine and Lee (2019a, 2019b) conducted a comprehensive analysis revealing notable similarities in production profiles among wells within the same resource play, except for early times dominated by fracture clean-up and choked flow, and late times when boundary-dominated flow (BDF) and operational challenges such as liquid loading may occur. Their findings suggested that individual well profiles within a reservoir could be accurately transformed into a shared "reference" production profile through horizontal and vertical shifts, resulting in an overlapping trend.

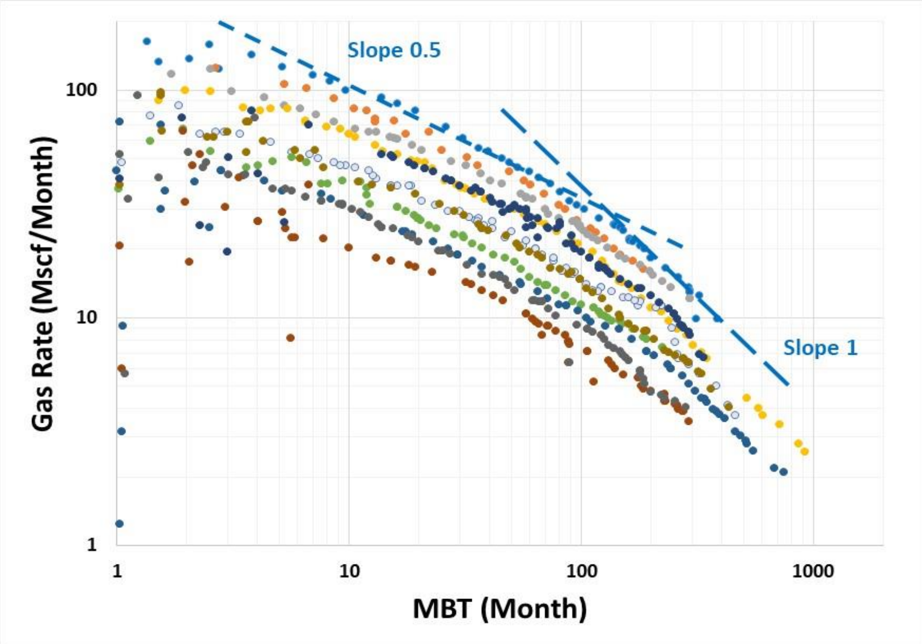

Figure 1. Log-log plots of unscaled rate vs. material-balance time plots for individual wells in the fayetteville shale.

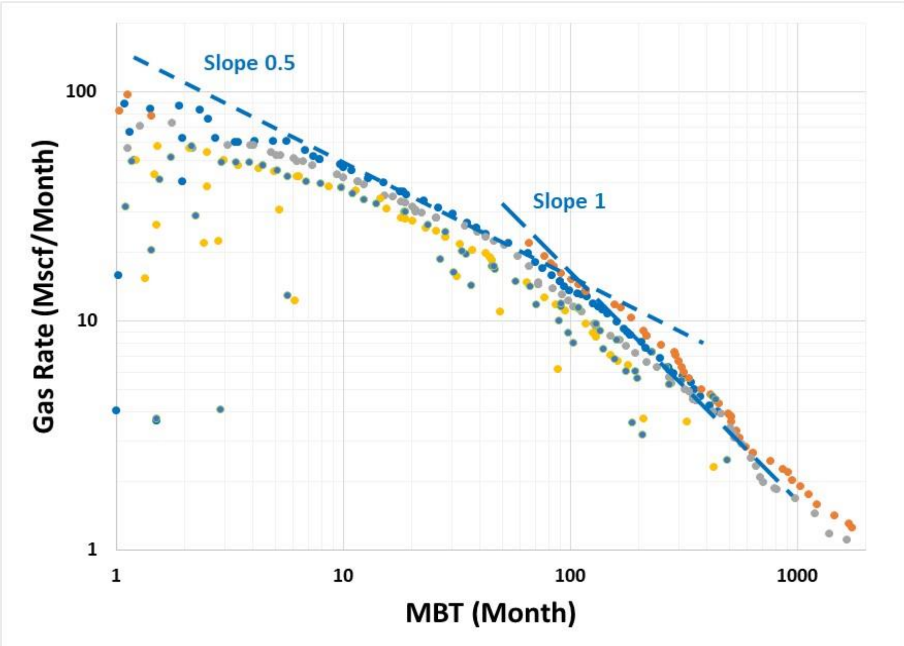

Figure 2. Log-log rate vs. MBT plots for all production profiles for Fayetteville shale wells to a common reference profile.

Figs. 1 and 2 illustrate the outcomes of this shifting for gas wells in the Fayetteville shale, showing a consistent trend during transient, transition, and boundary-dominated flow regimes. Notably, the shared slope observed during transient flow suggests a common Arps b-factor, inversely proportional to the slope on a log-log (rate-time) plot, as highlighted by Lee (2021) and confirmed by the half-slope during the transient flow regime for all the wells (b-factor is around 2). The unit slope line during BDF, while lacking information on the b-factor, serves as a distinctive identifier for this flow regime.

This pattern was consistently observed by Lemoine and Lee across gas wells in the Fayetteville, Barnett, and Montney shales, as well as oil wells in the Niobrara, Eagle Ford shale, and Bakken tight reservoirs. Despite potential complications from operational upsets, like liquid loading in gas wells that might shows deceiving straight lines (Hassan & Mattar, 2017), the unit slope line at late times remains crucial, anchoring the position of each shifted production profile onto the selected reference profile. These findings underscore a fundamental similarity in the behavior of wells across diverse resource plays, offering valuable insights for production forecasting and reservoir characterization.

The configurations of these production profiles show resemblance to the well-known Wattenbarger type curve (Fig. 3, adapted from (Wattenbarger et al., 1998)). This type curve, derived from an analytical solution for a well with hydraulic fractures in a closed drainage area, exhibits transient linear flow (slope is 0.5), a transition region, and finally boundary-dominated flow (slope is 1 on a q vs. MBT plot). The observed match prompts the consideration of employing the Wattenbarger type curve to align rate-time data from wells, presenting a potential means to estimate the average effective permeability (k) within the stimulated reservoir volume (SRV) of a horizontally fractured well.

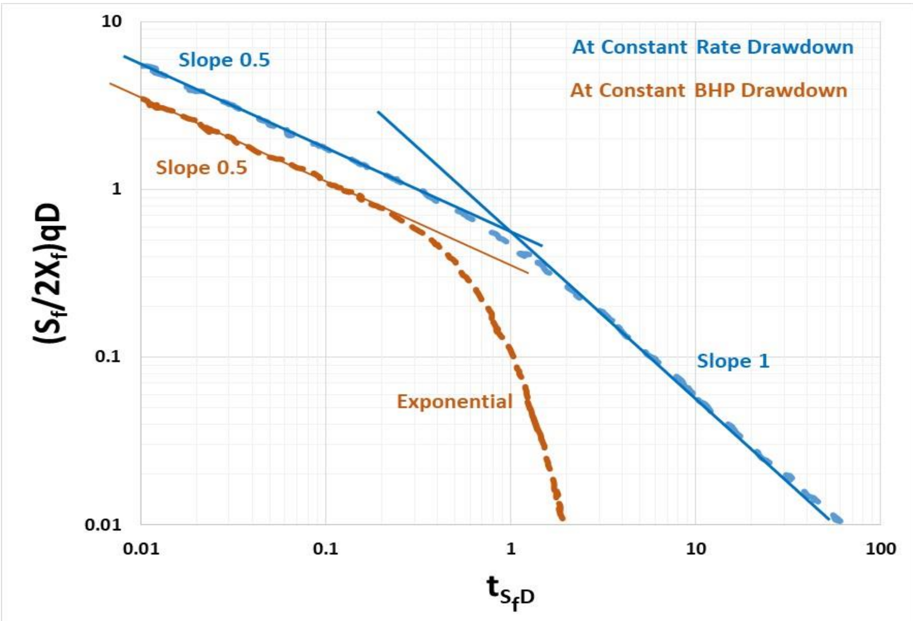

Figure 3. Constant rate and constant bottom hole pressure solutions.

Furthermore, this approach could facilitate the estimation of an average fracture half-length, denoted as xf (Clarkson, 2021), by determining the average area in fractures in a well open to flow. Matching the production history of each well within a reservoir allows individual estimates of k and xf. These well properties then enable the scaling of production profiles to a standardized set of reference property values. This process holds promise as a simplified alternative to type-curve matching, involving the alignment of rate vs. MBT to the constant-rate Wattenbarger type curve (Liang et al., 2011). While type-curve matching is often perceived as difficult and challenging, this proposed alternative offers a simplified solution.

Simplified Scaling Method

An efficient process enables the adjustment of rate-time profiles for potential analog wells, essential for constructing type wells under a uniform set of reference conditions. This method facilitates scaling to realistic values of lateral length, fracture spacing, and other distinct parameters within our analog dataset. Additionally, it allows the estimation of approximate values for effective average permeability within a stimulated reservoir volume (SRV) and average effective fracture length, followed by the scaling of all wells to suitable reference values for these factors.

The core of this simplified scaling approach lies in detecting the time marking the conclusion of the transient flow regime for a well. This temporal estimate can be derived either from the termination point of a straight line on a log-log rate-time plot or, potentially with greater accuracy, from a 1/q vs. √t plot. While these techniques are well-established for permeability estimation (e.g., (Clarkson, 2021)), a less commonly recognized aspect is the potential to estimate fracture length from the rate at the end of transient flow. This involves comparing the observed rate to the dimensionless rate in Wattenbarger's analytical solution (Wattenbarger et al., 1998), which provides both time and rate at the end of transient flow.

Wattenbarger, et al. (1998) contributed solutions to flow equations for constant bottom-hole pressure and constant-rate production. In the more pertinent constant BHP production scenario, they determined that the end of transient linear flow (line with a half slope) occurs at a dimensionless time of 0.25, with the corresponding dimensionless rate group being 0.694 (as illustrated in Fig. 2 from their paper, with large green dots indicating the end of the transient flow regime). This outcome aligns with the well-established depth of investigation equation, applicable irrespective of the transient flow regime's character (e.g., the transient b-factor, btr) within a production profile. According to Wattenbarger's solution, the dimensionless time at the end of transient linear flow is

$$t_{SfD,elf} = 0.25 = \frac{0.02532\,k\,t_{elf}}{\emptyset \mu c_t S_f^2} \quad \text{so} \quad k = \frac{9.870 \emptyset \mu c_t S_f^2}{t_{elf}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

and dimensionless rate group at the end of linear flow is

$$\frac{S_f}{2x_f} q_{D,elf} = 0.694 = \frac{70.6\, q_{elf} B \mu S_f^2}{x_f k h L_w \Delta p} \quad \text{hence} \quad x_f = \frac{101.7\, q_{elf} B \mu S_f^2}{k h L_w \Delta p} \quad \ldots\ldots\ldots\ldots\ldots (2)$$

Determining the rate and time at the end of transient linear flow from available rate-time data can be achieved through various methods, such as analyzing q vs. t on a log-log plot or 1/q vs. √t, with a focus on identifying a departure from an earlier linear trajectory. The Cartesian coordinate plot (1/q vs. √t) is likely more discerning, given the compression effect of logarithmic scales on numerical values.

Figs. 4 and 5 (after (Clarkson, 2021)) employ equivalent yet more intricate plots of $\frac{\Delta m(p)}{q}\ vs.\, t\ or \sqrt{t}$ plots. Here, m(p) represents the gas pseudo-pressure, often used to refine the accuracy of gas well analyses (we commonly depict Δp = pi – pwf for oil wells). The main objective is to identify the end of the initial linear trend on these plots. The following examples demonstrate potential applications of Eqs. (1) and (2). These figures illustrate graphical methods for determining the end of transient linear flow (telf). In Fig.4, a log-log plot of Δm(p)/q vs. t shows that transient linear flow concludes around t = 1,300 days. Similarly in Fig. 5, a cartesian coordinate plot of Δm(p)/q vs. √t indicates that transient linear flow terminates at √t = 36 (days)0.5, equivalent to t = 1,300 days.

Industrial Applications

In this section, we provide example calculations to illustrate the implementation of these principles to a set of wells within a reservoir of interest.

Example Well in the DJ Basin of the United States

Fig. 6 presents a plot of observed rate versus time data for a volatile oil well (well 1) in the DJ Basin of the United States. This well undergoes transient linear flow, as evidenced by a 0.5 slope line, suggesting a transient b factor of approximately 2 (in blue). Subsequently, the well transitions to Boundary-Dominated Flow (BDF), indicated by a unit-slope line at late times on the rate-MBT plot (in red), deviating from the half-slope line around 650 days. Emphasizing the need for caution, the unit slope line in late-time analysis can be misleading. Wells experiencing operational issues (liquid loading in gas wells for example) often exhibit data points that form "false" straight lines at late times. Nevertheless, it is evident that determining the unit slope in this context remains feasible as proved in this example (unit slope – line in green).

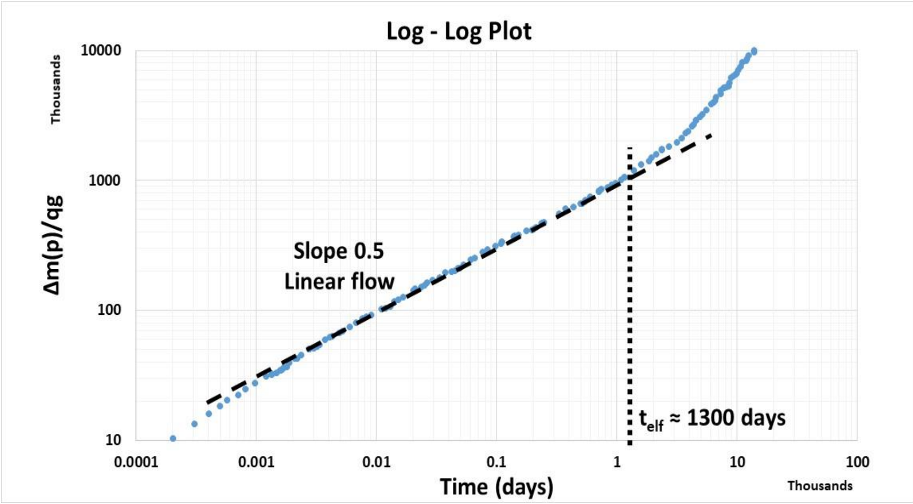

Figure 4. log-log plot of $\frac{\Delta m(p)}{q}$ $vs. t$

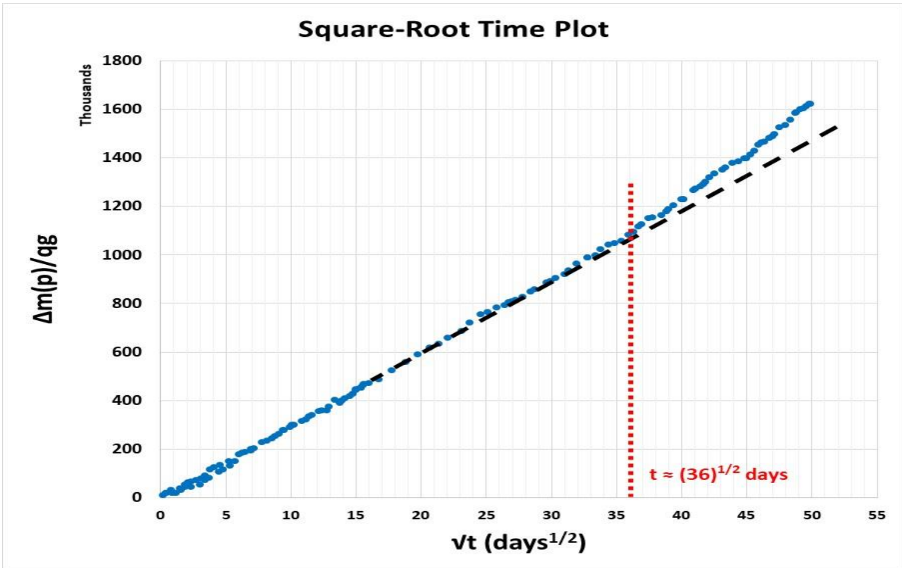

Figure 5. Cartesian plot of $\frac{\Delta m(p)}{q}$ $vs\sqrt{t}.$

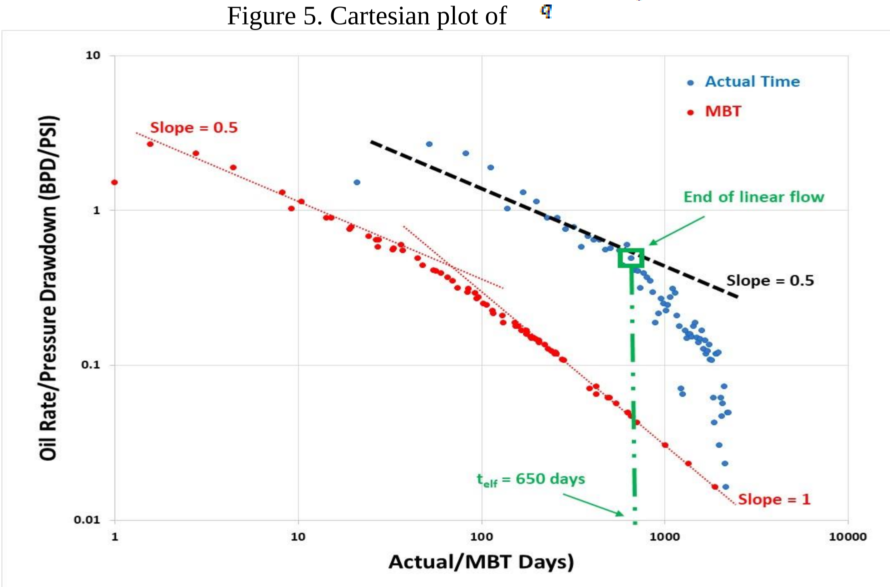

Figure 6. Log-log rate-time diagnostic plot of well 1

Application

To estimate k (effective average permeability) and xf (average effective fracture length), we utilize the plot of q vs. t where the time at the end of transient linear flow (telf) is determined to be 650 days, and the correspondent rate (qelf) is 1470 STB/D (Fig. 6). The known and estimated properties and characteristics are summarized in Table 1.

Table 1. Reservoir and completion properties for example well 1

Parameter	Units	Value
μ	cp	0.12
B	RB/STB	1.83
φ	fraction	0.085
pi	psia	3,312
h	ft	50
ct	psia-1	5.0e-04
Lw	ft	4,200
Sf	ft	125
pwf	psia	315

Then,

$$k = \frac{9.870\emptyset\mu\, c_t S_f^2}{t_{elf}} = \frac{9.87*0.085*0.12*5.0e-04*125^2}{650} = 0.00121\ md$$

$$x_f = \frac{101.7\, q_{elf} B\mu S_f^2}{khL_w\Delta p} = \frac{101.7*1470*1.83*0.12*125^2}{1.21e-03*50*4200*2997} = 673.5\ ft$$

Step 1: We determined that k=0.00121 md and xf =673.5 ft. The objective is to scale rates and times in the production profile to reference conditions of k=0.0002 md and xf=450 ft. Specifically, if the observed rate qobs=1470 STB/D at a time tobs of 650 days, the scaled rate qsc and scaled time tsc for this single data point on the rate-time schedule can be calculated from the relationships

$$t_{elf} = \frac{9.870\emptyset\mu c_t S_f^2}{k} \quad \text{and} \quad q_{elf} = \frac{x_f khL_w\Delta p}{196.1B\mu\, S_f^2}$$

Subsequently, by calculating ratios, the scaled time to the end of transient linear flow (tsc) and the scaled rate at the end of linear flow (qsc) can be determined, considering fixed values for all other parameters.

$$t_{sc} = t_{obs}\frac{k_{obs}}{k_{sc}} = 650 * \frac{0.00121}{0.0005} = 1{,}573\ days$$

and $$q_{sc} = q_{obs}\frac{k_{sc}x_{f,sc}}{k_{obs}x_{f,obs}} = 1470 * \frac{0.0002*5500}{0.0004*5262} = 541\ STB/D$$

Consequently, a rate of 1470 STB/D at a time of 650 days scales to a rate of 541 STB/D at a time of 1573 days when employing the specified reference values. This scaling approach can be uniformly applied to each point on the rate-time profile, generating a scaled rate-time profile that spans the entire production history.

Step 2: In order to scale all rates and times from a production profile to the reference conditions, the corresponding scaled values (qsc, tsc) for the observed point (1470 STB/D, 650 days) can be computed. Table 2 provides both observed and reference values. The target is to scale the observed rate and time to a set of reference values that accurately represent those anticipated for future wells.

By calculating ratios of equations for rates and the corresponding times at reference conditions to observed conditions, our working equations are then formulated as follows:

Table 2. Observed and reference values.

Parameter	Units	Observed Value	Reference Value
μ	cp	0.12	0.1
B	RB/STB	1.83	2
φ	fraction	0.085	0.075
pi	psia	3,312	3,800
h	ft	50	200
ct	psia-1	5.0e-04	5.0e-05
Lw	ft	4,200	5,000
Sf	ft	125	110
pwf	psia	315	400
k	md	0.00121	0.0002
xf	ft	673.5	450

$$q_{ref} = q_{obs} \frac{k_{ref} h_{ref} x_{f,ref} L_{w,ref} \Delta p_{ref} B_{obs} \mu_{obs} S_{f,obs}^2}{k_{obs} h_{obs} x_{f,obs} L_{w,obs} \Delta p_{obs} B_{ref} \mu_{ref} S_{f,ref}^2} =$$

$$1470 * \frac{0.0002*200*450*5000*(3800-400)*1.83*0.12*125^2}{0.00121*50*673.5*4200*(3312-315)*2*0.1*110^2} = 1243\ STB/D$$

and

$$t_{ref} = t_{obs} \frac{\phi_{ref} \mu_{ref} c_{t,ref} k_{obs} S_{f,ref}^2}{\phi_{obs} \mu_{obs} c_{t,obs} k_{ref} S_{f,obs}^2} = 650 * \frac{0.075*0.1*5e-05*0.00121*110^2}{0.085*0.12*5e-04*0.0002*125^2} = 224\ days$$

Therefore, a rate of 1470 STB/D at a time of 650 days scales to 1243 STB/D at a time of 224 days based on the provided reference values. This scaling methodology is consistently applicable to each point on the rate-time profile, facilitating the creation of a scaled rate-time profile. Step 3: Table 3 presents selected observed rates and times for the well 1 as well as the results of the scaling of all these (q, t) pairs to conform to the reference conditions specified in Table 2.

Table 3. Scaled rates and times from observed to reference values

Observed Time (days)	Observed Rate (BPD)	Scaled Time (days)	Scaled Rate (BPD)
228	2686	78	2272
381	2031	131	1718
503	1704	173	1441
654	1472	225	1245
769	1179	265	997
1012	674	348	570
1347	478	464	404
1683	354	580	299
2014	184	694	156
2131	69	734	58

Fig. 7 exhibits both the observed (rate vs. time) profile and the scaled (rate vs. time) profile. Scaling each well in the analog well dataset to these identical reference values would enable averaging, serving as the foundation for constructing a type well representative of this specific area within the reservoir of interest. It showcases the observed rate-time profile within the reservoir of interest, alongside the scaled rate-time profile derived from the scaling process.

Table 4 summarizes the properties of three additional volatile oil wells in the DJ Basin, sharing characteristics with the reference well previously discussed. Employing the same methodology, Fig. 8 presents observed and scaled values for these wells presents, offering a comprehensive overview of the four wells investigated in this study.

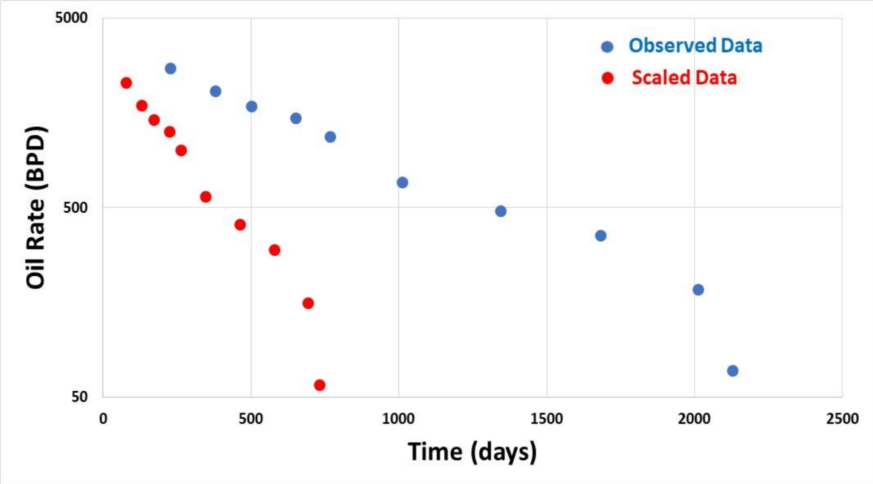

Figure 7. Selected observed versus scaled data of well 1

Table 4. Observed and reference values of the different other three wells from DJ Basin.

		Well 2	Well 3	Well 4
Parameter	Units	Value	Value	Value
μ	cp	0.14	0.13	0.13
B	RB/STB	1.8	1.75	1.6
φ	fraction	0.087	0.07	0.075
pi	psia	3500	3400	3350
h	ft	50	50	65
ct	psia-1	0.00045	0.00065	0.00045
Lw	ft	4100	4000	4300
Sf	ft	120	130	125
pwf	psia	325	320	315
telf	days	500	690	540
qelf	BPD	2500	1200	1900
K	md	0.00156	0.00143	0.00125
xf	ft	824	533	590

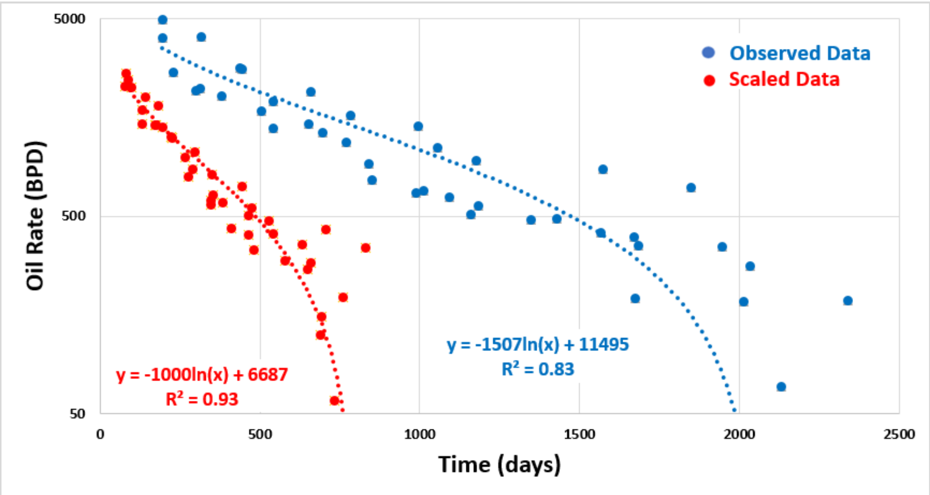

Figure 8. Selected observed and scaled data from the four DJ Basin wells.

First, Fig. 8 attests to the method's repeatability for various wells with diverse properties. Notably, the telf of well 2 is 38% less than that of well 3, while the qelf of well 2 is twice that of well 3. Second, the R-squared value of the logarithmic trendline has significantly improved from 0.83 to 0.93 for observed and scaled data, respectively. This enhancement reflects greater stability in results through the normalization methodology. The application of this procedure to a large dataset encompassing values from numerous wells thus yields more precise and accurate results. This precision is pivotal for refining the forecasting of type well production profiles in subsequent stages.

Implementation of Workflow for Constructing Type Wells

The applied workflow involved the systematic application to a set of wells within the reservoir area of interest, where average effective permeability and average fracture half-length were computed for each well. Subsequently, the wells were scaled to uniform reference values of properties, and the outcomes are depicted in Fig. 8. The wells were categorized into two distinct bins, characterized by differing values of the transient b-factor (b_{tr}). These scaled rates can be employed in the construction of a type well. This type well is designed to be indicative of the shared reference conditions to which all wells are scaled, contingent on a specific value of btr. In cases where future conditions are anticipated to deviate, such as due to alterations in completion design and lateral length, the type well can be recalibrated to the expected conditions in an upcoming drilling initiative, following the mentioned computational procedures.

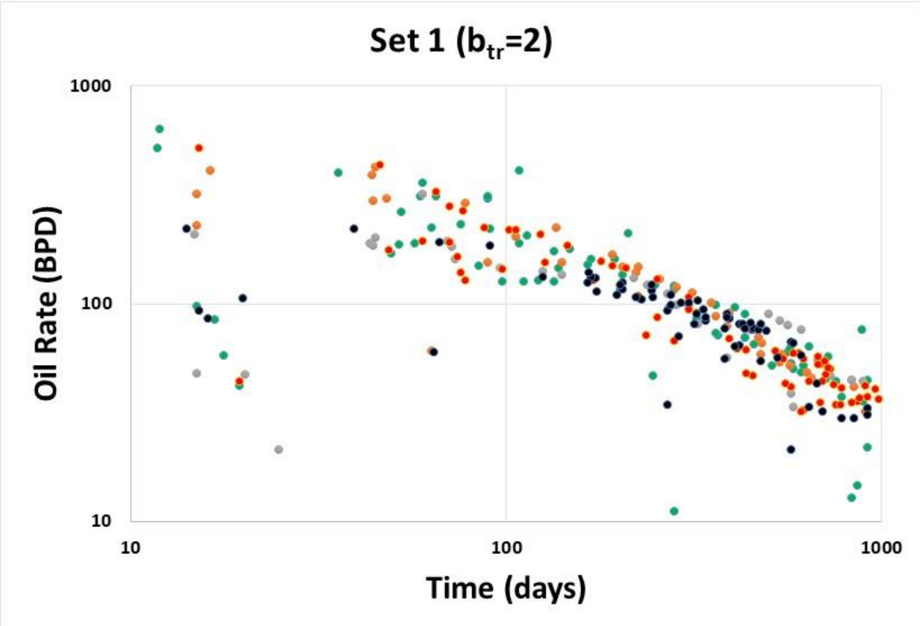

Figure 9a. Production profiles for wells with b_{tr}=2

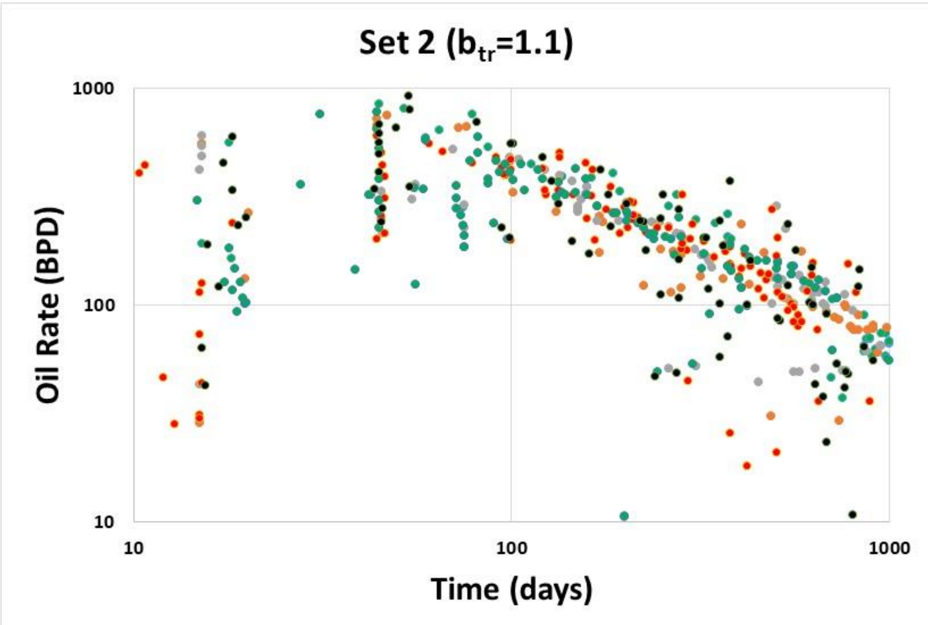

Figure 9b. Production profiles for wells of b_{tr}=1.1

Fig. 9 shows production profiles for wells sharing comparable transient region values of b scaled to uniform reference values of reservoir and completion properties, following Sukumar and Lee (2021)'s approach. The primary objective is to create a type well from a group of scaled well production profiles. However, a challenge arises as the original data points were spaced one month apart, corresponding to monthly production data. With the scaling process altering the time intervals between points, linear interpolation becomes necessary. For each well, we will employ linear interpolation between a point just before the beginning of a month and a point immediately after the start of a month. The averaging process will then be conducted based on these interpolated points to derive the desired average profile.

Results and Discussion

The process for constructing type wells involves scaling rate-time profiles to common reference conditions before averaging, aiming to group analog wells more effectively to reduce uncertainty in defining the "average." Despite deviations in the Arps b-factor from Wattenbarger's assumed value of 2, the workflow remains valid, with the key lying in determining the time at the end of the transient flow regime using the depth of investigation equation, independent of the Arps b-factor. Additionally, the rate at the end of transient flow remains unaffected by Wattenbarger's assumption of ideal linear flow followed by boundary-dominated flow, ensuring the robustness of the methodology for type well construction.

One challenge in the workflow is accurately determining the end of transient flow, especially in noisy datasets. While machine-learning filters can aid, their use is not discussed here (Jha et al., 2021; Jha et al., 2022). Alternatively, fitting data to type curves like Eleiott et al. (2019) or Chen and Teufel's (2000) modified Fetkovich (1996) curve can extract reservoir properties. The common assumption of b = 0 in boundary-dominated flow lacks theoretical backing and varies between 0.3 and 0.5 in practice, underlining the need for accurate determination and appropriate type curves for forecasting.

Permeability necessitates cautious interpretation, reflecting an average across all fracture stages, influenced by fracture treatment-induced microfractures and potentially activated natural fractures, enhancing permeability within the stimulated reservoir volume. This estimate should exceed values from laboratory measurements on matrix samples. Similarly, fracture half-length requires careful consideration, representing an average over all stages and assuming uniform propped fracture lengths.

Concerning wells in an analog well bin that have not transitioned beyond the transient flow regime, constructing type wells for them poses challenges. The unknown time for the end of transient flow complicates type curve matching. A tentative solution involves forecasting production to the economic limit, utilizing the forecasted time at which transient flow concludes for type curve matching. However, this approach relies on assumptions within the forecasting technique, potentially introducing uncertainties related to the forecasted end of transient flow. For wells in an analog well bin that have not surpassed the transient flow regime, constructing type wells poses challenges due to the unknown time for its conclusion, complicating type curve matching. A tentative solution involves forecasting production to the economic limit, relying on forecasted transient flow end times for type curve matching, albeit introducing uncertainties due to forecasting assumptions.

Conclusion

This study offers valuable insights for ultra-tight reservoirs with multi-fractured horizontal wells (MFHW). Analysts can estimate effective average permeability and fracture half-length for each well by analyzing production histories that exhibit distinct transient and boundary-dominated flow phases, based on the observed data at the end of transient flow regimes. Using these values for wells reaching boundary-dominated flow (BDF), analysts can scale production histories to common reference values, aligning with Wattenbarger's linear diffusivity equation solution and type curve. The proposed workflow involves grouping wells with similar production profiles into analog wells, facilitating type well construction. By averaging scaled rates within the bin, a representative type-well production profile is established, enhancing statistical validity by maximizing the number of analog wells in a bin and improving parameters like mean and standard deviation.

Scientific Ethics Declaration

The authors declare that the scientific ethical and legal responsibility of this article published in EPSTEM journal belongs to the authors.

Acknowledgements or Notes

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