Diagnostic assessment of reservoir response to fracturing: a case study from Hydraulic Fracturing Test Site (HFTS) in Midland Basin

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Received: 11 May 2021 / Accepted: 7 July 2021 / Published online: 22 July 2021
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Abstract

This paper outlines a data collection and diagnostics case study involving multiple horizontal shale wells. We look at well production profiles using rate transient analysis, differences in near wellbore complexity, geologic variations within the area of interest, as well as compositional differences in the rocks based on cores obtained from within the stimulated reservoir. The Hydraulic Fracturing Test Site is a multi-well experiment involving stimulation of unconventional shale wells in the southeastern Midland portion of the Permian Basin. The targeted formations include both the upper as well as the middle Wolfcamp formations, also referred alternatively as Wolfcamp A and Wolfcamp B. Data integration and analysis shared in this paper help us understand the various geologic controls impacting well productivity, particularly the wide variance observed between the Wolfcamp A and Wolfcamp B formations. Rate transient analysis indicates similar system permeabilities for stimulated wells. However, we observe higher effective fracture half-lengths for upper Wolfcamp wells. Using observations from 3D seismic interpretations (such as pad scale faults) as well as petrophysical and image log data, we highlight the substantial differences in stimulation as we move along the well laterals from the heel toward the toe sections. These differences are further reconciled with observations from zones with high data density at the core locations through stimulated rock, as well as independent data such as microseismic emissions. At the test site, Wolfcamp A was found to be relatively quartz rich with significant heterogeneity whereas Wolfcamp B is richer in clay and organic content. This impacts the geomechanical characteristics of the rock mass with much higher natural fracture density in the shallower interval. Thus, the fracture growth is more uniform in the deeper interval and more heterogeneous with branching likely in upper interval. Increased complexity also leads to consistently better productivity from the wells in the shallower interval as demonstrated from RTA results. This case study is unique because it provides valuable insights from actual sampling of the stimulated zones in hydraulically fractured wells and helps understand impact of various factors that contribute toward variability in well production. The findings from this study provides insights into need for optimization of completion designs in the various Wolfcamp landing zones, such as optimization of cluster or fracture spacing in various Wolfcamp intervals. In addition, it provides a useful template for data collection and research direction in future field test sites of similar nature in unconventional reservoirs.

Keywords HFTS · Shale · Fracturing · RTA · Well logs · 3D seismic · Interpretation · Fracture mechanics · Faulting

List of symbols

ϕ_{SRV}	Effective porosity of SRV
k_{SRV}	Effective permeability of SRV, ft ²
μ	Fluid viscosity, cP
C_t	Total compressibility, psi ⁻¹
Y_e	Distance between fracture and SRV boundary, ft

t_{BDF}	MBT at which boundary dominated flow is first observed, days
L	Wellbore lateral length, ft
X_f	Fracture half-length, ft
H_f	Fracture half-height, ft
B_f	Fracture half-width, ft
V_f	Modeled fracture volume, ft ³
B_o	Formation volume factor
m_{LF}	Slope of linear flow regime ($\sqrt{t}$ plot)
h	Fracture height, ft
ρ	Density, lb/ft ³
g	Gravitational acceleration, ft/s ²
ν	Kinematic viscosity, ft ² /s

This work was supported by the Department of Energy under Award Number DE-FE0024292.

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C	System capacitance (fracture)
R	System resistance (NWB + fracture)
k	Permeability, ft^2

Introduction

Test site

The Hydraulic Fracturing Test Site (HFTS-1) is in the eastern part of Midland Basin, between Central Basin Platform and the Eastern Shelf. This study was seed-funded by US Department of Energy and involved various industry stakeholders including many operators active in the Midland Basin. A fundamental element of this test program was the collection and analysis of SRV core across stimulated wells at the test site to better understand fracture and proppant transport behavior far-field as well as how various factors impact the productivity of the wells. Such large-scale field studies involving sampling of SRV is relatively rare. Apart from a recent ConocoPhillips study (Raterman et al. 2017), this test program was the only one to have captured more than 600 feet of SRV core across two horizontal shale wells in the Midland Basin. A more recent study in the Delaware Basin (Ciezobka and Reeves 2020) has gone one step further with close to 1000 feet of SRV core and multiple permanently installed fibers to understand cross-well fracture communication. The test wells for this study are situated in Reagan County, Texas. It involves an 11 well, multi pad hydraulic fracturing project in two of the Wolfcamp reservoir zones (Ciezobka et al. 2018). The project team collected and analyzed significant data at this site including micro-diagnostic formation injection tests, advanced open-hole logs, 110 side wall cores, complete core analysis including petrophysics, geomechanical analysis and petrography imaging, chemical tracers, microseismic surveys, tiltmeter surveys, bottom-hole pressure data, multiple pre- and post-treatment cross-well seismic surveys, etc. (Ciezobka et al. 2018). In addition, a slant core well was drilled and cored to mine-back samples from the stimulated rock volume (SRV). Fracture characterization as well as analysis of proppant from within the SRV have provided significant insights into fracture propagation and proppant distribution within the SRV (Gale et al. 2018; Maity et al. 2018; Maity and Ciezobka 2019b). Recent studies using HFTS data have highlighted impact of well interference (Kumar et al. 2020), provided advanced pressure data diagnostics using Chu Pressure Group method (Li et al. 2019), and examples of advanced data analytics techniques for well performance evaluations (Salahshoor et al. 2020). The rich dataset has also been instrumental in defining new fracture modeling framework for unconventional reservoirs (Birkholzer et al. 2021).

The horizontal wells at the site form a chevron pattern between the upper and the middle Wolfcamp zones. Figure 1 shows a map view as well as a gun-barrel view with spacing information and well nomenclature used in this study. Specifically, the spacing between wells within the same formation approximates 660 feet. At the test site, the vertical depth offset between upper and middle Wolfcamp wells is approximately 330 feet. The 11 horizontal wells were zipper fractured in groups as identified in Fig. 1b.

There were significant differences in the frac design in many of the wells at the test site. Various modifications in the designs are highlighted in Table 1. As can be observed, some wells were fractured relatively more aggressively with higher proppant loading and pumped treatment volumes compared with other wells at the site. In addition, perforation density was also varied independently for many of the wells. Two proppant sizes were pumped, i.e., mesh 100 sand followed by larger mesh 40/70 sand. For most of the stages, the ratio of pumped smaller mesh 100 to the larger mesh 40/70 sand ranged from 1:2 to 1:4 by weight. Average well-head treating pressures were higher by approximately 500 psi between the upper and the middle Wolfcamp formations.

Problem statement and motivation behind study

As described in “Test site” Section, HFTS-1 site had multiple wells landed in broadly two intervals in the UWC and MWC formations. While we did expect some differences in the well productivity from these two formations, particularly considering variations in the fracture designs (Table 1), longer term productivity data from these wells post completions showed significant variability in well productivity over time. Normalized cumulative production data are highlighted in Fig. 2a for reference. We can see a wide divergence in well productivity, particularly for UWC wells (> 50%). In addition, Fig. 2b displays a map view of the pad showing significant variability in rock properties, specifically, identified discontinuities from 3D ant-track volume extracted at specific depth horizon of interest (UWC formation).

Thus, the two most relevant motivations behind this study were to understand the likely drivers behind the observed variance in well productivity as well as the impact of geologic heterogeneity at the test location on performance of hydraulic stimulation program. Various datasets, such as OMBI derived fracture distribution, pumping data, production data analysis, lithologic variability between intervals could all help us better understand the factors driving well performance. While a holistic data analytics approach is useful (Salahshoor et al. 2020), in this paper, we will delve into specific datasets and techniques to better understand causality which in turn can be helpful when interpreting results

Fig. 1 Subplot **a** shows a map view of 11 horizontal wells as well as the slant core well and core locations drilled as part of the HFTS-Midland project. Subplot **b** shows the gun-barrel view of the wells in the two formations along with the relative location of the core

well. The zipper fracturing sequence is highlighted using the dashed bounded pairs or triplet. Upper Wolfcamp wells are shown as blue circles while the Middle Wolfcamp wellbores colored green

Table 1 Treatment parameters for various wells at test site

Well	W1	W2	W3	W4	W5	W6	W7	W8	W9	W10	W11
Proppant (lb./ft.)	1360	1840	1400	1110	1200	1130	1770	1100	1110	1080	1340
Volume (10 ⁶ gal.)	16.8	24.4	14.7	14.8	14.8	14.5	23.6	14.9	14.7	15.0	16.3
perforations/100 ft	14	19	14	14	18	14	14.5	13	14	17.5	13

from data analytics workflows published independent of this study.

This study involves various analysis techniques which were used in a complementary manner to better understand the impact of local reservoir heterogeneities on well performance. The following “[Method](#)” section outlines various

analytical steps including rate transient analysis to understand well productivity behavior over more than a year of production as well as modeling of pressure transients generated during pump shut-in (water hammer analysis) to understand near wellbore connectivity to the hydraulically fractured rock mass. Finally, we integrate independent

Fig. 2 Subplot **a** shows normalized production data from wells at HFTS-1 indicating wide variance on performance. Subplot **b** shows map view of major discontinuities from 3D seismic derived ant-track volume for the UWC formation wells (modified from Maity and Ciezobka (2019a))

observations from multiple OBMI (oil based micro-imager) logs and observations from tracer analysis to validate the observed variability at the test site.

Method

Rate transient analysis

Rate transient analysis (RTA) for multi-well multi-stage fractured reservoirs is a broad field of study with multiple methods and workflows available for practitioners to use. These range from simple techniques of estimating effective SRV properties (Paliwal et al. 2019) to more complex techniques involving simulation and history matching (Farooq et al. 2020; He et al. 2020). The SRV is generally considered to be a network of created hydraulic fractures as well as intersecting and communicating natural fractures along with the heterogeneous matrix distributed along the entire horizontal wellbore. During the life of the wells, as they flow, different flow regimes may dominate the production response. These generally reveal in the pressure or rate transient diagnostic plots. One such classification suggests early time linear flow toward hydraulic fracture wings in SRV near these created fractures followed by elliptical flow regime where fluid is thought to move toward the drainage area of

linear flow perpendicular to hydraulic fractures. This is followed by boundary-dominated flow where the stimulated reservoir around each of the fractures is depleted. Figure 3 highlights flow regimes during the initial life cycle of the horizontal well, i.e., the first few years which we are primarily concerned with for this study.

For RTA from production data, there are various considerations to follow. Firstly, since the rates vary with time, they need to be normalized with bottom-hole flowing pressure data. Specifically, the time for boundary dominated flow initiation has to be identified along with the observed slope of the linear flow regime from a $\sqrt{\text{time}}$ plot. The SRV permeability and fracture half-lengths can be identified using the following equations (Rasdi & Chu 2012; Bahrami et al. 2015):

$$k_{\text{SRV}} = (C_1 \phi_{\text{SRV}} \mu C_t Y_e^2) / t_{\text{BDF}} \quad (1)$$

where Y_e is the separation between the fracture and SRV boundary and can be calculated from number of stages and wellbore lateral length as:

$$Y_e = L / (2 \times n) \quad (2)$$

Once the SRV effective permeability has been estimated, the fracture half-length can be estimated based on the slope

of the linear flow regime identified from normalized pressure vs. $\sqrt{t_{\text{MBT}}}$ plot.

$$X_f \sqrt{(k_{\text{SRV}})} = (C_2 B_0) / (m_{\text{LF}} h) \sqrt{(\mu / (\phi_{\text{SRV}} C_t))} \quad (3)$$

where, C_1 and C_2 are conversion factors for units used in calculations, ϕ_{SRV} is the effective porosity within the SRV and k_{SRV} is the permeability of the SRV. In addition, μ is the fluid viscosity, C_t is the total compressibility of the reservoir, L is the length of the wellbore lateral, n is the number of stages, B_o is the formation volume factor for oil, h is the estimated fracture height, and X_f is the effective fracture half-length. t_{BDF} is the approximate time when boundary dominated flow is identifiable. Finally, m_{LF} is the slope from the square root time plot from the identified linear flow regime. Time variable t_{MBT} , or material balance time, is the time superposition function for volumetric depletion (Blasingame et al. 1991; Agarwal et al. 1999).

The pressure data can be normalized using rate data. The rate-normalized pressure, or dP/Q , is plotted against material balance time on log–log scale as shown in Fig. 4a. We can identify onset of boundary-dominated flow (t_{BDF}) when the slope changes from around $1/2$ to a higher value of approximately 1. However, when we consider the normalized pressure data example shown in Fig. 4a, though the beginning of boundary dominated flow can be discerned, there is some degree of uncertainty associated with the exact onset time. Since there is significant noise in time-series production data, we use a segmented spline interpolation technique to identify range of possible t_{BDF} values. Specifically, the segment boundary where the most significant change is observed is categorized as the most likely zone of t_{BDF} . To remove the

uncertainty associated with early time effects, only data at > 100 days are considered in the fitting process. Identifying a range is useful since the scale is logarithmic and even small changes can have a significant impact on estimated k_{SRV} and X_f values. Figure 4b shows how the spline interpolation over the derivative highlights probable t_{BDF} onset, which corresponds with the segment showing maximum change with respect to prior segment. As suggested earlier, the identification of t_{BDF} zone provides an upper and lower bound estimate for SRV properties per Eq. 1 & 3. Table 2 provides the identified t_{BDF} range and m_{LF} parameters estimated for various HFTS wells in our test area. As mentioned earlier, these ranges for t_{BDF} can cause a significant variation in estimated SRV properties. The workflow models shared here have been implemented into an RTA analysis tool for our own research. However, we have independently verified results using available commercial RTA software and have observed similar trends in fracture half-lengths and system permeabilities as reported in this paper.

Modeling pump shut-in transients

To understand near-wellbore behavior for various frac stages, treating pressure is modeled as a function of changing rates. Recent studies by other authors have suggested the potential to interpret fracture connectivity and stage productivities using water hammer pressure transient analysis (Nguyen et al. 2021). To solve the system numerically, we solve for the equation of continuity and equation of momentum using the “method of characteristics” for transient flow behavior (Maity et al. 2016). A conceptual description of the ‘water hammer’ phenomenon and the derivation of the mathematical model as a hyperbolic partial differential equation can be found in many sources, such

Fig. 3 Flow regime transitions during the life cycle of a multi-stage horizontal hydraulically fractured well

Fig. 4 **a** shows rate normalized pressure data against material balance time highlighting identifiable flow regimes based on slope change. The regimes are notional and representative with uncertain

boundaries. **b** shows identification process followed for t_{BDF} based on changes observed in the derivative plot using a segmented spline fitting approach

Table 2 Interpreted t_{BDF} and m_{LF} values from rate normalized pressure plots

Well	W1	W2	W3	W4	W5	W6	W7	W8	W9	W10	W11
t_{BDF} (days)–min	340	330	390	370	380	400	260	290	220	250	210
t_{BDF} (days)–max	600	510	590	600	580	690	420	420	360	420	350
m_{LF} (psi bbl ⁻¹ day ⁻¹)	3.02	2.65	2.83	2.93	3.07	3.13	4.27	4.18	4.85	5.28	4.77

as by Larock et al. (1999). The equivalent equations governing the resistance (R) and capacitance (C) terms (Holzhausen and Egan 1986) are developed by resolving the two partial differential equations into a single ordinary differential equation using Lagrange multiplier. The resulting differential equation can be solved using method of characteristics. To model for the downstream boundary conditions, i.e., the perforated interval and stage plug, we use analogous definition of an electrical resistive-capacitive system in parallel based on definition provided by Holzhausen et al. (1988).

$$C = \left(8\rho g X_f^3 (1 - \nu) \right) / 3\mu \quad (4)$$

$$R = 3kX_f / \left(4gB_f^3 H_f \right) \quad (5)$$

Implicit assumptions include penny shaped crack of radius (or half-length) X_f for the capacitive term and fracture with half-length, X_f and half-width, B_f for the resistive term (Bird et al. 1960). To model for leak-off behavior, we define a fluid loss parameter, which incorporates a flow/pressure bleed at the downstream boundary using a fractional multiplier. Data fitting between modeled and observed

pressure response is achieved using genetic algorithm with a composite misfit function defined by Maity et al. (2016). Figure 5 shows example of model and data fit achieved for two sample stages from an earlier hydraulic fracturing job in the Marcellus shale (Maity et al. 2016). Once a reasonable match is obtained, the computed fracture half-length and half-width can then be used to compute a composite fracture volume (V_f) parameter. As classically defined, V_f is calculated as:

$$V_f = (\pi/2)X_f H_f B_f \quad (6)$$

where, X_f , H_f , and B_f represent the half-length, half-height and half-width for the representative fracture. To arrive at a solution, half-height is fixed based on independent estimations or observations, such as from microseismic observations, fiber response, modeling. In this study, we fix the heights based on observed hydraulic fractures, proppant distribution, and pressure response data from slant core study well at the test site (Ciezobka et al. 2018).

Observations

Pad-scale variability–rate transient analysis

RTA analysis on production data from HFTS wells provides estimates of effective SRV properties, which are shared in Table 3. Note that for the X_f and k_{SRV} values, the median as well as upper most and lower most quantiles are tabulated to provide a sense of uncertainty associated with these values. The fracture half-lengths as reported here are normalized by average proppant loading per stage for individual wells in question. For the fracture height, h (Eq. 3), we use 70 ft. for UWC and 50 ft. for MWC wells. The lower height for MWC wells is based on the observed microseismicity depth distribution, i.e., its variation between the UWC and MWC well completions. Specifically, on average, microseismic cloud height in MWC wells were observed to be ~75% of that in UWC wells. Significant height difference was also predicted from independent fracture modeling work where stress

Table 4 Formation properties used for RTA analysis

Property	UWC	MWC
Compressibility, C_f (psi ⁻¹)	5.80152×10^{-6}	5.80152×10^{-6}
Porosity, ϕ	0.0625	0.05
Height, h (ft)	70	50
Formation volume factor (B_0)	1.42	1.47
Fluid viscosity, μ (cP)	0.63	0.51

contrasts associated with UWC and MWC sub-formations are identified as the driving factor behind differing fracture heights. Finally, proppant distribution observed in the slant core indicates proppant zone height of less than 40 ft for the UWC stage (Maity and Ciezobka 2019b) which fits reasonably well with the estimated fracture heights used for this analysis. Other reservoir or fluid properties used in our RTA workflow are listed under Table 4.

We observe significant differences in fracture half-lengths on average in the UWC and the MWC wells

Table 3 RTA derived SRV properties based on linear, and boundary dominated flow regimes identified from pressure normalized production data (see section “Rate transient analysis”)

Well	W1	W2	W3	W4	W5	W6	W7	W8	W9	W10	W11
X_f –0.1Q	1.19	0.98	1.30	1.57	1.33	1.46	0.94	1.58	1.31	1.21	0.99
X_f –0.9Q	1.49	1.17	1.54	1.90	1.58	1.82	1.13	1.83	1.59	1.50	1.22
X_f –M	1.35	1.08	1.42	1.74	1.46	1.65	1.04	1.70	1.45	1.36	1.11
k_{SRV} –0.1Q (10 ⁻⁶ Darcy)	0.56	0.66	0.56	0.56	0.6	0.5	0.55	0.55	0.61	0.55	0.66
k_{SRV} –0.9Q (10 ⁻⁶ Darcy)	0.88	0.93	0.82	0.82	0.84	0.77	0.81	0.74	0.9	0.83	0.99
k_{SRV} –M (10 ⁻⁶ Darcy)	0.69	0.77	0.67	0.67	0.7	0.6	0.65	0.63	0.73	0.66	0.79

The half-lengths are normalized by proppant loading. The median (M) as well as the lower 10th (0.1Q) and upper 90th (0.9Q) quantile values are reported

Fig. 5 Example of modeling results and fits achieved with two stages from a well in the Marcellus (Maity et al. 2016)

(1.45 ± 0.24 for UWC and 1.33 ± 0.27 for the MWC wells). However, the observed SRV permeability between the two formations ($0.68 \mu\text{D}$ for UWC compared with $0.69 \mu\text{D}$ for MWC wells) is very similar overall. This is largely because the differences in the start of boundary-dominated flow as identified from slope change method shared earlier gets nullified by differences in reservoir properties such as porosity and fluid viscosity for these two formations. On average, for UWC wells, t_{BDF} was observed to be about 480 days while for MWC wells, t_{BDF} was observed at approximately 320 days.

To validate the relative distribution of identified fracture half-lengths, we compare them with the total proppant loading (normalized per foot of lateral) for all the wells in the study. Figure 6 shows a cross plot highlighting positive correlation between the two parameters. Larger proppant loading seems to have a higher impact on the derived fracture lengths. However, the most significant outlier among the wells is well W8 (red marker) which employed a modified completion strategy involving variable rate fracturing (Ciezobka et al. 2018). We also observe that the impact of proppant loading on fracture lengths is much more pronounced in the MWC wells compared with the UWC wells. Thus, there might be scope for more aggressive designs, particularly with the MWC fracture stages.

Local variability–analysis of shut-in data

As discussed under section “Modeling pump shut-in transients”, we model pressure transients, which are generated due to rapid shut-in of pumps at the end of pumping of each individual stage. As is suggestive of the model shown, the resistivity of the analog resistive-capacitive system at the downstream boundary as per Eq. 5 indicates an inverse

Fig. 6 Derived X_f vs. proppant load for UWC and MWC wells showing positive correlation. The most significant outlier is one of the MWC wells where a modified completion strategy (variable rate fracturing or VRF) was utilized (Ciezobka et al. 2016, 2018)

relationship with X_f . Specifically, we expect transient signatures matching higher resistivity to have lower X_f and lower fracture openings, which makes intuitive sense. Hence, V_f parameter, as calculated, should be inversely correlated with the effective fracture opening (since it is a function of length as well as width). In addition, these transients travel very quickly with cycle times within a few seconds. Thus, the impact from propped fractures should primarily be proximal to wellbore since at shut-in, bottom hole pressures subside and the fractures close. The actual pressure signal, also referred to as water hammer, loses some energy as it traverses through the fractures. More complex near-wellbore fracturing should therefore cause higher attenuation. Recent research has investigated numerical modeling of proppant settling, fracture closure, SRV permeability development, and water hammer pressure transient effects during pump shut-in and how they impact the well productivity behavior post flow-back (Zheng et al. 2020).

This suggests that for stages where there is relatively low near wellbore complexity, resistance to fluid flow is lower and effective V_f as modeled is higher. On the other hand, stages with higher near wellbore complexity should cause higher resistance to fluid flow across the perforated zone near wellbore and therefore, should cause lower effective modeled V_f . We can use standard end-of-stage step-down analysis of data to evaluate frictional pressure drop from tortuosity, which shows a power law relationship with flow rates (Massaras et al. 2006). Simulation tools can also be used for more robust modeling of frictional pressure drop as well as perforation friction in the near wellbore region (Zheng et al. 2019). Figure 7 shows a comparison between near wellbore

Fig. 7 Modeled V_f compared with near wellbore tortuosity compiled for multiple fracture stages from the HFTS wells

tortuosity calculated for various stages against the modeled fracture volume V_f assuming a constant 85 barrels/minute slurry rate. We observe a reasonably strong indication of an inverse relationship between these two parameters. We observe significant variability across the stages in terms of V_f behavior for all the wells. These dissimilarities can be caused by variations in fracture properties, near wellbore variability in stresses, propagation effects, fracture complexity, or even stage isolation issues across plugs. Without independent data, it is hard to quantify the impact of, or the driving factors behind this observed behavior. However, the overall effect noticed through either smaller or larger near wellbore tortuosity can be clearly seen in the pressure transients as seen in Fig. 7. This allows us to look at the fracture stages individually and identify stages of interest which can then be used to compare different wells in the pad.

Reconciling with through fracture core observations

Since a major component of this test program was the through fracturing coring across both upper and middle Wolfcamp stages, it is instructive to view observations from the core in comparison with observations from production behavior or pump shut-in data discussed in “[Pad-scale variability–rate transient analysis](#)” Section and “[Local variability–analysis of shut-in data](#)” Section.

Past studies (Gale et al. 2018; Maity and Ciezobka 2019b) of available cores from HFTS-Midland site have shown significant differences between the two formations. These differences can be reconciled with observed behavior from analysis of the pressure transients. Figure 8a shows V_f distribution for wells W4 (UWC) and W9 (MWC). Figure 8b shows relative instantaneous shut-in pressures (ISIP) distribution for wells W4 and W9. These are shown since the core well traverses across fracture stages along these two horizontal laterals. The locations of stages, which are associated with the cored intervals are also highlighted in the figure. We note that more stages cover the core along the UWC well, W4, compared to well, W9. Moreover, stages close to the UWC cored interval show a lower modeled V_f value on average when compared with the stages close to the MWC cored interval. This indicates significant signal damping for stages close to the UWC core vs. the MWC core. As discussed in “[Local variability–analysis of shut-in data](#)” Section, one possible explanation could be higher fracture complexity close to the identified stages in W4 compared to well W9. We note that fracture characterization of the cores (Gale et al. 2018) shows much higher natural fracture density in the UWC core compared with the MWC core. These results are highlighted in Table 5 for reference.

Higher density of natural fractures close to the wellbore can cause higher fracture complexity and associated frictional pressure drop from tortuous flow behavior. This

Table 5 Natural fracture characterization of HFTS cores (from Gale et al. 2018)

Location	Interval (ft)	Natural fractures	faults	Natural fracture density (ft ⁻¹)
UWC	440	272	12	0.62
MWC	125	29	0	0.23

should also manifest in lower modeled V_f seen in Fig. 8. The two natural fracture sets conform with strike-slip stress state (Gale et al. 2018), which makes natural fracture reactivation and complex interaction with hydraulic fractures very likely. Maity and Ciezobka (2019a) compared the location of the cores against 3D seismic discontinuity maps close to the wells in the two formations and showed that the UWC core location is proximal to a significant east–west discontinuity while the MWC core is in an area with no significant discontinuity.

All these observations strongly indicate that the two core locations vary significantly based on local geologic setting. The presence of significant faulting identified within the upper core suggests that some of the differences in natural fracture density could be explained by fault damage-zone fracture mechanics (Johri et al. 2014). Thus, significant differences in terms of fracture density observed in the cores are likely influenced by core locations and is not systemic. Other factors such as differential stresses, fracture orientation and degree of cementation, bedding plane proximity, cement integrity may also influence complexity. If we consider a significant fault zone within the UWC core where seven faults were identified within a 15 ft section (Gale et al. 2018), we see this behavior manifest in the distribution of natural fractures close to the fault zone. This is highlighted in Fig. 9 where the natural fracture density generally shows a declining trend as we move away from the faults within a ± 50 ft MD section of the core.

Rock compositional analysis using X-ray fluorescence (XRF) and Fourier transform induced spectroscopy (FTIR) study showed that the MWC cored interval has higher clay/kerogen content compared to the UWC cored interval (Fig. 10a). Higher clay content causes lower frictional coefficient of rocks and increases the likelihood of stable aseismic slip on fractures vs. unstable (stick–slip) behavior for rocks with lower Clay or TOC content (< 30%). Specifically, based on earlier studies looking at frictional properties of various shale reservoirs, we know that for typical shales, ~ 10% increase in clay composition can cause 10% to 20% drop in the frictional coefficient (Tembe et al. 2010; Kohli and Zoback 2013; Sone and Zoback 2013). However, the upper and the middle reservoirs exhibit varying differential stress behavior (specifically, lower differential stress estimates for the MWC reservoir compared with the UWC

Fig. 8 **a** Modeled V_f distribution across stages for wells W4 in UWC formation and well W9 in MWC formation. Locations of stages close to the cored intervals are highlighted using the dotted inserts along with the average V_f values in those intervals. **b** Relative ISIP distribu-

tion across fracture stages along wells W4 and W9 with relative variation in ISIP values along the cored stages. The dotted horizontal line indicates the mean ISIP which is 1 for both wells based on normalization with average ISIP

Fig. 9 Decreasing natural fracture density as we move away from a significant faulted section in the UWC cored interval based on core analysis

reservoir (Maity and Ciezobka 2019a) as seen in Fig. 10b. Lower differential stress reduces the creep strain for a given rock composition. Thus, any difference in natural fracture reactivation tendency will be a combination of these opposing factors of Clay content vs. differential stress.

Considering the ISIP data from wells W4 and W9 stages associated with the cores (Fig. 8b), we observe distinct deviations when compared with the average ISIP's for these two wells. Specifically, for well W4, the ISIP associated with core stages is ~93% of average ISIP. On the other hand, for W9 stage, it is approximately 100% of the average ISIP for that well. The higher relative ISIP for the MWC stage compared with the UWC stages close to the cores correlates with slightly higher Clay content identified in the MWC core compared with the UWC core and similar correlations have been reported by others as well (Ma and Zoback 2017). Also note that the ISIP for the MWC core stage is very close to the average ISIP of the W9 well unlike the core stages along well W4 where the ISIP values are a lot lower compared to the average value. One way of characterizing this behavior in general

terms would be to categorize MWC core to be representative of MWC formation in this area unlike the UWC core where there is significant deviation likely resulting from localized geologic variability discussed earlier. The presence of faults within the UWC core which suggests significant faults/fracture swarms associated with the UWC core location could be a cause for observed variability in ISIP behavior. The higher clay content could also be a causative factor for lower natural fracture density observed in the MWC core (Table 5).

We have already observed higher differential stress associated with stiffer rocks validated using a comparison with rock properties, specifically, QFP% from core analysis (Fig. 10b). We note that the four discrete differential stress “clusters” observed in Fig. 10b are an artifact of the nature of stress model as defined for various depth intervals, each of which represents different lithologic units of interest. However, the average values (blue circular markers) validate our observation. The geomechanical model definition includes calibrated pore pressure, unconfined compressive strength, and magnitude/ orientations of principal stresses which have been discussed independently by Maity and Ciezobka (2019a).

Reconciling with well-logs and fracturing data

Apart from the differences in fracture density at the two core locations, there are systemic variations along the length of the laterals. Analysis of pad scale faulting at HFTS suggests that in the heel-half of the well, their orientation approximates the E-W strike, which is proximal to the known direction of maximum horizontal stress (S_{Hmax}). On the other hand, along the toe-half, the lineaments are generally at a much higher angle off the principal stress direction (Maity and Ciezobka 2019a). We can check whether similar behavior is observed with oil-based micro-imager (OBMI) data in wells which were logged. We have OBMI data for some of the wells at HFTS. However, it is instructive to note that since the wells are North–South trending and many of the lineaments identified toward the toe half of the pad for both the formations are at high strike angles with respect to principal stress direction, we do not expect a significant number of these fractures to be captured by the image logs. Figure 11 shows the cumulative density function of fracture strikes along the toe and heel halves from the OBMI logs for wells W4, W9, as well as the slant well. We do find evidence of systematic differences in fracture strikes based on OBMI log data from the pad despite non-optimal well orientation

Fig. 10 **a** Compositional plot showing slight variability in Clay/TOC content between the upper vs. middle cores. Note higher weight % of clay in MWC data cluster in lieu of lower QFP weight %. Plot of QFP% from FTIR data vs. differential stress ($S_v - S_{Hmin}$) based on

modeled stresses within the reservoirs of interest. S_v denotes the vertical stress. The blue circular inserts indicate median of the distributions at given differential stress environment (units)

Fig. 11 Fracture strike distribution from OBMI logs for an UWC (W4) well, an MWC (W9) well and the slant well which was drilled for through fracture coring (refer Fig. 1 for relative well locations).

Here strike angle is calculated as degree offset of the identified fracture vs. approximate S_{Hmax} orientation

as discussed. Specifically, in the heel half of the wells, we have more fractures oriented closer to the east–west or S_{Hmax} orientation vs the toe halves. This holds true for all wells with OBMI data at the pad.

In addition, unlike the OBMI from the horizontal laterals W4 and W9, the slant well shows a significant percentage of fractures to have a lower strike angle very close to 0° , which reflects the overall orientation of the core well, with a much higher offset from the north–south orientation which allows the logs to pick the high offset fractures more accurately. These differences in distribution of lineaments are significant. From classical fracture mechanics theory, we would expect more fractures close to heel end of the wells to activate relatively easily during pressurization and hydraulic propagation, when compared to fractures along the toe end of the wells. This is due to the fracture orientations being closer to the existing stress field orientation. Of course, this difference is relative since majority of the fractures still follow strike-slip orientations ($\pm 30^\circ$ to S_{Hmax}). However, this would suggest that fracturing behavior might show some differences when we consider the heel end vs. the toe end fractures of these wells. We look at independently obtained V_f (as modeled earlier) and estimated ISIP from three wells in MWC formation. We picked these wells since they had good quality completion (pumping) data (time step of 1/3 s) which allows for relatively accurate V_f determination (Wang et al. 2008) and ISIP estimates. Figure 12 shows cumulative stack for V_f (Fig. 12a) as well as ISIP (Fig. 12b), both of which are normalized before stacking for our comparison.

From the difference curves, it is obvious that toward the toe end, the parameter values, i.e., modeled V_f (near wellbore friction) and ISIP's are very similar across these three wells

in the pad. On the other hand, as we move toward the heel half, the stacks begin to diverge and show varying behavior. While this observed variability across the pad could also be due to stress reversals, stress-relaxation effects, or other factors, we believe that the geologic controls including natural fracturing/ faulting discussed earlier is the primary driver for this deviation. Corresponding variability in geologic factors has been independently discussed by the authors earlier (Maity and Ciezobka 2019a).

UWC vs. MWC fracture growth

V_f and ISIP variability can provide useful insights into geologic differences across various intervals under development. These can be used at the pad scale to provide diagnostic assessment of productivity post completions and help identify ways in which future wells or completions can be improved. As an example, higher Clay and organics seem to correlate with lower natural fracture density. In addition, we have observed higher hydraulic fracture density in the shallower UWC vs. the deeper MWC intervals. This would suggest that the observed differences in lithology, particularly the lack of heterogeneity from carbonate debris zones or quartz rich sections in the MWC interval impacts hydraulic fracture propagation and observed fractures far-field as sampled during this test (Table 5; Gale et al. 2018; Maity and Ciezobka 2021). Independent observations, such as using segmented tracer studies (Wood et al. 2018) provide inter-well communication estimates in UWC and MWC wells. Figure 13 and Table 6 highlight oil and water tracer behavior in the UWC vs. MWC wells which were part of this study. We can clearly see much higher lateral communication in

Fig. 12 Cumulative stacks of normalized (feature scaled) V_f and ISIP for three MWC wells (W7, W8 and W9) across completed stages. Also shows in the difference plot and the bottom, which indicates the

maximum difference in stacks between the three wells. Note that the difference is smaller toward the toe and larger toward the heel (ratios are indicated for the two properties)

Table 6 High level snapshot of oil and water tracer results

Traced well formation*	Avg. # of UWC wells receiving oil tracer	Avg. # of MWC wells receiving oil tracer	Avg. # of UWC wells receiving water tracer	Avg. # of MWC wells receiving water tracer
UWC	2.75	2	2	2.25
MWC	4	3.5	5.5	4

The first row shows average number of wells receiving either oil or water tracer from traces sections in UWC wells. The second row shows aggregates for traced MWC wells

the MWC wells. This suggests that lower hydraulic fracture counts observed far-field in MWC core could be indicative of systematically longer fracture growth, and therefore, fewer fractures observed far-field. This brings into question the fracture design used in MWC wells which can likely be further optimized to improve resource recovery and reduce longer fracture growths observed at the test site. Note that in Fig. 13, observations are averaged concentrations of either water or oil tracer found on other proximal wells based on tracers injected into various sections of the traced wells during stimulation. In Table 6, we tabulate number of wells where tracer concentrations from any given traced well was identified above a baseline threshold.

Summary and Conclusions

In this case study, we have looked at multitude of diagnostic information as well as general observations from HFTS wells. Based on RTA analysis, we find that most of the wells

at the test site have similar SRV permeability. However, the effective X_f varies significantly between the two formations (UWC vs. MWC). The difference is around 8% on average (relative to UWC wells) and it rises to around 15% on average if we drop the VRF well as an outlier. A significant difference in effective SRV volume between the two formations is driven by the difference in thickness of the producing zones as well as reservoir properties. Finally, VRF well as highlighted by Ciezobka et al. (2018) shows significantly high RTA derived X_f value but average k_{SRV} when compared with other wells at HFTS-Midland site. Generally, UWC wells on average see boundary dominated flow behavior in 480 days on average compared to 320 days on average for MWC wells.

Analysis of near wellbore complexity identified from pressure transient data from pump shut-in's suggests variability in fracturing behavior along the toe half of the wells across the pad compared to the heel half. Similar variations are also observed in the ISIP data identified during fracturing. These observations correlate with differences in fracture distribution in the toe half vs. the heel half of the HFTS pad. We further validate these differences using OBMI derived fracture density. Our analysis of transients also indicates that differences observed between the UWC and MWC core (natural fracture distribution) is likely a function of local geologic drivers (faulting/damage zone fracture mechanics, etc.) and not a systemic behavior. This is not to suggest that a systemic difference in natural fracture distribution within these two formations does not exist. However, we cannot verify any such difference based solely on the information we have from the available data. Compositionally, we also observe slight differences

Fig. 13 **a** Water tracer vs. **b** Oil tracer communication summaries. We note that there is significantly higher communication from MWC wells (dotted insert in subplot a)

between the UWC (heel side) and MWC (toe side) core data. Lower differential stress estimated for MWC formation complicates comparison of shear slippage behavior in the two formations. The slightly higher clay content in the MWC core compared with UWC core (Δ of 10%) seems to correlate with a relatively higher ISIP observed during pump shut in. Also, the compositional variance matches with variations in differential stresses at different depths within the reservoir.

Learnings from HFTS project in Midland Basin suggest that variations in rock properties or geologic differences likely play a key role in well productivity behavior. While it is sub-optimal to capture significant geologic data through high-resolution wireline logging, it might be worthwhile to use available well control data as well as wide area 3D seismic surveys, if available, to build 3D earth models which can help inform well placement or landing zones, well spacing, as well as cluster or stage design. Our key observations and recommendations for future development are as follows:

Diagnostics using pressure pumping records and other routinely collected data can be insightful and provide indication of fracture productivity. In this work, we have demonstrated the use of water hammer pressure transients from pump shut-ins as a useful diagnostic tool to understand near wellbore fracture system connectivity. Our results suggest that clay dominated zones such as those encountered in the MWC formation may require higher cluster density than those implemented at the test site. On the other hand, wells landed within UWC formation where rock is leaner in terms of clay and kerogen content may not require very high cluster density. At HFTS site, since both UWC and MWC stages

had similar fracture, or cluster spacing for majority of the wells, the varying impact of geologic controls has been clearly observed in the monitoring data.

Finally, based on our observations, we can hypothesize that the stages in the heel halves will likely produce more over the life of the wells compared to the toe halves. More preexisting natural fractures in the heel halves are oriented favorably for reactivation compared to fractures in the toe halves. Moreover, analysis of fracturing data further points to a distinct difference in behavior of stages in the two sections.

As a multi-million-dollar research program, a major advantage at HFTS has been availability of significant amounts of background data including geologic as well as geophysical properties, high-resolution earth model, high quality petrophysical logs, as well as wells of opportunity. In addition, involvement of various operators in the form of a joint industrial partnership (JIP) allowed pooling of significant human and material resources for substantial diagnostic data collection effort. However, the process cannot be easily replicated at other locations given the significant logistical challenges involved. In addition, a major limitation of this study is the need for significant background data which is not routinely collected by operating companies. In addition, useful diagnostic tools such as distributed fiber optics (temperature, acoustic as well as strain sensing) were not deployed at HFTS-1. Our hope is that the learnings from HFTS-1 in Midland Basin, as well as currently ongoing HFTS-2 project in Delaware Basin, would provide key insights to help improve fracturing process in the Permian.

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Acknowledgements The authors would like to thank Laredo Petroleum Inc. and Gas Technology Institute (GTI) for permission to present this paper. In addition, we thank Dr. Julia Gale and her team at BEG for fracture characterization of HFTS core, Chevron Corp. for their core characterization including XRF/FTIR analysis, and Laredo Petroleum Inc. for providing access to background information from the test site.

Authors' contributions Both authors contributed to the study conception and design. Material preparation, data collection and analysis were performed by DM. The first draft of the manuscript was written by DM and both authors commented on previous versions of the manuscript. All authors read and approved the final manuscript as submitted.

Funding This material is based upon work supported by the Department of Energy under Award Number DE-FE0024292.

Data Availability While some of the data are not available for public release, a significant portion of the data used for this study can be found at National Energy Technology Laboratory's Energy Data eXchange (EDX) portal [<https://edx.netl.doe.gov/group/hfts-1-phase-1-group>].

Code availability Not application.

Declarations

Conflicts of interest The authors declare that they have no conflict of interests.

Ethics approval Not application.

Consent for publication Yes.

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