Frac-n-Flow Testing to Screen Brittle Fracture Stages in Wolfcamp Formation, Permian Basin, USA

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Abstract: A new technique, fracturing-and-flowing (frac-n-flow) testing, is introduced for horizontal drilling and multistage hydraulic fracturing (HDMHF) practitioners to check if the next stage would be a brittle fracture using the instantaneous shut-in pressure (ISIP) from the current stage. It was developed to reduce the number of not-flowing clusters in HDMHF treatments due to stress shadows in the development of tight oil reserves in Wolfcamp, Permian Basin, USA, and other similar fields. Preliminary frac-n-flow testing results show that a medium (200–1000 psi) increase in confining pressure under representative field in-situ stresses can transfer Indiana limestone from brittle fracturing to semi-ductile failing. Consequently, folds of increase (FOI) of matrix permeability vary from +13 (i.e., increase by 1300%) to −0.39 (i.e., decrease by 39%). Limestone is one of the major lithological components in Wolfcamp formation. Field ISIP data of two HDMHF wells in Wolfcamp formation show that the maximum stress shadows are +1297 psi and +1716 psi, respectively. These stress shadows might have transferred the fracturing process from brittle to semi-ductile, converting the corresponding stages from being stimulated and conductive (fracturing-n-flowing) to being damaged and not-flowing (failing-n-not-flowing). Field completion reports of the two wells confirmed that screen-out and other interruptions of operation occurred in these high stress shadowed stages.

Keywords: frac-n-flow testing; brittle fracturing; conductive fracture; ductile failing; non-conductive fracture; multi-stage hydraulic fracturing; Permian Basin; Wolfcamp tight oil field

1. Introduction

During the energy crisis in the 1970s, the US Department of Energy (DOE) initiated financial support for research and development (R&D) efforts in the exploration and production of unconventional oil and gas resources [1,2]. After several decades of continuous efforts through partnerships between the public and private sectors, researchers in the industry, national labs and universities found that the US has huge amounts of oil and gas in low porosity low permeability tight formations, collectively termed as unconventional resources [3–5]. Using new completion technologies of combining horizontal drilling and multistage hydraulic fracturing, these unconventional oil and gas resources are technically producible [6,7].

Hydraulic fracturing (HF) technology was “invented” by accident in the 1940s [8]. It was improved later and applied to improve production through reservoir stimulation to overcome near wellbore damage and/or to increase drainage volume in low permeability formations [9,10]. In developing conventional oil and gas resources, HF was mainly applied to create fractures in vertical wells [9,11].

Horizontally drilled (HD) wells can increase contact area between the wellbore and the reservoir. This is especially useful in producing from thin pay zones. HD wells were actively attempted in the US during the 1940s [12], and later in the Union of Soviet Socialist Republics (USSR) during the 1950s [13]. However, the first economically successful operation of using horizontal wells was achieved in 1978 for heavy oil production in...
Canada [12]. Later, horizontal wells’ great success in the Austin chalk expedited its wide application worldwide [14]. In the 1990s, horizontal wells were mainly used to increase production in naturally fractured reservoirs and in some reservoirs of limited access [15].

Both HF and HD technologies serve the same ultimate purpose: to increase contact area and/or drainage volume between the well and the reservoir. Hence, it is logical to combine these two for synergy [7,16]. However, initiating HF in a horizontal well is much more complicated than doing so in a vertical well [17]. Theoretical and experimental studies have shown that HF initiation is controlled by local stress fields in the near wellbore region [18]. Hydraulic fracture propagation is governed by far field in-situ stresses [19]. In addition to technical challenges, economic issues are another factor affecting the combined application of these two technologies. Only in the late 1980s were technical progress and market conditions favorable enough for people to discuss the combined application of these two technologies [9].

Creating highly conductive hydraulic fractures is the key to commercial success for HDMHF completion technology. Due to the huge investment involved and the extremely low permeability of reservoir rocks, successful application of this technology is especially important to the development of unconventional resources, such as the Wolfcamp Formation, a tight oil play in Permian Basin located in southeast New Mexico and West Texas, USA [20–22]. Whether a hydraulically created fracture is conductive or not is dominated by how the fracture is initiated. Hydraulic fractures initiated in brittle mode are in general much more conductive than those initiated otherwise [23]. HDMHF procedures are critical to the initiation of brittle fractures.

The HDMHF operation consists of three main steps [10]. Step 1 is to initiate the fractures using a low viscosity pad fluid, such as slick water. Step 2 is to propagate the fractures deeper into the reservoir using fracturing slurry (fluid mixed with proppants). Step 3 is to flush the well bore with slick water again, and flow back the injected fluid while leaving the proppants on-site to keep the fractures open. Fractures initiated in brittle mode in the pad phase maximize the transport of the fracturing slurry and proppants from the wellbore through the perforations towards the fracture tips. In contrast, fractures initiated in semi-brittle and/or semi-ductile modes would more likely lead to early screen-out due to the limited width in the pad-fracture.

Initiating a brittle fracture involves the favorable combination and interaction among the following major factors: rock properties, in-situ stresses and pore pressure, the pad fluid, and injection operations. Although many efforts have been made to find the brittle sections of formation rocks using a variety of brittleness index definitions [24], initiating a brittle fracture is still not always guaranteed. In fact, some unsuccessful HF stimulation jobs can be attributed to the lack of brittle fractures [22], with each unsuccessful HF job potentially costing several million US dollars [25].

A recent study showed that wells drilled between 2013 and 2016 in Wolfcamp formation, Permian Basin, USA had an average lateral length of 7931 ft, and each was divided into 33.46 HF stages on average [26]. Each stage had several clusters; each cluster had multiple perforations within the length of the perf gun, for instance three pairs of 180° phasing perforations within 1.5 ft [27]. In simple terms, one could depict the following physical model: (1) each perforation in the same cluster would initiate a crack; (2) cracks from the same cluster would merge into one “crack bundle” at a certain distance away from the wellbore when the driving energy decreased with the distance; and (3) crack bundles from different clusters in the same stage would merge into a “fracture zone” when the driving energy further decreased with distance. Based on this typical configuration of perforation-cluster-stage-wellbore, there were three levels of stress shadows in a horizontal well: (1) among cracks initiated from different perforations in the same cluster at the near wellbore region; (2) among crack bundles initiated from different clusters in the same stage; and (3) among fracture zones initiated from different stages. Based on this simplified model of stress shadows, one could quantify the impact of stress shadows from the previous stage to the current stage, and from the current stage to the next stage.
Many research teams have performed investigations on stress shadow effects from different perspectives. Olson and collaborators presented a series of numerical simulation results on this topic. In simulating the stress shadowing of 7 hydraulic fractures using a pseudo-3D displacement discontinuity model, Olson [28] found that stress shadow effects become more significant with: (1) reduced fracture spacing; (2) increased propagation velocity, which is defined as proportional to fracture tip stress-intensity factor; and (3) heterogeneity in horizontal in-situ stress. According to that study, edge fractures always develop best compared to those in the middle; and the central and sub-central fractures are constrained inconsistently, depending on the combination of the above parameters. To model simultaneous growth of multiple hydraulic fractures and their interaction with natural fractures, Olson and Dahi-Taleghani [29] found that fracture pattern complexity is strongly controlled by the magnitude of the hydraulic fracture net pressure relative to the in-situ horizontal differential stress. Wu and Olson [30] investigated the impact of fracture spacing and fluid properties on the stress shadows of simultaneously- or sequentially-generated hydraulic fractures. They confirmed that stress shadow effects change the local stress field and influence fracture geometry. They found that simultaneous vs. sequential injection methods create almost the same fracture trajectories. Slick-water treatments generate narrower and much longer fractures with significantly lower net pressure compared to gelled-fluid fracturing treatments. Closely spaced hydraulic fractures can significantly restrict fracture width. Exterior fractures are much longer than interior ones. At low differential horizontal in-situ stresses, fractures tend to move away from one another; at high differential horizontal in-situ stresses, fractures propagate along a straight line.

Soliman et al. [31] investigated stress interference of multiple fractures in horizontal and vertical wells based on the results of laboratory experiments, analytical study and field observation. They concluded that stress interference due to multiple fractures in a horizontal well can be significant and needs to be addressed during design and optimization. They found that stress interference leads to an increase in fracturing pressure; the increased fracturing pressure gets larger with each successive fracture; and this increase is a function of the fracture location and dimension. They showed that the induced changes in in-situ stresses are not uniform, with the largest increase being in the direction perpendicular to the fracture, i.e., the minimum horizontal stress. For vertical wells, they found that stress interference in general may not change the in-situ stress orientation, but may increase the breakdown and extension pressures.

Min et al. [32] found that heterogeneity can cause multiple crack branching and affect the crack propagation direction. They concluded that, for better production results, optimal distance between multiple fractures is required, which is further confirmed by Wu and Olson [30]. Weng et al. [33] developed a model that can simulate the complex fracture-network propagation in a formation with pre-existing natural fractures. They found that stress anisotropy, natural fractures, and interfacial friction play critical roles in creating fracture-network complexity.

Roussel and Sharma [34,35] investigated stress re-orientation due to multi-stage stress interference and found that an increase in shut-in pressures was hampered by the reorientation of the hydraulic fractures as the minimum horizontal stress approached the maximum horizontal stress in a normal faulting region. Stress shadow effects change the magnitude and direction of the maximum horizontal stress, which depends on position and spacing. In some cases, these changes cause reorientation of the fractures from transverse to longitudinal. In 2017, Roussel proposed an ISIP-based analytical method to determine fracture height and horizontal stress anisotropy, assuming uniformity in (1) stage spacing, (2) perforation cluster spacing, (3) number of perforation clusters per stage, (4) stimulation design, (5) lag time between successive stages, (6) hydraulic fracture height, and (7) mechanical properties [36]. Results showed that the reality might be much more complicated than this model could handle.
Cheng [37] investigated impacts of the number and spacing of clusters on production performance in multistage transversely fractured horizontal wells. She found that the stress shadow effect significantly reduces the width of the central and sub-central fractures when more than two fractures are created in each stage. Her results showed that the ultimate recovery decreases with the increase of clusters in each stage at the same cluster spacing. Similarly she found that, for the same lateral length of a horizontal well, smaller cluster spacing increases the number of fractures but does not necessarily improve well performance. In brief, her results revealed that inadequate small cluster spacing can actually lead to a great number of less-effective or ineffective fractures, and thus lower production rate and ultimate recovery.

Wong et al. [38] presented a new, non-planar, three-dimensional hydraulic fracturing numerical model that included stress shadow effects. The simulator can capture the influence of key parameters such as injection rate, fracture spacing, formation properties, etc. Due to stress shadows, the conventionally-assumed uniform growth of all fractures within the same stage is more likely to have two or three fractures grow disproportionately, and some of the fractures may unknowingly be over-stimulated, resulting in excessive length or height.

Nagel et al. evaluated the stress shadow effect due to multi-stage hydraulic fracturing and its impact in developing stacked plays, such as the tight oil reservoir in Wolfcamp Formation, Permian Basin, West Texas, USA [39,40]. They found that stress shadows have their greatest impact on the minimum horizontal stress, both in the magnitude and in the influencing distance, echoing the conclusion of Soliman et al. [31]. Nagel et al. compared stress shadow impacts on single fracture vs. multiple fractures, and concluded that in a single fracture, the impact depends on the fracture height, whereas in the case of multiple fractures, stage spacing also plays a critical role.

Dohmen et al. [41] correlated micro-seismic observation and field production performance in the Bakken tight oil reservoir and found that production does not scale up in simple increments when adding hydraulic fracture stages in closely spaced stimulation treatments. Based on depth distribution of micro-seismic events, multi-stage hydraulic fractures were interpreted as periodically growing out of the pay zone due to stress shadow effects.

Daneshy [42] proposed the concept of fracture shadowing, which can be considered as the extension or reversion of stress shadow effects. In stress shadow effect study, focus is on the impact of earlier fractures on future fractures created from the same well. In fracture shadowing, emphasis is on the impact of new fractures on existing fractures created from the same well or an offset well. Using field data, it is shown that the fracture shadowing effect can be used to (1) determine fracture growth pattern as well as a rough indicator of orientation on the same well, and (2) estimate fracture orientation, type, length, and conductivity.

The aforementioned studies on stress shadow effects assumed elasticity conditions, which led to the implicit assumptions of creating brittle and conductive fractures. While these studies greatly enriched our understanding on the complexity of HDMHF, the validity of brittle fracture assumption depends on the geomechanical properties of the reservoir rocks and the magnitude of stress shadows. It is unlikely that one would be willing to eliminate stress shadows by increasing the spacing at the cost of contact areas and drainage volumes. A practical solution is to optimize the spacing at each stage so the stress shadow would reach a tolerable value within which the reservoir rock may create brittle and conductive fractures for optimal economic performance [10].

To create brittle and conductive fractures under a tolerable stress shadow, one needs to know: (1) how much the stress shadow is; (2) what the impact of stress-shadow on the rock’s brittle-ductile behavior is; and (3) what the impact of the stress-shadow on matrix permeability/fracture conductivity is. To the author’s knowledge, no published methodology is available to address these three issues simultaneously. The objective of this paper is to propose a new technology, fracturing-and-flowing testing, for users to quickly...
check the impact of stress shadows from present stage to next stage in terms of fracturing brittleness and induced fracture conductivity.

2. Background

2.1. Rock Fracturability and Fracture Mode

In civil and mining engineering and other related disciplines, rock strengths are usually measured by axially compressing the sample to fail under constant confining pressures [43]. As early as 1945, Terzaghi observed that rocks fail by splitting, shearing or pseudo shearing, depending on the failure plane inclination [44]. Splitting occurs when there is cracking along the axial loading direction, which causes bonds between mineral grains to fail due to lateral tension; shearing is due to grain displacement along a gliding plane (shear plane); and pseudo shearing is the combination of both, resulting in a “zig-zag” failure plane [44]. More research work revealed that the process of rock failure is much more complicated.

In 1960, Griggs and Handin [45] classified rock failure under room temperature and different combinations of axial and radial stresses into brittle and ductile. Furthermore they correlated each failure mode based on the stress-strain curves and their ultimate strains. Based on that classification, rocks can undergo a range of failures, from brittle splitting at an ultimate strain below 1% to ductile flowing/swelling at an ultimate strain larger than 10%.

Further investigation shows that a rock’s failure mode is determined by: (1) rock matrix structures, (2) magnitude of confining pressure, (3) temperature, (4) rate of loading, and (5) the nature of interstitial fluids [7,46,47].

2.2. Fracture Mode and Permeability Change

Petroleum-related rock mechanics experienced remarkable advancements in the 1990s [48]. At that time, only conventional oil and gas reservoirs were under consideration [49,50]. In oil and gas fields, reservoir rocks are subject to the combined total stresses from overburden and horizontal tectonic movements, and pore pressure from hydrocarbon fluids and salty formation water. These stresses remained in equilibrium for thousands of years after the geological processes which originated petroleum took place. When this equilibrium is disturbed due to drilling and production activities, reservoir rocks will respond through deformation, and sometimes failure, to reach a new equilibrium.

The rock deformation is proportional to the effective stresses, i.e., the net stresses on the rock matrix, which can be approximated as the differences between the total stresses and the pore pressure in permeable rocks [51]. When the combination of effective stresses meets a certain failure criterion, rocks start to fail following the corresponding deformational mode, i.e., shear sliding, tensile splitting, or a combination of both [48,52]. From the energy release rate point of view, if the rock fails in brittle mode, a conductive fracture will be created; the matrix permeability will increase (stimulated). In contrast, if the rock fails in ductile mode, non-conductive “fractures” will be formed; the matrix permeability will decrease (damaged). Early multistage HF operation induces extra horizontal stress, i.e., stress shadows, to late stages to be fractured. These stress shadows could transition the rock from brittle fracture to ductile failure.

2.3. Stress Shadow Effect in Multistage HF Completion

In HDMHF completion, horizontal wells are drilled in the direction parallel to the minimum horizontal in-situ stress. In a normally stressed tectonic environment, such as the Permian Basin, USA, a well in the minimum horizontal in-situ stress direction favors the creation of multiple vertical, transverse fractures in the plane that is perpendicular to the wellbore [9].

In most HDMHF operations, these transverse, vertical, parallel fractures are created using the plug and perforation (plug-n-perf) technique [6]. The horizontal section is divided into multiple stages from toe to heel, with the toe stage as Stage 1, and the heel stage as the last stage, Stage N. Each stage except Stage 1 typically covers a horizontal section of
150–500 ft [22]. Stage 1 is usually hydraulically fractured using wet shoe or toe sub without perforation [27]. From Stage 2 to Stage N, each is further divided into several (typically 3 to 5) clusters. Each cluster is perforated with multiple (typically 4) holes (shots) per foot (spf) in a helix format, with a spacing of 25–100 ft between clusters (Figure 1).

Figure 1. Sketch of a 3-cluster hydraulic fracturing stage.

Under ideal conditions, one vertical, transverse and permeable fracture will be created in each cluster at the end of the pad injection phase [22]; and multiple parallel vertical, transverse and permeable fractures will be created in each stage for HF fluids and proppants to be injected in the slurry injection phase. However, earlier created stages will alter the in-situ stresses around rocks in later stages, because several hundred thousand pounds of HF proppants and several million gallons of HF fluids are normally injected during each earlier stage [22]. The huge amount of injected masses would not only cause changes and redistribution of in-situ stresses within the reservoir rock among neighboring clusters within the same stage, but also transfer and impose extra stresses to the neighboring stages [53,54]. These stress alternations on the neighboring clusters and stages are collectively called the stress shadow effect, (similar to the shadow effect from closely arranged tall buildings), which was first noticed in the Multi-well Experiment Site near Rifle, Colorado, USA [55]. While there are different consequences due to the stress shadows, the most significant one is that the magnitude and orientation of the minimum horizontal in-situ stress of the target stage/cluster could have been changed to such a level that the formation rock might have been converted from brittle fracturing under original stresses to ductile failing under the later stresses, thus a non-conductive stage/cluster. How much the anticipated stress shadow impacts fracture permeability needs quantitative characterization.

2.4. Matrix Permeability and Pad-Fracture Conductivity

In multistage HF stimulation, matrix permeability refers to the reservoir rock’s ability to allow fluid to flow through it and onto the fracture while HF conductivity describes the capacity of the hydraulically-created fracture to transfer reservoir fluids to the wellbore. Matrix permeability is routinely measured using reservoir rock samples mounted in a core-holder [56]. In the oil and gas industry, HF conductivity is measured following industrial standards by packing one or more layer(s) of proppants into two artificially cut rock plates [57]. While this test provides valuable parameters to describe the transferring capacity of the proppant-filled fracture, it is equally important to know if the pad-injection-initiated fracture (pad-fracture) would be conductive enough to allow the proppants being injected in the slurry injection phase [22]. It is therefore necessary to measure the permeability evolution while the rock sample is being compressed and as it changes from intact to fractured. In the early period of compression, the rock sample is intact; the measured result is the matrix permeability. Later, when the rock sample starts fracturing, the measured result is fracture permeability, or pad-fracture conductivity. Because a brittle fracture enhances permeability, a comparison of matrix permeability and the pad-fracture conductivity provides a lab test-based version of “folds of increase”, a widely used index in hydraulic fracturing field operation [10,58]. The frac-n-flow testing technique provides
seamless, continuous measurement of matrix permeability and fracture conductivity while the rock is being fractured.

3. Frac-n-Flow Testing

The fracturing-and-flowing (frac-n-flow) test was designed to provide a convenient tool for users to quickly check if a rock sample would experience brittle fracture or ductile failure, or somewhere in between; and how much the matrix permeability would be changed after the rock sample failure.

3.1. Testing Facility

The frac-n-flow testing facility was a multipurpose triaxial acoustic core flooding system [59,60]. The key component was a triaxial core-holder (Figure 2). This core-holder allows users to independently control (1) axial load (axial stress), (2) radial load (radial stress, confining pressure), and (3) pore pressure (reservoir pressure). Reservoir temperature was achieved by putting the core-holder into an industrial oven (air bath) [60]. Fluid flow under reservoir conditions was realized by setting the outlet pressure to the target reservoir pressure using a back pressure regulator (BPR), and injecting the pad fluid from the inlet at designated flow rate using a syringe pump.

![Figure 2. Triaxial core-holder in 3-dimensional (right) and cross-sectional (left) views.](image)

Six thermocouples were installed to measure/monitor temperatures at the following spots in the system: (1) inlet of the core-holder, (2) outlet of the core-holder, (3) exterior wall of the core-holder, (4) outlet port of the reservoir fluid injection pump, (5) oven ceiling, and (6) middle of the oven (air temperature) [60]. The average of temperatures at Spots (1) and (2), i.e., the inlet and the outlet of the core-holder, was used as the reservoir temperature. Temperatures at Spots (3) and (5) were used to prevent overheating. The temperature at Spot (6), compared to those at (3) and (5), was used to monitor heating homogeneity. Temperatures at Spots (4) and (1) were used to calculate properties of the injected reservoir fluid(s) and the quantity of injected mass [60].

3.2. Testing Methodology

Frac-n-flow testing combined techniques suggested in triaxial rock mechanics compression test [61–63] and core flooding petrophysical test [64,65]. Standards and suggested methods from both disciplines were followed. When differences arose, either the higher
standard was followed, or an appropriate parameter/value (e.g., geometry) that met requirements of both disciplines was chosen.

3.2.1. Preparing the Sample

In petrophysical tests for the oil and gas industry, cylindrical samples of 1-in diameter by 1-in length have been routinely used [56]. Rock mechanics triaxial testing methods suggested that the optimal ratio of diameter to length was 1:2 [63]. Therefore, cylindrical samples of 1-in diameter by 2-in length were prepared. Because both stress and strain were tensors and were correlated with rigid constraints by their counterparts in planes perpendicular to each other, samples for rock mechanics testing were required to be cut and grinded to very high precisions [63]. Frac-n-flow testing samples were thus prepared to meet these standards [61,63].

3.2.2. Initiating Frac-n-Flow Testing under Hydrostatic Pressure

The cylindrical rock sample was first saturated with de-ionized water (DI water) using a vacuum pump. The saturated sample was then put in a sleeve and installed into the core-holder (Figure 3). The core-holder was connected to three pumps (Figure 3), which independently controlled the radial load (minimum horizontal stress, confining pressure), axial load (overburden stress), and pore pressure (injection pressure), respectively. Reservoir pressure was set to a designated value using a BPR at the downstream outlet [66].

![Figure 3. In-situ stresses and reservoir pressure in the frac-n-flow system.](image)

Initial confining pressure was first applied in both radial and axial directions. Pressure lines of radial and axial loading were mutually connected at the beginning. Outlet valves of the radial and axial chambers were open to allow trapped air to be expelled. Distilled water was injected from the confining pressure pump to fill the radial and axial loading chambers first. When distilled water started to flow out of the outlets of the axial and radial loading chambers, outlet valves were turned off, and initial pressurization started until 30 psi was reached. Valves and connectors were checked for leakage. Initial pressure was held for 10 min to check system stability.

Target confining pressure was then applied to the designated value at both the radial and axial loading chambers using the radial loading pump. Constant pressure mode was used in the radial loading pump. The rock sample was now in hydrostatic status with equal compression from both the axial and radial directions.

Initial reservoir fluid flowing through the rock sample was established by injecting D.I. water using the pore pressure pump (hydraulic fracturing fluid pump in Figure 3). The pore pressure pump was set for constant flowrate mode. Initial flowrate started at
0.01 mL/min, and was adjusted to reach a stabilized pressure difference of about 10 psi between the upstream and downstream of the rock sample.

Reservoir temperature was then set for the oven to heat the core-holder after the initial fluid flowing through the rock sample was established. Fluid flow continued while the system was being heated up to the target reservoir temperature.

3.2.3. Performing Frac-n-Flow Test under Non-Hydrostatic Pressure

When the target reservoir temperature was reached and stabilized, the valve connecting axial and radial loading tubings was turned off. Axial loading was then being increased above the radial stress (confining pressure) using the axial loading pump. To catch the detailed dynamics of the rock sample failing process, the impact of different strain rates on failure behaviors have been investigated by many researchers (e.g., $10^{-2} - 10^{-7}$/s and slower e.g., [47, 67]). It has been commonly agreed that tests using strain rates between $10^{-2} - 10^{-6}$/s were proper to obtain a reasonably repeatable peak strength [43, 51]. Fairhurst and Hudson [62] suggested strain rates between $10^{-3} - 10^{-5}$/s were needed to capture both brittle and ductile behaviors at the peak strength region in uniaxial compression. In frac-n-flow tests axial strain rates between $10^{-4} - 10^{-6}$/s were recommended.

For the axial stress loading chamber of the frac-n-flow facility, its outside diameter (OD) was 3.5-in; and inner diameter (ID) was 2.375-in (Figure 4). Rock samples were 1-in diameter by 2-in length. Based on these geometry dimensions, the recommended axial strain rates between $10^{-4} - 10^{-6}$/s led to a range of injection rates between 0.01–1.02 mL/min, assuming negligible fluid compressibility. Detailed calculations are given in the Appendix A (Table A1). This range of axial loading injection rates defined the boundaries of the injection rates for measuring permeability while compressing the rock. The optimal injection rate depended on the poromechanical behavior of the rock. Based on prior experience through trial and error, an injection rate of 0.02 mL/min for the axial loading pump was used for the frac-n-flow tests in this paper.

![Figure 4. Dimensions of the axial loading chamber in the frac-n-flow system.](image-url)

Axial compression continued until the rock sample failed or reached an estimated axial strain of 5% based on the volume of injected distilled water.

3.2.4. Testing Control and Data Processing

The frac-n-flow testing system was controlled with a personal computer [60]. The control box was designed to carry out multiple functions and serve as an interface between the
electrical connections of the hardware components and a local computer. All pressure transducers, thermocouples, and pump readings were routed via the control box.

A digital oscilloscope was used in place of a data acquisition board (DAQ) with a high sampling rate. While confining pressure and pore pressure were controlled by pumps and BPRs, the temperature was established by heating in an air bath. The core-holder was placed inside the air bath with a temperature controller, which could be adjusted by the PC to a desired level. The oven element was switched on and off from a solid-state relay, which was controlled by the personal computer.

Data acquisition started when the system was ready. Data was saved in Microsoft Access Database format. The major items of the database include: (1) time, (2) pressure and fluid volume of each pump, (3) core-holder temperatures at the upstream and downstream, (4) oven interior temperatures, (5) rock sample inlet pressure, (6) rock sample outlet pressure, and (7) redundant differential pressure between the upstream and downstream of the rock sample. Data acquisition interval was 6 s.

Permeability was calculated using Darcy’s law with Equation (1) defined below [68]:

$$k = \frac{1000 \, Q \mu A}{L \Delta P}$$

where

- $k$—permeability, milli-Darcy;
- $Q$—injection rate, cm$^3$/s, (1 cm$^3$/s = 1 mL/s);
- $\Delta P$—differential pressure across the rock sample, atm, (1 atm = 14.7 psi);
- $\mu$—viscosity, cp, ($\mu_{DI \, \text{water}} \approx 1$ cp at the testing conditions in this paper);
- $A$—Cross-section area of rock sample, cm$^2$, (2.54 cm = 1 in); and
- $L$—Length of rock sample, cm, (2.54 cm = 1 in).

Data processing included creating stress-time curve and permeability-time curve. The stress-time curve was generated straight from the recorded data in the Microsoft Access Database.

The permeability-time curves were generated after the permeability at each time was calculated using Equation (1) with the differential pressure between the upstream and the downstream of the rock sample at each time.

4. Testing Results

4.1. Indiana Limestone Geology and Basic Petrophysical Properties

The Indiana limestone samples used in this study were cut from blocks that were originally quarried from the Salem Limestone Formation of the Mississippian System located in the central south of Indiana, USA [69]. This formation was formed in shallow marine environment about 300 million years ago in the Mississippian Epoch. It was classified into two types by color, Buff and Gray. However, their mineral compositions were quite similar, with over 97% calcium in both. The major difference was in silica (0.69% vs. 0.80%) and alumina (0.44% vs. 0.68%), which might be the reason for the lighter color in the Gray Indiana limestone [69]. According to this classification, the rock samples used in this study belonged to the Gray Indiana limestone.

Some basic petrophysical properties, i.e., density and porosity, were measured using ten cylindrical samples prepared per ISRM standards [63]. Table 1 showed the bulk density, saturated density, dry density and porosity of these samples.

4.2. Failure Mode Impact on Post-Failure Axial Stress and Induced Fractures

Following the above testing protocol, a series of frac-n-flow tests on Indiana limestone under confining pressures from 30 to 4000 psi were conducted. Figure 5 shows the re-assembled differential axial stress-time records of five tests, together with their post-failure samples [59]. It can be seen that confining pressure has a significant impact on the failure behavior of the rock sample and, the geometry and orientation of the induced fractures.
Table 1. Density and porosity of 10 Indiana limestone samples.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Bulk Density $g/cm^3$</th>
<th>Saturated Density $g/cm^3$</th>
<th>Dry Density $g/cm^3$</th>
<th>Porosity %</th>
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<td>2.410</td>
<td>2.270</td>
<td>14.000</td>
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<td>2.230</td>
<td>14.667</td>
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<tr>
<td>Std. Dev.</td>
<td>0.016</td>
<td>0.018</td>
<td>0.023</td>
<td>0.667</td>
</tr>
</tbody>
</table>

Figure 5. Failure modes of Indiana limestone under different confining pressure $\sigma_c$, at room temperature with constant axial compressive strain rate. (*Note: Confining pressures marked next to the fractured samples are accurate. Initial portions of the axial stress-time curves at high confining pressures were modified in reassembling all the curves into one figure.

Figure 5 showed that Indiana limestone failed in different modes under different confining pressures:

1. When the confining pressure was low ($\sigma_c \leq 100$ psi), the post-failure axial stress fell sharply. The sample experienced a sudden loss of strength. The rock fractured in a brittle mode. A single, straight, near vertical fracture was induced;
2. When the confining pressure was low to intermediate ($\sigma_c = 1000$ psi), the post-failure axial stress fell gradually. The rock experienced a gradual loss of strength. The rock fractured in a semi-brittle mode. A single, straight, near vertical fracture was induced, with a flattened toe;
3. When the confining pressure was intermediate to high ($\sigma_c = 2000$–3000 psi), there was no obvious peak or sign of failure in axial stress. The “post-failure” axial stress stayed almost constant or only slightly changed. The rock fails in a semi-ductile mode. A single, near horizontal fracture, i.e., almost perpendicular to the overburden—the maximum stress, was formed; and
(4) When the confining pressure was extremely high ($\sigma_c = 4000$ psi), there was no peak or sign of failure in axial stress. Instead, the “post-failure” axial stress continued increasing, slightly but steadily. The rock experienced a ductile mode of failure. No obvious single fracture was formed. Instead, two sets of conjugating “fracture” networks were formed, with an obtuse angle (i.e., larger than 90°) facing to overburden stress.

The fracturing mechanical behaviors described above were in line with those observed by other researchers in studies of pure solid/rock mechanics [43] and those for earthquake-related investigations [70].

It was seen that Indiana limestone experienced transition from brittle fracture to ductile failure when confining pressure varied from 30 to 4000 psi. While more tests and in-depth investigations are needed to more accurately define the brittle-ductile transition confining pressure, it can be expected that the variation in confining pressure would result in not only different fractures, but also different consequences in permeability change.

4.3. Failure Mode Impact on Permeability Change

The differences in the geometry and orientation of the induced fractures shown in Figure 5 greatly impacted the fracture conductivity of the post-fracture sample. Figure 6 showed the time history of differential axial stress and corresponding permeability.

![Figure 6](image-url)
Based on Figure 6, the following was summarized about the relations between the variation of axial stress (strength) and matrix permeability/fracture conductivity:

(1) When the fracture was created in brittle mode, the permeability continuously improved during the fracturing process (Figure 6a). Accompanying the sudden loss of rock strength, the matrix permeability/fracture conductivity jumped up rapidly. As the fracturing process continued in the post-failure phase, fracture conductivity continued to be enhanced;

(2) When the fracturing was semi-brittle, the matrix permeability significantly increased at the failure. However the total improvement was not as significant as when the sample failed in brittle mode because the matrix permeability experienced a bigger decrease at the initial phase of compression (Figure 6b);

(3) When the fracturing process was semi-ductile, the matrix permeability decreased monotonically, except for small ripples at the failing moments (Figure 6c–e). In these three cases, obvious decreases in axial stress are observed in a short period of time during the failure phase. With the exception of Case C (Figure 6c), which had a small up-ripple in fracture conductivity at the failing phase, the overall impact was that fracture conductivity continued the reduction tendency of matrix permeability and experienced monotonic decline; and

(4) When the rock failed in ductile mode, the matrix permeability decreased exponentially (Figure 6f). In this case, the matrix permeability was completely damaged to zero.

Analyses in this and the previous section show that confining pressure has a significant impact on the failure behavior of Indiana limestone. Different failure behavior controls the geometry and orientation of the induced fractures. The difference in induced fractures result in different changes in matrix permeability and fracture conductivity.

In addition, the fracturing process is very complicated. Axial stress curves reveal part of the dynamics. Fracturing-induced fracture geometry and orientations show additional sides of the process. However, the success criterion of HDMHF is to achieve the designed increase of fracture conductivity from its matrix permeability. Therefore, a quantitative parameter is needed to describe the overall change in permeability during the frac-n-flow testing; that is, how much has been changed (improved or damaged) from matrix permeability or fracture conductivity. For this reason, a frac-n-flow test-based folds of increase, FOI, is proposed.

### 4.4. Frac-n-Flow Test-Based Folds of Increase in Matrix Permeability

To quantify the matrix permeability change after the fracturing, a frac-n-flow test-based folds of increase, FOI, is defined as follows:

$$\text{FOI} = \frac{\text{Post Frac Permeability}}{\text{Initial Permeability}} - 1,$$

where

- \(\text{FOI}\) — test-based FOI in permeability induced by fracturing of the rock sample;
- \(\text{Initial Permeability}\) — rock matrix permeability at the beginning; and
- \(\text{Post Frac Permeability}\) — permeability after the rock is fractured or failed.

In Equation (2), the term “−1” was added to emphasize the “increase” from its origin value. Using Equation (2), corresponding FOI values of the six Indiana limestone frac-n-flow tested samples shown in Figure 6 are calculated. Table 2 presents the detailed results and comments.
Table 2. Failure mode impact on post-frac permeability and FOIₜ.

<table>
<thead>
<tr>
<th>Test</th>
<th>Pore Press.</th>
<th>Fail Mode</th>
<th>Perm., mD</th>
<th>Test-Based Folds of Increase (FOI)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>σₑ, psi</td>
<td>Pₑ, psi</td>
<td>Initial</td>
<td>Post Frac.</td>
<td></td>
</tr>
<tr>
<td>10IL08</td>
<td>100</td>
<td>14.5 Brittle</td>
<td>0.50</td>
<td>7.00</td>
<td>13.00</td>
</tr>
<tr>
<td>09IL06</td>
<td>300</td>
<td>14.5 Semi-brittle</td>
<td>0.62</td>
<td>0.67</td>
<td>0.08</td>
</tr>
<tr>
<td>08IL92</td>
<td>1500</td>
<td>14.5 Semi-ductile</td>
<td>3.96</td>
<td>2.41</td>
<td>−0.39</td>
</tr>
<tr>
<td>08IL95</td>
<td>2200</td>
<td>14.5 Semi-ductile</td>
<td>6.43</td>
<td>2.61</td>
<td>−0.59</td>
</tr>
<tr>
<td>08IL12</td>
<td>3000</td>
<td>14.5 Semi-ductile</td>
<td>5.00</td>
<td>1.44</td>
<td>−0.71</td>
</tr>
<tr>
<td>08IL11</td>
<td>4000</td>
<td>14.5 Ductile</td>
<td>0.55</td>
<td>0.00</td>
<td>−1.00</td>
</tr>
</tbody>
</table>

These computational results show that:

1. When the rock sample was fractured in brittle mode, its matrix permeability significantly improved. For instance, in Test 10IL08 (Figure 6a) the matrix permeability increased 13 times post fracturing, or 1300%.

2. When the rock sample was fractured in semi-brittle mode, its matrix permeability only slightly improved. For instance, in Test 09IL06 (Figure 6b) the matrix permeability increased by 0.08 time or 8% from intact matrix to post-fracture.

3. When the rock sample was fractured in semi-ductile mode, its matrix permeability was damaged to different degrees, instead of being improved. For instance, matrix permeability of Tests 08IL92, 08IL95 and 08IL12 (Figure 6c–e) decreased by 0.39, 0.59 and 0.71 time, i.e., 39%, 59% and 71%, respectively; and

4. When the rock sample failed in ductile mode, its matrix permeability was damaged completely. For instance, matrix permeability of Tests 08IL11 (Figure 6f) decreased 1.0 time, i.e., 100% lost.

The test-based folds of increase provided a simple and explicit indicator to quantify the effectiveness or risk of the upcoming HDMHF stimulation under the specific reservoir conditions. Compared to qualitative descriptions about the impact of fracturing mode on fracture conductivity via the shape of post-fracture axial stress curves, the induced geometry and orientation of the fractures, and the permeability curves, the test-based FOI is much more straightforward and useful.

5. Discussion

5.1. Brittle-Ductile Behavior under 3D Compression vs. 3D Extension

In HDMHF field operation, ideal fractures are initiated in the pad injection under pure 3-dimensional extension in which slick water or other HF fluids are injected from the wellbore to the reservoir rock body through the perforations to increase the pore pressure in reservoir rock until a breakdown occurs [22]. In the meantime, the total overburden and total horizontal stresses (including the stress shadow) are kept constant, as represented by points A and A’ in Figure 7, where shear stresses are zero.

In reality, more fractures were formed in mixed modes of 3-D extension and compression [71]. For this reason, the frac-n-flow testing technology was developed to cover the majority of the 3-D stress space, from part of the pure brittle domain, to the transition zone and ductile range (Figure 7). For convenience in testing operation, frac-n-flow testing was designed so that the rock is fractured under 3-D compression by maintaining constant outlet reservoir pore pressure while increasing overburden until failure.
Figure 7. Frac-n-flow testing range in 3-D effective stress space with failure envelop ABCDE and representative Mohr’s circles \( M_A \), \( M_B \), \( M_C \), \( M_D \) and \( M_E \) at failure. \( M_A \)—triaxial extension failure, \( M_{A0} \)—initial Mohr’s circle before injection; \( M_B \) and \( M_C \)—triaxial shear failure; \( M_D \)—triaxial non-hydrostatic compaction failure, and \( M_E \)—triaxial hydrostatic compaction failure. \( \sigma_1'_{\text{A0}}, \sigma_1'_{\text{A}} \) and \( \sigma_1'_{\text{C}} \)—axial effective stresses of Mohr’s circles \( M_{A0}, M_A \) and \( M_C \); \( \sigma_3'_{\text{A0}}, \sigma_3'_{\text{A}}, \text{ and } \sigma_3'_{\text{C}} \)—radial effective stresses of Mohr’s circles \( M_{A0}, M_A \) and \( M_C \). \( \sigma_{3\min} \)—minimum radial effective stress required to seal rock sample sleeve, 30 psi and 200 psi recommended for thin and thick sleeves, respectively.

When comparing Figure 5 with Figure 7, it is seen that results in the two figures support each other: (1) perfect brittle fracturing and perfect ductile failing only occur in a very small range of confining pressures; (2) semi-brittle fracturing and semi-ductile failing (transitional domain) are the dominant behavior; (3) shifting the transitional behaviors toward the brittle side using frac-n-flow testing results helps to reduce the number of non-conductive fractures.

5.2. Estimation of the Stress Shadow Effect

The extra stress due to the stress shadow effect is the key factor for the possible conversion of reservoir rock from brittle to ductile failure. Finding the extra horizontal stress is essential to the reliable prediction of the mechanical behavior under the altered in-situ stresses. Two methods are introduced to estimate the extra and/or the altered minimum horizontal stress.

5.2.1. Analytical Solution for the Stress Shadow Effect

Griffith’s work from 1920 [72] set up the foundation of modern fracture mechanics. Sneddon’s work in 1946 [73] established the theoretical foundation for modern hydraulic fracturing analysis. He presented the stress distribution and failure criterion about a crack in an elastic solid under internal pressure. Modern formulas for the stress shadow effect were all directly or indirectly derived based on Sneddon’s work, with clearly defined coordinates. The two of them can be used to calculate stress shadows. Soliman et al. [31] presented a contemporary version of stress shadows in 3-D space with a better illustration of the arbitrary orientation of the wellbore in the horizontal plane. A simplified 2-D version for stress shadows was available in a paper by Daneshy [42].

5.2.2. Field Observation of Altered Minimum Horizontal Stress

While there are many ways of measuring and estimating in-situ stresses in solid rocks e.g., [74,75], the one that is commonly used for minimum horizontal stress in the oil and gas industry is mini-frac (a.k.a. micro-frac, DFIT) [76,77]. While more precise determinations of minimum horizontal methods are available with more detailed data analysis, instantaneous shut-in pressure is often used as an approximation and much simpler to obtain [48].

In the ISRM-suggested method, ISIP is measured directly using pressure transducers at the packer [78]. In HDMHF operations, ISIP is calculated from wellhead recorded
treating pressure at the end of the pad injection and/or at the end of the flush injection [79] (Figure 8). In Figure 8, \( P_h \) is the hydrostatic pressure of slick/clean water at the depth of the stage, which can be determined from true vertical depth (TVD) and the water density [22]. In general, both ISIP\(_{Pad} \) and ISIP\(_{Flush} \) are available in the completion report. Alternatively, they can be calculated using the treating pressure record, the true vertical depth of the stage, and the water density as shown in Figure 8.

![Figure 8](image_url)

**Figure 8.** ISIP in pad and flush injection phases from surface treatment pressure records in multistage hydraulic fracturing. (Note: These curves are not from Wolfcamp cases.)

5.2.3. Case Study: Stress Shadows from Two Wolfcamp Wells

Instantaneous shut-in pressures of two Wolfcamp HDMHW wells, Well 1 with 37 stages and Well 2 with 24 stages, were collected from field completion reports. Using the ISIP recorded in pad (ISIP\(_{P} \)) and flush (ISIP\(_{F} \)) injections [22], stress shadow (Shd) of each stage \((n)\) is calculated following Equation (3):

\[
\text{Shd}_I(n) = \text{ISIP}_I(n) - \text{ISIP}_I(n - 1) \quad (I = P, F; n = 3, 4, \ldots, N)
\]

where \( P \)—Pad, \( F \)—Flush, and \( N \)—stages.

Calculated stress shadows of Well 1 and Well 2 are detailed in Table 3. Calculation of the stress shadow starts from Stage 3 because the normal plug-n-perf operation begins at Stage 2. Stages without ISIP data, an indicator of a problematic operation, are skipped.

The following are observed from the statistics of stress shadows in Wells 1 and 2 shown in Table 3:

1. Pad phase stress shadows varied from a minimum of -398 psi (stress release) to a maximum of +460 psi (stress increase);
2. Flush phase stress shadows varied from -2149 psi (stress release) to 1716 psi (stress increase);
3. The average stress shadows of all stages was 0.89 psi in the pad phase, and 1.36 psi in the flush phase, meaning the overall stress shadow is well constrained within the horizontal section;
4. The median stress shadow of all stages was -9 psi in the pad phase, and -19 psi in the flush phase. These relatively small values, compared to the maximum and minimum shadows, were consistent with the near-zero average; and
5. Statistics of stress shadows in Well 2 show similar characteristics as seen in Well 1, except a wider range in the pad phase (-1045 psi to +1141 psi) and a narrower range in the flush phase (-1233 psi to +1297 psi).
Table 3. Stress shadows of two Wolfcamp wells.

<table>
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<tr>
<th>Stage</th>
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<th></th>
<th>Well 2</th>
<th></th>
<th></th>
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<td>ISIPF psi</td>
<td>ISP psi</td>
<td>ShdF psi</td>
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<tr>
<td></td>
<td>Std Dev.</td>
<td>155 psi</td>
<td>585 psi</td>
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</tr>
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</table>
Figure 9 graphically illustrated the characteristics of the stress shadow for comparison. It is fair to conclude that flush injection, after a huge mass was injected in the slurry phase, amplified the stress shadow initiated in the pad phase. The near-zero average stress shadows in both wells, an indicator of effective containment of stress shadows within the horizontal sections, provide a sound confirmation of the ISIP data quality in the two wells.

![Figure 9: Stress shadows of two Wolfcamp wells.](image)

Reviewing field completion reports of these two wells show that stages of high stress shadow effects suffered screen-outs or other injection interruption during the stimulation treatment. These stages were also the ones that have low HF quality [22].

5.3. Frac-n-Flow Test-Based FOI vs. Field-Based FOI

The frac-n-flow test-based FOI, $\text{FOI}_t$, defined in Equation (2), is a revised version of the conventional, field-based FOI [10,58].

In conventional oil and gas reservoir hydraulic fracturing operations where a single fracture with two symmetric wings is created in the vertical well (Figure 10), “folds of increase (FOI)” has been widely used to quantify the success of the stimulation, and is defined as follows [58]:

$$\text{FOI} = \frac{\ln\left(\frac{r_e}{r_w}\right) + s}{\ln\left(\frac{r'_e}{r'_w}\right)}$$  (4)

where
- $s$—skin factor of the well pre-fracture;
- $r_e$—well drainage or reservoir radius,
- $r_w$—normal wellbore radius,
- $r'_w$—equivalent wellbore radius post-fracture, defined in Equation (5) as below,

$$r'_w = \frac{2}{\pi}x_f$$  (5)

where
- $x_f$—half length of the fracture, as shown in Figure 10.

Although bearing/sharing the same name, the two FOI’s are different in three major aspects:

1. They were defined for different purposes. Field-based FOI was mainly used to guide the selection of fracture length based on pre-fracture well characterization results [62]. Test-based FOI is defined to quantify how much is the matrix permeability improvement at post-fracture, serving as an indicator for improvement of pad-injection fracture;
(2) They were obtained in different ways. Field-based FOI was pre-determined based on the economic model for the success of HF treatment [9]. Test-based FOI is experimentally measured; and

(3) They have different ranges of value. Field-based FOI was in general positive, and has a bigger magnitude in tight formation (e.g., 10+) than in medium permeable rocks (e.g., ~2) [80]. In contrast, test-based FOI is positive for brittle and semi-brittle fracturing, and negative for ductile failure.

Figure 10. Equivalent wellbore radius, \( r_{e}^{'w} \), for drainage area in terms of fracture half length, \( x_{f} \), in conventional reservoir stimulation.

5.4. Impact of Pore Pressure and Reservoir Temperature

In the preliminary frac-n-flow tests, the effluent from the tested rock was released to the air, i.e., reservoir pressure was set to atmospheric pressure, i.e., 14.7 psi. If the real reservoir pressure is known, the outlet BPR of the frac-n-flow facility can be adjusted to the target value.

According to experiments on other rocks, pore pressure could have two opposite impacts on fracture behavior. For high permeability rock, increasing pore pressure would reduce effective confining pressure, which would increase the likelihood of brittle fracture [81,82]. On the other hand, the chemical impact of the fluids coupled with reservoir temperature might cause the rock to behave in ductile mode [83].

How pore pressure affects the fracture behavior of Indiana limestone is a topic for future investigation. In the field application, the frac-n-flow facility allows the application of pore pressure up to 10,000 psi, and fluids with different chemical compositions.

Similar to the difference between the regular reservoir pressure and the one used in the preliminary tests, reservoir temperature is usually higher than room temperature used in this paper. High temperature tends to change the rock toward behaving in ductile mode [43]. For instance it was observed that a rock sample fractured in brittle mode at room temperature of 20 °C (68 °F) may experience ductile mode at 300 °C (572 °F) [43]. In general, oil reservoir temperature is below 150 °C (302 °F), and gas reservoir temperature is below 260 °C (500 °F), beyond which the hydrocarbon is burnt [84]. From an application point of view, results observed under room temperature should cover most oil reservoir rocks. On the other hand, the core-holder and the oven system can support temperature up to 177 °C (350 °F) if needed [60].
Future experimental work will be focusing on more representative reservoir pressure and reservoir temperature.

5.5. Samples, Tests and Future Work

Some post-fracture samples fell apart when they were removed from the sleeve. Post-fracture samples shown in Figure 5 are for illustration purposes. They are not exactly the same as those in Figure 6 and Table 2.

From Table 2, it can be seen that the failure mode of Indiana limestone is very sensitive to confining pressure. An increase of 200 psi in confining pressure changed the failure from brittle to semi-brittle, resulting in a significant difference of permeability improvement in the un-propped fractures in these two cases. Similarly, an increase of 1200 psi in confining pressure changed the failure from semi-brittle to semi-ductile, resulting in the permeability changing from being (slightly) improved to being slightly damaged. Further increases in confining pressure changed the “fractured” Indiana limestone from being slightly damaged to damaged, severely damaged, and completely damaged (Table 2).

Future experimental work is required to investigate the impact of lithology under more realistic unconventional reservoir geomechanical conditions [85], with focus on Wolfcamp tight oil formation, Permian Basin. More work is also needed on optimal injection rates.

6. Conclusions

The Wolfcamp formation in the Permian Basin, USA was assessed as the largest tight oil field. Advanced well completion technology of combining horizontal drilling with multistage hydraulic fracturing is the dominant technology used in producing tight oil from Wolfcamp formation. By design, each fractured cluster and stage is to be created in brittle mode and conductive. Production log data indicated that many clusters are not-flowing; and many HF stages are performing below the nominal average production rate. These not-flowing clusters were likely created in non-brittle mode because of the stress shadow effect caused by injecting a large amount of masses in neighboring stages. The stress shadow effect imposed extra horizontal stress from the current stage onto the rock of the next stage. While the extra horizontal stress due to stress shadow effect can be analytically calculated or assessed from field observations, ensuring the new stage to be fractured in a brittle mode under the impact of the extra horizontal stress is critical. Frac-n-flow testing offers a quick solution for operators to check if the next stage treatment would be a brittle fracturing using instantaneous shut-in pressure of the current stage. Two Wolfcamp cases show that stress shadows could be more than 1000 psi in some stages. Results of the frac-n-flow testing indicate that such a stress shadow could have converted an Indiana limestone from being stimulated, with permeability increasing by 1300%, to being damaged, with permeability decreasing by 39%. Completion reports confirmed that stages with high stress shadows encountered screen-outs and other injection-related difficulties that could have been avoided by fine-tuning the design to keep the rock in the brittle domain if frac-n-flow testing were performed.

Funding: This research was funded by The University of Texas System through the UT STARs program (Project P5011236-23).

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Data used in this paper are available upon request by email.

Acknowledgments: Efforts in collecting field data by an undergraduate research assistant were supported by the University of Texas Permian Basin. Alberto Valdez-Nunez and Hedan Zeng helped proofread the manuscript. The author thanks all the help and support.

Conflicts of Interest: The author declares no conflict of interest.
Abbreviations and Nomenclatures

2-D two dimension(al)
3-D three dimension(al)
BPR back pressure regulator
DFIT diagnostic fracture injection test
DOE Department of Energy (US)
FOI folds of increase
FOI\textsubscript{t} test-based folds of increase
frac-n-flow fracturing-and-flowing
HD horizontal drilling (drilled)
HDMHF horizontal drilling and multistage hydraulic fracturing
HF hydraulic fracturing
ID inner diameter
ISIP instantaneous shut-in pressure
ISIP\textsubscript{p}, ISIP\textsubscript{f} flush instantaneous shut-in pressure at flush injection phase, psi
ISIP\textsubscript{p}, ISIP\textsubscript{pad} instantaneous shut-in pressure at pad injection phase, psi
ISRM International Society for Rock Mechanics
N, n number of stage
OD outside diameter
P\textsubscript{h} hydrostatic pressure, psi
plug-n-perf plug and perforation
P\textsubscript{r} reservoir pressure, psi
R&D research and development
r\textsubscript{e} reservoir radius (well drainage), ft
r\textsubscript{w} normal wellbore radius, ft
r\textsubscript{w}' equivalent post-fracture wellbore radius, ft
s skin factor
shd stress shadow, psi
SPE Society of Petroleum Engineers
Spf shots per foot (holes per foot)
Std Dev. Standard Deviation
TVD true vertical depth
USSR the Union of Soviet Socialist Republics
\sigma'\textsubscript{1} axial effective stress, psi
\sigma'\textsubscript{3} radial effective stress, psi
\sigma'\textsubscript{3\textsubscript{min}} minimum confining pressure to seal the sleeve, psi

Appendix A. Calculation of Injection Rate for Axial Loading Pump

<table>
<thead>
<tr>
<th>Item</th>
<th>Formula</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Axial strain rate 1, \varepsilon\textsubscript{a1}</td>
<td>Given</td>
<td>1.0 \times 10^{-4}</td>
<td>1/s</td>
</tr>
<tr>
<td>Axial strain rate 2, \varepsilon\textsubscript{a2}</td>
<td>Given</td>
<td>1.0 \times 10^{-6}</td>
<td>1/s</td>
</tr>
<tr>
<td>Sample length, L</td>
<td>Given</td>
<td>2.000</td>
<td>in</td>
</tr>
<tr>
<td>Sample diameter, D</td>
<td>Given</td>
<td>1.000</td>
<td>in</td>
</tr>
<tr>
<td>Axial pressure chamber OD, OD</td>
<td>Given</td>
<td>3.500</td>
<td>in</td>
</tr>
<tr>
<td>Axial pressure chamber ID, ID</td>
<td>Given</td>
<td>2.375</td>
<td>in</td>
</tr>
<tr>
<td>Axial chamber loading area, A</td>
<td>\frac{1}{4} \times 3.14 \times (OD^2 - ID^2)</td>
<td>5.188</td>
<td>in^2</td>
</tr>
<tr>
<td>Sample axial deform rate 1, L\textsubscript{a1}</td>
<td>L \times \varepsilon\textsubscript{a1}</td>
<td>2.000 \times 10^{-4}</td>
<td>in/s</td>
</tr>
<tr>
<td>Sample axial deform rate 2, L\textsubscript{a2}</td>
<td>L \times \varepsilon\textsubscript{a2}</td>
<td>2.000 \times 10^{-6}</td>
<td>in/s</td>
</tr>
<tr>
<td>Axial injection rate 1, Q\textsubscript{1}</td>
<td>A \times L\textsubscript{a1}</td>
<td>1.038 \times 10^{-3}</td>
<td>in^3/s</td>
</tr>
<tr>
<td>Axial injection rate 2, Q\textsubscript{2}</td>
<td>A \times L\textsubscript{a2}</td>
<td>1.038 \times 10^{-5}</td>
<td>in^3/s</td>
</tr>
<tr>
<td>Axial inj. rate 1 in mL/min, Q\textsubscript{1\textsubscript{mL/min}}</td>
<td>2.54^3 \times Q\textsubscript{1} \times 60</td>
<td>1.020</td>
<td>mL/min</td>
</tr>
<tr>
<td>Axial inj. rate 2 in mL/min, Q\textsubscript{2\textsubscript{mL/min}}</td>
<td>2.54^3 \times Q\textsubscript{2} \times 60</td>
<td>0.010</td>
<td>mL/min</td>
</tr>
</tbody>
</table>


81. Noël, C.; Passelègue, F.X.; Violay, M. Brittle faulting of ductile rock induced by pore fluid pressure build-up. J. Geophys. Res. Solid Earth 2021, 126, e2020JB021331. [CrossRef]
