Chapter 2
Modeling Production from Shale

Mitchell[1] and his team of geologists and engineers began working on the shale challenge in 1981, trying different combinations of processes and technologies before ultimately succeeding in 1997 with the use of a "slick-water" frac that made Barnett Shale economical to develop and in turn changed the future of the US natural gas industry [7]. Continuing on Mitchell's success progress followed a path that included horizontal wells, multi-cluster, multistage, hydraulic fracturing of horizontal wells and pad drilling, and the rest is history.

The success in overcoming the technical difficulties to unlock the huge potentials of oil and gas production from shale is very much tied to an integration of long lateral horizontal drilling, coupled with multistage, multi-cluster hydraulic fracturing that initiates new fractures while activating a system of natural fracture networks in shale. This system of highly permeable conduits introduces the highly pressurized shale formation to a lower pressure, causing a pressure gradient that triggers the flow of oil and natural gas to the surface at very high rates, albeit, with steep decline. Looking at the list of most important technological innovations that have made production from shale possible one can see the challenges that are associated with understanding and modeling and eventually optimizing the production of hydrocarbon from shale. So let us examine what are the realities that we are aware of, and how we go about modeling them in our traditional techniques.

First and foremost is the fact that shale is naturally fractured. The natural fractures are mostly sealed by material that have precipitated in them and/or reside in the natural fracture as a result of chemical reactions of the material present in the fractures throughout the geologic time. The only way we can detect presence of the system of natural fractures in the area being developed is by detecting (using logs, video, etc.) the presence of the intersection of these natural fractures with the wellbore. Even when we are successful in detecting the presence of natural fractures, we only have indications about their width (openings) and direction. We

[1]Mitchell Energy and Development. He sold his company to Devon Energy in 2002 in a deal worth $3.5 Billion.

S.D. Mohaghegh, *Shale Analytics*, DOI 10.1007/978-3-319-48753-3_2

cannot tell how far beyond the wellbore they extend. The rest is actually (educated) guess work. To model this system of natural fracture networks to be used in our numerical simulation models (i.e., when we actually bother to be this detailed in our analysis), we "estimate" parameters such as direction and density of the major and minor fracture networks and generate them stochastically. In other words, there is not much that we can actually measure and what we model has little to do with realities that can be measured. Once the presence of the system of the natural fracture networks is modeled, then it can be made to be used during the flow modeling.

The reality is that while the system of natural fracture networks is under extensive pressure and stress, it still presents a network of sealed conduits that is vulnerable to failure (opening) prior to the matrix of the rock, once an external force finds its way into the rock to counter the overburden pressure and the in situ stresses. This breaking of the rock (fracking) is caused by hydraulic pressure exerted during the hydraulic fracturing. During hydraulic fracturing large amount of "slick water" (or other fracking fluids) is injected into the rock at pressures that is above the natural in situ pressure in order to break the rock. The crack that is initiated in the rock is extended by continuing the injection of the fluid. The rock will break at its weakest points that are usually the system of natural fracture networks along with other places in the fabric of the rock where there are structural vulnerabilities.

All previous (theoretical and modeling) work on hydraulic fracturing is concentrated on propagation of hydraulic fractures in nonnaturally fractured formations, specifically when the hydraulic fracturing is to be modeled (coupled) in a numerical reservoir simulation that will be used to model fluid flow to the wellbore and eventually to the surface. As such, all such models assume a so-called a "penny-shaped" (or modified penny shaped) hydraulic fracture propagation into the formation. Figure 2.1 shows examples of traditional modeling of hydraulic fractures. Well, although we may not know what is the shape of the hydraulic fracture propagation in a shale formation, it would be very hard to find a reservoir engineer or completion engineer that would be naïve enough to think that hydraulic fractures in shale is anything remotely like a penny (Fig. 2.1). In other words, although the shape and the propagation of the hydraulic fractures in shale are unknown, it definitely is not "penny-shaped".

These gross simplifying assumptions that are used during the modeling of hydraulic fracturing in shale demonstrate that we have been modeling shale using a "Pre-Shale" technology. Coining the phrase "Pre-Shale" technology aims to emphasize the combination of technologies that are used today in order to address the reservoir and production modeling of shale assets. In essence, almost all of the technologies that are used today for modeling and analyses of hydrocarbon production from shale were developed to address issues that had originally nothing to do with shale. As the "shale boom" started to emerge these technologies are revisited and modified in order to find their application in shale. For example, the way we numerically model fluid flow in, and production from, shale is essentially a combination of what our industry has devised to better understand, address, and

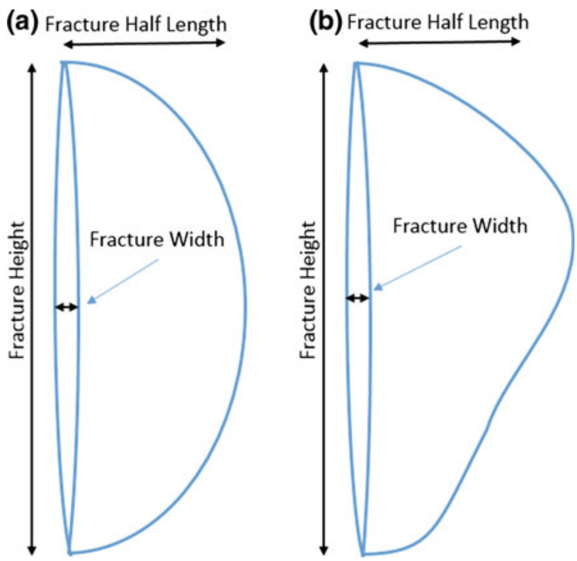

Fig. 2.1 Traditional penny-shaped model of hydraulic fracturing **a** nonmodified, **b** shape of the fracture is modified due to nonuniform stress

model carbonate (Discrete Fracture Networks) and coalbed methane (diffusion of gas through the matrix via concentration gradient). This has given rise to today's numerical simulation formulation for shale that can be summarized as "Carbonate + CBM = Shale." Technologies such as wellbore image logs and microseismic are not much different and can fit this definition as well.

Most of the analytical solutions to the flow in the porous media as well as other simplified solutions may also be included in the "Pre-Shale" technology category. Technologies such as Decline Curve Analysis, Rate Transient Analysis, Volumetric calculation of reserves and material balance calculations may be categorized as the "Pre-Shale" technologies. Of course some of these techniques are fundamental enough to find application to shale (like material balance) but their full applicability is still a function of better understanding of the storage and flow mechanisms in shale and that is yet to be solidified.

2.1 Reservoir Modeling of Shale

Since there seems to be plenty of "Unknown Unknowns" and a certain number of "Known Unknowns" when it comes to storage and fluid flow in shale, it may not be a bad idea to start with some "Known Facts" and see if we can come up with some general ideas that enjoy wide acceptance among the professionals in the industry. ***Fact Number One*** is that "Shale is Naturally Fractured." This is a fact that hardly anyone will dispute. A quick survey of the papers published on the reservoir simulation and molding of shale (or any other analysis regarding hydrocarbon production from shale) shows that almost everyone starts with the premise that shale is naturally fractured. Please note that at this point in the book the nature, characteristics, and distribution of the natural fractures in shale are not being considered. Just the fact that shale contains a vast network of natural fractures is the essence of the Fact Number One.

Fact Number Two that seems to have been widely accepted is that "Hydraulic (induced) Fractures Will Open (activate) Existing Natural Fractures." Many recent modeling techniques (few of them being cited here) start with such a premise in order to map the complexities of induced fracture in shale. Even if we believe that hydraulic fracture will create new fractures in shale (which seems to be a fact as well), it would be very hard to argue against the notion that it can and will open existing natural fractures in shale. This is due to the fact that existing natural fractures provide a path of least resistance to the pressure that is imposed on the shale during the process of hydraulically fracturing the rock.

Unfortunately, it seems that here is where the "Known Facts" that are widely accepted among most scientists and engineers, comes to an end. Almost every other notion, idea, or belief, is faced with some sort of a dispute by some along with reasonably strong arguments "for" and "against" them.

2.2 System of Natural Fracture Networks

Reservoir development is impacted by natural fractures in three ways. First, natural fractures are planes of weakness that may control hydraulic fracture propagation. Second, high pressures from the hydraulic fracture treatment may cause slip on natural fractures that increases their conductivity. Third, natural fractures that were conductive prior to stimulation may affect the shape and extent of a well's drainage volume [8].

Natural fractures are Digenetic fractures and/or tectonic fractures. Natural fractures are mechanical breaks in rocks, which form in nature, in response to lithostatic, tectonic and thermal stress, and high fluid pressure. They occur in a variety of scales and with high degree of heterogeneity [9].

The most common technique for modeling the System of Natural Fracture Networks (SNFN) is to generate them stochastically. The common practice in carbonate and some clastic rocks is to use Borehole Image Logs in order to characterize the SNFN at the wellbore level knowing that such characterization is only valid a few inches away from the wellbore. These estimates of SNFN characteristics are then used for the stochastic generation of the discrete fracture networks throughout the reservoir. Parameters such as mean and standard deviation of fracture orientation, form of fracture length distribution, averages for fracture length, aperture (width), density of center points and relative frequency of terminations are among the characteristics that are needed (guessed or estimated) so that the stochastic algorithms can generate a given System of Natural Fracture Networks.

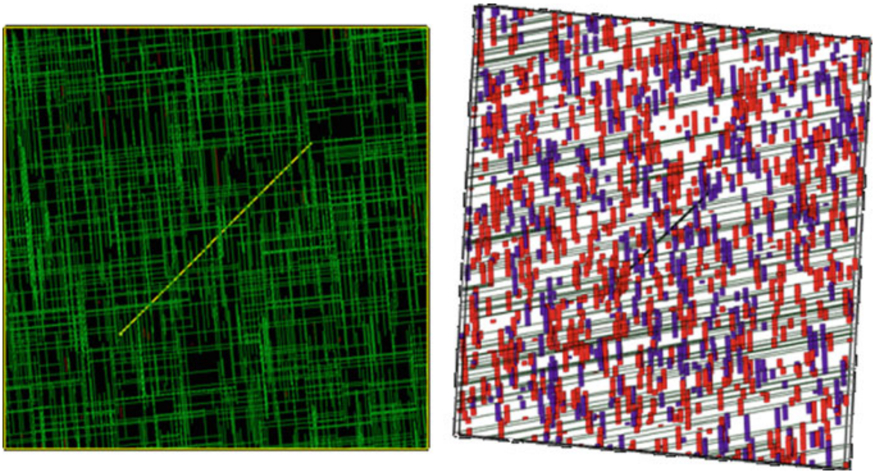

Fig. 2.2 System of Natural Fractures Networks (SNFN) generated using stochastic techniques

Sometimes such exercise is performed in multiple sets, changing the aforementioned parameters in order to generate multiple sets of networks to resemble some of the observed characteristics in the outcrops. Figure 2.2 displays typical networks of natural fractures that are generated using stochastic techniques. For the purposes of this chapter, we name this type of generation of natural fracture networks, the "Conventional SNFN" to distinguish its characteristics, and the consequences of its use and implementation, from the potential SNFN that we postulate happening in shale as "Shale SNFN."

System of Natural Fracture Networks models have many advantages over conventional Dual Porosity (DP) approaches, especially in heterogeneous reservoirs where the dominant flow mechanism is through the network of fractures rather than the reservoir matrix. The SNFN approach is based on the stochastic modeling concept and therefore, every realization of the System of Natural Fracture Networks will produce different results. As such, SNFN-type modeling is not a direct competitor to DP reservoir modeling. Rather, it provides an additional insight into the potential variability of production histories [10].

Idea of SNFN is not new. It has been around for decades. Carbonate rocks and some clastic rocks are known to have networks of natural fractures. Developing algorithms and techniques to stochastically generate SNFN and then couple them with reservoir simulation models was common practice before the so called "shale revolution." Most recently a number of investigators have attempted to model production from shale by making effective use of the SNFN and its interaction with the induced fractures.

Li et al. [11] proposed a numerical model that integrates turbulent flow, rock stress response, interactions of hydraulic fracture propagation with natural fractures, and influence of natural fractures on formation's Young's modulus. They postulated

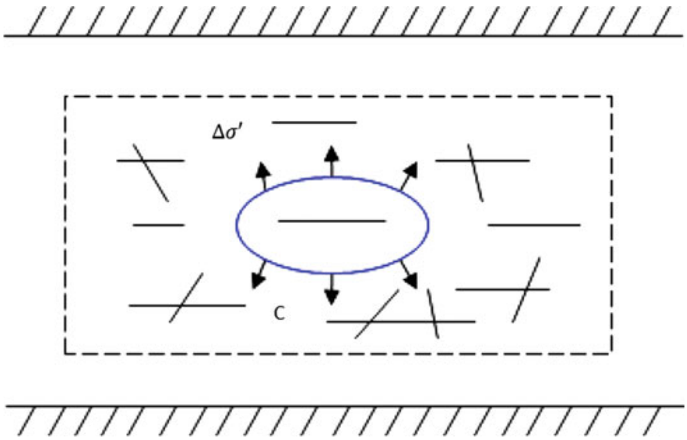

Fig. 2.3 Preexisting Natural Fracture distribution in shale [11]

that the preexisting natural fractures in shale formation complicate hydraulic fracture propagation process and alter its Young's modulus. Their preliminary numerical results illustrate the significant differences in modeling hydraulic fracture propagation in comparison with current models that assume laminar flow in hydraulic fracture process. They conclude that length and density of natural fracture have significant impact on formation Young's modulus, and interactions between hydraulic fracture and natural fractures create complex fracture network.

Figures 2.3 and 2.4 [11] clearly show the SNFN used in the literature that we have named Conventional SNFN. The impact of the nature and distribution of the SNFN in the overall performance of the well and specifically in the propagation of the hydraulic fracture in shale has been emphasized in the literature.

Other authors [12] have presented simulation results from complex fracture models that show stress anisotropy, natural fractures, and interfacial friction play critical roles in creating fracture network complexity. They emphasize that decreasing stress anisotropy or interfacial friction can change the induced fracture geometry from a bi-wing fracture to a complex fracture network for the same natural fractures. The results presented illustrate the importance of rock fabrics and stresses on fracture complexity in unconventional reservoirs.

Figure 2.2 [12] shows that the natural fracture network that they have considered in their development is very much the same as mentioned in other papers when it comes to propagation of hydraulic fractures in shale and its interaction with the natural fractures, a system of natural fractures that we have chosen to call the Conventional SNFN.

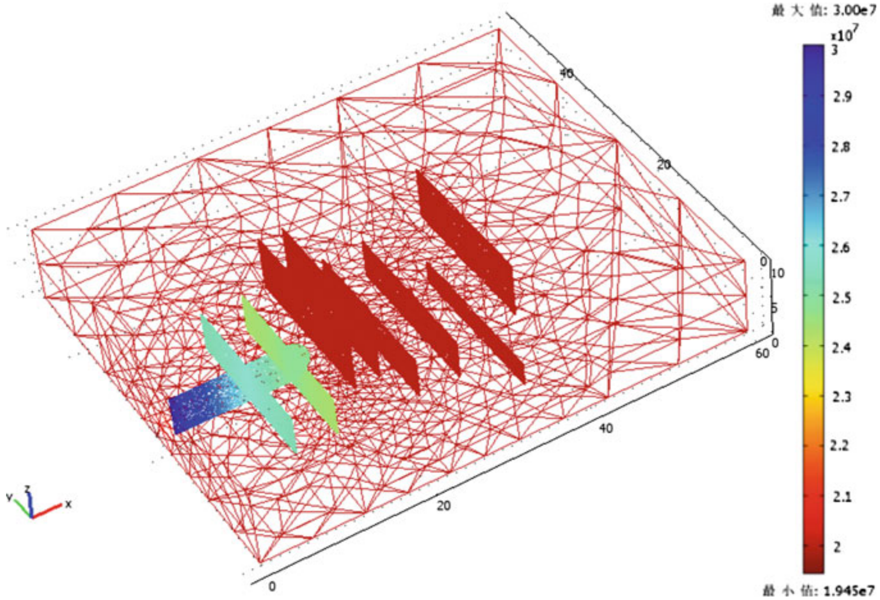

Fig. 2.4 Hydraulic Fracture propagation distribution at time-step 20 [11]

Recent petroleum engineering literature is full of similar examples. They have two common themes

1. The preexisting system of natural fracture networks in shale formations plays a dominant role in determining the propagation path of the induced hydraulic fracture and consequently determines the degree of productivity of hydrocarbon producing shale wells,
2. Conventional SNFN is the only form of network of natural fractures that is considered in shale formations.

While the first point is well established and commonly accepted among most of the engineers and scientists, and is accepted by the author, the second point should not be taken so lightly. Author would like to propose an alternative to this commonly held belief that the network of natural fractures in shale can be categorized as what we have called in this manuscript to be the Conventional SNFN.

2.3 System of Natural Fracture Networks in Shale

Above examples demonstrate that although different scientists and researchers attempted to find better and more efficient ways to address the propagation of hydraulic fractures in shale, all of them have one thing in common. They all use the

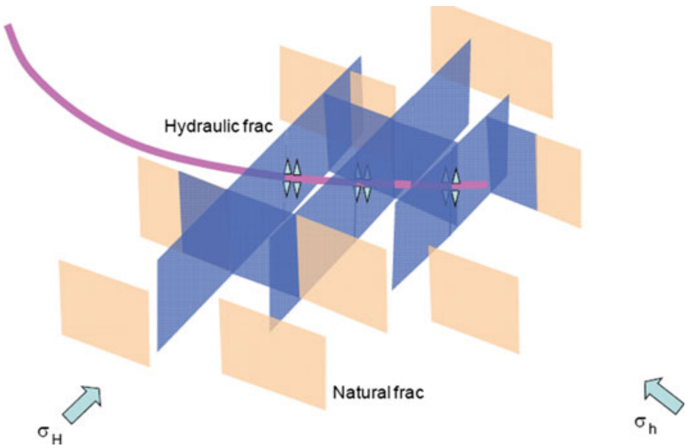

Fig. 2.5 Diagram of hydraulic fracture network and preexisting natural fractures [12]

legacy definition and description of SNFN. As was shown above, this legacy description includes a network of natural fractures that exist in the fabric (matrix) of the porous medium and it is mainly characterized by random occurrences, length, aperture, and intersections and is described by J1 and J2 type fractures (Figs. 2.2, 2.3, 2.4 and 2.5).

But what if this legacy definition and description of network of natural fracture that is essentially borrowed from carbonate rocks and is an indication of our lack of understanding and ability to visualize and measure them in the matrix, is not applicable to shale? What if the network of natural fractures in shale has a completely and fundamentally different nature, structure, characteristics, and distribution than what is commonly used in all of our (commercial, academic, and in-house) models?

2.4 A New Hypothesis on Natural Fractures in Shale

What is the general shape and structure of natural fractures in Shale? Is it closer to a stochastically generated set of natural fracture with random shapes that has been used for carbonates (and sometimes clastic) formations? Or is it more like a well-structured and well-behaved network of natural fracture that have a laminar, plate-like form, examples of which can be seen in the outcrops such as those shown in the Fig. 2.6

Shale is defined as a fine-grained sedimentary rock that forms from the compaction of silt and clay-size mineral particles that we commonly call “mud.” This

Fig. 2.6 Examples of natural fractures in shale that is clearly observable from the outcrops

composition places shale in a category of sedimentary rocks known as "mud-stones." Shale is distinguished from other mudstones because it is fissile and laminated. "Laminated" means that the rock is made up of many thin layers. "Fissile" means that the rock readily splits into thin pieces along the laminations.[2]

If such definitions of the nature of shale is accepted and if the character of network of natural fractures in shale is as it is observed in the outcrops and depicted in the diagram of Fig. 2.7, then many questions must be asked, some of which are

(a) How would such characteristics of the network of natural fractures impact the propagation of the induced hydraulic fractures in shale?
(b) How would the production characteristics of shale wells are impacted by this potentially new and completely different way of propagation of the induced hydraulic fractures (as compared to how we model them today).
(c) What are the consequences of these characteristics of natural fractures on the short and long-term production from shale?
(d) How would this impact our current models? And finally,
(e) What can it tell us about the new models that need to be developed?

Obviously, there are many more questions that can be asked. Here we postulate that such definition of the system of natural fractures in shale is similar to those shown in Figs. 2.6 and 2.7. We then try to hypothesize the consequences of such assumptions.

[2]http://geology.com/rocks/shale.shtml.

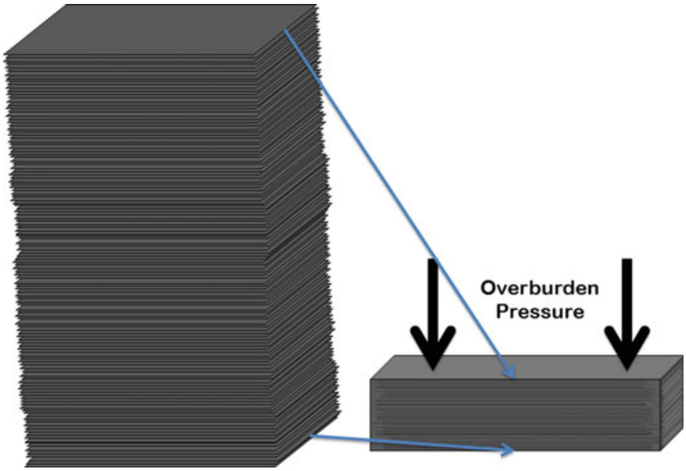

Fig. 2.7 Schematic of the nature of the SNFN in shale outcrops and its potential shape when subjected to overburden pressure

2.5 Consequences of Shale SNFN

To address some of the questions posed above, one needs to observe that if the natural fracture network in shale is indeed anything like what is suggested in this chapter then we may have to go back to the drawing board and start the development of our shale models from scratch. Given the thin nature of the plates one must consider the density of the plates, or density of natural fractures per inch of formation thickness. While fluid flow in matrix or fabric of the shale remains the territory of diffusion of gas through solids, modeling of the flow through propped open natural fractures and interaction between natural fractures and the rock matrix may no longer be efficiently modeled as flow through porous media. May be flow through parallel plates coupled with diffusion is a more robust manner of modeling.

On the other hand, this new way of thinking about Shale SNFN may enable us to provide a reasonable answer to the large amount of hydrocarbon that is produced upon hydraulically fracturing the shale and can substitute the unrealistic and in some cases even humorous notion that the hydraulic fractures in shale are penny shaped (may be somewhat deformed) and can be modeled in the same manner that we used to model the hydraulic fracture propagation in carbonate and clastic formations.

Previously we mentioned that it is widely accepted that (a) shale is naturally fractured, and (b) the induced hydraulic fracture tend to first open the existing natural fracture. If the two above mentioned facts are accepted, then the natural next step may be to discuss the shape, the characteristics, and the distribution of the natural fracture networks in shale.

Almost all the published papers assume that the natural fracture networks are stochastic in nature and therefore must be modeled as such. Furthermore, these assumptions inherently include only vertical fractures in the form of J1 and J2, etc. They follow by identifying a series of statistical characteristics that will be used in a variety of algorithms that will generate natural fracture networks. Once generated, the natural fracture networks are treated in many different ways in order to contribute to the reservoir modeling of shale assets. Effect and impact of these natural fracture networks are approximated analytically in some studies, while they are solved using an elaborate system of equations in other studies. Some have opted to use the natural fracture networks in order to identify the complex growth of hydraulic fractures. The authors observe that in all these cases the shape, the characteristics, and the distribution of the natural fracture networks in shale are common and include only vertical fractures in the form of J1 and J2, etc. The inevitable question is: "are we using these types of shape, characteristics, and distribution because we are able to readily model them in our reservoir simulation codes, or that we have coded such shapes, characteristics, and the distributions, because this is what we believe is happening"?

We start by posing a set of questions

1. What is the most probable shape for the network of natural fractures in shale?
2. When we hydraulically fracture shale, is it possible that we are opening the existing horizontal and plate-like natural fractures, before, or during creation of other fractures ?[3]
3. What are the consequences of opening these well-behaved, horizontal plate-like natural fractures in shale during the hydraulic fracturing?
4. Are the existing simulators adequate for modeling the production from shale wells, if indeed the above hypotheses are correct?

The answer may be revealed if the question is asked in a different fashion. If the dominant natural fracture networks in shale are horizontal (instead of vertical as shown in Fig. 2.2, 2.3, 2.4 and 2.5) can our current reservoir simulation models handle them? Imagine a vast, massive network of horizontal natural fractures with solid plates no thicker than 1–2 mm (essentially a stack of cards) that can be opened upon hydraulic fracturing and can contribute to flow.

This type of model provides a very large porosity that initially (prior to hydraulic fracturing) is not necessarily connected (or is only connected locally and in limited scope). This vast network of natural fractures is opened and become connected upon hydraulic fracturing which then creates substantial permeability. Furthermore, the very thin nature of the solid (very tight) rock plates that are themselves easier to crack upon losing their original calcite support (though giving rise to potential J1, J2 type fractures) are the medium for possible diffusion of trapped hydrocarbon

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[3]This notion, of course, has the obvious issue with the magnitude of stresses at different direction. It seems that the overburden pressure (vertical stress) is not the minimum stress. Therefore, maybe, the horizontal/laminated fractures are not the first set of fractures that open. However, totally dismissing theses natural fractures seem to be an oversight that needs to be addressed.

(in addition of the hydrocarbon in the dominant horizontal natural fracture networks that are released upon opening) to support continued production.

2.6 "Hard Data" Versus "Soft Data"

As we move forward with explaining use of traditional technologies in modeling reservoir and production from shale it is important to explain and distinguish between "Hard Data" and "Soft Data." This is necessary since in this book we will demonstrate that Shale Analytics is a technology that uses "Hard Data" to model production from shale while most of the traditional technologies use "Soft Data."

"Hard Data" refers to field measurements. This is the data that can readily be, and usually is, measured during the operation. For example, in hydraulic fracturing variables such as fluid type and amount, proppant type and amount, injection, breakdown and closure pressure, and injection rates are considered to be "Hard Data." In most shale assets "Hard Data" associated with hydraulic fracturing is measured and recorded in reasonable detail and are usually available. Table 2.1 shows a partial list of "Hard Data" that is collected during hydraulic fracturing as well as a list of "Soft Data" that is used by reservoir engineers and modelers.

In the context of hydraulic fracturing of shale wells, "Soft Data" refer to variables that are interpreted, estimated, or guessed. Parameters such as hydraulic fracture half length, height, width and conductivity cannot be directly measured. Even when software applications for modeling of hydraulic fractures are used to estimate these parameters, the gross limiting and simplifying assumptions that are made, such as well-behaved penny like double wing fractures (see Fig. 2.1), renders the utilization of "Soft Data" in design and optimization of frac jobs irrelevant.

Table 2.1 Examples of hard versus soft data for hydraulic fracture characteristics

Hard Data	Soft Data
Fluid types	Hydraulic Fracture Half Length
Fluid amounts (bbls)	Hydraulic Fracture Width
Pad volume (bbls)	Hydraulic Fracture Height
Slurry volume (bbls)	Hydraulic Fracture conductivity
Proppant types	Stimulated Reservoir Volume: • SRV height • SRV Width • SRV length • SRV Permeability
Proppant amounts (lbs)	
Mesh size	
Proppant Conc. (Ramp Slope)	
Max. Proppant Concentration	
Injection Rate	
Injection Pressure: • Average Inj. Pressure • Breakdown Pressure • ISIP • Closure Pressure	

Another variable that is commonly used in the modeling of hydraulic fractures in shale is Stimulated Reservoir Volume (SRV). SRV is also “Soft Data” since its value cannot be directly measured. SRV is mainly used as a set of tweaking parameters (dimensions of the Stimulated Reservoir Volume as well as the permeability value or values that are assigned to different parts of the stimulated volume) to assist reservoir modelers in the history matching process.

2.7 Current State of Reservoir Simulation and Modeling of Shale

Since reservoir simulation and modeling of shale formations became a task to be tackled by reservoir engineers, the only available option, and therefore the solution that has been presented, has been a modified version of existing simulation models. These modifications are made so that the existing simulators can mimic the storage and flow characteristics in shale. Although our information regarding the required characteristics of a shale-specific simulation models were quite limited, the possible choices in using the existing simulators meant the inclusion of a combination of algorithms such as discrete fracture networks, dual porosity and stress dependent permeability, as well as adding concentration driven Fickian flow and coupling it with Langmuir’s isotherms. However, our inability to model hydraulic fractures and its nonuniform propagation in a naturally fractured system did not stop us from going forward with the business of modeling.

In other words, our choices, especially at the start of this process, were quite limited. Probably the main reason was that the industry was, and still is, in need of tools that can help in making the best possible decision during the asset development process. Although some interesting work has been performed, especially in the area of transport at the micro-pore level, they have not yet found their way into the popular simulation models that are currently being used by the industry.

The current state of reservoir modeling technology for shale uses the lessons learned from modeling naturally fractured carbonate reservoirs and those from coalbed methane (CBM) reservoirs in order to achieve its objectives. The combination of flow through double porosity, naturally fractured carbonate formation, and concentration gradient driven diffusion that is governed by Fick’s law integrated with Langmuir isotherms that controls the desorption of methane into the natural fractures, has become the cornerstone of reservoir modeling in shale.

Most of the competent and experienced reservoir engineers and modelers that the author has communicated with regarding this issue recognize the shortcomings of this approach when applied to shale. Nevertheless, all agree that this is the best option that is currently available when we attempt to numerically model fluid flow through shale. While most of the recent reservoir simulations and modeling of shale have the above approach in common, they usually vary on how they handle the massive multi-cluster, multistage hydraulic fractures that are the main reason for economic oil and gas production from shale reservoirs.

The presence of massive multi-cluster, multistage hydraulic fractures only makes the reservoir modeling of shale formation more complicated and the use of current numerical models even less beneficial. Since hydraulic fractures are the main reason for economic production from shale, modeling their behavior and their interaction with the rock fabric, becomes one of the most important aspects of modeling storage and flow in shale formations. Therefore, the relevant question that should be asked is: How do the current numerical reservoir simulation models handle these massive multi-cluster, multistage hydraulic fractures?

When the dust settles and all the different flavors of handling multi-cluster, multistage hydraulic fractures in reservoir modeling are reviewed, all the existing approaches can be ultimately divided into two distinct groups. The first is the Explicit Hydraulic Fracture (EHF) modeling method, and the second is known as Stimulated Reservoir Volume (SRV).[4] We will briefly discuss these techniques later in this chapter.

Before examining some details of the EHF and SRV techniques, it must be mentioned that there are a couple of other techniques that have been used in order to model and forecast production from shale wells. These are Decline Curve Analysis (DCA) and Rate Transient Analysis (RTA). These two methods are quite popular among practicing engineers for their ease of understanding and use.

2.7.1 Decline Curve Analysis

Decline Curve Analysis (DCA) is a well-known and popular technology in our industry. The popularity of DCA is due to its ease of use (and in many cases it can be, and is, easily misused). When applied to shale wells DCA has many shortcomings. Several authors [6, 13–17] have come up with interesting techniques to overcome some of the well-known shortcomings of DCA, but nevertheless, many facts remain that make the use of Decline Curve Analysis suboptimal.

One of the major criticisms of Decline Curve Analysis is its lack of sensitivity to major physical phenomena in shale wells that has to do with the fluid flow, the hydraulic fracture, and the reservoir characteristics. In cases like Marcellus and Utica shale reservoirs where short periods of production are available, the use of Decline curve Analysis becomes increasingly problematic.

When it comes to hydrocarbon production from shale, there is a major flaw in the application of decline curve analysis, whether it be the ARP's original formulation or other flavors that have emerged in the recent years [18–20]. Limitations associated with decline curve analysis are well known and have been discussed

[4]Some have chosen to use alternative nomenclature such as Estimated Stimulate Volume (ESV) or the Crushed Zone, but the idea behind them is all the same.

comprehensively in the literature. Nevertheless, most of the limitations that have to do with specific flow regimes or nuances associated with operational inconsistencies have been tolerated and clever methods have been devised to get around them. However, when it comes to analysis of production data from shale, a new set of characteristics, that may not have been as dominant in the past, stands out that seriously undermine the applicability of any and all production analysis techniques that rely on traditionally statistics-based curve fitting techniques (including DCA).

What is new and different about production from shale is the impact and the importance of completion practices. There should be no doubts in anyone's mind that a combination of long laterals with massive hydraulic fractures is the main driver that has made economic production from shale a reality. So much so that professionals in the field have started questioning the impact and the influence of reservoir characteristics and rock quality in the productivity of shale wells [21]. While the importance of reservoir characteristics is shared between conventional and unconventional wells, design parameters associated with the completion practices in wells producing from shale are the new and important set of variables that create the distinction with wells in conventional resources. In other words, completion design parameters introduce a new set of complexity to production behavior that cannot be readily dismissed, and they are being completely dismissed and overlooked anytime decline curve analysis are used in shale.

Therefore, there is a new set of inherent and implicit assumptions that are associated with production data analyses in shale when methods such as decline curve analysis are used. In previous cases (non-shale) production is only a function of reservoir characteristics while the human involvements in form of operational constraints and completion design parameters played minimal roles. In shale, completion design practices play a vital role. By performing traditional statistics-based production data analysis, we are assuming that reasonable or optimum or may be even consistent completion practices are common in all the wells in a given asset. Production and completion data that have been thoroughly examined in multiple shale plays, clearly point to the fact that such assumptions are indeed invalid and may prove to be quite costly for the operators.

2.7.2 Rate Transient Analysis

Rate Transient Analysis (RTA) is a clever technology [22–27] that approximates the essence of reservoir simulation and modeling using a series of analytical and graphical (plotting routines) approaches. RTA's ease of use and consistency of results are among its strong points. On the other hand, RTA suffers from the same problems as numerical reservoir simulation and modeling does, since almost all of its approaches, especially when it forecasts production, mimics those of numerical modeling.

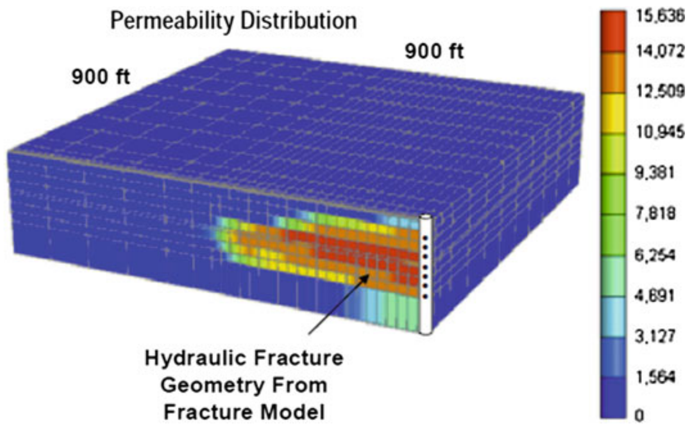

Fig. 2.8 Example of explicit hydraulic fracture (EHF) modeling [28]

2.8 Explicit Hydraulic Fracture Modeling

When compared with other traditional techniques, Explicit Hydraulic Fracture (EHF) modeling is the most comprehensive, complex, and tedious (as well as the most robust) approach for modeling the impact of hydraulic fracturing during numerical simulation of production from shale (example shown in Fig. 2.8). The Explicit Hydraulic Fracture (EHF) modeling technique of reservoir simulation and modeling of shale wells couples three different technologies (software applications [hydraulic fracture modeling software, geological modeling software, and numerical reservoir simulation software]) and includes the following steps:

1. ***Modeling the impact of the hydraulic fracture***; during this step each cluster of hydraulic fracture is modeled individually using independent hydraulic fracture simulation software applications such as MFrac,[5] FracPro,[6] etc. These models use the frac job characteristics (recipe) such as fluid and proppant amount and rate of injection, along with some reservoir characteristics and stresses, and calculate the characteristics of an idealized hydraulic fracture. It is important to note that most of the time the reservoir characteristics (including the stresses) needed as input to these models are not available and are guessed (assumed) so that these models can be used.
   Since these models assume a well-behaved penny-shaped hydraulic fracture (albeit a deformed penny from time to time—see Fig. 2.1), the characteristics they calculate are fracture half length, fracture height, fracture width, and fracture conductivity. This process is repeated for every single cluster of hydraulic fractures. This means that in some cases up to 60 or 70 hydraulic

[5]Meyer Fracturing Software, a Baker-Hughes Company, www.mfrac.com.

[6]Carbo Ceramics, http://www.carboceramics.com/fracpropt-software/.

fracture clusters per well (about three clusters per stage) need to be modeled independently.

2. ***Developing a geological model***; as in all other serious reservoir simulation and modeling exercises, developing a geological model is a necessary step in the numerical modeling of production from shale. During this step all the geological, petrophysical and geophysical information available to the modeling team is used to develop a reasonably detailed geological model. Even for a single well model this process may generate a detail multimillion grid block geological model. Usually data from all the available wells are used to generate the structural map and volume that is then discretized and populated with appropriate data based on availability. This process is usually performed using a geological modeling software application, several of which are currently available in the market and are extensively used during the modeling process.
   Inclusion of Discrete Natural Fracture Network (DNF) in the modeling process is usually performed during this step. The common approach is to develop the DFN using statistical means and then use analytical or numerical technics to incorporate the impact of the develop DFN into the existing grid block system developed during the construction of the geocellular model.
3. ***Incorporation of frac characteristics in the geological model***; in order to incorporate the hydraulic fracture characteristics into the geological model, first the wellbore must be included. Upon inclusion of the wellbore, all the calculated characteristics from step 1 (hydraulic fracture impact such as fracture half length, fracture height, fracture width, and fracture conductivity), are imported into the geological model (mentioned in step 2). This is a rather painstaking process through which the grid system developed during geological modeling is modified in order to be able to accommodate the hydraulic fracture characteristics. Usually a local grid refinement process is required (both horizontally as well as vertically) for this process. The result is usually a detail model that includes a large number of grid blocks. When building a model that includes multiple pads and wellbores this process may take a long time.
   Due to the detailed nature of the model, the computational cost of such models is very high. This fact makes full field modeling of shale assets, impractical (in this book we introduce a solution for this specific problem—Chapter Nine—using data-driven analytics). That is the main reason behind the fact that the overwhelming number of numerical simulation studies conducted on shale formations is single well models. From time to time one may find studies that are performed on a pad of multiple horizontal wellbores rather than a single well, but such studies are few and far between.
4. ***Completing the base model***; using numerical reservoir simulation software application. Completion of the base model usually requires some up-scaling and incorporation of operational constraints. Identification and incorporation of appropriate outer boundary conditions and making a first run to check for convergence are among the other steps that need to be taken for the completion of the base model.

5. ***History matching the base model***; once the base model is completed and runs properly, the difference between its results and the observed measurements (e.g., production rates from the field) indicates the proximity of the model to where it needs to be. During the history matching process, geological and hydraulic fracture characteristics are modified until an acceptable history match is achieved.
6. ***Forecasting production***; the history matched model is executed in the forecast mode in order to predict future production behavior of the shale well.

A survey of most recent publications shows that many modelers have selected not to use the Explicit Hydraulic Fracture (EHF) modeling methodology. This may be attributed to degree of detail that goes into building and then history matching an Explicit Hydraulic Fracture (EHF) model for shale wells. The amount of time it takes to complete the above steps for a moderate number of wells can be quite extensive. Imagine trying to build a full field model where tens or hundreds of wells are involved. The size of such a model can (and usually does) make the development and history matching process computationally impractical.

2.9 Stimulated Reservoir Volume

The second technique for modeling production from shale wells is known as Stimulated Reservoir Volume (SRV) modeling technique. Stimulated Reservoir Volume (SRV) modeling technique is a different and much simpler way of handling the impact of massive multi-cluster, multistage hydraulic fractures in numerical reservoir simulation and modeling. Using SRV instead of EHF can expedite the modeling process by orders of magnitude. This is due to the fact that instead of meticulously modeling every individual hydraulic fracture, in this method the modeler assumes a three dimensional volume around the wellbore with enhanced permeability as the result of the hydraulic fractures (see Figs. 2.9 and 2.10). By modifying the permeability and dimensions of the Stimulated Reservoir Volume (SRV), the modeler can now match the production behavior of a given well in record time.

The first question that comes to mind upon understanding the impact of the Stimulated Reservoir Volume on production is how one would calculate, or more accurately, estimate, the size of the Stimulated Reservoir Volume. Given the fact that Stimulated Reservoir Volume results from hydraulic fractures, the next question that comes to mind is whether the SRV is a continuous medium or it has discrete characteristics for each hydraulic fracture and whether or not these discrete volumes are connected to one another. Furthermore, how are the aspect ratios (ratio of height, to width and to length) of the Stimulated Reservoir Volume determined?

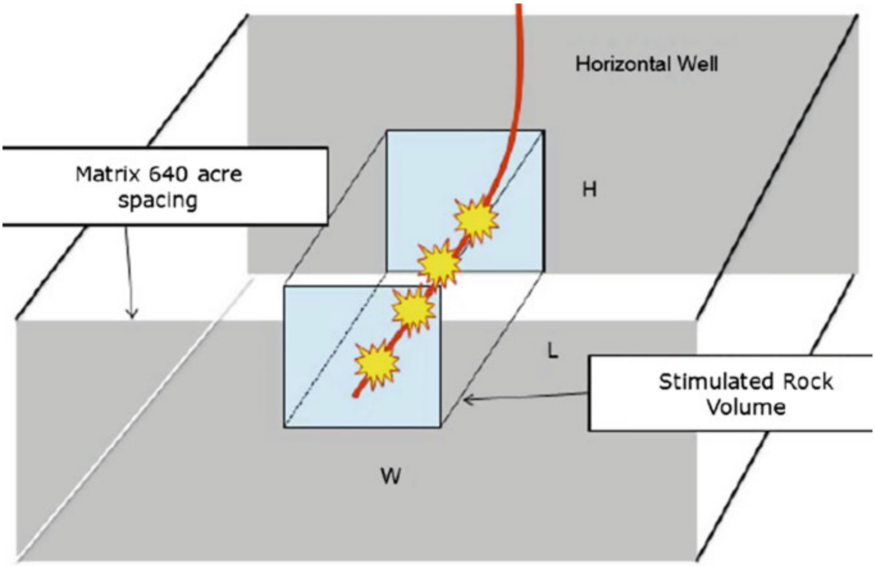

Fig. 2.9 Example of stimulated reservoir volume [29]

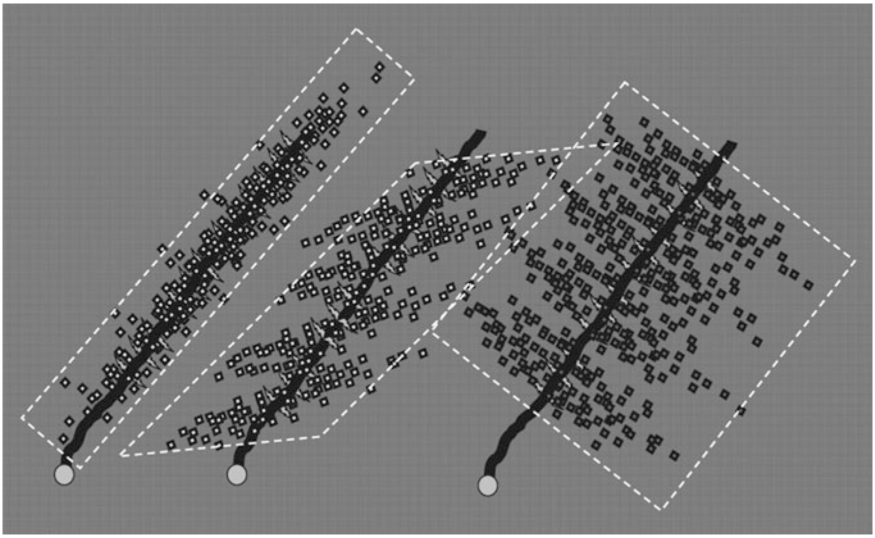

Fig. 2.10 Example of stimulated reservoir volume [30]

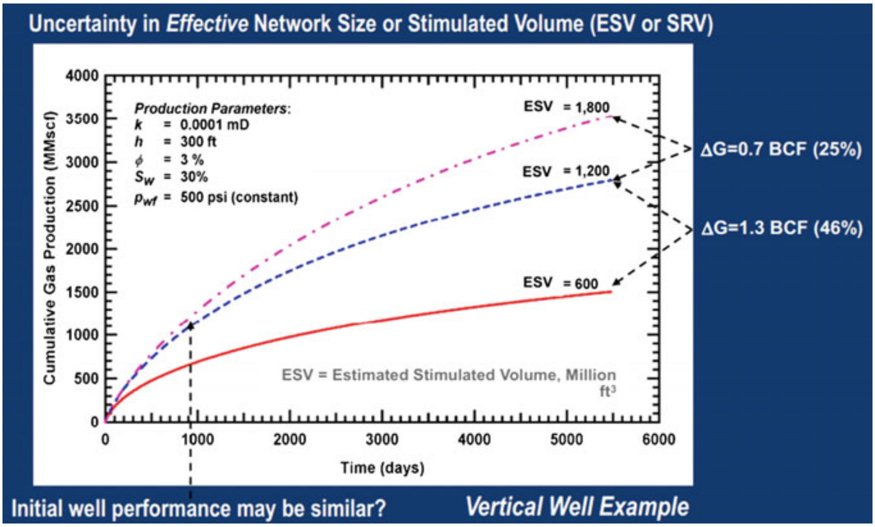

Fig. 2.11 Sensitivity of cumulative production to stimulated reservoir volume [31]

In some recent publications and presentations, the concept of Stimulated Reservoir Volume (SRV) has been linked to microseismic. In other words, it is advocated that by collecting and interpreting microseismic data and identifying microseismic events in a shale well that has been subject to multistage hydraulic fracturing, one can estimate the size of the Stimulated Reservoir Volume. As we will show in the next section, it should be noted that the evidences supporting such claims are equally countered by evidences that dispute them. Furthermore, it has been shown that misinterpreting the size of the Stimulated Reservoir Volume can result in large discrepancies in forecasting the potentials of a given well (see Fig. 2.11). It is a well-established concept that productions from shale wells to a large degree are a function of the amount and the extent of contact that is made with the rock. Therefore, the notion of production being very sensitive to estimation of the size and conductivity of the Stimulated Reservoir Volume is logically sound.

The sensitivity of production from shale wells to the size and the conductivity assigned to the Stimulated Reservoir Volume explains the uncertainties associated with the forecasts that are made using this technique. Although there have been attempts to address the dynamic nature of the SRV by incorporating stress dependent permeability (opening and closure of the fractures as a function of time and production), the entire concept remains in the realm of creative adaptation of existing tools and techniques to solve a new problems. In the opinion of the author, while SRV serves the purposes of modeling and history matching the observed production from a well, its contribution to forecasting the production (looking forward) is questionable, at best. Furthermore, SRV techniques are incapable of making serious contribution to designing an optimum frac job specific to a given well (looking backward).

2.10 Microseismic

The utility of microseismic events (as it is interpreted today from the raw data) to estimate Stimulated Reservoir Volume is at best inconclusive. While it has been shown that microseismic may provide some valuable information regarding the effectiveness of the hydraulic fractures in Eagle Ford Shale [32], the lack of correlation between recorded and interpreted microseismic data and the results of production logs in Marcellus Shale has been documented [33]. In some shale reservoirs, such as Marcellus, as shown in Fig. 2.12, although the current interpretation of microseismic raw data shows locations in the reservoir where "something" is happening or has happened, it does not seem to have much to do with the most important parameter that all parties are interested in, i.e., the production. The proven and independently verified value-added by microseismic as a tool for assessing the effectiveness of hydraulic fracture in production is a debatable issue that remains to be settled as more data becomes available and is published. Therefore, using the extent of microseismic events as an indicator for Stimulated Reservoir Volume seem to be a premature conclusion that has more to do with forceful justification of the utilization of the data that has cost a lot of money to generate than actual utilization of such data.

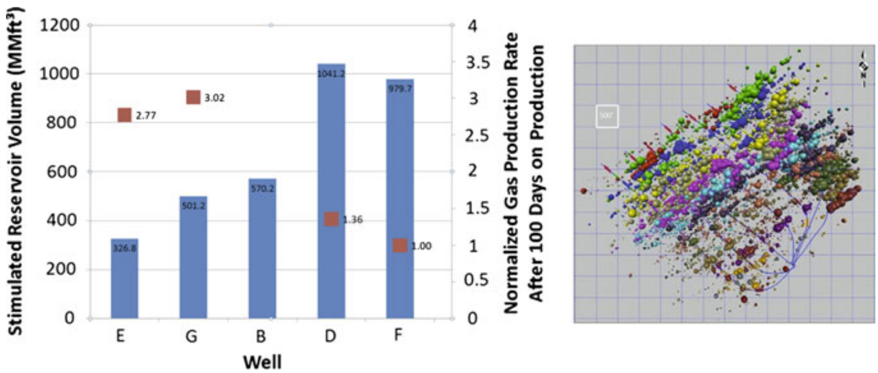

Fig. 2.12 Microseismic events, stimulated reservoir volume, and their contribution to production [33]

Due to its interpretive nature "Soft Data" cannot be used as optimization variables. In other words, one cannot expect to design a particular frac job that results in a well behaved induced fracture with a *designed* half length, height, and conductivity by tweaking the amount of fluid and proppant that is injected. Similarly, *designing* SRV (size and permeability) by modifying the amount of fluid and proppant that is injected during a frac job or by modifying the injection rate and pressure is not an option.[7] Therefore, although "Soft Data" may help engineers and modelers during the history matching process, it fails to provide a means for truly analyzing the impact of what is actually done during a frac job.

[7]Those who have opted to correlate "hard data" to Stimulated Reservoir Volume through microseismic events, are either technically too naïve to realize the premature nature of this effort, or trying to justify a service that is provided by their business partners.

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Shale Analytics
Data-Driven Analytics in Unconventional Resources
Mohaghegh, S.D.
2017, XIV, 287 p. 243 illus., 235 illus. in color.,
Hardcover
ISBN: 978-3-319-48751-9