An Overview of New Developments in Shale Gas: Induced Seismicity Aspect

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Additional information is available at the end of the chapter

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Abstract

New advances in technology such as advances in horizontal drilling, the use of multi-well drilling pads, and multi-stage hydraulic fracturing allow for the economic consideration of recovering formerly uneconomic, yet proven resources. Hydraulic fracturing perturbs the local stress field and causes slip/shearing in naturally fractured shale formations. Monitoring this process using microseismic techniques provides a valuable tool helping to detect the progression of the treatment and understand the efficacy of the operation. This article provides basic definitions regarding shale gas and development of shale gas reservoirs along with results of many new developments in the field of monitoring induced seismicity associated with hydraulic fracturing operations and characterizing of the efficacy of such operations.

Keywords: shale gas, induced seismicity, microseismic monitoring, hydraulic fracturing optimization

1. Introduction

Unconventional resources such as shale gas are energy reserves under study and development. “Unconventional resources” is a useful term for resources that are trapped, and not primarily controlled by buoyancy forces. In other words, unconventional resources are oil or gas-bearing formations where the permeability and porosity are very low. This makes it extremely difficult or impossible for oil or natural gas to naturally flow through pores and into a production well. For this reason, unconventional resources require specialized techniques and tools to achieve economic production. Unconventional resources can be classified into different groups according to their type, origin and deposition. Shale gas, shale oil, tight

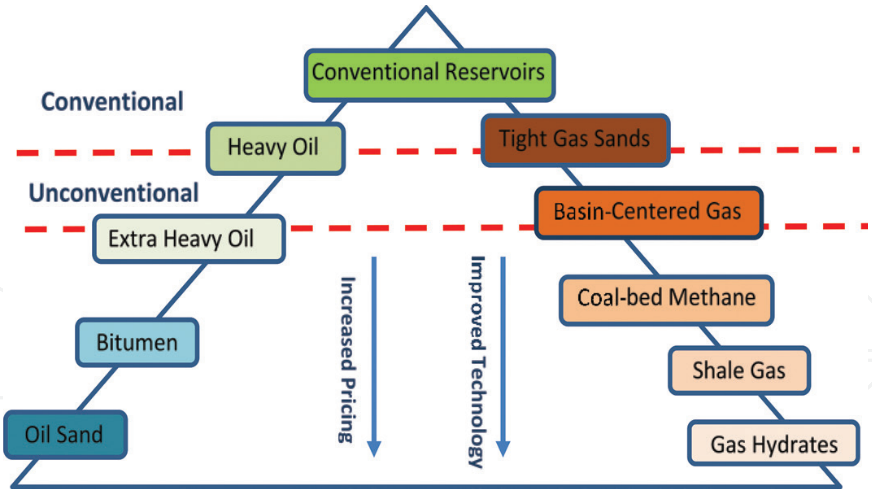

Figure 1. Petroleum resources triangle.

gas sands, oil shale, coal-bed methane, oil sands, and methane hydrates are all considered unconventional gases and tight oil. Shale gas is the focus of this study and refers to natural gas that is locked within shale formations. **Figure 1** illustrates the relative relationship between different unconventional and conventional resources by a resource triangle.

2. Shale gas

Natural gas, particularly shale gas, is an abundant energy resource that will be playing an active role in future energy demand and enabling the nation to transition to higher support on renewable energy sources.

2.1. Definition

Shale gas is unconventional natural gas, which is primarily methane (60–95% v/v), ethane and propane. This natural gas is found in shale rocks, some of which were formed during a Silurian period of Earth's history (400–450 million years ago). Shale gas is generally considered a dry gas which means that it is essentially methane in it but not much else, though some formations do produce wet gas that means in addition to methane, the gas contains compounds like ethane and butane. Shale is composed of fine-grained silt and clay particles that accumulated at the bottom of relatively enclosed bodies of water. These bodies of water had a high organic matter content. Shale typically functions as both the reservoir and the source rocks for the natural gas.

Some of the methane formed from the organic matter buried with the sediments remained locked in the tight, low-permeability shale layers, becoming shale gas though the gas is generated and stored in situ in gas shale as both sorbed gas on organic matter and free gas in fractures or pores. As such, shale contained gas is considered a self-sourced reservoir. Global discoveries of shale gas reserves will affect the geopolitical map of energy production. Shale gas is expected to be one of the leading sustainable energy sources in the twenty-first century [1, 2].

2.2. Origin

Gas from shale is typically generated in two different ways; although a mixture of gas types is possible too. Thermogenic gas originates from cracking of organic matter or the secondary cracking of oil, while biogenic gas is generated from microbes in areas of freshwater recharge [3, 4]. Thermogenic gas is associated with a mature organic matter that has been subjected to relatively high temperature and high pressure in order to form hydrocarbons. Considering all other factors being equal, the more mature organic matter is the more in situ gas resources generate. Vitrinite reflectance (% Ro) is representative of organic maturity, and its value can vary. The value above 1% implies that the organic matter is adequately mature to be considered as an effective source rock [5, 6]. Further, biogenic gas is associated with either mature or immature organic matter and can add substantially to the shale gas reservoir [7].

2.3. Shale gas reservoirs

Shale gas reservoirs generally recover less gas, e.g., less than <5% up to 20% (v/v) relative to conventional gas reservoirs (approximately 50–90% (v/v)) [8]. Some naturally fractured shale reservoirs can have a recovery as high as 50–60% (v/v). Aside from the low permeability of the shale formation in shale gas reservoirs, the critical properties of shale formations regarding gas-containing potential are total organic content and their thermal maturity. The former key property refers to the total amount of organic material present in the host rock. The higher the total organic content, the better the potential for hydrocarbon generation. The latter key property is an indicator to measure the degree to which organic material in the rock has been heated over geological time and converted into the liquid or gas form of hydrocarbons. Gas storage characteristics of shale reservoirs are in practice different from conventional reservoirs. In shale gas reservoirs, besides the presence of gas in the porous matrix (similar to what is found in conventional reservoirs), gas can be found in the form of bound or absorbed to the surface of organic matters in the shale. Therefore, the key element of the production outline of the reservoir is the relative contributions and combinations of these two sources of free gas from matrix pores and from desorption of absorbed gas. The initial reservoir pressure, the petrophysical properties of the shale formation and its adsorption characteristics are the parameters that determine the amount and distribution of gas within the shale formation.

There are three main processes during gas production. The first process is the depletion of gas from the fracture network, which rapidly declines due to limited storage capacity. The second process is the depletion of gas stored in the matrix, and the third is desorption where the adsorbed gas is released from the rock as pressure declines within the reservoir. The rate of production via the latter process depends on the amount of declined reservoir pressure. Pressure changes within the reservoir usually occur very slowly because of the low permeability of the rock. Therefore, to increase the production via this latter process, the small well spacing needs to decrease the reservoir pressure significantly enough to cause the adsorbed gas to be desorbed. Key inputs that play a crucial role in volumetric analysis of evaluation of each shale gas resources are: the maturity of the organic matter, the type of gas generated and stored in the reservoir (biogenic or thermogenic gas), the total organic carbon (TOC) content, the permeability/porosity of the reservoir, and matrix and sorbed gas saturation. One of the common approaches for resource evaluation is a probabilistic approach where the key parameters can be modeled using mathematical distributions and combined in Monte Carlo simulations to derive a resulting distribution [9]. The combination of TOC (known as a measure of organic richness), the thickness of organic shale, and organic maturity are key attributes to estimate the economic viability of a shale gas reservoir [2, 7, 10, 11]. The permeability of the matrix is the most important parameter that influences the sustainable gas production from the reservoir [12]. Natural or induced fracture density, and consequently the permeability of the shale matrix is the most important factor to sustain yearly production, since gas has to diffuse from the low permeability matrix to fractures. A higher matrix permeability leads to a higher rate of diffusion and higher rate of flow and production [2, 7, 12, 13]. Microfractures within shale formations can have a critical role in both economic production [14] and creating an induced fracture network resulting from the interaction with those natural microfractures. This statement needs further research and analysis both numerically and experimentally to determine their role in shale gas development and production. The other important factor to be considered is the thickness of the shale formation. A general rule is that a thicker shale gas reservoir is a better target. Though as drilling and completion techniques are improving, the necessary thickness of a shale gas reservoir to be developed economically may decrease.

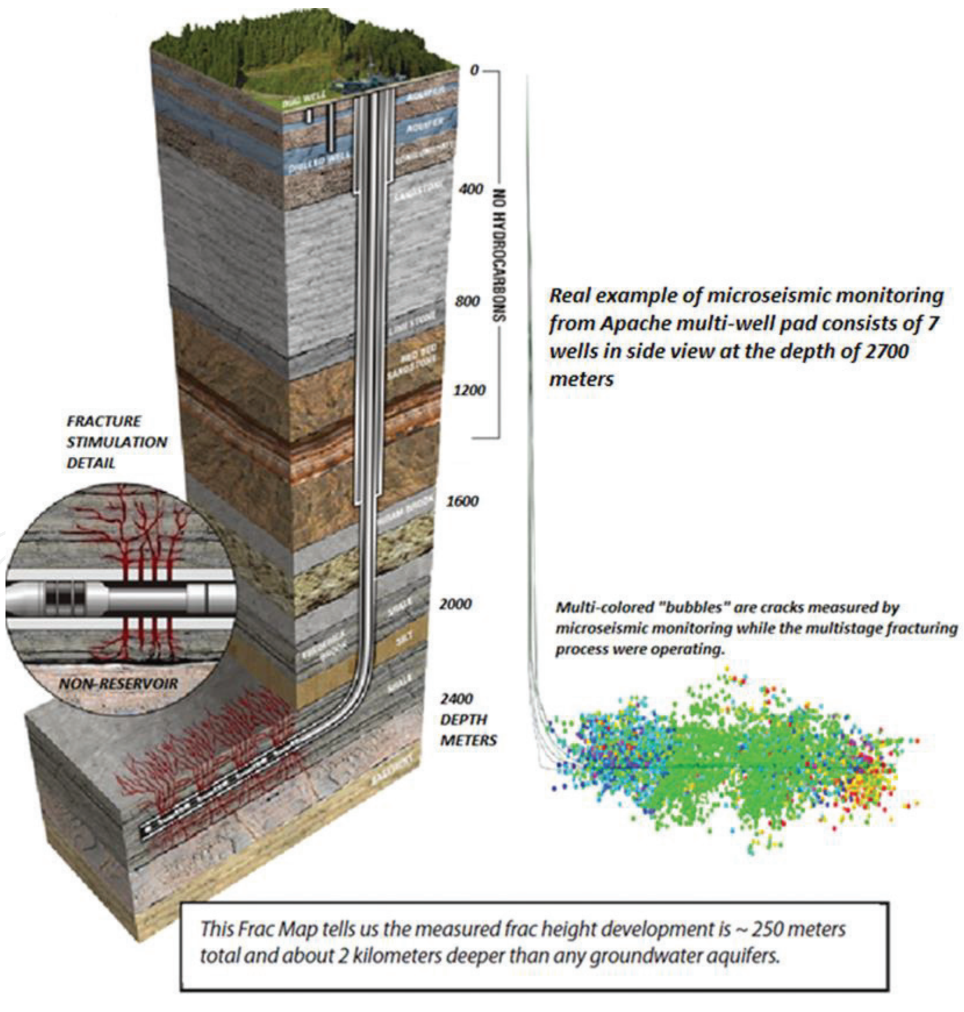

Figure 2. Horizontal well completions and multistage hydraulic fracturing (modified from: Apache Canada Ltd., Canadian Society for Unconventional Gas (CSUG)).

2.4. Shale gas development

Natural gas will not willingly flow to any vertical well drilled through it because of low permeability of shales. The combination of horizontal well completions and multi-stage hydraulic fracture treatments have been crucial to the expansion of shale gas development. **Figure 2** illustrates the process of horizontal well completions and multistage hydraulic fracturing including microseismic events recorded during hydraulic fracturing operations. This technique is a necessary operation to complete the horizontal drilling technique since these wells have an extended horizontal leg section, and combining these two techniques can provide the effective stimulation of the reservoir. Previous to the successful application of these two technologies, similar resources in many basins were ignored because production was not considered economically feasible. The low natural permeability of shale has limited the production of gas shale resources because such low permeability allows only minor volumes of gas to flow naturally to a wellbore. This characteristic of low matrix permeability represents a key difference between shale and other gas reservoirs and must be surmounted for gas shales to be economically viable. The description of technologies essential for a successful shale gas extraction operation is outside the scope of this study.

3. Development in induced seismicity of shale gas

Large-scale fluid injections under high pressures can cause seismicity by reducing the effective normal stress on pre-existing discontinuities and causing them to slip. **Figure 3** illustrates the different mechanisms that create induced earthquakes. Induced earthquakes occur because of geomechanical changes in the reservoir because of the fracturing process [15–19]. Earthquakes may occur by increasing the excess pore pressure acting on a fault and/or by changing the shear and normal stress acting on the fault plane [20]. This phenomenon was

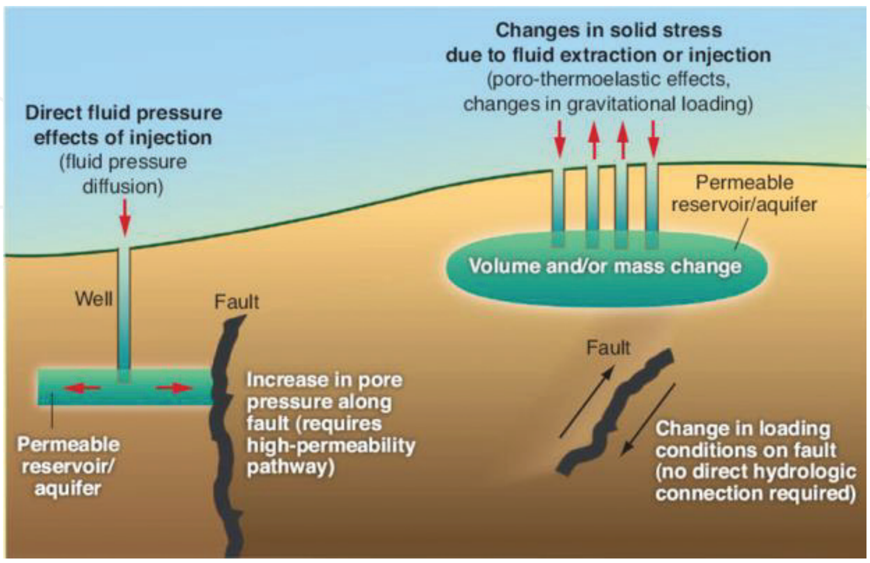

Figure 3. Different mechanisms cause induced earthquakes; earthquakes may be induced by increasing the pore pressure acting on a fault (left) or by changing the shear and normal stress acting on the fault (right) [20].

observed over half a century ago during Denver [21] and Rangely [22] experiments. Smaller-scale experiments later extended this conclusion to much smaller microseismic events, especially when clear evidence of a double-couple source was provided by fault-plane solutions [23, 24]. Seismicity refers to recorded earthquakes caused primarily by fault movement, which are typically events greater than 0.5 ML.

Induced Seismicity are earthquakes (events) resulting from human activity. Microseismic monitoring describes both the recording and processing of very low magnitude events produced by hydraulic fracturing. Typically, these events range from −3.0 to 0.5 ML. Hypocenter is the point within the earth where an earthquake starts. Hypocenters include both the horizontal surface location and depth of an event. Microseismic monitoring is a valuable tool for understanding the efficacy of hydraulic fracture treatments. The determination of event locations and magnitudes leads to estimations of the geometry of the fracture zone and the dynamics of the fracturing process. With sufficient resolution, the hypocenters may even reveal failure planes or other underlying structures controlling the distribution of events and interest petroleum engineers to test various hypotheses on fracture growth.

3.1. Induced microseismicity monitoring and its applications

Induced microseismic monitoring is a geophysical remote-sensing technology that gives the ability to detect and locate associated fracturing processes, which could be either in real-time or in post-processing mode. A typical field deployment involves installation of an array of continuously recording three-component geophones within an observational well(s) near the zone of interest, and/or a set of surface sensors. Besides the oil and gas industry application, which is relatively new, the seismological and mining research communities have developed microseismic monitoring technologies for years [25–27]. Microseismic monitoring aims to detect, locate, and describe the nature of microseismic events resulting from any geomechanical changes for caprock integrity, wellbore integrity and/or optimization of hydraulic fracturing in the oil and gas industry. When hydraulic fracturing monitoring and its optimization are the goals, microseismic events usually occur in large numbers within cloud-like distributions that imitate underlying fracture networks. This method allows monitoring of fracturing treatments in real-time with the aim of detecting the extent of the stimulated rock volume, and thus the success of the treatment. It can also lead to possible improvements in reservoir drainage. Oil and gas companies have set aside significant funds ($100’s MM) for microseismic monitoring, but face extraordinary technological challenges to utilize the results in their full capacity. These challenges are consequences of inadequate insights of seismological and geomechanical processes associated with induced microseismicity.

3.2. Microseismic monitoring in shale gas development

There has been a growing number of reports about the application of microseismic techniques in Shale Gas reservoirs for characterizing fracture growth and geometry, as this technique is an established and reliable one for this purpose. Some studies have relied on surface equipment when seismicity was high enough to be recorded on the surface. However, the majority of cases are based on the use of downhole microseismic equipment that focuses on much smaller events, which simply cannot be detected on surface due to attenuation. The Horn River Basin in northeastern British Columbia (BC) in Canada has hosted many pilot studies and research with regard to the development of Shale Gas reservoirs. Thousands of hydraulic fracturing operations have been performed in the area and anomalous seismicity has been observed in the last decade [28, 29]. The Canadian National Seismograph Network (CNSN) operative throughout Canada is designed to monitor large-scale seismicity and has a minimum magnitude detection limit of 2.0 ML.

The BC Oil and Gas commission [28] performed a comprehensive study on this phenomenon in three areas of the Horn River Basin. The investigation established that during the period of April 2009–December 2011, there was a link between events observed within remote and isolated areas of the Horn River Basin and hydraulic fracturing in the proximity of pre-existing faults. A local seismograph array was deployed for a couple of months within that period and recorded 19 events. A total of 38 events were analyzed. The events recorded ranged in magnitude between 2.2 and 3.8 ML on the Richter scale.

In the Etsho study area, hydraulic fracturing of Horn River Shales was performed in horizontal wells using multiple stages of slickwater fracturing, which consists of pumping a water-based fluid, chemicals, and proppant combination that has low-viscosity to increase the fluid flow. Microseismic monitoring showed that fracture growth was confined to the target shale layers. Hydraulic fracturing operations in the February 2007 to July 2011 period involved 14 different pads and 90 wells with more than 1600 hydraulic fracturing stage completion operations [28].

As a result of the previous study, eight new seismograph stations were added to the existing two of the CNSN in the area. The new investigation focused on the Montney Trend of BC that represents over a third of the province's recoverable natural gas reserves [29] under development since mid-2000s. The area has seen thousands of horizontal gas wells and hundreds of wastewater disposal wells. CNSN recorded 231 events attributed to gas and oil activities in the area from August 2013 to October 2014. Hydraulic Fracturing operations were at the root of 193 of these events that were in the range 1.0–4.4 ML. Wastewater disposal was the cause of 38 events in the 1.2–2.9 ML. The study period covered about 7500 hydraulic fracturing stages. Only 11 were felt on the surface without causing any damage on the surface. No loss of wellbore containment was observed either. **Figure 4** shows the comparison between wastewater disposal-induced seismicity and hydraulic fracturing ones. The investigation confirmed that the mechanism at the root of observed seismicity was the reactivation of pre-existing faults due to increasing pore pressure due to fluid injection. It also demonstrated the critical importance of a dense array in understanding induced seismicity. Moreover, some active faults could be precisely delineated that can be crucial in risk assessment and mitigation of this phenomenon.

The Marcellus Shale formation in Greene County Pennsylvania was subject to a comprehensive investigation of induced seismicity using six horizontal gas wells [30]. The objectives were to find the maximum fracture height in hydraulic fracturing operations and to determine if any natural gas or fluids had migrated upward to an overlying gas field 3800 ft above. The investigation included microseismic monitoring using vertical geophone arrays, gas pressure

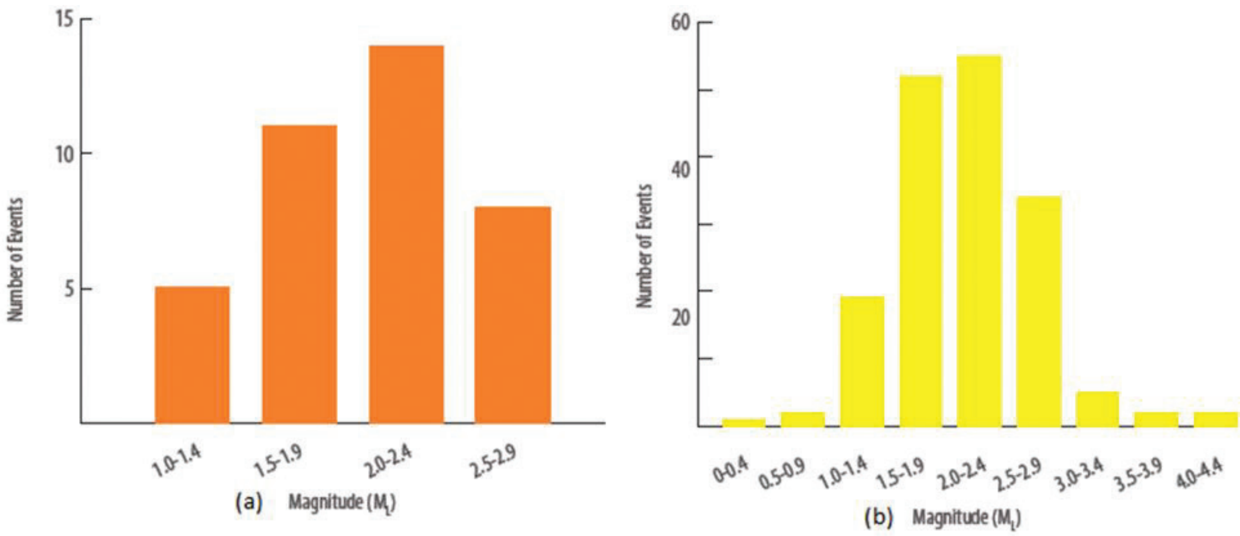

Figure 4. Number of events versus magnitude for (a) wastewater disposal wells induced events, (b) hydraulic fracture induced events (modified from: BC Oil and Gas Commission [29]).

and production histories of three wells, chemical and isotopic analyses of produced gas from seven wells, and monitoring for perfluorocarbon traces of gas from two wells [30]. The findings showed no evidence of gas migration from Marcellus Shale and no evidence of brine migration from this formation. It was demonstrated that the impact of hydraulic fracturing operations did not extend to the overlying shallower gas field and no detectable gas or fluid migration took place in that formation.

Seismicity (M > 3) observed in the Western Canada Sedimentary Basin in the 1985–2015 period has been investigated recently by Atkinson et al. [31]. This basin is where most of Canada's shale gas developments are concentrated. The data set included seismicity induced by hydraulic fracturing, wastewater disposal and production. Both seismicity rates and the number of hydraulic fracturing wells rose sharply between 2010 and 2015, and more than half of all seismicity occurred in close proximity of hydraulic operations in both time and space [31]. The authors pointed out that hydraulic fracturing is responsible for a larger proportion of observed seismicity rather than wastewater injection operations. They also noted that their findings are markedly in contrast with those from similar studies focused on the Central United States where wastewater injections were responsible for most of the induced seismicity. McGarr [32] proposed a linear equation, and it shows the maximum seismic moment as a function of total volume of liquid injected up to the time of the largest induced earthquake. For most of case histories mentioned here, magnitude exceeds the maximum bounds provided by the McGarr relation as shown in **Figure 5**. For many of the events above the McGarr line, it has been proven that use of the maximum volume value might just allow the point to come beneath the line. However, two events are clearly above the line, even with the combination of the maximum volume and the minimum magnitude; these are the August 2014 M 4.4 and August 2015 M 4.6 events near Fort St. John [29, 33–35].

Ellsworth [20] has reviewed many cases of induced seismicity reported previously and points out that seismic activity in the central and eastern United States has increased dramatically

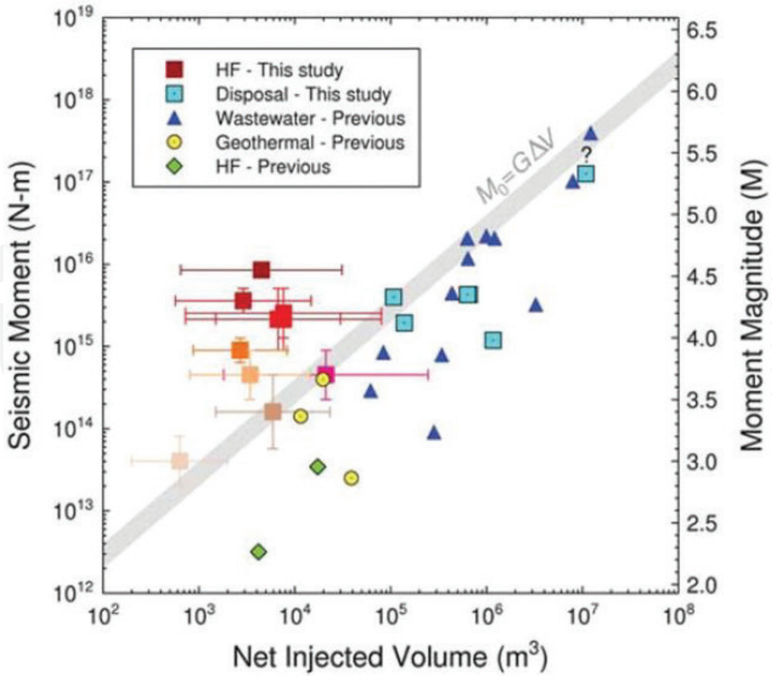

Figure 5. Seismic moment versus net injected volume from Atkinson et al. [31]. The authors have shown their own results (squares) and those from previous studies. The gray band shows the maximum magnitude predicted by McGarr [32] for shear modulus G in the range 20–40 Gpa.

in the recent past. Ellsworth relates this observation to cases of hydraulic fracturing and disposal of wastewater injected in deep wells. The mechanics of this phenomenon is analyzed and described. The intimate relationship between the development of unconventional gas fields and new technologies are well explained, and many cases are enumerated. The author pointed out the importance of well documenting the specifics of each operation in the ability to get to the root of the observations and described how important that was in the case of pioneering experiments of Denver and Rangely mentioned above. A case study of microseismic imaging of hydraulic fracturing in the Barnett shale gas reservoir in Texas demonstrated some complications about the use of microseismic results in reservoir simulations [36].

While the technology is mature and well established when dealing with detecting fracture geometry and growth, the author states that the disability of the technique in distinguishing between seismicity induced by fracture opening and closing. In addition, more detailed information about the fracturing process and mechanism need to be implemented in order to make the technique more valuable for reservoir management.

Zeng et al. [37] describe results from a multi-stage hydraulic fracturing experiment carried out in a horizontal well of a shale gas reservoir using a surface broadband 3C seismic array. They state that it is possible to detect and locate small events ($M < -1$) with a relatively sparse array, particularly for shallow reservoirs. Their focal mechanism analysis of the observed seismic activity was consistent with the regional stress field. The seismicity formed into two clusters; one fell into a small volume surrounding the horizontal well, and another group fell 500 m away from the well. Both groups of events showed similar properties in their focal mechanisms. The authors point out that in order to reduce the hazard of such operations, a better understanding of the pre-existing fractures, the tectonic stress regime in the region, and appropriate design and management of the injection operation would be necessary.

A combination of surface and downhole sensors were used to monitor microseismic activity associated with hydraulic fracturing of a shale gas reservoir in China [38]. The results were used in real-time to optimize pre-pad fluid parameters, perforation and temporary additive releasing time to optimize fracturing operation. The authors mentioned that the average shale gas production's rate was increased 2–5 times through optimization using real-time microseismic monitoring, and they could prove the benefit of using this technique by later production tests, too. The real-time results played a vital role in the immediate evaluation and optimization of fracture parameters. The gas field under study is the largest commercially available shale gas field in the world outside North America. Another study conducted by Yaowen et al. [39] built further on the success of the previous paper and provides guidelines for the optimization of fracturing parameters at the later stage.

Kaka et al. [40] presented the results of the microseismic monitoring of a multistage stimulation experiment of a shale gas reservoir in Saudi Arabia. A string of 12 3C-sensors with 30.5 m spacing was used, and a total of 415 events were recorded. The objective of the study was to better understand fracture growth during the operation and the role of pre-existing fractures in the process. No changes were observed in the direction of local stresses along the treatment well. Significant changes in total length and aspect ratio (length/width) of the fracture induced in different stages have been observed. The authors enumerated parameters that may have had a role in this observation such as in situ fracturing, local rock heterogeneity or the influence of the treatment parameters. The conclusion made from their observations was that early and late stages of stimulation show the longest fracture networks, with events induced further away from the initiation point. They did not find any immediate relationship between treatment parameters (peak pressure and pumping rate) and fracture extension. Sensitivity analysis using the Monte Carlo simulation method was attempted to clarify location uncertainties. The results of these simulation methods show a higher location uncertainty for events located at the early stages, consequently restrained interpretation from monitored seismicity in the early stages. One of the main purposes of their study was to develop a methodology for generating dynamic, high-resolution seismic and geomechanical models of shale reservoirs before, during and after stimulation, and interpreting the models regarding fracture susceptibility and fracture dynamics.

3.3. Emerging trends

The abundance of applications of microseismic monitoring in gas reservoirs in recent years and the high quality of collected 3C data have been accompanied by attempts to extract more detailed information about the fracturing process from recorded signals. The basic motivation of these attempts, understandably, has to do with the need to reduce production expenses. Hence, application of new seismic techniques that can actually help achieve this objective through increasing the efficiency of production and rate of production has been welcome. In this section, we enumerate some of such initiatives presented in recent years. The list is not in any way exhaustive, but it is a sample of recent efforts in this regard.

Application of seismic moment tensor inversion techniques is one promising trend in the analysis and interpretation of microseismicity related to shale gas reservoirs. The technique is fundamentally superior to fault plane solution determination in that it does not include a priori assumption about the mechanism of failure. It allows, in simple terms, for the source mechanism to be decomposed into three components: a double-couple component that is expected to be of a pure shear failure source, an isotropic component that can be described as an explosive or implosive source, and the so-called compensated linear vector dipole (CLVD) [25].

Baig and Urbancic [41] have presented a case of such studies for a collection of 147 microseismic events recorded during a fracture treatment using three borehole arrays. The authors have adopted the method of Gephart and Forsyth [42], originally applied to California earthquakes, to their microseismic data by considering the double-couple approximations of their moment tensors. The idea is that seismic moment tensor is a symmetric second-order tensor with six independent components. Mapping the total amplitudes of the P, S_V, and S_H phases to the focal sphere surrounding the source should determine this tensor. For monitoring hydraulic fractures, at least two linear borehole arrays non-coplanar with the event are required for identifying the full resolution of all six independent components of the tensor. These six independent components include three geometric parameters controlled by the orientation of the fracture and the sense of slip on; one parameter is the total seismic moment, the second is to control the relative strength of the double-couple, and the last using compensated linear vector dipole and isotropic components [41]. **Figure 6** illustrates the radiation patterns from various failure mechanisms according to different crack modes.

Using the algorithm proposed by Gephart and Forsyth [42] and considering the double-couple approximations of the seismic moment tensors, Baig and Urbancic [41] could invert the measured strain axes in the treatment zone represented by the seismic moment tensors for the stress regime that best fits these events. Each suit of results provides a set of P (pressure) and T (tension) axes,

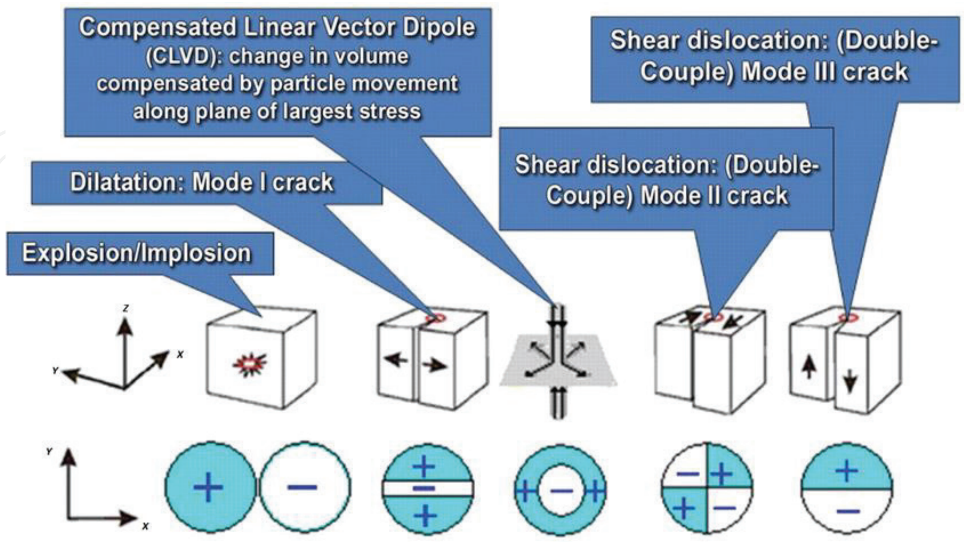

Figure 6. Different modes of failure create various moment tensors visualized by the beach ball diagrams, which are stereographic projections of the P-wave radiation patterns over the focal sphere [41].

just like for a focal mechanism plot. Then they search for an in-situ stress field that minimizes the total rotation required for the strain axes for the data set at hand. The results showed distinct differences among different stages of fracturing. For instance, **Figure 7** shows the locations and moment tensor solution for 147 events recorded in the study using three borehole arrays during one hydraulic fracturing operation. According to this figure, the events fall along a vertical plane trending N40°E and the presence of a variety of mechanisms, suggesting that the events cannot be categorized as simple shear failures but consist of volumetric components of failure.

Urbancic and Mountjoy [43] also reported the results of the moment tensor inversion. The former have applied the technique to two distinct microseismic clusters observed during production cycles of two wells with remarkably different types of source mechanism. They attribute this difference to changes observed in fracture types, which became active and production methods. The latter applied the technique to a microseismic data set recorded at a shale gas reservoir in order to estimate fracture planes and orientations, volumetric strain, crack movements and timing and relationships with pumping operations.

Norton et al. [44] have used Amplitude Variation with Offset (AVO) inversion to estimate elastic properties and fault mapping to identify potential barriers that could affect fracture propagation in a shale gas reservoir. They argued that by correlating the results of the two techniques in parallel could provide valuable information about the local heterogeneity within the reservoir and the effect on the fracture simulation programs. Xu et al. [45] presented results of microseismic monitoring of hydraulic fracturing simulation in a tight sand reservoir. They stated that although the use of a single well has been widely adopted, much better results could be obtained with a dual-well set up regarding fracture delineation and location accuracy. Both surface and downhole microseismic equipment have been employed to monitor a shale gas field in China [39]. The results helped to evaluate reservoir stimulation in order to optimize fracturing operation.

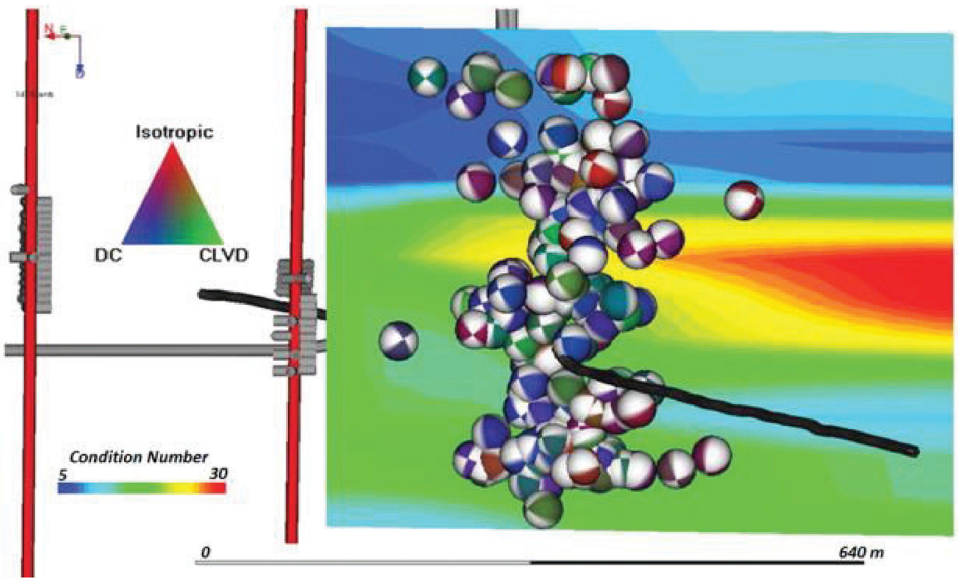

Figure 7. The moment tensors for 147 events plotted with the condition number that determines how well one can invert for the mechanism of the event [41].

Xu et al. [45] studied the hydraulic fracturing stimulation using microseismic monitoring of two wells simultaneously in low porosity and low permeability formation in Ordos basin with the aim of improving fracture geometry and optimization of good placement. Comparing with single-well microseismic monitoring, they concluded that the dual-well technique could explain features in far more precise details and accuracy and then subsequently can reduce uncertainty. Maxwell and Norton [46–48] discussed a case study on Montney formation (NE British Columbia, Canada) with the focus on integrating the microseismic data with the available geotechnical/geomechanical resources. They concluded that the combination of this data could provide valuable information to deeper insights about hydraulic fracturing behavior, optimal hydraulic fracturing geometry, and optimal production rates. In general, it leads to more optimized completion design with closer perforation clusters and increased reservoir contact in future wells.

One of the most controversial discussions in shale gas development is the interaction between natural fractures in fractured shale reservoirs and hydraulically induced fractures resulting from multi-stage hydraulic fracturing. In general, three main scenarios describe the interaction between these two sets of fractures. When a fracture has been created by the hydraulic fracturing method, the propagation of that induced fracture may cross a natural fracture without any change in propagation direction, terminate against a natural fracture and then continues to propagate along the natural fracture, or terminate and then open the natural fracture, as new fractures initiate from the natural fracture. Huang et al. [49] conducted a comprehensive study coupling a geomechanic-microseismic model using numerical simulation. They have run the model under different situations such as various fracture intensities, different number and orientation of fracture sets, hydraulic-natural fracture crossing versus arrest scenarios, and various frictional properties for the natural fractures for two horizontal wells from the Barnett Shale. They concluded that the number and orientation of fracture sets, fracture frictional properties, wellbore orientation, and fracture spacing/intensity are the governing factors influencing complex fracture network geometry, reactivation patterns, and synthetic microseismic events.

Rutqvist et al. [50] studied the reactivation of natural fractures and faults and induced microseismicity regarding hydraulic fracturing operations in shale gas reservoirs. They developed and conducted three-dimensional coupled fluid-flow and geomechanical modeling of fault activation where a horizontal injection well intersects a steeply dipping fault. A three-hour hydraulic fracture operation was modeled, and the results indicated that shale-gas hydraulic fracturing along faults would not likely induce seismic events that could be felt on ground surface. The results indicated several small microseismic events, as well as aseismic deformations along with the fracture propagation. The magnitudes of the created events ranged from −2.0 to 0.5, excluding one case regarding a very brittle fault with low residual shear strength for which the magnitude was 2.3, an event that would possibly go unrecognized or might be felt by humans at its epicenter. A dependency on injection depth and fault dip was found after conducting sensitivity analyses on various parameters such as injection depth, fault dip, and slip-weakening model parameters. That dependency could be attributed to the variation of the shear stress on the fault plane and the variation of stress during the reactivation process. The plastic zone, according to the results, expanded up to 200 m from the injection well at the end of the hydraulic fracturing operation.

Shahid et al. [51] did an inclusive review on numerical simulation analyses and strategies using commercial codes or developing new specific codes for modeling hydraulic fracturing, the natural fracture reactivation, and induced microseismicity associated with either hydraulic fracturing operation itself or the interaction between hydraulically induced fractures and natural fractures and discontinuities. There are different numerical models to use for this purpose according to the assumption/s of the studies. For example, there are different approaches depending on the 2D or 3D assumption, or considering media under study as continuous or discontinuous media. It is obvious that if the interaction between a natural fracture and an induced one is the subject of the study, the DFN (discrete fracture network) must be considered. In term of shale gas reservoir modeling, there are plenty of "unknown unknowns," and there is a certain number of "known unknowns." The "known facts" are the best place to start with to come up with general ideas accepted by professionals and experts. One of the known facts is that shale is naturally fractured and another one is that the induced hydraulic fractures will open and activate these existing natural fractures.

In some recent publications and presentations, the concept of Stimulated Reservoir Volume (SRV) has been connected to microseismic. It is proposed that by gathering and interpreting microseismic data and detecting microseismic events in a shale well subjected to multistage hydraulic fracturing, the size of the stimulated reservoir volume can be estimated. Shreds of evidence that dispute them equally counter the amount of evidence supporting such claims [52]. Furthermore, it has been proven that misinterpreting the size of the Stimulated Reservoir Volume can result in substantial inconsistencies in predicting the potential of a well [52].

As another application of induced seismicity monitoring in the oil and gas industry, wellbore integrity in shale gas development can be considered as an outcome of using that technology as it has been long used for Cyclic Steam Stimulation (CCS) projects to observe, detect, and locate casing failure or slip due to steam injection in thermal oil recovery operations [53–55].

4. Discussion

Shale gas exploitation is no longer an inefficient operation with the availability of improved technology, as the demand and preference for this clean form of hydrocarbon have made Shale Gas an energy in order. The production and development of shale gas from one reservoir to another around the world are swiftly increasing. Real-time monitoring of microseismic events allows optimizing the hydraulic stimulation process by modifying the fracture stage design while pumping into the formation. Recording micro-seismic events to monitor rock fracturing in 3D space and time during the stimulation process allows one to confirm the rock volume and formation geometry being stimulated. As a result, future well placement and completion designs can be optimized for cost-effective drainage of unconventional reservoirs. The technological advances that led to the initial exploitation of shale gas reservoirs, namely horizontal drilling and multi-stage fracture stimulations, were not entirely new to the industry. This supports the concept that advanced technologies must be aligned with in-depth knowledge and understanding of the potential and possible challenge/s for best outcomes.

The increased application of micro-seismic monitoring in the field of shale gas exploitation seems like an obvious technology to complement fracture stimulation treatments.

Microseismic monitoring of fracture stimulations has seen huge growth in the past decade, in line with the increase in shale gas development activity. Although the technology is not new, monitoring of microseismic events has been used in mine safety monitoring for years. It is still a relatively new technique in the oil and gas industry, and in some ways, not an entirely developed technology. Although it is a comparatively simple method to detect microseismic events, to locate them correctly in the subsurface is not an easy task. The aim of many current advanced seismic developments is to use the clustering of microseismic events and their character/attributes to evaluate the volume of stimulated rock and compare it to the volume of pumped fracturing fluids.

An extensive review of new technologies developed to monitor induced microseismicity has been carried out. The application of these technologies and their impact on shale gas development have been reviewed in this article.

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