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Perspective

Technologies for Oil and Gas Production: Present and Future

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Introduction

The petroleum industry, encompassing the production and utilization of oil and natural gas, has dominated the energy scene for a century and by all reasonable indications will continue to do so well into the twenty-first century.[1,2]

At the time of this writing, 35% of world energy derives from oil and 22% from natural gas. At current oil prices of around \$100 per barrel, oil production amounts to about \$10 billion per day while natural gas adds at least \$2 billion more. These figures translate to a nominal value of the extraction part of the industry at about \$4.4 trillion annually. An economic multiplier of four, which has been used in the past for commodities, makes the oil and gas industry an almost \$18 trillion economic entity, larger than the U.S. economy at \$15 trillion.

In attempting to present technological state-of-the-art of the oil and gas industry it is essential to address energy future prospects. In the beginning of the twenty-first century there are two scenarios that one may envision. One is a carbon-constrained world, based on the relatively recent effect of man-made carbon dioxide on global climate change;[3] another is unrestricted use of all potential energy sources as dictated by market forces and the physics of the individual sources. Regardless of one's own views, one must certainly consider both notions, as recent events and international geopolitical developments have highlighted the inexorable difficulties of finding a balance between short-term economically viable decisions and orchestration of a globally concerted effort to deal with a carbon-constrained future and/or a warmer planet.

With full subscription to the dictum "It is hard to make predictions, especially about the future", it is clearly our contention that oil and gas (along with coal) will continue to dominate the energy scene for decades.[1,2] Alternative primary sources of energy, such as solar—by far the largest exploitable source, which theoretically could offer more energy than humanity would ever need—will have to resolve multiple issues, including technological, economic, and compatibility with a vast and expensive existing infrastructure.[4] In addition, harnessing primary energy sources into usable forms of energy "currency"—such as liquid fuels, which currently dominate the transportation sector worldwide—creates a formidable array of potential future scenarios, for which one can make educated projections but can hardly offer accurate predictions.[5]

As it has evolved, electric power generation from nonrenewable sources in the U.S. has been the realm of coal, natural gas and nuclear (itself at the short end of adversity because of recent unfortunate events) whereas transportation has been almost exclusively from oil. Making these energy sources overlap under some capacity or another, such as using natural gas for transportation either directly, or through conversion to liquid or even by using electrical vehicles is clearly desirable to diversify the energy mix. Of course there are formidable economic, logistical and infrastructural issues.

Technology has played a pivotal role and will continue to do so in the foreseeable future. In fact, advances will be needed in multiple scales, from the molecular level[6] (e.g., for solar cells, electric power storage devices or liquid fuels) all the way to global systems. This is certainly an area where chemical engineers have a long history of contributions and are well equipped to contribute in the future.

Upstream petroleum technology, on the other hand, is unlike the technology of other engineering disciplines. In terms of the ultimate goal and its scope it is simple: find oil and gas, drill for them, and complete the wells (i.e., fit them with the right equipment) and then produce from them. No Nobel-prize awards are to be expected here.

Yet, the importance of the enterprise, its value, the risks involved and the ever increasing challenges in its application, have motivated some of the most formidable and evolutionary/revolutionary technological developments. This is tantamount to the conundrum: here is the Earth, there is the Moon. The ultimate task is clear and obvious; but making it there becomes an enormous challenge.

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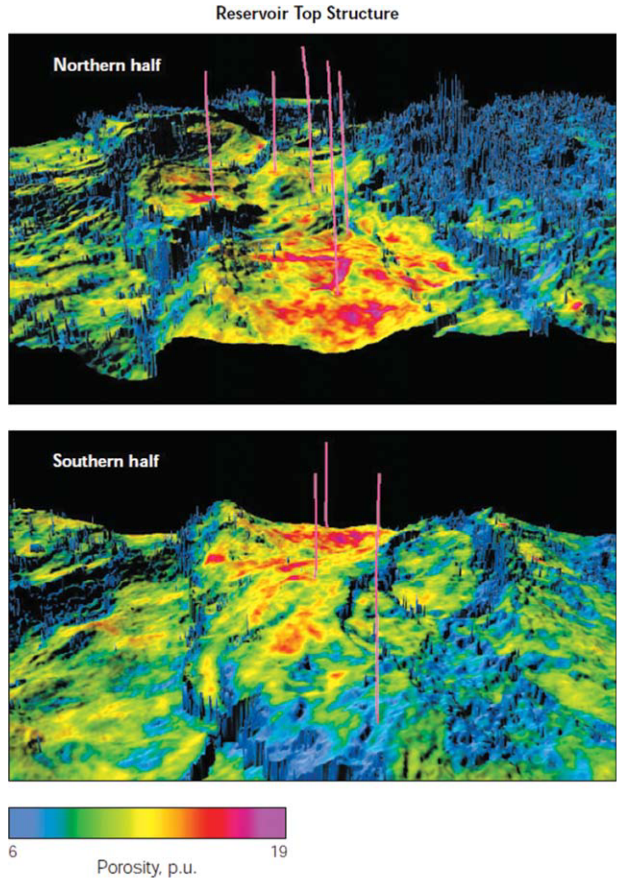

Figure 1. Color-coded porosity on a 3-D image of a reservoir surface.

As part of a reservoir characterization study, interpreters derived a correlation between seismic reflection strength and porosity determined from well logs, then mapped the lateral variation in porosity on the reservoir surface. The results are used to determine where to place subsequent wells as the reservoir is developed.[26]

In this article, we have selected to present three technologies that have had already a seminal impact on petroleum production: three-dimensional (3-D) seismic imaging, horizontal (directional) drilling, and hydraulic fracturing. The subject is certainly very broad, and touches on science, technology, geopolitics, and human behavior. Here, we only intend to offer an outline of these technologies, along with some recent developments and the basic engineering behind them. We hope that the discussion will inspire chemical engineering talent to identify opportunities for future contributions.

3-D Seismic imaging

3-D seismic imaging is a crucial enabling technology in oil and gas exploration and production. Seismic prospecting, first used in rudimentary form in the early 1910s,[7] entered its modern era in the 1950s.[8] The rapid increase in available computing power in the 1970s and advances in display technology resulted in development of 3-D seismic technology,[9] which gradually displaced 2-D seismic technology that had been used extensively until mid-1980s. The result of using 3-D seismic technology was the ability to perform reservoir characterization of unprecedented quality with pivotal (roughly order-of-magnitude) effects on exploration finding rates and volumes, oil and gas recovery, reserves replacement, reduction in the risk of drilling dry holes or marginal wells, and ultimately economics.[10,11] As new oil and gas deposits are found in increasingly challenging locations,[12] the use of 3-D seismic imaging technology is certain to remain essential and pivotal for both technical and economic reasons.

In its core, seismic imaging technology is an echo location technique, similar in principle to sonar, radar, and medical ultrasound technologies. In a nutshell, controlled vibrations on the surface of a medium generate a very small artificial earthquake (hence, the term seismic), with resulting waves bouncing around in the medium, and part of them reflected back to the surface. Once measurements of the reflected signal are collected, an attempt is made to infer internal features of the medium. Such inference is possible because of variations in the acoustic impedance of the various solids and fluids of an oil and gas reservoir in a layered, porous rock formation. In fact, seismic imaging is a complex operation that entails three basic tasks.

- *Generation* and *acquisition* of data using mechanical devices and geophones, respectively.
- *Processing* of collected data, namely travel time, amplitude and waveform information, from which the parameters of the corresponding earth model must be estimated by solving an inverse problem.[13]
- *Interpretation* of the results, namely extraction of all available geologic information from the data.[14–16] This entails geological structure, stratigraphy (rock layering), reservoir properties (e.g., porosity), and perhaps reservoir fluid changes in space and time (time-lapse or 4-D seismic).

Each of the aforementioned tasks has its own challenges. While impressive advances have taken place in all three over the years, the most far reaching recent outcomes have come from improvements in processing and particularly interpretation of seismic data.[17–19] Of all advances in seismic data processing, chemical engineers are probably most familiar with wavelet analysis, Jean Morlet's exceptional invention[20] that blossomed as a signal processing tool permeating many disciplines with widespread applicability. Notions of multiscale modeling[21] also touch on similar concepts studied in chemical engineering science.

Advances in computational efficiency and cost reduction have made it profitable to conduct multiple 3-D seismic surveys in the same field over time. Known as time-lapse or 4-D seismic,[22] the technology relies on comparing data from seismic experiments separated by a few years as the reservoir produces. From this comparison, values of several variables associated with the reservoir, e.g., fluid location and saturation (water, oil, and gas), pressure and temperature, can be inferred and used in reservoir management plans, such as well and facilities placement[23] or production optimization.[24] This is particularly important for offshore applications, where the drilling and production cost is high, and where the vast majority of 4-D seismic surveys are employed (Figure 1).[25]

Most development activity for seismic technology is today concentrated toward interpretation. The difficulty lies in that interpretation is both art and science, namely an efficient synthesis is needed that combines numerical results of elaborate computations with domain knowledge and experience. While impressive results can be produced with today's computational and display technologies, there is every indication that future improvements in computer and electronics technology, evolving oil industry economics, and software life cycle costs will continue driving the complexity and capabilities of interpretation systems, which will further grow in importance.

Horizontal drilling

The principle of drilling hydrocarbon wells is simple: A rotating drill bit at the bottom of a drill string suspended from a derrick penetrates a rock formation into a hydrocarbon reservoir. The rock cuttings are transferred from the bottom of the drilled hole to the surface by a circulating fluid (drilling "mud"), pumped from the surface to the bottom through the drill pipe and back to the surface through the annulus between the drill pipe and the well walls. The drill bit rotation is provided by drill pipe rotation or, for horizontal wells, by a bottom hole mud motor. In fact, the drilling mud serves many more tasks, such as lubrication, protection of well walls from collapse or damage, and containment of hydrocarbons within the reservoir during drilling, to prevent a blow-out. The importance of failing to maintain wellbore pressure at the right level and to ensure that fluids from the reservoir do not enter the well became painfully familiar to the general public after the Macondo well accident in the Gulf of Mexico in April 2010, which made *blow-out preventer* a household term. The accident also highlighted the complexities and risks of drilling deep offshore wells, and the crucial role of the interplay between equipment and humans in following safe practices.

Horizontal and multilateral well drilling started in the 1980s, and is now used routinely. Even though technically complex and costly, it offers distinct economic benefits, such as improved contact area with the reservoir (translated into improved hydrocarbon recovery—a decisive factor for shale gas production), and a convenient—or single-entry point for exploitation of an entire reservoir (a crucial factor for offshore production, where the cost of a platform easily reaches billions of dollars).

Managed-pressure drilling of offshore wells

The drilling operation combines elements of a mechanical system and a unit-operations process. All concerns associated with mechanical systems, such as mechanical integrity and resiliency, vibration control,[27] weight-on-bit control,[28] equipment health monitoring and maintenance are pronounced with offshore drilling systems. At the same time, process control issues, such as drilling fluid flow and consistency, pressure management in the borehole,[29] and management of surface facilities (such as pumps, mixers, and storage tanks) are equally important, for reasons of efficiency and—foremost—safety. This is not surprising, given that a drill string (the long string of thread-joined pieces of pipe and tools hanging from the derrick and transferring motion and weight to the drill bit at the bottom) traverses several thousand feet through sea water and rock formation. To enhance flexibility, efficiency, and safety, a number of drilling technologies, collectively known as managed pressure drilling[30] (MPD), have emerged as a powerful proposition for precise control of wellbore pressure. The primary goal of MPD is to keep wellbore pressure within constraints (Figure 2). This can be done by coordination of all the pumps, valves and chokes involved in the operation, as shown in Figure 3. A general approach can borrow concepts that have been used successfully in constrained plantwide control of oil refineries.[31]

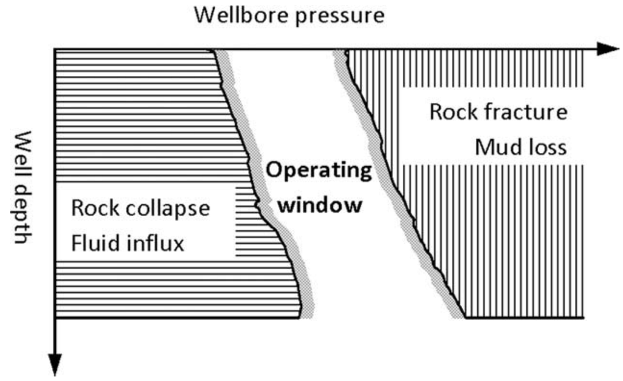

Figure 2. For drilling to proceed safely, wellbore pressure in the annulus between the drill pipe and well wall must remain within the narrow operating window shown in the schematic.

If the annular pressure drops below its lower bound, i.e., takes values in the horizontally hatched area, then the rock may collapse or fluid from the reservoir may flow into the well (a "kick") possibly causing an accident if not disposed of properly. On the other hand, if the annular pressure exceeds its upper bound (vertically hatched area), then the rock may be fractured and/or drilling mud may be lost into the pores of the rock formation. The preceding constraints are some of the most important safety constraints in the drilling operation. Note the uncertainty in the upper and lower bounds.

Production from horizontal and multibranched wells

Traditionally oil and gas production was accomplished with vertical wells. Depths varied from shallow (e.g., 100 ft) to deep (e.g., 30,000 ft). Shallow formations generally contain heavy oil, i.e., high-viscosity liquid with very low-bubble point pressure and therefore not involving any solution gas. At the other end of the spectrum, over geologic time, high-reservoir pressure and high temperature have cracked the hydrocarbons, resulting in reservoir fluids that are primarily gas *in situ*. At the middle of the two extremes, around 10,000 ft depth, are the most desirable reservoirs in the world, producing light oil with substantial quantities of associated gas.

To select the appropriate well configuration, petroleum engineers must not only have a good reservoir description, but they must also be able to predict well performance and reserves as well as optimize well systems.[32,33] A comprehensive multi- and single-well productivity or injectivity model has been introduced that allows arbitrary positioning of the

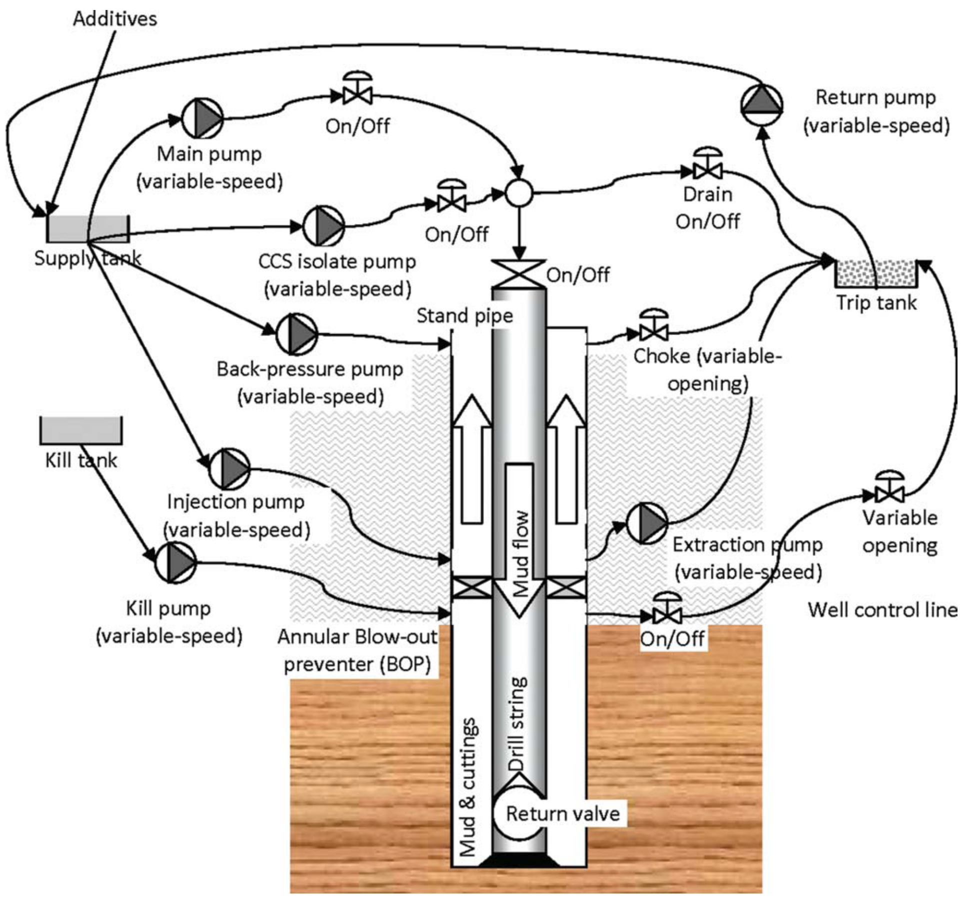

Figure 3. Generic managed pressure drilling (MPD) schematic.

well(s) in anisotropic formations.[32] This flexible, generalized model can be used for the study of several plausible scenarios, especially the economic attractiveness of drilling horizontal and multilateral wells.

Traditionally, petroleum engineers have not been too concerned about horizontal permeability anisotropy. When vertical wells are considered, permeability anisotropy is not very important, because in cylindrical flow, the average permeability k_H is in the horizontal plane and is simply equal to $\sqrt{k_x k_y}$. Several studies have shown that large permeability anisotropies in the horizontal plane are common in many reservoirs.[34,35] Naturally fractured formations, which are generally excellent candidates for horizontal wells, are likely to exhibit horizontal permeability anisotropy. In this situation, two principal horizontal permeabilities can be identified: $k_{H\max}$ and $k_{H\min}$. The direction to drill a horizontal well is often based on the shape of the presumed drainage area, when instead; the deciding parameter should be the horizontal permeability anisotropy, particularly in the cases of natural fracture orientation or depositional trends. Warpinski[36] and Buchsteiner et al.[36] note cases where permeability ratios in the horizontal plane are as much as 50:1, although ratios of 3:1 or 4:1 are considerably more common.

Permeability anisotropy and direction can be determined either with stress measurements in a vertical pilot well before a horizontal well is directed, or by experiments with directional cores obtained in the vertical pilot well. Horizontal well tests or multiwell interference tests are the best permeability anisotropy measurement techniques. Pressure transient tests at a well are most commonly used for measures of the magnitude and direction of permeability, while interference tests are seldom used in the field.

Before a horizontal well is drilled, a vertical pilot well should first be drilled, followed by a partial-penetration drill-stem test. This test can be performed in two different ways: (a) by drilling only partially into the net pay, or (b) by drilling through the net pay and then packing off only a small portion of the interval. The spherical flow regime, the negative one-half slope straight line on the early-time pressure derivative curve, provides the spherical permeability $\sqrt{k_H k_V}$. A second test conducted with the entire pay thickness permeability, open to flow should provide the horizontal permeability k_H. The vertical and horizontal permeabilities, and the reservoir thickness can indicate the feasibility of drilling a horizontal well in the tested formation. If a horizontal well will be drilled, the proper well azimuth should then be determined.

The stress field in a reservoir can be described with three principal stresses: a vertical stress σ_V, a minimum horizontal stress $\sigma_{H\min}$, and a maximum horizontal stress $\sigma_{H\max}$. Measurements can identify the maximum and minimum horizontal stress directions, usually coinciding with the maximum and minimum horizontal permeability directions. The measurement of stresses in a vertical pilot well is valuable for the proper steering of a horizontal well.

Productivity model

Researchers have made several attempts to describe and estimate horizontal and multilateral well productivity and/or injectivity indices. Several models have been used for this purpose. Based on the tradition of vertical well productivity models, analogous well and reservoir geometries have been considered in the pursuit of simple but elegant analytical or semianalytical models. A widely used approximation for the well drainage is a parallelepiped model with no-flow or constant-pressure boundaries at the top or bottom and either no-flow or infinite-acting boundaries at the sides. Numerical simulation can be used for incorporating heterogeneities and other reservoir complexities. However, the use of analytical models for productivity index calculations is both attractive and instructive.

Borisov[37] introduced one of the earliest models, which assumed a constant pressure drainage ellipse in which the dimensions depended on the well length. This configuration evolved into Joshi's[38] widely used equation, which accounted for vertical-to-horizontal permeability anisotropy. It was adjusted by Economides et al.[39] for a wellbore in elliptical coordinates. This model, while useful for first approximations and comparisons with vertical well productivity indices, does not account for either early-time or late-time phenomena nor, more importantly, realistic well and reservoir configurations.

The Economides et al. solution obtains dimensionless pressures for a point source of unit length in a no-flow boundary "box". Using a line source with uniform flux, it integrates the solution for the point source along any arbitrary well trajectory. Careful switching of early- and late-time semianalytical solutions allows very accurate calculations of the composite dimensionless pressure of any well configuration.

The productivity index J, is related to the dimensionless pressure under transient conditions (in oilfield units)

$$J = \frac{q}{\bar{p} - p_{wf}} = \frac{\bar{k}x_e}{887.22B\mu\left(p_D + \frac{x_e}{2\pi L}\sum s\right)} \tag{1}$$

where $\bar{p}$ is the reservoir pressure (psi), p_{wf} is the flowing bottomhole pressure (psi), μ is the viscosity (cp), B is the formation volume factor, is the calculated dimensionless pressure, and $\bar{k}$ is the average reservoir permeability $\sqrt[3]{k_x k_y k_z}$. $\sum s$ is the sum of all damage and pseudoskin factors. Dimensioned calculations are based on the reservoir length x_e; L is the horizontal well length.

The generalized solution to the dimensionless pressure p_D starts with early-time transient behavior and ends with pseudosteady state if all drainage boundaries are felt. At that moment, the 3-D is decomposed into one 2-D and one 1-D part

$$p_D = \frac{x_e C_H}{4\pi h} + \frac{x_e}{2\pi L} s_x \tag{2}$$

where C_H is a "shape" factor, characteristic of well and reservoir configurations in the horizontal plane, and s_x is the skin accounting for vertical effects.

The expression for this skin effect (after Kuchuk et al.[40]) is

$$s_x = \ln\left(\frac{h}{2\pi r_w}\right) + \frac{h}{6L} + s_e \tag{3}$$

and s_e, describing eccentricity effects in the vertical direction, is

$$s_e = \frac{h}{L}\left[\frac{2z_w}{h} - \frac{1}{2}\left(\frac{2z_w}{h}\right) - \frac{1}{2}\right] - \ln\left[\sin\left(\frac{\pi z_w}{h}\right)\right] \tag{4}$$

which is negligible if the well is placed near the vertical middle of the reservoir.

The production from horizontal and multibranched wells presents certain opportunities and challenges:

1. A typical horizontal well is likely to perform between two and five times the production from a vertical well.
2. Because the production is not linear with length, two shorter wells invariably outperform one long well of equal total length. They are also easier to drill and complete. Thus "opposing laterals" drilled from the same vertical trunk are common.
3. Vertical-to-horizontal permeability anisotropy is an important reservoir property: the smaller the vertical permeability the lower the horizontal well performance. In thick reservoirs (e.g., net thickness of 100 ft or more) the vertical permeability is crucial to the point that a horizontal well may not be as attractive as a vertical well.
4. For thin reservoirs (i.e., 20 ft or less) vertical-to-horizontal anisotropy is not important and horizontal wells If successfully drilled) will outperform vertical wells by a large multiple.
5. In very thick reservoirs with bad vertical permeability "multilevel" or "stacked multilaterals" can be drilled from the same vertical trunk. They partition the reservoir vertically into thinner zones since they create a vertical no-flow boundary and in total they can be quite attractive.
6. The orientation of a horizontal well is also important. Drilled perpendicular to the maximum horizontal permeability (revealed through the measurement of stresses in a vertical pilot hole) can outperform another well drilled at right angle by a factor of three or more.

Hydraulic fracturing for production enhancement

Of profound importance in petroleum production is the reservoir permeability k, a defining porous medium property. Shallow reservoirs are likely to be unconsolidated or loosely consolidated with large grains. This would lead to large permeability. Deep reservoirs are likely to be highly consolidated, cemented and with small size grains. Their permeability is much smaller.

Darcy's law has led to widely used relationships between production rate q, pressure gradient Δp, and rock and fluid properties k, h and μ. For oil, under steady state and in consistent units

$$q = \frac{2\pi kh}{B\mu(\ln r_e/r_w)}\Delta p \tag{5}$$

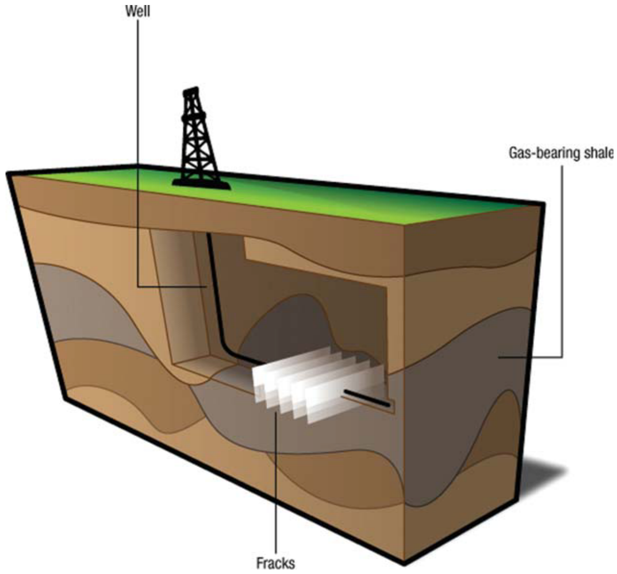

Figure 4. Hydraulically fractured ("fracked") horizontal well.

Equation 5 is important. It shows clearly the impact of rock permeability and fluid viscosity. In addition, tantamount to the film coefficient in heat transfer, the near-well zone can be characterized by a *skin effect* that can be added to ln r_e/r_w the denominator of Eq. 5. Positive skin effect means damage or impediments to flow; negative skin effect means *stimulation*, i.e., a series of actions that would facilitate near-well flow. The most prominent of them is hydraulic fracturing.

Starting 60 years ago but growing in the 1980s for tight gas applications and accelerating in the last decade, hydraulic fracturing has been established as the premier production enhancement procedure in the petroleum industry. By 2010, hydraulic fracturing had emerged as a $13 billion annual activity, second only to the drilling budgets in magnitude. Fracturing has continued to overwhelmingly dominate low-permeability reservoirs and has been instrumental in monetizing shale gas in North America, arguably one of the most important new activities of the petroleum industry.

What fracturing accomplishes is to alter the way the fluids enter the wellbore, changing from near-well radial flow to linear or bilinear flow. This implies that the flow is from the reservoir into the fracture and then along the fracture into the well (Figure 4). It should be noted here that a hydraulic fracture bypasses the near-wellbore damage zone. Thus, the pretreatment skin effect has little or no impact on the post-fracture equivalent skin effect value.

Although for the first 40 years since its inception in the late 1940s hydraulic fracturing had been exclusively for low-permeability reservoirs, this is no longer true. It has expanded into medium to high-permeability formations through the tip screenout (TSO) process. Reservoirs with permeabilities of several hundred md are now fractured routinely.

Cinco-Ley and Samaniego[41] introduced the fracture dimensionless conductivity C_{fD}, which is

$$C_{fD} = \frac{k_f w}{k x_f} \tag{6}$$

The equivalent skin effect s_f, resulting from a hydraulic fracture of a certain length and conductivity can be added to the well inflow equations as described previously. The pseudosteady-state flow equation for a hydraulically fractured oil well, in ''oilfield units'' would be

$$q = \frac{kh(\bar{p} - p_{wf})}{141.2B\mu[\ln(0.472 r_e/r_w) + s_f]} = \frac{kh(\bar{p} - p_{wf})}{141.2B\mu[\ln(r_e/r_w) - 0.75 + s_f]} \tag{7}$$

The dimensionless productivity index, J_D is a useful quantity, and it is

$$J_D = \frac{1}{(\ln r_e/r_w) - 0.75 + s_f} \tag{8}$$

Cinco-Ley and Samaniego related C_{fD} and s_f directly. Subsequent work by Economides et al.[42] showed that optimum fracture performance, under pseudoradial flow conditions happens

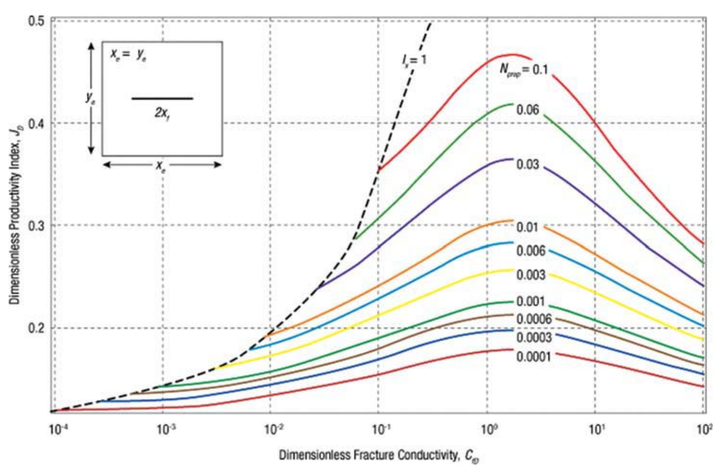

Figure 5. Maximum J_D at optimum C_{fD} for $N_{prop} < 0.1$.

at a value equal to 1.6. With that finding, the induced fracture geometry (length and width) are *de facto* set and, therefore, fracture design and execution should be oriented toward delivering that geometry. This finding is a seminal conclusion in modern petroleum production enhancement.

Unified Fracture Design

Valkó and Economides and coworkers introduced in Romero et al.[43] an optimization technique to maximize the productivity index of a hydraulically fractured well that they have called the unified fracture design (UFD) approach. The method starts with a simulation of the behavior of a fractured well in a closed system, i.e., eventually the well will experience pseudosteady state. Any well and drainage geometry can be simulated including elongated shapes which are appropriate for infield drilling and reservoir exploitation strategies with fractured wells. Similarly, horizontal wells with multiple transverse fractures can be designed and evaluated with this approach.[44]

Central to UFD is the concept of the dimensionless proppant number, given by

$$N_{prop} = I_x^2 C_{fD} = \frac{4k_f x_f w}{k x_e^2} = \frac{4k_f x_f w h}{k x_e^2 h} = \frac{2k_f V_p}{k V_r} \tag{9}$$

where $I_x = 2x_f/x_e$ is the penetration ratio; C_{fD} is the dimensionless fracture conductivity, is the reservoir drainage volume, and V_p is the volume of the proppant *in the pay*. It is equal to the total volume injected times the ratio of the net height to the fracture height. K_f is the proppant pack permeability, and k is the reservoir permeability.

For a given value of N_{prop} for a fracture producing from a drainage area, there is an optimal dimensionless fracture conductivity at which the productivity index is maximized. Figure 5 (for $N_{prop} < 0.1$) is a graph of the dimensionless fracture conductivity vs the dimensionless PI with the Proppant Number as the parameter.

At ‘‘low’’ Proppant Numbers (Figure 5), the optimal conductivity $C_{fD} = 1.6$. However, as the Proppant Number increases, the fracture penetration approaches the drainage boundaries ($I_x = 1$ is a fully penetrating fracture), and the boundaries normal to the fracture plane force the flow to remain linear, which is far more efficient than radial, until eventually pseudosteady-state flow develops. The absolute maximum for the pseudosteady state dimensionless productivity index J_D, in a square reservoir is $6/\pi = 1.9$.).

Once the optimal dimensionless fracture conductivity is known, the optimal fracture length and width can be readily determined

$$x_{fopt} = \left(\frac{k_f V_f}{C_{fDopt} k h}\right)^{0.5} \quad \text{and} \quad w_{opt} = \left(\frac{C_{fDopt} k V_f}{k_f h}\right)^{0.5} \tag{10}$$

where $V_f = V_p/2$ is the volume of one propped wing. The fracture execution then is tailored to achieve this optimum fracture geometry. Adjustments of the design may include the selection of the fracturing fluids, the injection rate, the injection pressure and the slurry concentration.

Closing Thoughts

Although not the only factor, technology in many forms has played a pivotal role in exploration and production of oil and gas, the world's biggest business. It is understandable, then, that petroleum engineering entails diverse competencies catering to the needs of finding and extracting a precious commodity from the earth—in contrast to other engineering disciplines, for which a core set of competencies may be applied to a wide array of different areas.

In addition to the three important technologies we discussed in the preceding sections, many other technological solutions have made contributions to varying degrees. For example, the term *enhanced oil recovery* (EOR), the focus of many chemical engineering researchers, is used to encompass the use of materials and operating practices to increase the amount of oil extracted from a reservoir. As another example, the term *intelligent fields* or similar is used to denote the extensive use of computers and communications for integrated, remote, and heavily computer-assisted work flows in drilling and production operations.[45,46] In fact, monitoring a drill bit or a remotely activated valve in a ‘‘smart well’’ thousands of feet below surface from thousands of miles away is not unlike space mission control, and in some ways not less challenging. As a more recent example, nanotechnology is holding promise for developing new materials for diverse applications in the oilfield.[47]

Of course, oil and gas are finite resources and will not last for ever. However, technology has repeatedly found ways to push back in time the inevitable ultimate decline in the production of oil and gas. To wit a recent development, *proved* natural gas reserves in the U.S. totaled about 175 Tcf in 1998; in 2009, after about 250 Tcf of production in the intervening years, US proved gas reserves *rose* to 285 Tcf. The main reason is shale gas, whose extraction became possible only after the development of horizontal drilling and massive hydraulic fracturing, two of the enabling technologies we singled out in this article. Granted, it is becoming increasingly difficult to extract oil and gas from the ground. As an extreme example, it takes about one unit of energy to extract three units of energy in oil from Canadian tar sands. The corresponding ratio was more than an order of magnitude better in the early days of the Texas oil boom in the beginning of the 20th century.[48] Yet as oil becomes more difficult to find and extract, its use becomes more prudent. For example, almost no oil is used in the US today for electricity generation. On the other hand, transportation runs almost entirely on oil, relying on a highly integrated, refined, and voluminous infrastructure. It should not escape the reader's attention that attempts to replace fossil fuels by alternative sources (wind, solar) for electricity generation will hardly make a dent on the dependence of the US on oil in the immediate future, unless transportation is electrified.

It should also be emphasized that environmental friendliness, particularly in the long run, places constraints on how various energy sources are used, in addition to their availability. For example, the use of natural gas in electricity generation results in substantially lower emission of pollutants and greenhouse gases in comparison to other fossil fuels. Similarly important is a careful analysis, development, and enforcement of practices that avoid unacceptable environmental impact of oil and gas exploration and production operations.

Predicting what the future will hold is risky, as already emphasized. In the absence of game-changing breakthroughs, it appears plausible that fossil fuels will continue to play a key role in the global energy mix for many decades. Breakthroughs or gradual improvements that eventually exceed a critical threshold hold the key for making practical the large-scale use of alternative energy sources. Such breakthroughs, however, could have a strong impact on fossil fuel use as well, as in the case of natural gas hydrates,[49] whose practical exploitation, if ever made feasible, could provide vast amounts of natural gas. Whatever the case, it is certain that chemical engineers will have many opportunities to shape the oil and gas energy future or its alternatives.

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