Tight Gas Reservoirs – An Unconventional Natural Energy Source for the Future

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Summary

With the decline of production and increase in demand of fossil-fuel, economically producing gas from unconventional sources (tight gas, coal bed methane (CBM), and gas hydrate) is a great challenge today. The large volume and long-term potential, attractive gas prices and unprecedented interest in world markets, brings the unconventional gas into the forefront of our energy future. Tight gas exists in underground reservoirs with microdarcy-range permeability and have a huge future potential for production.

Four criteria that define basin-centered gas accumulations, **including low permeability, abnormal pressure, gas saturated reservoirs and no down dip water leg.** Although "tight gas sands" are an important type of basin-centered gas reservoir, not all of them are Basin-centered gas (BCGAs). A concerted technology effort to both better understand tight gas resource characteristics and develop solid engineering approaches is necessary for significant production increases from this low-permeability, widely dispersed resource. Gas production from a tight-gas well will be low on a per-well basis compared with gas production from conventional reservoirs. A lot of wells have to be drilled to get most of the oil or gas out of the ground in unconventional reservoirs

Exploration efforts in low-permeability settings must be deliberate and focus on fundamental elements of hydrocarbon traps. Understanding gas production from low permeability rocks requires an understanding of the petrophysical properties-lithofacies associations, facies distribution, *in situ* porosities, saturations, effective gas permeabilities at reservoir conditions, and the architecture of the distribution of these properties. Petrophysics is a critical technology required for understanding low-permeability reservoirs. Improvements in completion and drilling technology will allow well identified geologic traps to be fully exploited, and improvements in product price will allow smaller accumulations or lower-rate wells to exceed economic thresholds, but this is true in virtually every petroleum province. Well Clusters and Onsite Waste Management are the key components of New Technology Concepts for tight gas development

Geologists, engineers, log analysts, and other professionals have to come to the common table with a need to better understand and predict reservoir properties in low-permeability reservoirs and use that information in resource evaluation, reservoir characterization and management. There is no fear of running out of oil or natural gas. An enormous volume of unconventional oil and gas will be there to fill the gap once conventional oil begins to decline in the next 5 to 20 years.

Introduction: The Key Words

The title "**Tight Gas Reservoirs – An Unconventional Natural Energy Source for the Future**" contains a few key words like **Tight Gas Reservoirs**, **Unconventional Energy Source** and **Future**. The first group of words '***Tight Gas Reservoirs***' says about the type of reservoirs and the natural resource contained in it where as the second group i.e '***Unconventional Energy Source***' spells about the scale of economics of exploitation with the present technological know-how and the last word '***Future***' deals with the time frame. When looked in totality, it speaks about the type of natural energy resource that is being focused by the geoscientists and the energy planner world-over as an alternative to the already declining source of fossil fuel.

The present study purports to make a global review of the various works and current researches relating to tight gas reservoirs and gain a solid scientific background in this aspect, then to apply these ideas to a practical evaluation of opportunities in India. The '***essenc***' of the study is a systematic review of major tight gas plays in the different parts of the globe. Geological characteristics (depositional environments, lithologies, diagenesis), fracture potential, reservoir development, resource density, and overall resource prize will be addressed.

The overview will include definitions of tight gas reservoirs and related concepts such as basin-centred gas and the Deep Basin versus conventional resource paradigms. The concept of reservoir ***sweet spots*** – both stratigraphic and structural – will be summarized. A spectrum of tight gas play types will be described to provide a framework of reference in comparing specific plays.

The central theme to the paper will be to assess whether this is a real possibility or may be simply a '*pipe dream*', over the medium-term (20 years or more).

From Conventional to Unconventional Reservoirs: the Future of the Oil and Gas Business

Conventional reservoirs are those that can be produced at economic flow rates and that will produce economic volumes of oil and gas without large stimulation treatments or any special recovery process. A conventional reservoir is essentially a high- to medium-permeability reservoir in which one can drill a vertical well, perforate the pay interval, and then produce the well at commercial flow rates and recover economic volumes of oil and gas.

On the other hand, an unconventional reservoir is one that cannot be produced at economic flow rates or that does not produce economic volumes of oil and gas without assistance from massive stimulation treatments or special recovery processes and technologies, such as steam injection. Typical unconventional reservoirs are tight-gas sands, coal-bed methane, heavy oil, and gas shales.

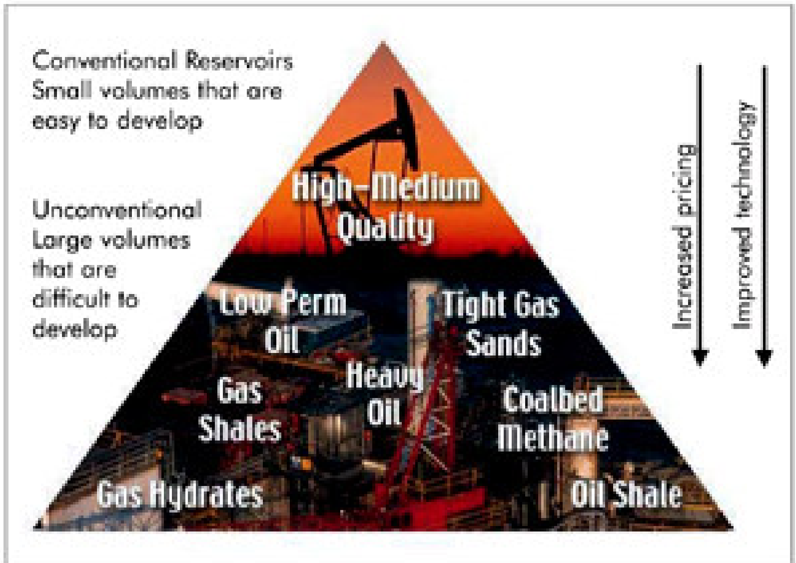


Fig. 1—The resource triangle.

Figure 1 depicts the resource triangle of both the conventional and unconventional resources.

Unlike conventional reservoirs, which are small in volume but easy to develop, unconventional reservoirs are large in volume but difficult to develop. Increasing price and the improved technology are the key to their development and the future. Unconventional resources are probably very large, but their character and distribution are not yet well understood. It is known to exist in large quantity but does not flow easily toward existing wells for economic recovery.

Fractured, tight and unconventional petroleum reservoirs

Fractured, tight and unconventional petroleum reservoirs, although less common and less well understood than conventional sandstone and carbonate reservoirs, have become an increasingly important resource base. Fractured reservoirs are composed of naturally fractured rock. Tight reservoirs contain no natural fractures, but cannot be produced economically without hydraulic fracturing. Unconventional reservoirs include tar, bitumen and heavy oil reservoirs as well as coalbed methane, shale and basin-center gas reservoirs and rely on emerging exploration strategies and new production technologies to be commercially productive. As a group, all of these reservoirs are increasingly important contributors to world oil and gas reserves and production.

Fractured, tight and unconventional reservoirs are often perceived as entailing higher costs and risks than conventional reservoirs. Historically, they have been unpopular with geologists and petroleum engineers. Geologists find that techniques such as regional facies mapping and sequence stratigraphy, which are useful for finding and delineating conventional reservoirs, are often ineffective for fractured, tight and unconventional reservoirs. Engineers look unfavorably on them because they are difficult to evaluate and recovery techniques must be judiciously chosen and carefully applied in order to avoid production problems. However, new technologies developed in recent years are making more and more of these accumulations economic.

Many individuals may think that unconventional reservoirs are not important now but may be very important in the future. Actually, unconventional reservoirs are very important now to many nations. The U.S. currently produces substantial volumes of natural gas from tight sands, gas shales, and coalbed-methane reservoirs. At the present time, >25% of daily U.S. gas production is recovered from tight and unconventional reservoirs and >25% of daily Canadian oil production is recovered from heavy oil sands. Also, heavy-oil production, especially in California, is quite important to the national economy. Other countries, such as Canada, Venezuela, and Russia, produce substantial volumes of heavy oil, while countries such as Australia, Argentina, Egypt, Canada, and Venezuela produce gas from low-permeability reservoirs. Clearly, fractured, tight and unconventional reservoirs represent a great resource base that has come of age. A number of such fields are in production right now, but in many areas production with the current technology is hardly economical. Economically producing gas from these unconventional sources is a great challenge today. Now it is the time to carefully examine these reservoirs and the new and emerging approaches and technologies that are being used to find and develop them.

The Golden Age of Gas

With a dimming possibility of an economically viable alternative sources of energy in near future, ever widening gap between the energy demand and supply and the decline of production of conventional fossil-fuel, the thrust on unconventional sources of gas (tight gas, coal bed methane (CBM), and gas hydrate) is glowingly increasing World-over. The large volume and long-term potential, attractive gas prices and unprecedented interest in world markets, brings the unconventional gas into the forefront of our energy future. With the successful marketing of natural gas as an "environmentally-friendly" fuel, demand of gas has increased sharply in the opening years of the 21st century. As it is less damaging to the environment, gas may command a premium price over other fossil fuels. Increasingly therefore, a significant percentage of the world's energy demand will be satisfied by natural gas. Some experts believe that gas consumption may exceed that of the oil by the year 2025 (Fig.2). Today' s unconventional resources will play a critical role in the Nation' s energy base in the next century.

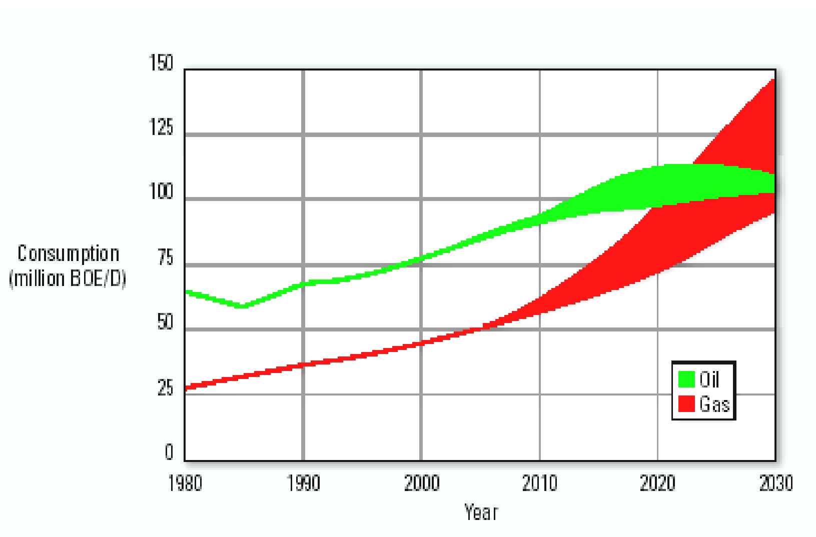


Fig.2. Expected oil and gas consumption. Some experts believe gas consumption will exceed that of oil by about 2025, when put in consistent units of barrels of oil equivalent per day (BOE/D). Future estimates indicate prediction ranges. (2003 World Gas Conference)

Unconventional gas reservoirs

Substantial amounts of gas have accumulated in geologic environments that differ from conventional petroleum traps. These are termed unconventional gas and occurs in "tight" (i.e., relatively impermeable) sandstones (Tight Gas), in joints and fractures or absorbed into the matrix of shales (Shale Gas), adsorbed in coal cleats or matrix (Coal Bed Gas), associated with gas hydrates, dissolved or entrained in hot geopressured…

"Future energy resources of the world, particularly gas, will be found in what we consider today to be unconventional reservoirs, especially low-permeability reservoirs in shales, siltstones, fine-grained sands, and carbonates. These are not, in fact, undiscovered resources, since their occurrences are fairly well-known. However, we do not have adequate geologic data to evaluate the contribution such reservoirs will make to the National energy endowment in the future.

What is a Tight Gas Reservoir?

"Tight gas" lacks a formal definition, and usage of the term varies considerably. Law and Curtis (2002) defined low-permeability (tight) reservoirs as having **permeabilities less than 0.1 millidarcies**. Therefore, the term "**Tight Gas Reservoir**" has been coined for reservoirs of natural gas with an average permeability of less than 0.1 mD (1×10^{-16} m²).

Recently the German Society for Petroleum and Coal Science and Technology (DGMK) announced a new definition for tight gas reservoirs elaborated by the German petroleum industry, which includes reservoirs with an **average effective gas permeability less than 0.6 mD.**

Tight gas Reservoir is often defined as a gas bearing sandstone or carbonate matrix (which may or may not contain natural fractures) which exhibits an in-situ permeability to gas of less than 0.10 mD. Many 'ultra tight' gas reservoirs may have in-situ permeability down to 0.001 mD

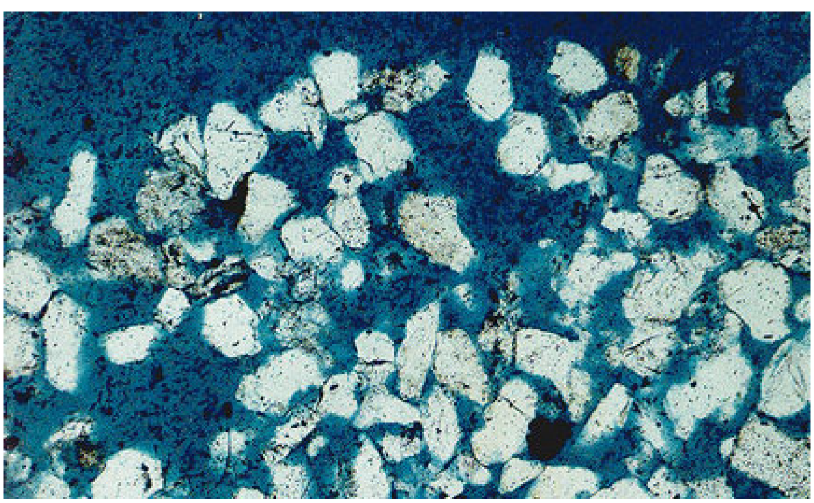


Fig..3a. Thin section of a conventional sandstone reservoir that has been injected with blue epoxy. The blue areas are pore space and would contain natural gas in a producing gas field. The pore space can be seen to be interconnected so gas is able to flow easily from the rock.

Fig.3b.Thin section Photo of a tight gas sandstone. The blue areas are pores. The pores are irregularly distributed through the reservoir and the porosity of the rock can be seen to be much less than the conventional reservoir.

The pores are poorly connected by very narrow capillaries resulting in very low permeability. Gas flows through these rocks generally at low rates and special methods are necessary to produce this gas.

What Makes a reservoir tight ?

There could be a number of reasons for making a reservoir tight. Basically the permeability that determines the easy at which a fluid can flow, is a multivatriate function governed by the Darcy's law of fluid flow in porous media. Effective porosity, viscosity, fluid saturation and the capillary pressure are some of the import parameter controlling the effective permeability of a reservoir. Besides the factors relating to the fluid nature, the rock parameters are equally important. These are controlled by depositional and post-depositional environments the reservoir is subjected to. The depositional setting like deep basinal site or the over-bank levees in flood plain areas are more prone to the deposition of very fine sand to silt and clays, which form poor reservoirs on lithification. It is not necessary that the muddy sandstones are having low permeability. Low-permeability sandstone reservoirs in the United States are not dominated by "immature, muddy sandstones with large volumes of diagenetically reactive detrital clay matrix, but rather are generally clean sandstones deposited in high-energy depositional settings whose intergranular pores have been largely occluded by authigenic cements (mainly quartz and calcite)" (Dutton et al., 1993). Post-depositional diagenetic events act many times negatively, reduce the effective porosity and thereby make the rock less permeable.

Interaction between Quartz Cementation and Fracturing in Sandstones- Quartz cementation and fractures are complexly interrelated. Quartz cementation influences fracture systems by affecting the rock mechanical properties at the time of fracture formation, which, in turn, influences fracture aperture distributions and clustering. Additionally, cementation affects flow properties of fracture networks by partially or completely occluding fracture pores. Due to extensive cementation by authigenic clays, the matrix permeability of these sandstones is extremely low, on the order of microdarcies

Tight Gas Reservoir Distribution: *Types of Tight Gas reservoirs*

Many explorationists think of tight or low-permeability reservoirs as occurring only within basin-centered, or deep basin settings. However, tight gas reservoirs of various ages and types produce where structural deformation creates extensive natural fracture systems whether it is basin margin or foothills or plains. Fractured, tight and unconventional reservoirs can occur in tectonic settings dominated by extensional, compressional or wrench faulting and folding. Late burial diagenesis of the sandstone may also result tight reservoirs. ***Although "tight gas sands" are an important type of basin-centered gas reservoir, not all of them are*** **Basin-centered gas** **(*BCGAs)***

What Is A Basin-Centered/Deep Basin Gas System?

Basin-centered gas /Deep Basin (>15,000ft) accumulations are a component of BCGSs that Law defines as "***an abnormally-pressured, gas-saturated accumulation in low-permeability reservoirs lacking a down-dip water contact***". They are characterized by regionally pervasive gas-saturated reservoirs, containing abnormally-pressured gas accumulations (Fig.4). The up-dip boundary of the Deep Basin is somewhat nebulous, as each reservoir unit may have its own up-dip edge.

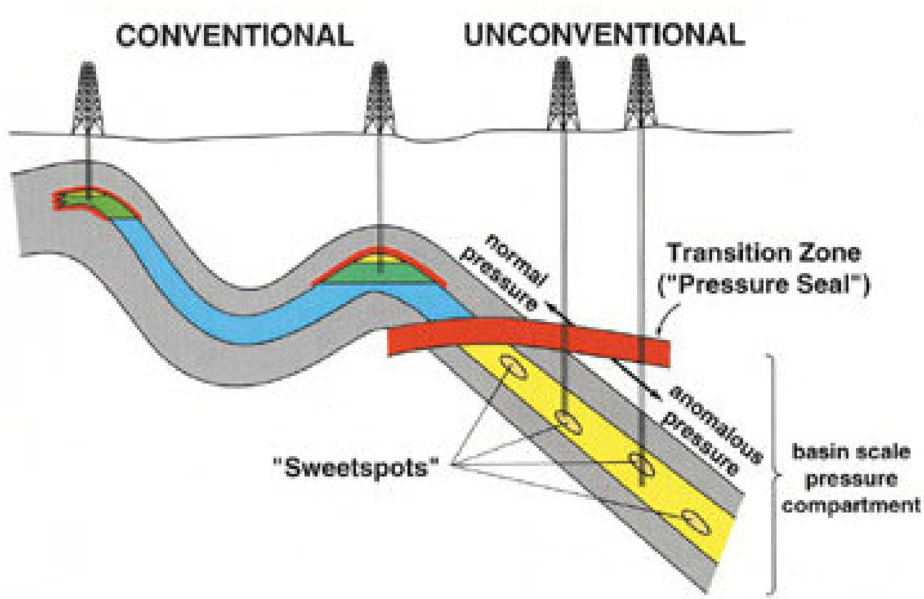
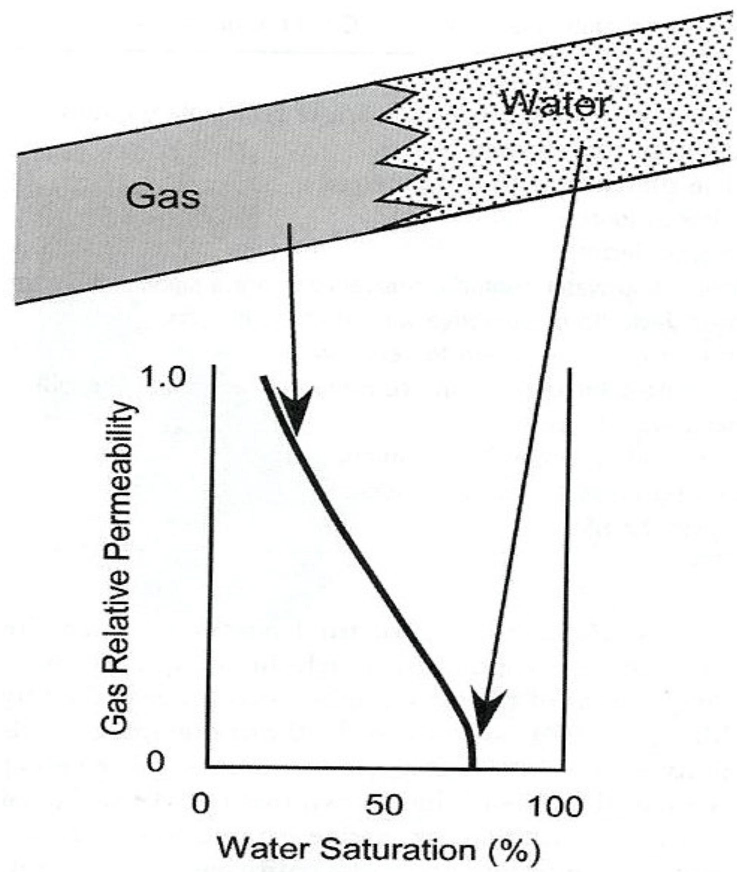


Fig.4. Basin Centred Gas Accumulation Model

The first description of a low-permeability gas province that are commonly associated with basin-centered systems is by Masters (1979), who described the deep, gas-saturated

Cretaceous sandstone reservoirs of western Alberta, the San Juan basin in New Mexico, and Wattenberg field in the Denver basin of Colorado. All these basins have relatively low porosity and permeability (7 – 15%, 0.15 – 1.0 md), moderate water saturations (34 – 45%). The reservoirs are located in the deeper portions of the basin. Masters (1979) also noted water-bearing strata structurally updip of gas-bearing strata. To describe the transition from gas to water, Masters (1979) stated that "…the water-saturated section grades imperceptibly through a transition zone 5 to 10 mi wide into a gas-saturated zone," and that "…there is no evidence for a stratigraphic or structural barrier between the water and gas zones."



Juxtaposition of water-bearing strata that lie updip of gas-saturated reservoir has been explained by the concept of a water block (Masters,1979), in which the relative permeability to gas would dramatically deteriorate at higher water saturations, rendering the reservoir rock incapable of producing gas (Fig. 5). The water block described by Masters (1979) essentially forms the up-dip seal on large basin-centered gas accumulations.

Fig.5.The concept of water block (Masters, 1979) has been used to explain how, within lithologically continuous units, downdip gas-bearing strata could be trapped by updip water-bearing strata. In this model, water effectively provides the updip seal.

Attributes common to BCGSs include: A continuous gas accumulation

- is regional in extent,
- can have diffuse boundaries,
- has existing "fields" that commonly merge into a regional accumulation,
- does not have an obvious seal or trap,
- does not have a well-defined gas-water contact,
- has hydrocarbons that are not held in place by hydrodynamics,
- commonly is abnormally pressured,
- has a large in-place resource number, but a very low recovery factor,
- has geologic "sweet spots" of production,
- typically has reservoirs with very low matrix permeabilities,
- commonly has natural reservoir fracturing,
- has reservoirs generally in close proximity to source rocks,
- has little water production (except for coal-bed gas),
- has water commonly found updip from gas,
- has few truly dry holes, and
- has Estimated Ultimate Recovery (EUR) of wells that are generally lower than
- EUR' srfom conventional gas accumulations.

There are two basic types of BCGSs: **direct and indirect**

A direct type is defined as having a **gas**-prone source rock while an indirect type is defined as having an oil-prone source rock

Attributes of direct BCGS

- **Gas**-prone source rock
- Pressure mechanism-hydrocarbon generation
- Under-/over-pressured
- Relative permeability/ capillary block seal
- Variable temporal integrity of seal
- Top cuts across structural/ stratigraphic boundaries
- **Gas** migrates short distances
- Top of BCGA Commonly >0.7% Ro

Attributes of indirect BCGS

- Oil-prone source rock
- Pressure mechanism - oil cracking
- More likely under-pressured
- Lithologic seal
- Long temporal integrity of seal
- Top conformable with bedding

- **Gas** migration distances can be short or long
- Top of BCGA >1.3-1.4 Ro

The term basin-centered includes gas systems variously referred to as deep-basin gas systems, tight-gas systems, and continuous-type gas systems. In many basin-centered accumulations, source rocks are thought to be in close physical proximity to reservoir rocks, and structural and stratigraphic traps, in the sense of conventional hydrocarbon systems, are thought to be of little importance. Table 1 summarizes the attributes commonly associated with basin-centered gas systems.

Table 1. Summary of Characteristics Commonly Associated with Low-Permeability, Basin-Centered Gas Accumulations

Geographic area	tens to hundreds of square miles
	commonly in the more central, deeper portions of sedimentary basins
	located in widespread gas-saturated regions
	much larger than conventional oil and gas traps
Resource size	very large in-place resource
	low overall recovery factor
Relationship to water	generally lack downdip water contacts; buoyancy is not a significant factor
	generally located downdip of pervasive water-saturated rocks
	water production is generally absent to very low
Trap boundaries	structural and stratigraphic traps, in the conventional sense, are thought to be of limited importance
Reservoir pressure	overpressure and underpressure both common
Source rocks	in close physical proximity to reservoir rocks
Reservoir permeability	generally less than 0.1 md

Commercial production of gas from these BCGA is generally associated with areas having improved productivity and/or permeability These are described as sweet spots. Surdam (1997a), designated sweet spots "…as those reservoir rocks that are characterized by porosity and permeability values greater than the average values for tight sands at a specific depth interval." Commercial production from BCGAs is strongly dependent on the presence of open natural fractures and the ability to connect these natural fracture systems through hydraulic fracture stimulation (Surdam 1997a).

Trapping Mechanism of Deep Basin Gas

Deep Basin Gas is an abnormal gas accumulation whose formation conditions, trapping mechanism and distribution are different from those of normal gas accumulations. Deep basin gas accumulation is characterized by gentle dip angles, subnormal pressure, gaswater inversion and co-occurrence of reservoir and source rock. The major processes associated with deep **basin** hydrocarbon accumulation are related to hydrocarbon generation and accumulation dissipation. The fundamental conditions favourable to the formation of deep basin gas accumulation include a plentiful gas source, tight reservoir and tight seal under the reservoir.

Two balances are the prerequisite for formation and preservation of deep basin gas accumulation. One is the force balance that occurs between the upward forces, including gas volume expansion pressure and buoyancy, and the downward forces including hydrostatic pressure and capillary pressure. The other is material balance that occurs between the supply amount of gas and the escaping gas. If the amount of gas charging the reservoir is more than that of escaping gas, the distribution range of the accumulation will expand up to the boundary limited by the force balance; and vice versa, a lower supply will cause shrinkage of the range.

The force balance determines the theoretical maximum range of deep basin gas accumulation. In this range, gas expelled from the source rock can be accumulated to form a deep basin gas pool. The greater the amount of gas that is expelled from the source rock, the larger will be the distribution range of deep basin gas accumulation. Beyond this range, gas that is expelled from the source rock has no choice but to migrate under the force of buoyancy to form a normal gas accumulation.

Overpressure is basically caused by two volume changing processes: shrinkage of maturing kerogen accompanied by creation of compactable non-equilibrium porosity and creation of fluid hydrocarbons whose volume exceeds both original and created porosity. Pressure is maintained in the bottom of the **basin** by a rate of generation and reservoir charge that exceeds the migrational rate capacity of the system as controlled by the capillary entry pressure of confining non-source rocks. Hydrocarbon generation overpressures have created hydraulically induced fractures that have enhanced the low matrix permeability of nearby sandstone reservoir rocks

Shallow Gas Systems in Tight Reservoirs in Basin Margins

Shallow gas accumulations in tight reservoirs on basin margins fall into three distinct systems: ***early generation biogenic, late generation biogenic, and nonassociated thermogenic***.

For example, the southeastern margin of the Alberta basin has early generation biogenic gas in Cretaceous, marine clastic reservoirs. Reservoirs and source rocks are interbedded; gas has not migrated significantly since generation shortly after deposition. Gas is methane-rich with microbial isotopic signatures. Fields tend to be underpressured and have little co-produced water.

The northern margin of the Michigan basin has late generation biogenic methane in fractured Antrim Shale (Devonian). The marine black shale acts as both reservoir and source rock; gas migration is minimal. The gas was generated in the recent geologic past .

The northwestern margin of the Anadarko basin has non-associated thermogenic gas produced from heterogeneous Permian rocks in the Hugoton embayment. Reservoirs on the basin margin are widely separated from the areas of thermogenesis in the deeper basin. Gas has migrated substantial distances up the basin margin and contains the heavier hydrocarbons characteristic of thermogenic gas.

Examples:

i) Shallow biogenic gas trapped in tight reservoirs in the Western Plains and Rocky Mountain Basins of North America forms a substantial unconventional gas resource hosted in Cretaceous-Tertiary clastic reservoirs. SBG generally occurring at depths of less than 1,000 m (3,300 ft) represents a poorly understood by-passed resource. A potential for greater than 70 TCF of gas-in-place has been determined in the Western Plains region extending from central Alberta in Canada into the U.S. mid-west. The play potentially continues south to the Gulf Coast.

A broad areal extent, subnormal formation pressures ranging from 20 to 70% of hydrostatic and occurrence in low permeability sand-shale sequences characterizes the resource. Subnormally pressured gas-charged sands often show a transition updip to normally pressured water-wet sands. Downdip flow, which is usually observed in the water-wet section, may enhance the trap in some cases. SBG is often by-passed due to deep invasion, relatively high water saturation (45-75%) and fresh formation water (<10,000 ppm), which together invalidate conventional petrophysical analysis and testing techniques.

Recognition of the unique hydrodynamic signature and an understanding of the basin evolution required for its occurrence are key to identifying and exploiting the shallow gas resource and extending the play into other basins.

ii) Areally-extensive, low resource-density shallow gas plays – e.g., Second White Specks, Milk River, Horseshoe Canyon, Paskapoo.

Debate Taps Petroleum Systems- Drilling deeper into the debate:

It started at the AAPG annual meeting in Salt Lake City 2003 - a new Great Debate. Three independent Denver geologists gave a presentation challenging the conventional wisdom of basin-centered gas accumulations, and on what controls production from gas fields like the giant Jonah Field in Wyoming' s Greater Green River Basin.The debate continued at a Rocky Mountain Association of Geologists' symposium on "Petroleum Systems and Reservoirs in Southwest Wyoming."

The controversy is more than academic. Potentially billions of cubic feet of gas could be at stake depending on which theory is championed.

Some specific thoughts on a couple of basins

"We just didn' t understand the mechanisms ... so it became a topic of conversation among us as to how petroleum systems function and how traps are formed in areas of low permeability reservoirs," Shanley said. "What were the controlling factors?"

Over several years they developed a new concept for low-permeability reservoirs like those in the Greater Green River Basin, and determined that most fields are not part of a continuous-type gas accumulation or a basin center gas system in which productivity is dependent on the development of "sweet spots." Rather, most gas fields there occur in low-permeability, poor-quality reservoir rocks in conventional structural, stratigraphic or combination traps ("sweet spots"). The basin is neither regionally gas-saturated nor near irreducible water saturation, and that water production is both common and widespread. All of the larger fields in the Green River Basin are controlled by conventional trapping mechanisms and produce down dip water.

"Understanding field occurrence as well as reservoir and well performance in these low-permeability gas systems requires an understanding of multi-phase, effective permeability to gas at varying degrees of water saturation under conditions of overburden stress," (Shanley, et al 2004). "Understanding low-permeability gas systems such as those found in the Greater Green River Basin does not require a paradigm shift in terms of hydrocarbon systems. Low-permeability gas systems should be evaluated in a manner similar to and consistent with conventional hydrocarbon systems.

Successful exploitation of resources within low permeability gas systems requires a focused, deliberate effort that fully understands the unique petrophysical nature of these reservoirs and is able to integrate that information with all elements of petroleum systems analysis, particularly an understanding of trap-related elements.

Petrophysical Attributes of Low-permeability Reservoirs and Implications for Trapping Mechanisms

The most significant differences between conventional reservoir and low-permeability reservoirs lie in the low-permeability structure itself, the response to overburden stress, and the impact that the low-permeability structure has on effective permeability relationships under conditions of multiphase saturation. Figure 5 provides a comparison of traditional reservoir behavior with low-permeability reservoir behavior. In a traditional reservoir, there is relative permeability in excess of 2% to one or both fluid phases across a wide range of water saturation. Further, in traditional reservoir, critical water saturation and irreducible water saturation occur at similar values of water saturation. Under these conditions, the absence of widespread water production commonly implies that a reservoir system is at, or near, irreducible water saturation. In low-permeability reservoir, however, irreducible water saturation and critical water saturation can be dramatically different. In traditional reservoir, there is a wide range of water saturations at which both water and gas can flow. In low-permeability reservoir, there is a broad range of water saturations in which neither gas nor water can flow. In some very low-permeability reservoir, there is virtually no mobile water phase even at very high water saturations.

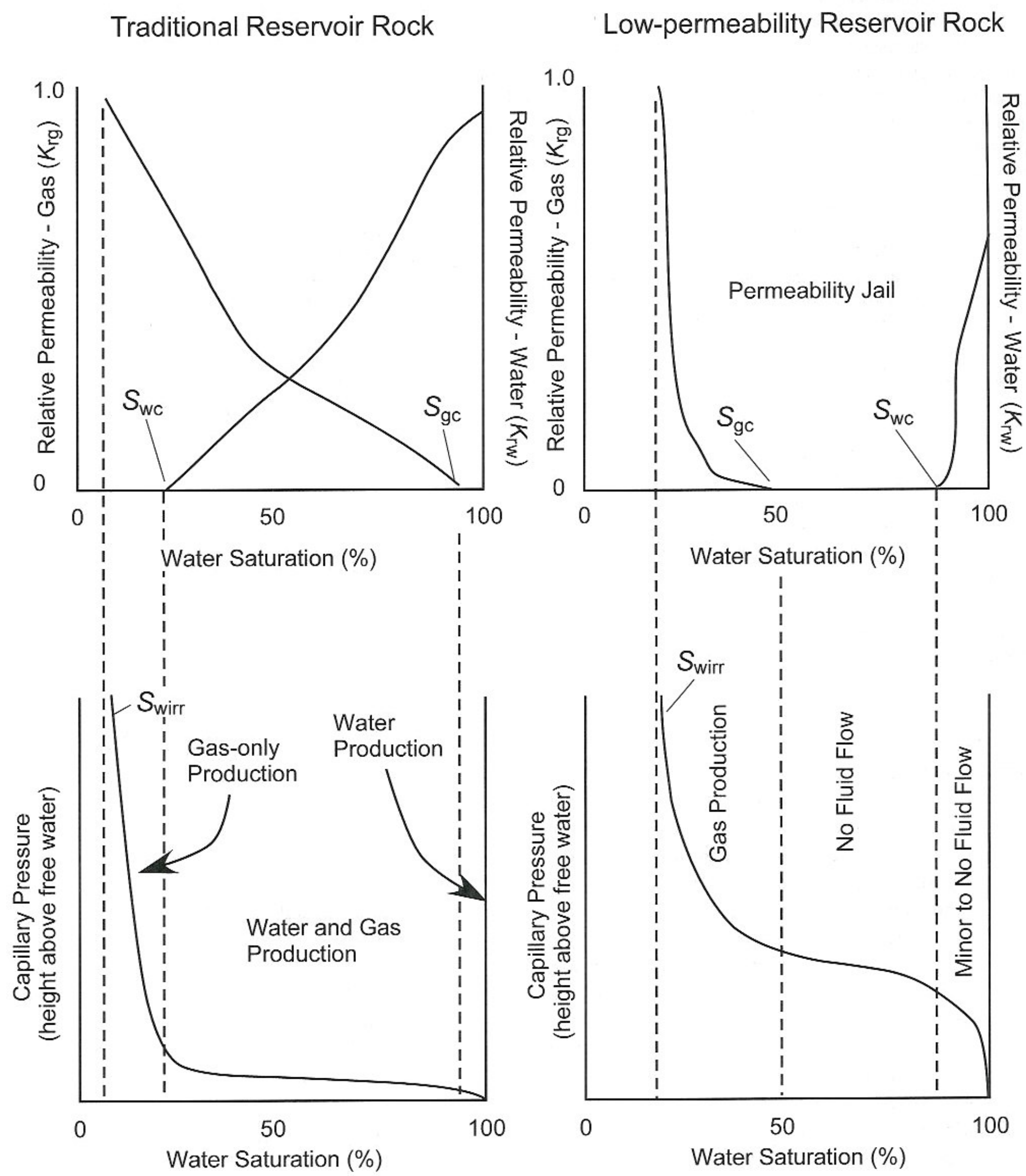


Fig.5. Schematic illustration of capillary pressure and relative permeability relationships in traditional and low-permeability reservoirs rocks (Shanley et al., 2004). Critical water saturation (S_{wc}), critical gas saturation (S_{gc}), and irreducible water saturation (S_{wirr}) are shown.

Because of the effective permeability structure of most low-permeability reservoir, there is a large range of water saturations over which both water and gas are essentially immobile. A lack of water production (or recovery from a test) should not be used to infer that the rocks are at, or near, irreducible water saturation nor should these regions be regarded as water free. Instead, low-permeability reservoir rocks should be regarded as having insufficient permeability to either gas or water over a wide range of water saturations.

Figure 6 highlights the relationships between capillary pressure, relative permeability, and position within a trap, as represented by map and cross section views in conventional and low permeability reservoirs. In both cases (A) and (B), the map illustrates a reservoir body that thins and pinches out in a structurally updip direction. In conventional reservoir, water production extends downdip to a free-water level (FWL). In the middle part of the reservoir, both gas and water are produced, with water decreasing updip. The updip portion of the reservoir is characterized by water-free production of gas. In low-permeability reservoirs, significant water production is restricted to very low structural positions near the FWL. In many cases, the effective permeability to water is so low that there is little to no fluid flow at or below the FWL. Above the FWL, a wide region of little to no fluid flow exists. Farther updip, water-free gas production is found.

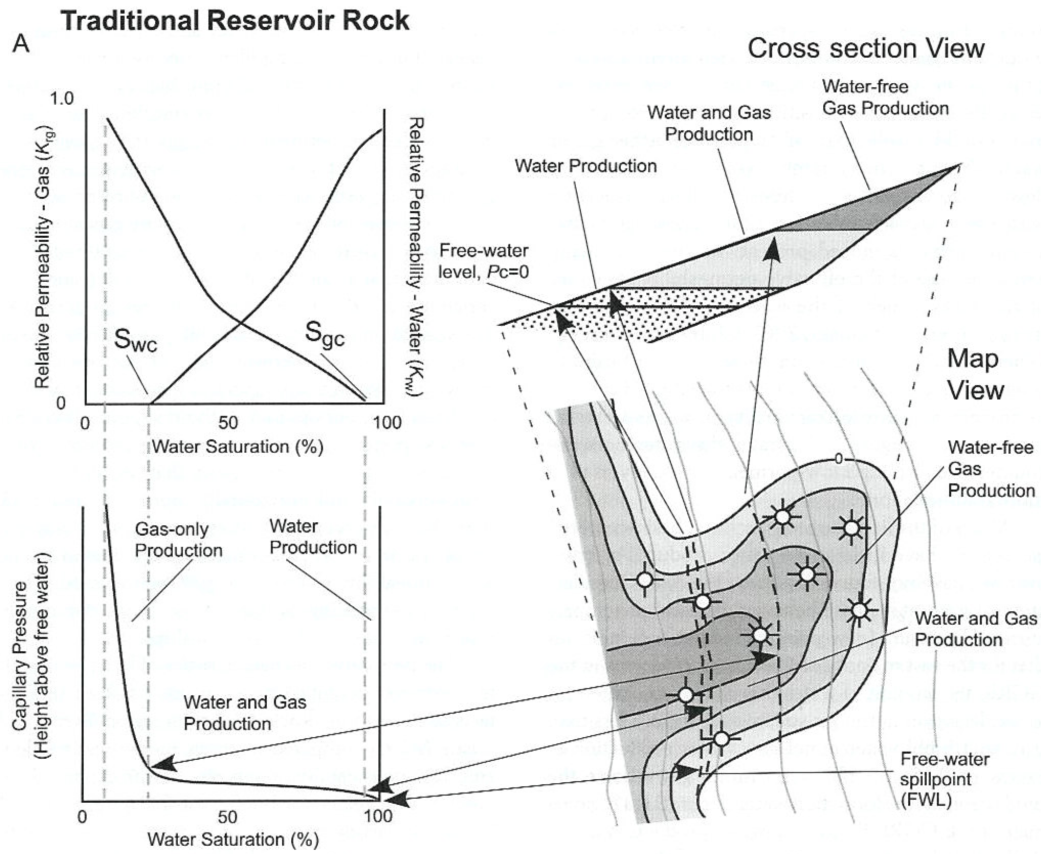


Fig. 6A. Schematic illustration highlighting relationships between capillary pressure, relative permeability, and position within a trap, as represented by map and cross section views for a reservoir with traditional rock properties. The map illustrates a reservoir body that thins and pinches out in a structurally updip direction. (Shanley et al., 2004)

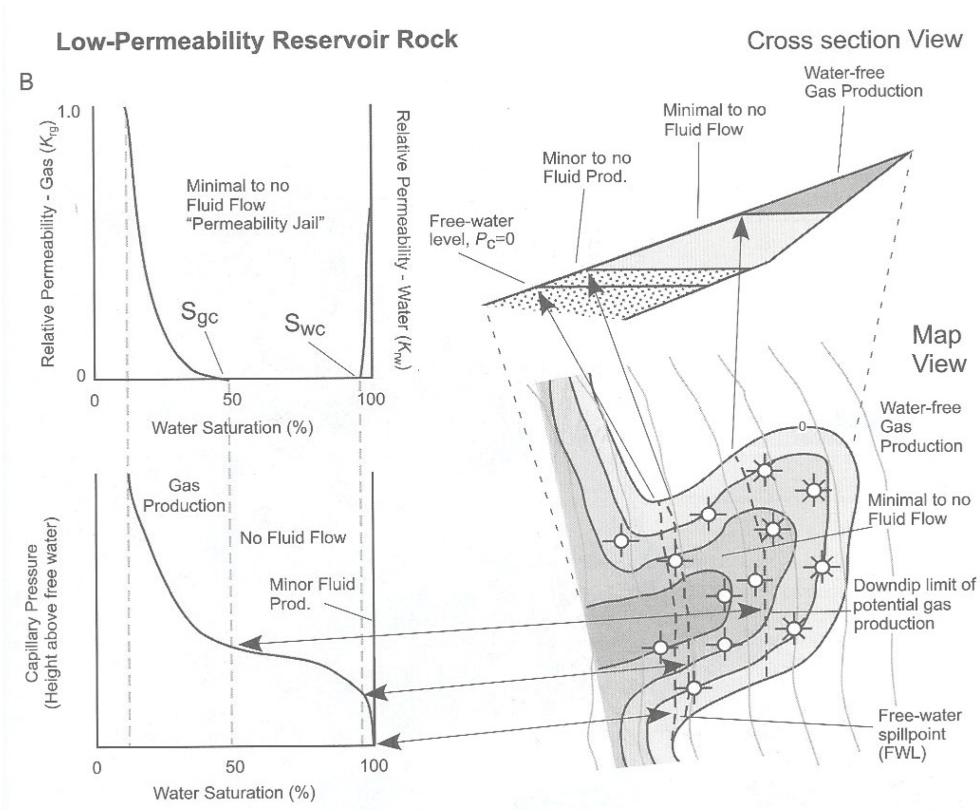


Fig. 6B. Schematic illustration highlighting relationships between capillary pressure, relative permeability, and position within a trap, as represented by map and cross section views for a reservoir with low-permeability. The map illustrates a reservoir body that thins and pinches out in a structurally updip direction. (Shanley et al., 2004)

Based on the petrophysical studies and the relative permeability variations in low-permeability, poor-quality reservoir rocks as illustrated above, Shanley et al., 2004, concluded that the gas fields in the Greater Green River basin are not examples of basin-center or continuous-type accumulations, nor are they a unique type of petroleum system as generally believed. All these occur in conventional structural, stratigraphic, or combination traps rather than regionally gas saturated unconventional basin centered type. Further, they opined that the only truly continuous-type gas accumulations are to be found in hydrocarbon systems in which gas entrapment is dominated by adsorption similar to coal-bed methane, some oil-prone source rocks, and some organic-rich shales.

Low-permeability reservoirs have unique petrophysical properties, and failure to fully understand these attributes has led to a misunderstanding of fluid distributions in the subsurface. An understanding of multiphase, effective permeability to gas as a function of both varying water saturation and overburden stress is required to fully appreciate the controls on gas-field distribution as well as the controls on individual well and reservoir performance. A better understanding of the relationship between rock fabric and gas productivity requires careful investigations into multiphase permeability under conditions of varying water saturation and net-overburden stress, as well as an analysis of capillary pressure and net-overburden stress. The lack of widespread water production does not imply that vast areas of a sedimentary basin are at irreducible water saturation. Instead, it implies a complex, effective permeability-to-gas relationship.

Shanley et al. (2004), made some startling remarks on the controversy of basin centered and low-permeability reservoirs, which are critical to the future exploration and production of these resources. Some of these conclusions are briefly discussed below.

- Exploration efforts in low-permeability settings must be deliberate and focus on fundamental elements of hydrocarbon traps.
- Improvements in completion and drilling technology will allow well identified geologic traps to be fully exploited, and improvements in product price will allow smaller accumulations or lower-rate wells to exceed economic thresholds, but this is true in virtually every petroleum province.
- Petrophysics is a critical technology required for understanding low-permeability reservoirs.
- Low-permeability reservoir systems like those found in the Green River Basin are not examples of "basin-center" or "continuous-type" accumulations, nor are they a unique type of petroleum system.
- Only truly ‘continuous-type’ gas accumulations are found in hydrocarbon systems in which gas entrapment is dominated by adsorption, such as coalbed methane, or where the reservoirs are in close juxtaposition with their source rocks.
- .Resource assessments of these regions have assumed a continuous, recoverable gas accumulation exists across a large area locally interrupted by the development of "sweet spots." However, this viewpoint is at odds with the reservoir characteristics of low-permeability reservoirs.
- Significant production is dependent on the presence and identification of conventional traps.

Therefore, Shanley et al., 2004, believe that existing resource estimates are likely overestimated. Resource assessments in these low-permeability "basin-centered" regions must recognize the reservoir properties inherent to these rocks and should integrate the necessary concept of source, trap, seal, migration and charge, and be conducted in a manner consistent with the assessment of conventional oil and gas systems

Much Ado About ... ?

While reactions to the new model have varied from both extremes, there are some geologists who wonder what all the fuss is about.

"They seem to be making the point that you can' t just drill anywhere in the center of a basin and get gas. We' ve known that for the last 20 years," said Larry McPeek, a geologist with Thomasson Partner Associates, Denver.

"You need some reason to have a sweet spot, and that sweet spot may be controlled by structural and stratigraphic changes," he said. "The two views don' t have to be mutually exclusive.

"My only concern is that some might take away from this discussion a negative outlook on basin centers as hydrocarbon hunting grounds," he continued. "That would be unfortunate, because there is a tremendous amount of oil and gas in basin centers because it is the cooking pot, and if you have any sort of trap it is apt to be filled."

Shanley emphasized that the group is in no way detracting from the prospectivity of these basins or basin centers.

"We want to be perfectly clear that we think there are substantial gas resources in these basins," he said. "These are gas-charged, hydrocarbon-rich basins that have a multitude of trap styles. They are complex, and in that complexity lies opportunity -- but it is not the low risk hunting ground many believe it to be. "We simply cannot pray to the gods of fracture stimulation, drilling fluids and strong prices to make gas come out of the ground," he added. "So, we feel the industry needs to think in terms of the risk process by evaluating source, reservoir, seal and trap, just as companies do in other regions.

Identifying the different types of reservoirs (fracture vs standard Matrix): *Describing Petroleum Reservoirs of the Future*

Natural vertical fractures are important factors in the economic production of gas from tight reservoirs because the permeability of the natural fractures is almost always much higher than the unfractured rock. However, most of the gas resources reside in the rock pores and move out of the rock to the wellbore via fractures. Different techniques are used in identifying and studying the tight gas reservoirs and the associated fractures.

Petrographical Methods:

Special emphasis is given on the study of cements and other authigenic minerals such as clay minerals, that partially fill the primary and secondary pore spaces using optical- and electron microscope examinations, along with XRD-analysis and organic carbon measurements. The descriptive characterisation is supported by the quantitative results of petrophysical examinations such as inner surface- and conductivity measurements.

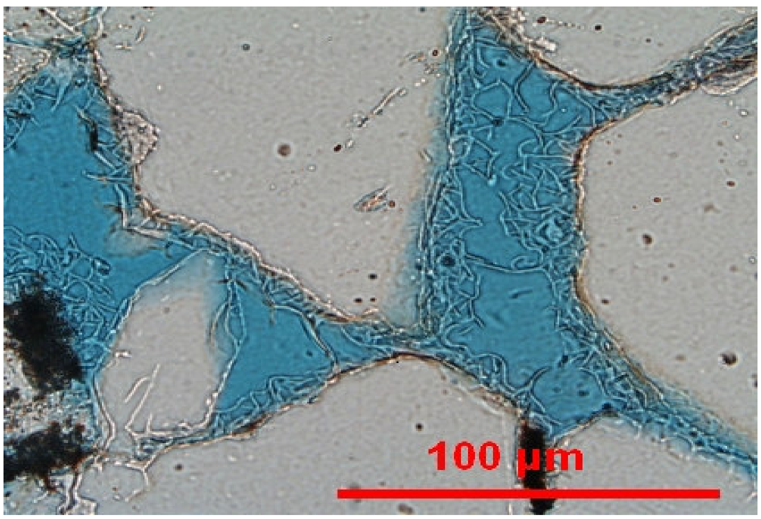
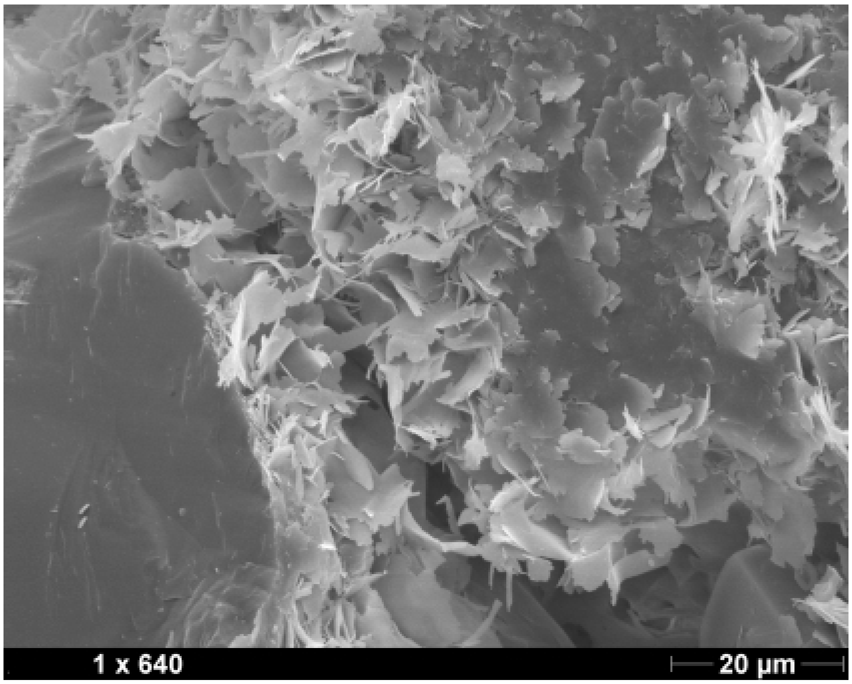


Fig.7. Image from thin section of a sandstone. The pore spaces have been filled by a special resin that makes them appear blue and can easily be identified. Notice the fine clay minerals (illite), grown on the pore surfaces during diagenesis. Clay

minerals are most likely the main cause for pore throat clogging during hydraulic fracturing treatments.
Thin sections provide a very clear impression of the relation between sedimentary grains, cement minerals and diagenetic clay minerals.



The same sandstone sample contemplated under electron microscope. For the much higher resolution, the three dimensional appearance and the possibility of element analysis by EDX technique, the minerals can easily be identified than by thin section analysis. Magnification can be increased up to several thousand times.

Well log Analysis:

Besides standard logs, Formation image logs are used to determine the presence and orientation of natural fractures. Nuclear magnetic resonance log analysis can detect possible depleted zones and provide estimates of formation permeability.

Most unconventional reservoirs characteristically have low porosity and low permeability. Because most logging tools were developed to evaluate formations with high porosity, they often lose their sensitivity in low-permeability, low-porosity reservoirs. Better formation-evaluation methods for low-porosity reservoirs are of vital importance. If technology can be developed that will give us a better estimate of formation permeability, along with formation porosity and water saturation, the development of unconventional reservoirs can be improved substantially.

3-D Seismic Horizon-Based Approaches to Fracture-Swarm Sweet Spot

Horizon attributes (e.g., dip, azimuth, and curvature) derived from 3-D seismic data hold considerable potential for identifying fracture-swarm sweet spots in low permeability reservoirs (Hart et al., 2002). Typically, these attributes are used to define subtle faults that can play important roles in compartmentalizing conventional reservoirs. However, in low permeability gas reservoirs, where fracture permeability is critical, these same attributes can be used to define high-permeability fracture swarms. Based on three case studies, two clastic (Mesaverde Blanco Field and Basin Dakota Field) the other carbonate (Ute Dome Paradox Field), from the San Juan Basin area of northwestern New Mexico, . Hart et al., 2002 opined that development drilling plans for low permeability reservoirs should take into account geologic heterogeneity that can be associated with fracture swarms.

Picking prospects in tight gas sands using multiple azimuth attributes

Multiple-azimuth 3D seismic attributes and petrophysical data help find the sweet spots

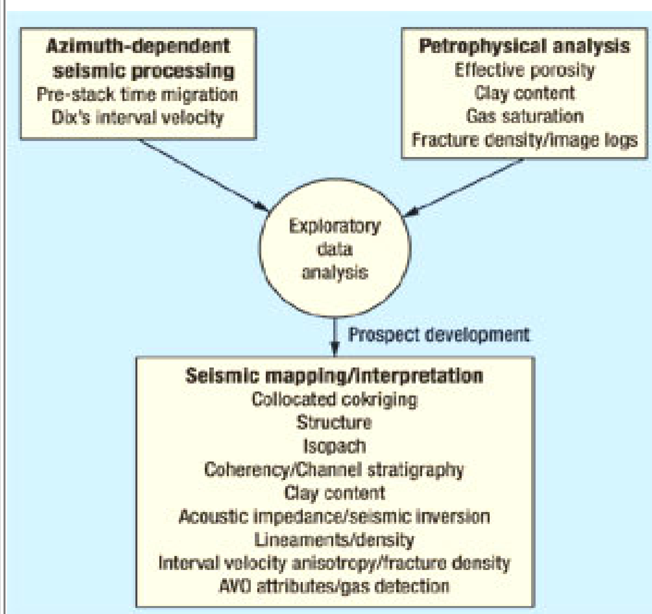


Fig. 9. Workflow of prospect development methodology

Figure 9. shows the work flow of prospect development methodology in tight gas reservoir. The processing is generally focused on stack analysis of anisotropy in multiple azimuths followed by pre-stack analysis of amplitude variation with offset (AVO). The processed data and subsequent statistical analysis of seismic attributes are interpreted for identification of fractures prospective for commercial gas production. This can be validated with the relationships between seismic attributes and measured reservoir properties, such as clay content, as well as fracture density interpreted from borehole-image logs.

P-wave velocity and permeability distribution of sandstones from a fractured tight gas reservoir

Fractures are an important fabric element in many tight gas reservoirs because they provide the necessary channels for fluid flow in rocks which usually have low matrix permeabilities. Laboratory measurements have shown the directional dependence of the permeability and P-wave velocities. Higher permeability values are generally in the plane of the nearly horizontal sedimentary layering with regard to the core axis. With the occurrence of subvertical fractures, however, the highest permeabilities were determined to be parallel to the core axis. At higher confining pressure, sedimentary layering is approximately the only effective fabric element, resulting in a more transverse isotropic V_P symmetry. Furthermore, water saturation increases the velocities and decreases the anisotropy but does not change V_P symmetry. This indicates that at this state, all fabric elements, including the fractures, have an influence on P-wave velocity distribution.

Formation/Production testing

Reservoir permeability and pressure are generally calculated from G-function analysis of pump-in tests and from pressure build up tests.

Examining similarities and differences of Tight Gas Development: *Reviewing lessons learnt and best practices*

Better reservoir knowledge and increasingly sensitive technologies are making the production of unconventional gas economically viable, and more efficient. This efficiency is bringing tight gas, coal-bed methane and gas hydrates into the reach of more companies around the world. However, production from tight gas reservoirs is still in its infancy, only limited knowledge is available about the causes of the problems concerning frac stimulations of low permeability reservoirs. Economically producing gas from the unconventional sources is a great challenge today.

Besides the cognition and solution of technical problems the petroleum engineers and geoscientists have to deal with the question whether some low permeability reservoir rocks may be potentially vulnerable to secondary skin effect (mechanical damage caused by the frac treatment itself). The most important of these damage features may be the loosening and transport of fines from the pore-fillings such as clay minerals due to treatment-induced stress and their redeposition at the tight pore throats.

Tight gas reservoirs require advanced techniques to enable migration distances from formation to well to be reduced. Therefore modern technologies for the production of tight gas reservoirs are horizontal and multilateral wells, as well as under-balanced drilling. Stimulation and cementing technologies are proving most significant for improved economic production. Conventional and novel technologies are deployed for field development of tight gas reservoirs.

The fundamental question to be answered is can we get economic production from micro Darcy, possibly condensate rich gas fields? Answer to this fundamental question depends on

- Petrophysical and geological aspects: permeability, porosity, water saturation, condensate rich gas, capillary forces, presence of reactive clays, etc.
- Field/well modelling
- Drilling and completion – the need for UBD/UBO
- Hydraulic fracturing
- Novel completion and stimulation techniques

Conventional methods of producing gas from tight reservoirs usually requires some form of artificial stimulation, such as hydraulic fracturing. Wells completed in tight reservoir rocks have to be stimulated by one or several hydraulic fracs in order to achieve an economically adequate production rate. Compared with more permeable rocks, tight gas reservoirs often show a much weaker response to the frac treatments, resulting in low production rates and a high economic risk. It is known that natural rock fractures are an important factor in the economic recovery of gas from tight reservoirs. Advanced methods of gas production in these environments are taking advantage of gas flow from natural fractures in the reservoir rock. The distribution, orientation, and density of these fractures is key to proper planning and well scheduling in tight gas reservoirs. In addition to these physical attributes, reservoir engineers also need detailed analyses of the effects of interstitial clays and fluids. The nature of the natural fractures and other characteristics of the reservoir were sufficiently well-determined that drilling could be accurately directed.

Understanding gas production from low permeability rocks requires an understanding of the petrophysical properties-lithofacies associations, facies distribution, *in situ* porosities, saturations, effective gas permeabilities at reservoir conditions, and the architecture of the distribution of these properties.

Development methods of tight reservoirs include a resolution of the traditional methods problems of the fields development. However in contrast to the traditional methods the development methods of tight reservoirs mainly direct to prevention of the problems on the scale of micropores. Those problems result from the interactions between molecules of fluid and of reservoir rock and develop through formation of the boundary phases (films and layers). The boundary phases drastically transform dynamics of filtration and in some cases suspend that one. Structure and properties of the boundary phases are predetermined by the reservoir rock properties, peculiarities of the hydrocarbon fluid composition, temperature and pressure in a deposit.

The fields development is accompanied with problems resulting from the highly heterogeneous spatial distribution of permeability and porosity throughout the reservoirs, stratification of deposits, variable production rate of wells inducing the selective bottom water intrusion to the deposit and giving rise to the trapping of hydrocarbons behind the hydrocarbons - water front, fall out of condensate, paraffins, resins and asphaltenes etc.

Traditional methods of fields development resolve those problems on the scale of a deposit.

Further modern technologies for the production of tight gas reservoirs are horizontal and multilateral wells, as well as underbalanced drilling. Compared with more permeable rocks, tight gas reservoirs often show a much weaker response to the frac treatments, resulting in low production rates and a high economic risk. As production from tight gas reservoirs is still in its infancy, only limited knowledge is available about the causes of the problems concerning frac stimulations of low permeability reservoirs.

Well Testing in Tight Gas Reservoirs

The low permeability of these reservoirs slows down their response to pressure transient testing so it is difficult to obtain dynamic reservoir properties and to production so it is difficult to characterize the gas in place. The need to hydraulically fracture wells in these reservoirs to obtain commercial flow rates adds to the complexity of the problem.

Determination of real composition of fluids trapped in tight reservoirs

Determination of the real composition of fluids trapped in a tight reservoir is a groundwork of the calculation of the deposit actual resources. The greater a variety of components dissolved in fluid and greater a specific surface of reservoir rock the less a composition of an average sample taken from the bottom hole corresponds to the real fluid composition in a deposit. A composition of an average sample taken from the bottom hole computed on a basis of a gas condensate testing of wells approximately corresponds to a fluid composition in the largest pores and interstices. That fraction of fluids to a lesser degree influenced by the reservoir rock. The rheological properties and phase behavior of the substantial fraction of hydrocarbon resources are transformed to a high degree by the tight reservoir rock. Those resources involved to the recovery at the variation of temperature, pressure and another physicochemical conditions significantly vary the value of the predicted recoverable resources.

The Use of An Integrated Approach for Reducing Uncertainty of In-Place Volume Estimation and Productivity Forecast in Tight Gas Reservoirs

To reduce the uncertainty in the estimation of hydrocarbon in place and fluid contact in tight gas reservoirs, it is essential to integrate core data and log analysis. A newly developed saturation-height function approach has been successfully applied to calibrate log analysis to better define petrophysical properties such as formation water saturation and free water level in tight gas reservoirs. The application of this approach has played a critical role in exploration and development decision-making processes for tight gas reservoirs.

Unlike most of the models published in the literature, this approach accommodates different forms of J-Sw regressions, which is applicable to different pore geometries and very powerful in tight gas reservoirs. Using this approach, water saturation is calculated continuously from log porosity and free water level without formation resistivity and Archie exponents. This approach also estimates free water level by iterating on water saturations until matching those derived from log data.

Overview of Tight gas areas worldwide: Which spots hold the most reserves ?

Out of the 5500 TCF of the world's gas reserves, a large percentage of the reserves is in tight formations of 1 mD down to 0.005 mD. Current USGS studies suggest that enormous quantities of gas and oil may be tied up in unconventional reservoirs.

Tight gas production first developed in the Western United States San Juan Basin, fueled by improvements in hydraulic fracturing technology. By 1970, approximately 1 trillion ft^3 per year were being produced nationwide. Price incentives in the form of tax credits and advancing technologies during the 1980' s increased development, with production levels eventually reaching the current level around 2.5 trillion ft^3 per year. This represents 13% of current lower-48 gas production. There are approximately 40,000 tight gas wells producing from 1600 reservoirs in 900 fields.

Estimates of gas-in-place contained within tight gas sands vary considerably but they mostly agree on one aspect, that this is a large resource: some estimates suggest as much as 100 000 x 10^9 m^3worldwid potential. Total gas in place in the United States may exceed 15,000 Tcf, with annual production between 2 and 3 Tcf. In the Rocky Mountain region, the U.S. Geological Survey suggested a mean recoverable resource of 160.5 tcf gas, 568 million bbl oil, and 1829 million bbl of natural gas liquid (NGL) across four basins in unconventional, continuous-type accumulation hosted in sandstone reservoirs. More recently, the U.S. Geological Survey has conducted additional detailed geologic studies and new assessments of several key basin, including those basin with large unconventional resource potential. These studies suggest that continuous-type sandstone reservoirs contain mean, undiscovered resources of approximately 80.6 tcf gas and 2500 million bbl NGL in the Green River basin of southwest Wyoming, 18.8 tcf gas and 33.4 million bbl NGL in the Uinta and Piceance basin, and 26.2 tcf gas and 144.4 million bbl NGL in the San Juan basin

USGS investigations have led to larger gas-resource estimates for some western basins. The Gas Research Institute (GRI) has estimated a new field gas potential in low-permeability reservoirs in the Rocky Mountain region to exceed 206 tcf gas
Studies in the Piceance Creek and Greater Green River basins indicate that estimates of gas recoverable with advanced technology exceed previous estimates by as much as six times. Advanced technology assumes exotic drilling and well-completion methods, some of which are currently being tested with reasonable success.

In Germany the potential resources of undiscovered and tight gas is in the range of 50 to 150 x 10^9 m^3. Potentially producible gas from low-permeability horizons in the Northern Great Plains of Montana and the Dakotas could exceed 100 trillion cubic feet.

Tight Gas Reservoirs - Some World Examples

Devonian:

Jean Marie Member and related carbonates (NEBC)

Mississippian / Pennsylvanian / Permian:

Mattson Formation (Liard Basin)
Stoddart Group (NEBC Foothills and Peace River Plains)

Triassic:

Montney – turbidite play (Peace River Plains)
Doig – shoreface/channel sands – Groundbirch play (NEBC)
Halfway – NEBC Foothills, Peace River Plains
Baldonnel / Pardonet – (NEBC Foothills)

Jurassic

Rock Creek (west-central Alberta)
Nikanassin – Buick Creek (NEBC, West-central Alberta)
Kootenay (southwestern Alberta)

Lower Cretaceous

Cadomin / Basal Quartz (Alberta / B.C. western Plains and Foothills)
Bluesky / Gething (Peace River Plains, west-central Alberta)
Falher / Notikewin (NEBC and adjacent Alberta)
Notikewin / Upper Mannville channels (west-central Alberta)
Cadotte (west-central Alberta and adjacent B.C.)
Viking – (west-central Alberta)

Upper Cretaceous

Dunvegan (west-central Alberta and adjacent B.C.)
Cardium – Kakwa shoreface (west-central Alberta and adjacent B.C.) Belly River (west-central Alberta)

Tight Gas potential in India - a sketchy picture:

Tight gas reservoirs in its wider meaning can be found in any geological and tectonic setting. However, the basin centered/deep gas system do occur in axial part of the rift basin, the foredeep part of the foreland basin or the synclinal part of the orogenic belts. Keeping these facts in mind and the over all geodynamic scenario of the India, a few areas look prospective for basin centered gas prospects.

The Assam Arakan fold-thrust system in northeastern India represents a long orogenic system that includes the Cachar fold belt in south and the Naga Schuppen belt in the north. In south, the majority of this belt consist of Tertiary clastic rocks (except the Lower to mid- Eocene Sylhet Limestone) that are deformed into broad, open synclines separated by tight anticlines and a few thrust faults. The Paleogene Dishang Group constitute shallow marine to deepwater turbidite deposit that may play an important role in the subsurface as a potential tight gas reservoir in the mountail belt. In the foothill region of Assam foreland, lenticular sandstones within the Paleogene sequence may also form potential targets for tight gas reservoirs.

Many sizeable gas seepages in the Naga schuppen belt indicate ample gas generation at depth. The distribution of the gas seepages suggest that the generation below the thrust belt within the autochthonous sedimentary section, notably in the coal bearing Barail or the Kopili/Dishang shales. Pressure compartments, formed as a result of active hydrocarbon generation, combined with lithologic, tectonic and diagenetic sealing, are expected to have been episodically fractured by "seismic valving", a mechanism related to the interaction of tectonic stress and elevated pore pressure.

The east coast passive margin basins like Krishna Godavari, Cauvery, Mahanadi etc. may hold good potential for tight gas reservoirs particularly in the deep basinal side.

The Cambay aborted rift contains different sub-basins with different sediment fills. Some of the depressions like Bharuch, Tarapur, Wamaj etc. are good local where basin centered gas are expected.

Key existing and needed technologies

No single tool delineates the combination of lithologies and geometries of faults and fractures associated with commercial tight gas sand reservoirs. Seismic (especially multicomponent three-dimensional seismic) information, specialized wireline logs, cementing and stimulation methodology, drilling and measurement, conventional subsurface data, reservoir engineering data, and simulation are all necessary. Each domain depends on input from others, and the importance of validated, timely information to users in all areas of expertise, at any point in the process, is recognized across the industry.

Advanced techniques like horizontal drilling and technologies that permit efficient fracturing of multiple zones per well allow gas to migrate a shorter distance to reach a location where it can enter a well and be produced. When these reservoirs extend vertically for several thousand feet, new fracturing techniques are required. To create better solutions adapted for gas, industry researchers will need to understand underlying flow physics in greater detail.

Geologists, engineers, log analysts, and other professionals have to come to the common table with a need to better understand and predict reservoir properties in low-permeability reservoirs and use that information in resource evaluation, reservoir characterization and management.

NEW TECHNOLOGY FOR TIGHT GAS SANDS

A concerted technology effort to better understand tight gas resource characteristics and develop solid engineering approaches is necessary for significant production increases from this low-permeability, widely dispersed resource. The current understanding of the tight gas resource and past experience with production enhancement techniques, from nuclear detonations to hydraulic fracturing, both indicate that significant gas recovery can be achieved, only by positioning a wellbore in the near vicinity of the formation to be produced. To meet the economic requirement of wellbore positioning close to the producing formation, tens of thousands of wells would need to be drilled to reach targeted production levels—a staggering economic and environmental challenge.

The basic components for construction of a tight gas sand well include rotary drilling of a wellbore eventually completed with a hydraulic fracture stimulation. Many technology improvements over past years, while incremental in nature, have combined to allow costs to be reduced while exploration techniques have allowed better well locations to be selected. The incremental improvements have combined to offset the impact of lower quality rock being developed. It is postulated that for a significant increase in tight gas production levels, a greater than "incremental" technology development must be developed.

New Technology Concepts

"Township Drainage" - The concept of draining an entire "township" with a single surface area of activity is required, in contrast to the multiple location approach. This can be achieved by "**Well Clusters**" in potential tight-gas productive areas. Further, environmental impact can be minimized by "**Onsite Waste Management**" - Nothing leaves the location except saleable product. All waste materials (drill cuttings, drilling fluids, produced fluids) are safely re-injected into appropriate zones in the same formations. Recycle of materials is maximized.

New Technology Components

- The concept of bringing offshore technology onshore i.e the multiple-well single location, with many wells being drilled from a single location and with lengths of some wellbores reaching a few miles, allowing wide coverage. This will reduce rig moving costs, location preparation costs and road building costs.
- Drilling the well with real-time near-bit sensors for sending information to the wellsite geologist who can integrate these data with Mud-logging and seismic, and alter the target as the new information dictates: "geosteering"and look-ahead seismic steering of the drill bit helps to maximize the quality and quantity of pay zone penetrated by the drill bit.
- Use of new fracturing technology help accessing the payzones, e.g., with multiple jobs, each optimized to specific formation properties. Each treatment, while not achieving propped lengths once envisioned, can be pumped at significant cost savings and effective proppant placement allows for quick and complete well cleanup, enhancing productivity.
- The multiple wellbores may be drilled and completed with the latest "slimhole" technologies and tubulars (Coiled tubing)to minimize material and increase speed of drilling. This drilling environment allows for utilization of underbalanced drilling for all wellbores: this increases rate of penetration, limits wellbore damage and provides better insight into payzone selection, primarily through targeting and exploitation of naturally fractured environments.
- One wellbore can be used for disposal of all required materials on site, eliminating the cost of trucking and land filling of these materials. Drill cuttings, drilling fluids and subsequently produced water never leave the location.
- Operating expenses can be reduced by the centralized location of the wells. Cost of gas compression, metering, well workovers, well monitoring, providing safety, travel and labor are all reduced.
- The environmental footprint can be minimized due to multiple wellbores at a single location. A great deal of activity below the surface coupled with a minimum of surface disturbance and land utilization holds environmental costs down and maintains a positive industry image. Environmental concerns of air emissions, noise, footprint etc., are mitigated by the environmental control enabled by the cluster of wells.

Many of these technologies exist today, although their application is limited to prolific producing areas (e.g., offshore and onshore Alaska) due to the high cost of technology application. A part of the challenge for the future will be to contain these costs, allowing deployment to low permeability environments. Some of the technologies need to be developed and some have not yet been adequately thought about. The future will require a contribution from all participants. The following table summarizes the quantitative impact of the new technology assumptions.

Assumption	Impact
Geosteering, Zone Selection	Maintain Porosity at 5%
Geosteering, Underbalanced Drilling Zone Selection (e.g., Natl. Fracs)	Maintain Permeability at 0.001 md
Geosteering and Underbalanced Drilling	Add 5% to Well Costs
Multi-well locations	Reduce Well Costs 5%
On-Site Waste Management	Reduce Well Costs 5%
Advanced Fracture Treatments	Reduce Treatment Cost 25%
High Angle Drilling	Add 5% to Well Costs
Coiled Tubing Drilling and Tubulars	Reduce Well Costs 10%
Hydraulic Fracture Conductivity	Increase by 40%

Lessons Learned

The future for exploration cannot be with the familiar, conventional anticlinal and stratigraphic buoyancy traps. In the U.S. most of these traps have been discovered. All of the major companies agree with that conclusion and have shifted their investment to the Gulf and Overseas

New onshore **gas** will largely be from **basin-centered gas** systems. At present most **basin-centered gas** fields have the following parameters: thermal **gas**, sandstone reservoirs, Cretaceous age, **gas** shows, permeability less than 3 md, are widely fractured requiring fracs for commercial production, are synclinal or on **basin** flanks and are roughly parallel to strike, are downdip from water, and can be large to extremely large. Exploration competency in the new **basin-centered** fields will require more flexibility and more highly-experienced subsurface technical expertise than was necessary for discovering fields related to buoyant traps.

Review of different tight gas reservoirs of the world in general and United States in particular suggests that the tight gas resource is ubiquitous: all geologic basins in the United States contain some tight gas. These reservoirs of various ages and types produce where structural deformation creates extensive natural fracture systems whether it is basin margin or foothills or plains. Fractured, tight and unconventional reservoirs can occur in tectonic settings dominated by extensional, compressional or wrench faulting and folding.

It is of interest to look back over the past twenty years of history with regard to tight gas production and speculate as to what factors actually drove the activity which resulted in more than doubling of annual production. The question can be quickly narrowed to two areas in general:

1. Gas Price Incentives
2. Impact of New Technology

Tight gas well drilling activity was primarily price-driven as opposed to the advent of some new technology or breakthrough in understanding of the tight gas resource. Certainly the significant decrease in activity that took place in 1986, coincident with a significant decrease in gas price, would further suggest that no breakthrough technology or combination of technologies existed to maintain activity levels in the absence of price. All of this is not to suggest that technology was dormant during this time period but that it was probably not the crucial factor.

Importance of New Technologies

In the coming decades, production from unconventional oil and gas reservoirs will become even more important all over the world when conventional oil production begins to decline. To prepare for the future, it is important that the oil and gas industry focus on the technologies that will be needed to continue development of oil and gas from unconventional reservoirs. A few of the important technologies are listed in the following.

- Special formation-evaluation methods.
- Special reservoir-engineering methods.
- Special completion methods.
- Massive hydraulic-fracturing treatments.
- Steam injection.
- Horizontal and multibranched wellbores.
- Advanced drilling methods.

A common characteristic of many of these unconventional reservoirs is that the formations can be several hundreds or even thousands of feet thick. To produce such reservoirs, multizone completions, oriented perforating, massive hydraulic fracturing, and cased-hole logging methods are all required to maximize recovery and minimize the cost associated with well completions. In many cases, horizontal or multibranched wellbores along with steam injection can improve recovery from heavy-oil reservoirs. Finally, because most of the money developing every field is required for drilling the wells, any advancements in drilling methods that reduce costs can substantially improve the economics of developing unconventional reservoirs.

Gas production from a tight-gas well will be low on a per-well basis compared with gas production from conventional reservoirs. A lot of wells have to be drilled to get most of the oil or gas out of the ground in unconventional reservoirs.

Small well spacing is required to deplete a low-permeability reservoir in a 20- to 30-year time frame. Thus, to substantially increase oil and gas production from unconventional reservoirs, the industry will need many more rigs and a lot more equipment. Currently, it does not have enough rigs, logging trucks, cement trucks, or fracturing trucks to develop unconventional reservoirs to any great extent in any part of the world. In addition to needing more wells and more equipment, the industry also will require many new engineers and geoscientists.

There is no fear of running out of oil or natural gas. An enormous volume of unconventional oil and gas will be there to fill the gap once conventional oil begins to decline in the next 5 to 20 years. However, increased oil and gas prices and better technology will be required to bring much of those resources to market.

Conclusions and future directions for exploration of and production from low-permeability systems:

- Tight gas reservoirs have a huge future potential for production.
- Four criteria that define basin-centered gas accumulations, **including low permeability, abnormal pressure, gas saturated reservoirs and no down dip water leg.**
- Although "tight gas sands" are an important type of basin-centered gas reservoir, not all of them are Basin-centered gas (BCGAs)
- Past tight gas sands production was fueled by both technology and gas price incentives, primarily price incentives.
- Gas price incentives for the future are thought to be limited, therefore technology development must play the major role for future increases.
- The rate of current technology improvement is just offsetting the increasing challenges created by lower quality reservoir rock, increasing costs from environmental issues and downward pressure on gas prices from energy competition.
- A concerted technology effort to both better understand tight gas resource characteristics and develop solid engineering approaches is necessary for significant production increases from this low-permeability, widely dispersed resource.
- Exploration efforts in low-permeability settings must be deliberate and focus on fundamental elements of hydrocarbon traps.
- Gas production from a tight-gas well will be low on a per-well basis compared with gas production from conventional reservoirs. A lot of wells have to be drilled to get most of the oil or gas out of the ground in unconventional reservoirs.
- Improvements in completion and drilling technology will allow well identified geologic traps to be fully exploited, and improvements in product price will allow smaller accumulations or lower-rate wells to exceed economic thresholds, but this is true in virtually every petroleum province.
- Petrophysics is a critical technology required for understanding low-permeability reservoirs.
- Well Clusters and Onsite Waste Management are the key components of New Technology Concepts for tight gas development
- Although, tight gas reservoirs hold huge potential, simply praying to the gods of fracture stimulation, drilling fluids and strong prices to make gas come out of the ground will not do. The industry needs to think in terms of the risk process by evaluating source, reservoir, seal and trap, just as companies do in other regions.

- λ Geologists, engineers, log analysts, and other professionals have to come to the common table with a need to better understand and predict reservoir properties in low-permeability reservoirs and use that information in resource evaluation, reservoir characterization and management.
- λ There is no fear of running out of oil or natural gas. An enormous volume of unconventional oil and gas will be there to fill the gap once conventional oil begins to decline in the next 5 to 20 years.

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