Unconventional Reservoir Shale Gas*

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Abstract

Shale gas is natural gas from shale formations which acts as both the source and the reservoir for the natural gas (Figure 1, Figure 2). Each shale gas reservoir has unique characteristics. Shale has low matrix permeability, so gas production in commercial quantities requires fractures to provide permeability. For a given matrix permeability and pressure, gas production is determined by the number and complexity of fractures created, their effective conductivity, and the ability to effectively reduce the pressure throughout the fracture network to initiate gas production. Understanding the relationship between fracture complexity, fracture conductivity, matrix permeability, and gas recovery is a fundamental challenge of shale gas development.

Shale gas reservoirs almost always have two different storage volumes (dual porosity) for hydrocarbons - the rock matrix and the natural fractures. Because of the plastic nature of shale formations, these natural fractures are generally closed due to the pressure of the overburden rock. Consequently, their very low matrix permeability, usually on the order of hundreds of nanoDarcies (nD), makes unstimulated conventional production impossible. Almost every well in a shale gas reservoir must be hydraulically stimulated (fractured) to achieve economical production. These hydraulic fracture treatments are believed to reactivate and reconnect the natural fracture matrix. Shales and silts are the most abundant sedimentary rocks in the earth's crust. In petroleum geology, organic shales are source rocks as well as seal rocks that trap oil and gas. In reservoir engineering, shales are flow barriers. In drilling, the bit often encounters greater shale volumes than reservoir sands. In seismic exploration, shales interfacing with other rocks often form good seismic reflectors. As a result, seismic and petrophysical properties of shales and the relationships among these properties are important for both exploration and reservoir management.

Another key difference between conventional gas reservoirs and shale gas reservoirs is adsorbed gas. Adsorbed gas is gas molecules that are attached to the surface of the rock grains. The nature of the solid sorbent, temperature, and the rate of gas diffusion all affect the adsorption. Presently, the only method for accurately determining the adsorbed gas in a formation is through core sampling and analysis. Understanding the effects of adsorption on production data analysis increase the effectiveness of reservoir management in these challenging environments.

They contain natural gas in both the pore spaces of the reservoir rock and on the surface of the rock grains themselves that is referred to as adsorbed gas.This is a complicated problem in that desorption time, desorption pressure, and volume of the adsorbed gas all play a role in how this gas affects the production of the total system. Adsorption can allow for significantly larger quantities of gas to be produced. Shale gas reservoirs present a unique problem for production data analysis. The effects of the adsorbed gas are not clearly understood except that it tends to increase production and ultimate recovery. The phenomena of gas storage and flow in shale gas sediments are a combination of different controlling processes. Gas flows through a network of pores with different diameters ranging from nanometres (nm = 10^{-9} m) to micrometres (μm = 10^{-6} m). In shale gas systems, nanopores play two important roles. Petrophysical imaging employs first, second and third generation wavelet to delve deep into a complex shale gas reservoir. Nanoscale gas flow in shale gas sediments has scope to cope with research on dry nanotechnology (smartfluid/nanofluid).

Anisotropy in sediments may develop during deposition or post-deposition. In clastic sediments, anisotropy can arise both during and after deposition. In carbonates, anisotropy is controlled mostly by fractures and diagenetic processes, and so tends to arise after deposition. For anisotropy to develop during deposition of clastics, there needs to be an ordering of sediments - in essence, some degree of homogeneity, or uniformity from point to point. If a rock were heterogeneous in the five fundamental properties of its grains - composition, size, shape, orientation and packing - anisotropy cannot develop because there would be no directionality intrinsic to the material. Anisotropy at the bedding scale that arises during deposition therefore may have two causes. One is a periodic layering, usually attributed to changes in sediment type, typically producing beds of varying material or grain size. Another results from the ordering of grains induced by the directionality of the transporting medium. Anisotropy is therefore governed not only by variation in the type of material but also by variation in its arrangement and grain size. The main cause of elastic anisotropy in shales appears to be layering of clay platelets on the micron (micrometer) scale due to geotropism - turning in the earth's gravity field - and compaction enhances the effect.

Shale, with its inherent heterogeneity and anisotropy, has always been problematic in many operations ranging from seismic exploration, well-log data interpretation, well drilling and wellbore stability problems, to production. Research work focuses at bridging the gap between invariant characteristics at nano-scale of sedimentary rocks and their macroscopic properties. 3D seismic is becoming successful because of the ability to identify fracutre and fault trends. Surface geochemistry cannot identify in the subsurface where the fracture or fault systems will be intersected by the drill bit. This is why 3D is now being used aggressively and successfully.

Seismic Applications

Unconventional reservoirs (Figure 2) require some form of stimulation to obtain commercial production. Shale gas reservoirs require fracture stimulation to unlock gas from extremely low-permeability formations. As fracture stimulation is an important aspect of well completions, production companies need to know basic information about fractures, such as whether they will open (and stay open), direction of fracture propagation, dimensions and type of fractures, and whether they will stay in zone. Increasingly, seismic is utilized to provide such information and guide drilling and completions. Three types of information extracted from seismic are useful in optimizing drilling locations: fracture characterization, geomechanical properties, and principal stress measurements (vertical maximum and minimum horizontal stresses). Given the target depth of formations in shale gas basins that are being exploited today, the maximum principal stress is vertical, giving rise to HTI (horizontal transverse isotropy). This means that the fracture system is comprised of vertical fractures which cause anisotropic effects on seismic waves as they pass through. These anisotropic effects are observed on 3D seismic data as changes in amplitude and travel time with azimuth. In multicomponent data, shear wave splitting can be observed. The relationship between changes in P-wave amplitude with azimuth in anisotropic media to invert the observed seismic response and predict fracture orientation and intensity. This information is of great value to production companies because it indicates the optimum horizontal drilling azimuth and offers the prospect of subsequent fracture stimulation as a solution to tap into existing natural fracture systems. A clear understanding of the geomechanical properties and their distribution explains the reservoir heterogeneity and thus the variation in economic ultimate recovery (EUR) between wells. Geophysicists derives a host of geomechanical properties from migrated CDP gathers, including Young's Modulus, Poisson's Ratio, and shear modulus, by first inverting the data for P- and S-wave velocities and density. With this information, fracture dimensions can be predicted and wells drilled in the most brittle rock. Linear Slip Theory for geomechanical properties is used to calculate stress values.

Generally the stress state is anisotropic, leading to the estimation of both the minimum and maximum horizontal stress. As the seismic data measure dynamic stress, results are then calibrated to the static stress that is effectively borne by the reservoirs at depth, making it possible to predict the hoop stress and the closure stress as key elements defining the type and motion of fractures. At locations where the differential horizontal stress ratio (DHSR – the ratio of the difference between the maximum and minimum horizontal stresses to the maximum horizontal stress) is low, tensile fractures will form in any direction, creating a fracture swarm. If the maximum horizontal stress is much greater than the minimum, then fractures will form parallel to the direction of maximum horizontal stress.

Hydraulic Fracturing

Hydraulic fracturing is a process that results in the creation of fractures in rocks (Figure 3), the goal of which is to increase the output of a well. The hydraulic fracturing is used to increase or restore the rate of fluid flow within the shale reservoir, while horizontal drilling creates maximum borehole surface area in contact with the shale. Hydraulic fracture complexity is the key to unlocking the potential of shale plays. Microseismic monitoring suggests that a complex fracture network can be developed in some shale plays. Microseismic monitoring is a proven technology and has been widely used to monitor and evaluate the effectiveness of hydraulic fracture treatments in various formations, including shale. Theoretically, in shale plays a complex fracture should produce better compared to bi-wing planer fractures as a result of increased fracture surface area. The value of the microseismic data is that it provides operators with 3D visualization of where the hydraulic fracture process is impacting the rock in the reservoir. When real-time monitoring is used, the micro-seismic information can be used to prevent fracture growth out of zone. Micro-seismic hydraulic fracture monitoring is another of these new technologies. One of the principal costs in extracting natural gas is the hydraulic fracture process. The rock must undergo extensive fracturing to create the permeability required to allow gas to flow into the wellbore. Micro-seismic methodologies arguably offer industry the best method to determine the efficiency of the fracture stimulation process, as it applies to making contact with the gas resource locked in the rock.

Real-time monitoring of micro-seismic events allows operators to immediately optimize the hydraulic stimulation process by modifying the fracture stage design while pumping into the formation. In one case, the operator used the real-time data to experiment with how different perforation patterns impacted fracture propagation. The firm also used the data to make real-time changes in the fracture program. At one point, the data showed an absence of growing micro-seismic activity geometry, alerting the operator to stop pumping proppant and flush the well with water to avoid a potentially costly sanding-off of the fractures. Recording micro-seismic events to monitor rock fracturing in 3D space and time during the stimulation process allows operators to confirm the rock volume and formation geometry being stimulated. As a result, operators can optimize future well placement and completion designs for cost-effective drainage of unconventional reservoirs.

The dual porosity model consists of two different media. These two media are the fracture system and matrix system. The fracture system contains very little fluid (gas/oil) with low storage capacity but possesses a high conductive path for fluid compared to the matrix system. The other medium, which is the matrix system, has a high storage capacity but a poor fluid conductive path. Presently, there are many models that characterize natural fractures already existing in the reservoir and artificial hydraulic fractures based on dual porosity. At the core of the shale story is the stunning progress in the technology used to extract the gas from 'tight' rocks, through a process of hydraulic fracturing. This involves bombarding the rocks with millions of litres of chemically treated water to force the gas to flow. Shale gas is no different from the regular natural gas (primarily methane), and its presence over a wide area of thousands of acres has been known for years. But it was not pursued vigorously due to the difficulties of extracting it.

Water Lifecycle of Hydraulic Fracturing in Shale Gas Reservoirs

In addition to water and proppant, nano-enhanced proppant (OxBall and OxFrac light, high-strength ceramic proppants) and other additives are essential for successful fracture stimulation. Hydraulic fractures are formed in the direction perpendicular to the least stress. The water lifecycle for hydraulic fracturing consists of water acquisition, chemical mixing, well injection, flowback and produced water (hydraulic fracturing wastewater), and wastewater treatment and waste disposal. Implications of hydraulic fracturing water lifecycle and the potential impacts are analysed in the large volume of water withdrawals from ground and surface waters on drinking water resources, chemical mixing (surface spills on or near well pads of hydraulic fracturing fluids on drinking water resources), well injection (the injection and fracturing process on drinking water resources), flowback and produced water (surface spills on or near well pads of flowback and produced water on drinking water resources), wastewater treatment and waste disposal (inadequate treatment of hydraulic fracturing waste waters on drinking water resources). Laboratory studies provide a better understanding of hydraulic fracturing fluid and shale rock interactions, the treatability of hydraulic fracturing wastewaters, and the toxicological characteristics of high-priority constituents of concern in hydraulic fracturing fluids and wastewater.

Indian Scenario

India is going to play a leading role of this unique unconventional energy. The broad outline of the policy may include: (1) Generation of data to have a shale gas database for prospective basins and areas, (2) Estimation of shale gas resources, (3) Carving out of exclusive shale gas blocks, (4) Preparation of basin information dockets and data packages, (5) Bringing in necessary Amendments/modifications in relevant rules and regulations in order to include shale gas as another producible hydrocarbon, (6) Finalization of a policy framework for offering the blocks under international bidding rounds, (7) Policy for simultaneous exploration and exploitation of shale gas with oil and gas and CBM in the same area.

With availability of improved technology, shale gas exploitation is no longer an uneconomic venture, and the demand and preference for this clean form of hydrocarbon has made shale gas an energy in demand. The reserve accretion, production and development of shale gas from one basin to another around the world are rapidly increasing. India also appears to have a large resource of prolific matured shale distributed in different onshore sedimentary basins such as Cambay, Assam-Arakan, Damodar Valley, Krishna-Godavari, Cauvery and Rajasthan (Figure 5). Out of these, Cambay Basin is probably the best explored and therefore most suitable and ideal to start meaningfully delve deep into research and development projects. The government of India or some leading PSUs are probably well placed to take a quick lead in this respect. Given the nature of global enthusiasm in the form of participation of large companies in shale gas exploration and exploitation the world over, vast shale deposits with high TOC and maturity values in the above mentioned petroliferous basins of India, together with increasing oil/gas prices, concern for carbon emission and availability of improved modern technologies can bring India in the top bracket of shale gas producers in the world, once the above concerns are addressed and a shale gas policy is put in place. Potential of shale gas in India is being examined by oil regulator Directorate General of Hydrocarbons (DGH), Government of India. ONGC finds maiden shale gas reserves in India (January, 2011**)** - ONGC created an exploration landmark when gas flowed out from the Barren Measure shale at a depth of around 1,700 meters, in its Pilot project first R&D well RNSG-1 near Durgapur at Icchapur, West Bengal. DGH in association with USGS has forged agreements on cooperation for shale gas exploration in India. The USGS would work out resource assessment under the Global Shale Gas Initiative.

Damodar Valley Basin

The Damodar Valley Basin is part of a group of basins collectively named the "Gondwanas", owing to their similar dispositional environment and Permo-Carboniferious through Triassic stratigraphic fill (Figure 4). The "Godwanas," comprising the Satpura, Pranhita-Godavari, Son-Mahanadi and Damodar basins, were part of a system of rift channels in the northeast of the Gondwana super continent. Tectonic activity formed the major structural boundaries of many of the Gondwana basins, notably the Damodar Valley Basin. Sedimentation in the Early Permian Gondwana basins was primarily glacial-fluvial and lacustrine, resulting in significant deposits of coal. As such, the majority of the exploration activities have focused on the basins' coal resource potential, which accounts for essentially all of India's coal reserves (about half of which are in the Damodar Valley Basin). However, a marine incursion took place between periods of continental deposition, depositing a layer of early Permian shale, called the "Barren Measure" Shale Formation. This formation, called the Ironstone Shale in the Raniganj sub-basin, is the target of India's first shale gas exploration well in the eastern Damodar Valley.

Krishna Godavari Basin

The Krishna Godavari Basin extends over a 7,800 mi^2 area onshore (plus additional area in the offshore) in eastern India (Figure 6). The basin consists of a series of horsts and grabens. The basin contains a series of organically rich shales, including the deeper Permian Kommugudem Shale, which is gas prone and appears to be in the gas window in the basin grabens. The Upper Cretaceous Raghavapuram Shale and the shallower Paleocene and Eocene shales are in the oil window and thus were not assessed.

Cambay Basin

The Cambay Basin is an elongated, intra-cratonic rift basin (graben) of Late Cretaceous to Tertiary age located in the State of Gujarat in northwestern India (Figure 7). The basin covers an onshore area of about 20,000 mi^2. The Deccan Trap Group, composed of horizontal lava flows, forms the basement of the Cambay Basin. Above the Deccan Trap, separated by the Olpad Formation, is the Late Paleocene and Early Eocene Cambay "Black Shale", which represents the marine transgressive episode in the basin. The "Black Shale" interval ranges from 1,500 feet thick to more than 5,000 feet thick. In the northern Mehsana-Ahmedabad Block, the Kadi Formation forms an intervening 1,000 feet thick non-marine clastic wedge within the "Black Shale" interval.

Conclusions

According to geologists, there are more than 688 shales worldwide in 142 basins. With the availability of improved technology, shale gas exploitation is no longer an uneconomic venture as the demand and preference for this clean form of hydrocarbon has made shale gas an energy in demand. The reserve accretion, development and production of shale gas from one basin to another around the world are rapidly increasing.

Seismic anisotropic data processing provides information of fractures in shale. Real-time monitoring of micro-seismic events guides fracturing experts to immediately optimize the hydraulic stimulation process by modifying the fracture stage design while pumping into the formation. The real-time data is employed for experiment in how different perforation patterns impacted fracture propagation and make real-time changes in the fracture technologies. As a result, fracturing experts can optimize future well placement and completion designs for cost-effective drainage of unconventional reservoirs.

Shale gas performance is analysed by using wavelet transform. Geomechanical (break outs) information is obtained by wavelet analysis of petrophysical log data. NMR is very efficient for characterization of reservoir, petrophysical imaging and gas dynamics in gas shale nanopores. Water management and environmental impacts of hydraulic fracturing should be analysed to cope with our earth system. India has great potential for shale gas to explore and exploit with a view to energy security of the world. India also has great potential of shale gas for the upstream business sector.

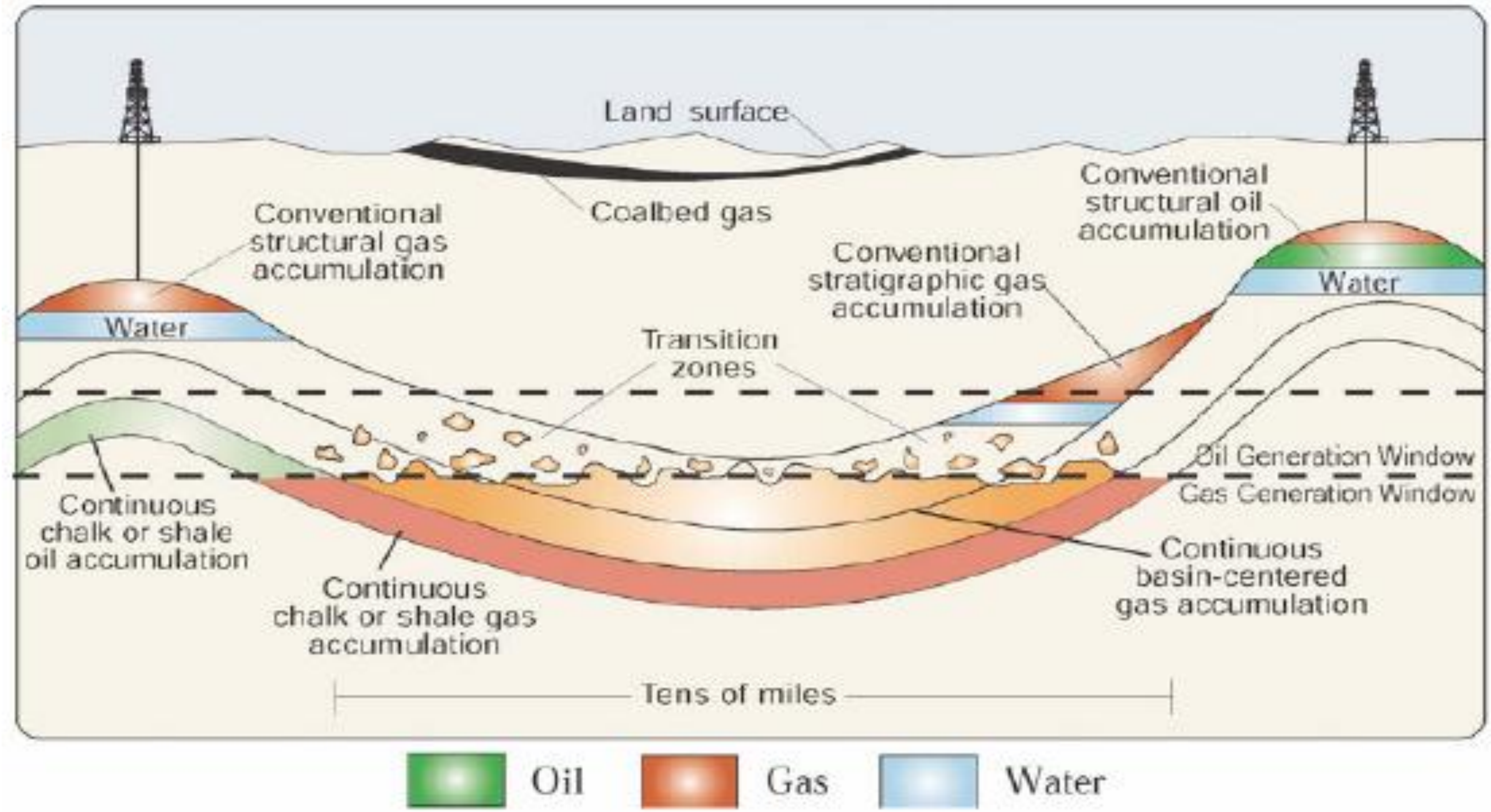

Figure 1. Diagram showing the general stratigraphic occurrence of shale gas.

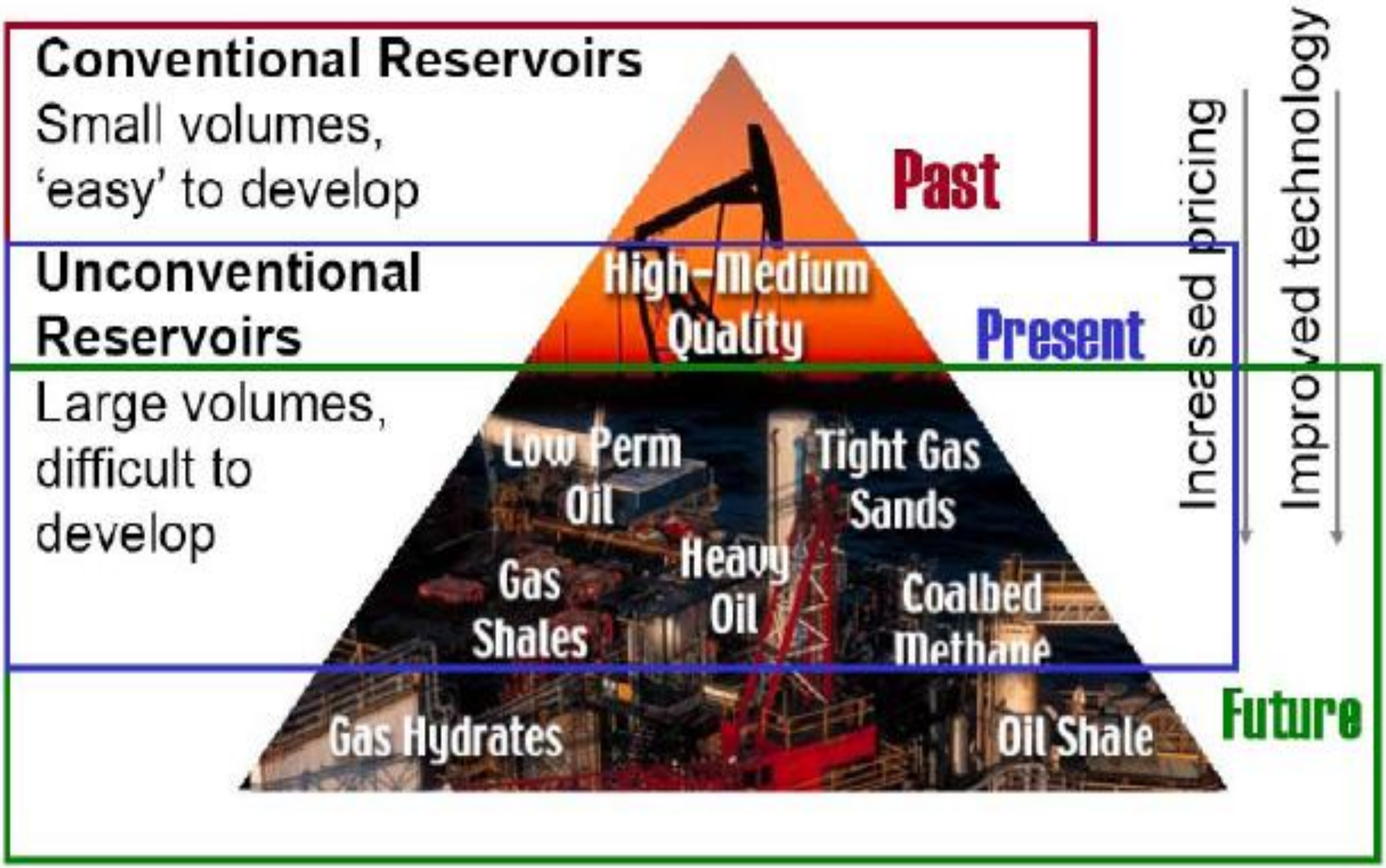

Figure 2. The resource triangle showing unconventional resources.

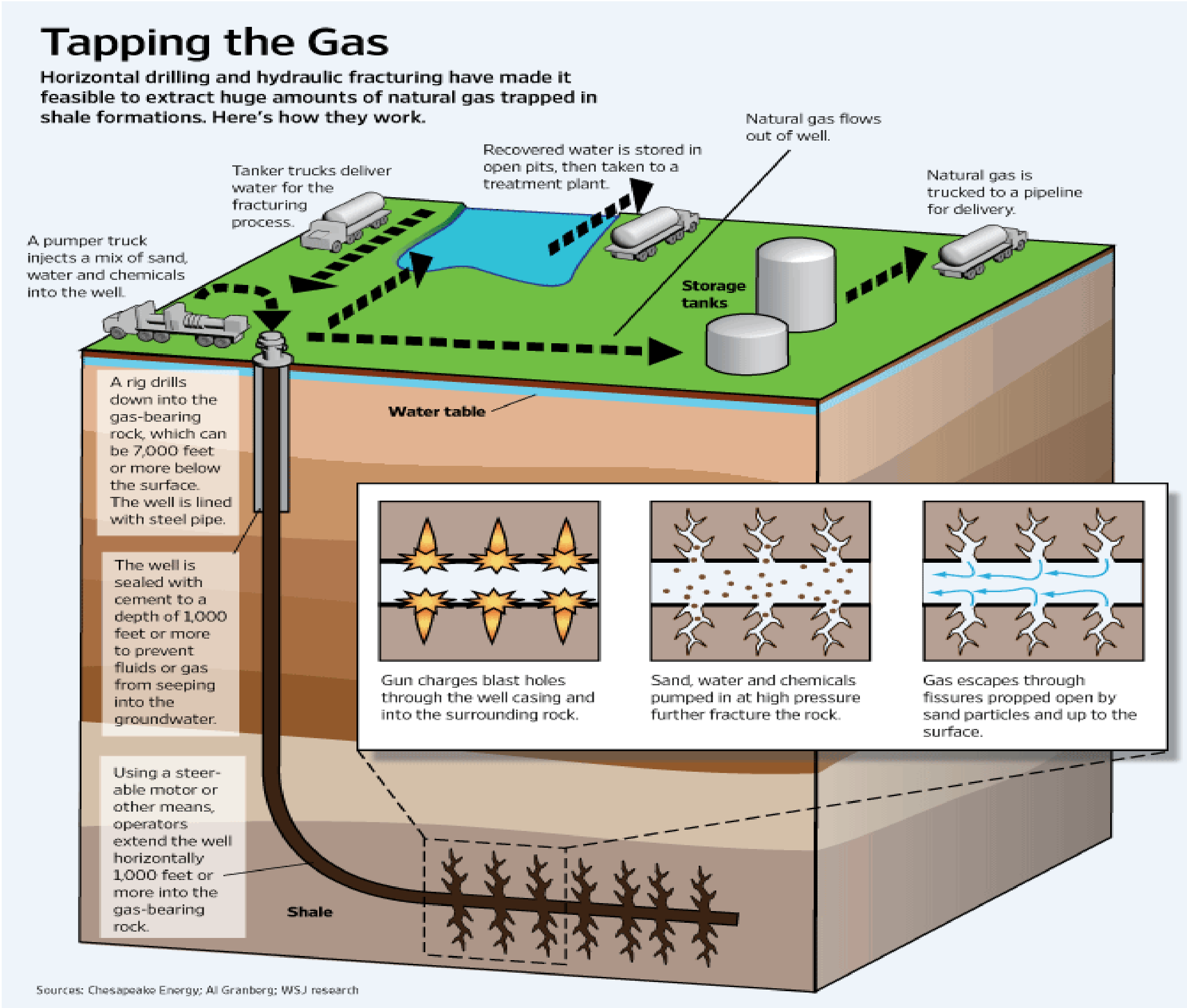

Figure 3. Diagram showing general methods of horizontal drilling and hydrofracturing in shale.

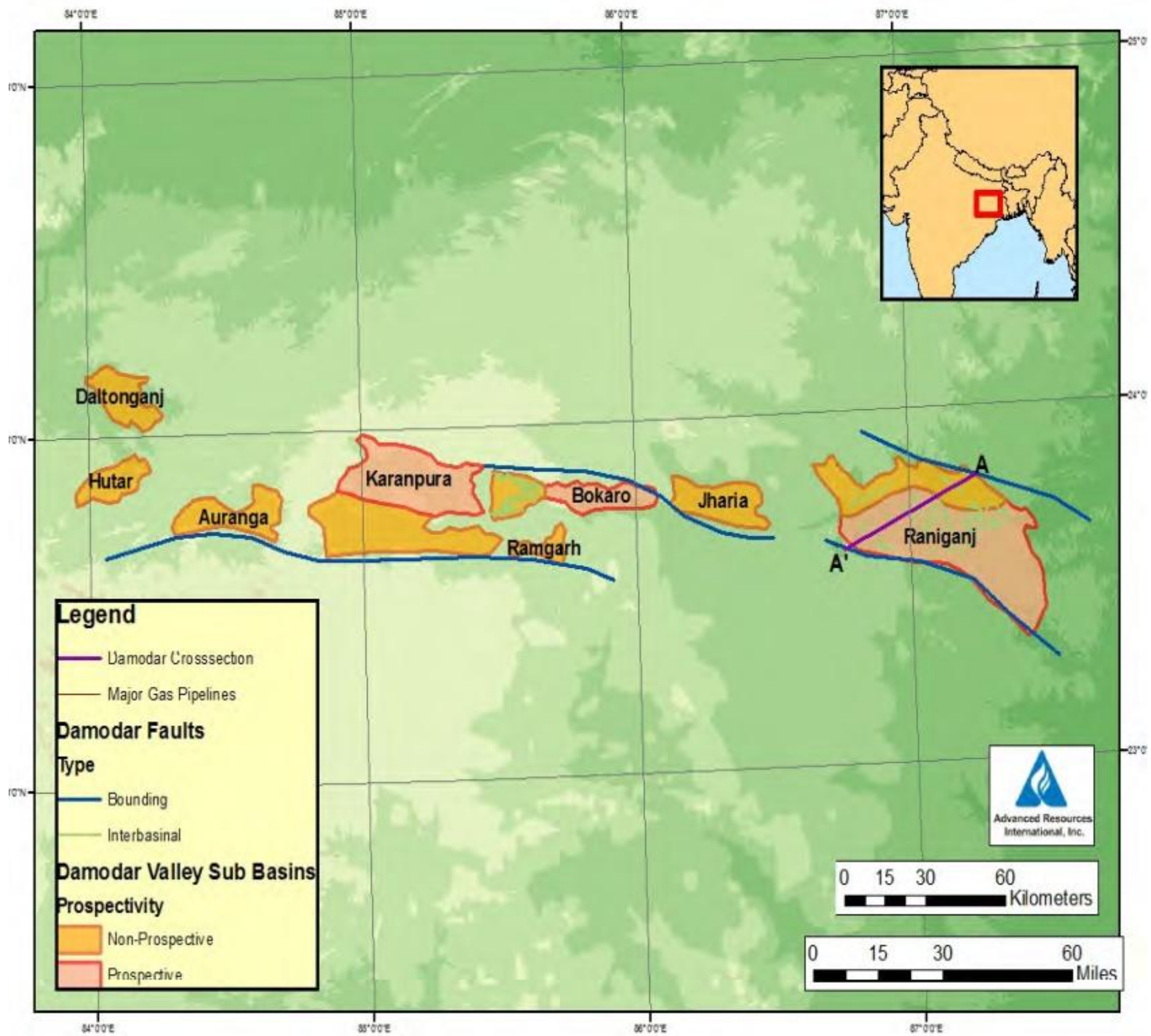

Figure 4. Damodar Valley Basin and prospectivity for shale gas.

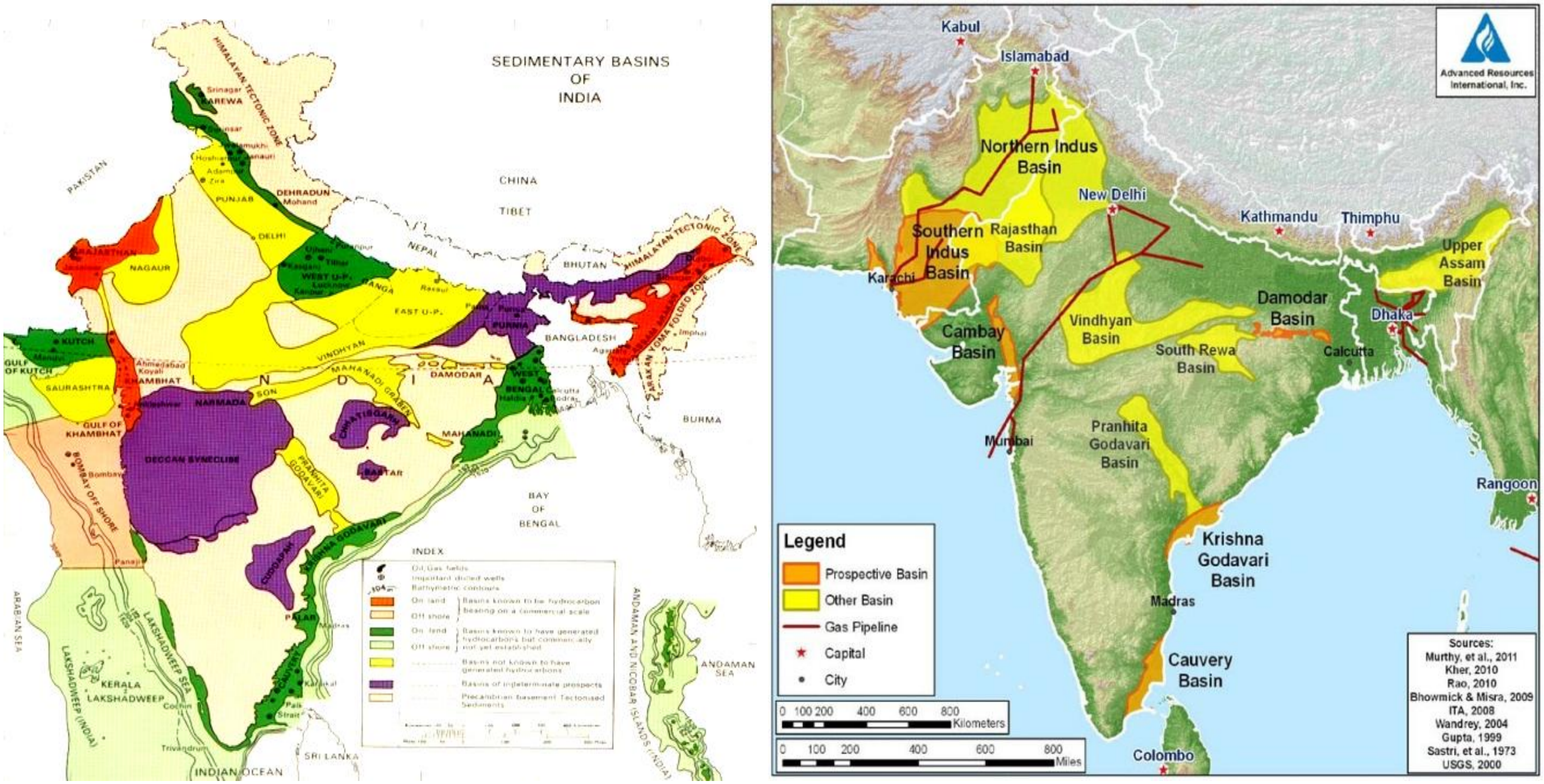

Figure 5. Potential shale gas basins: Cambay, Assam-Arakan, Gondwana, Vindhyan, Rajasthan, Bengal, Krishna- Godavari, and Cauvery.

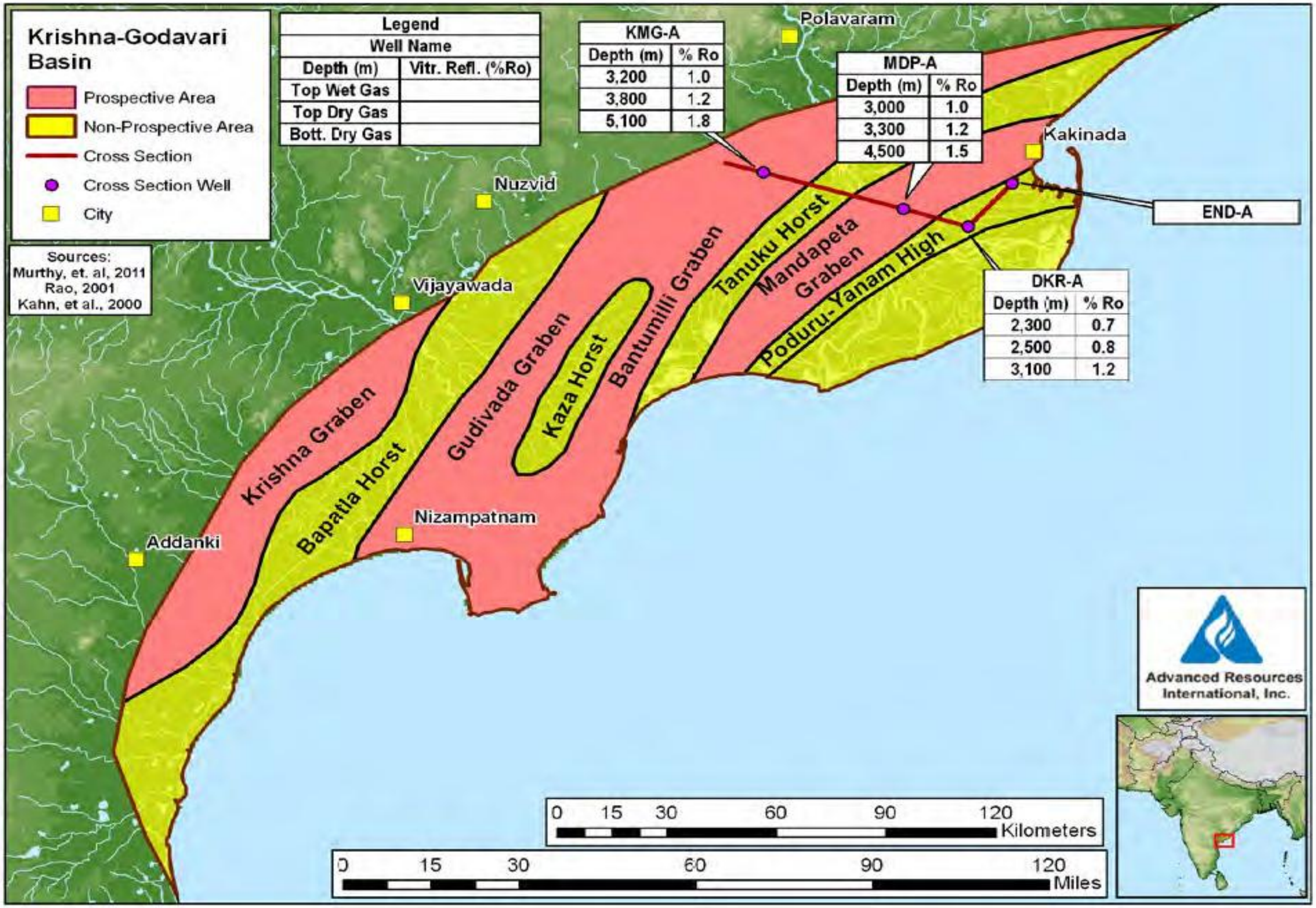

Figure 6. Prospective areas for shale gas in the Krishna Godavari Basin.

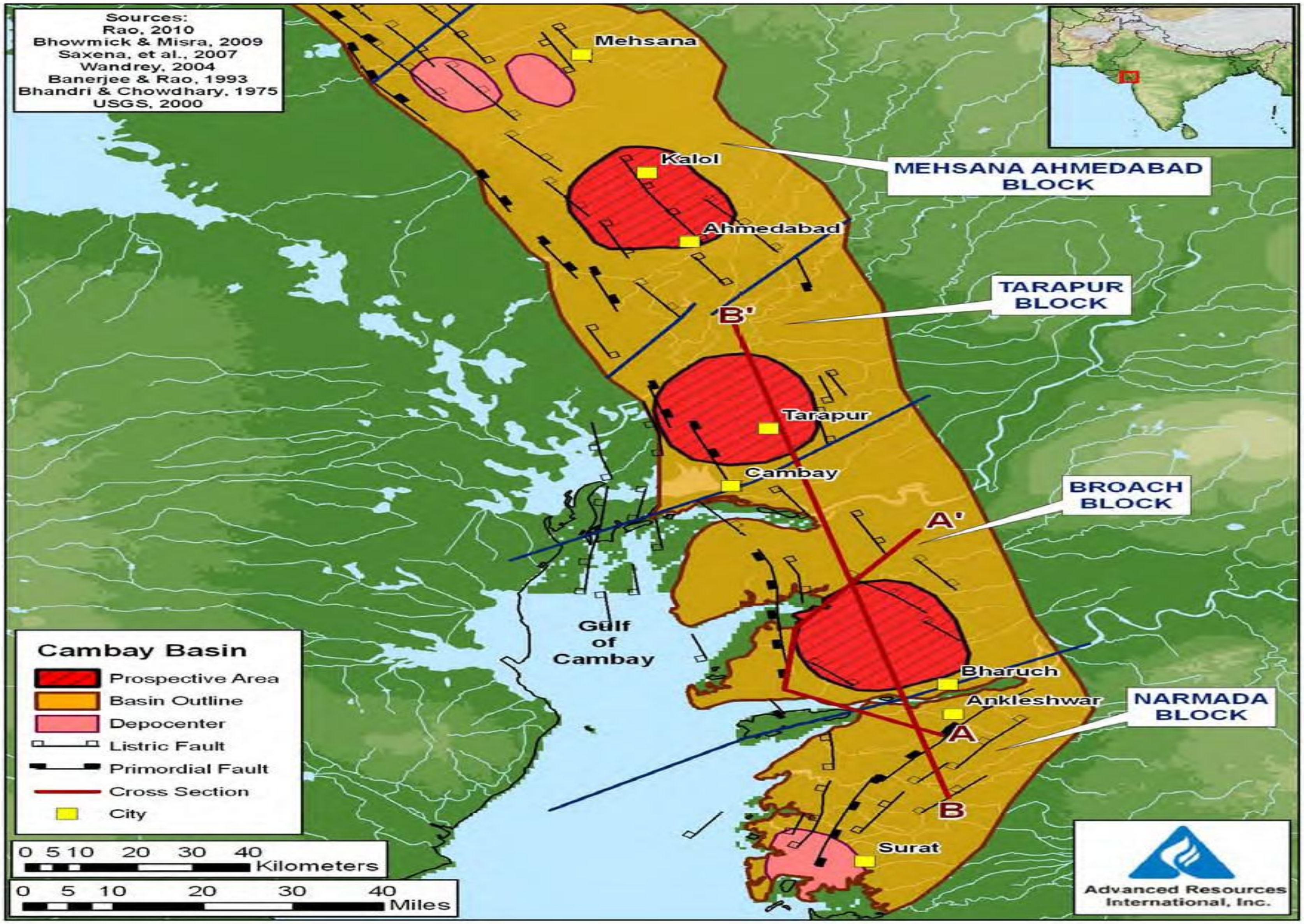

Figure 7. Prospective areas of the Cambay "Black Shale" in the Cambay Basin.