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The Spectrum of Fine-Grained Reservoirs from 'Shale Gas' to 'Shale Oil'/ Tight Liquids: Essential Attributes, Key Controls, Practical Characterization

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Abstract

A spectrum of combinations of rock and hydrocarbon properties in fine-grained rocks can result in significant production, effectively spanning 'conventional' tight oil to fractured 'shale' gas reservoirs, in four main families based on dominant porosity-permeability system and stratal relations (*i.e.*, 'Conventional' tight, Hybrid/Interbedded, Porous 'shale', Fractured 'shale'). Fine-grained reservoir types comprise 'shale-oil' reservoirs at lower thermal maturities and pressure-temperature (P-T) conditions to 'shale-gas' reservoirs at higher maturities and P-T conditions. These fine-grained reservoirs can contain a variety of pore types: inter-granular, intra-granular, fracture, intra-kerogen, and intra-pyrobitumen/char -- the last two, 'organic-hosted' types, are more obvious at higher maturities.

'Shale-oil' reservoirs share many attributes with 'shale-gas' reservoirs, but have some distinct differences. The key additional dimension is the properties of the hydrocarbon fluids: Over geological time, fluid density and phase influence fluid saturation in the matrix, and in the short term, viscosity and phase affect flow and production rates. Hence, two main classes of attributes affect ultimate 'shale' reservoir performance: rock properties (mainly permeability) and fluid properties (mainly viscosity) that are influenced by the full geological history of the reservoir. Overall reservoir permeability includes both matrix and fracture characteristics: Matrix permeability is a function of original depositional composition, texture, bedding, and stratal stacking plus burial history (thermal stress, diagenesis). Fracture permeability is a function of the same controls as matrix permeability along with structural history (mechanical stress). Fluid properties (viscosity, density) are also controlled by original depositional properties (which determine kerogen type) and burial/uplift history, along with present-day reservoir pressure and temperature.

The higher thermal maturities of 'shale-gas' reservoirs result in contrasts with 'shale-oil' reservoirs: they tend to have less smectite due to illitization, but more obvious porosity associated with kerogen and bitumen. These factors modify the porosity-permeability system and well-log responses. Appreciation of the similarities and differences between 'shale-gas' and 'shale-oil' enables more efficient and effective exploitation of the full range of resource types.

Introduction and Background

Hydrocarbons can be produced from a spectrum of combinations of rock and hydrocarbon properties in fine-grained rocks, spanning 'conventional' tight oil to 'shale' reservoir matrix production (Table 1). So-called 'shale' reservoir systems can be classified in various ways: characteristic lithofacies association, dominant poro-perm type, hydrocarbon fluid properties, stratal architecture, migration distance, decline curves, basin setting, *etc*. We find a combination of the first four parameters to be useful to portray the essential interaction of rock and fluid properties that influences flow. (Note that all plays have some component of inter/intra-granular porosity as well as some fracture permeability, but can be categorized meaningfully by their dominant or distinctive factor.) Our research at ExxonMobil indicates that various, predictable combinations of rock and fluid properties can result in viable plays: i.e., lower poro-perm rocks require single-phase, lower viscosity fluids to be effective, whereas higher poro-perm strata can produce such higher viscosity fluids as black oil (Figure 1).

System Type	Characteristics	Secondary migration	Poro-Perm Components	Examples
1 – 'Conventional' Tight *Reservoir ≠ Source*	Tight SS, siltstone, carbonate interbedded w/ lean, immature source rock; Black oil to dry gas	Significant		*Spraberry* *Lewis Shale* *Mancos* *Mesa Verde*
2 - Hybrid/Interbedded *Reservoir ≠ Source*	Tight SS, siltstone, carbonate interbedded w/ rich, mature source rock; Light oil to dry gas	Moderate		*Bakken* *Bone Springs* *2nd White Specs*
3 - Porous Mudstone *Reservoir = Source*	Source rocks with significant inter/intra-grain porosity at oil to gas/condensate level of maturity; includes organic-hosted porosity	Minimal		*Eagle Ford* *Haynesville* *Barnett* *Woodford*
4 - Fractured Mudstone *Reservoir ± = Source*	Mature source rocks with significant fracture porosity; Heavy oil to dry gas	Minimal		*Monterey* *Woodford* *Austin Chalk* *Barnett*

Table 1 – Characteristics and attributes of various types of fine-grained reservoirs. Note that all plays have some component of inter/intra-granular porosity as well as some natural fracture permeability. They are named for the dominant or distinctive component.

The key aspects and combinations of these parameters are summarized in Table 1. Lithofacies association comprises composition, grain-size distribution, and bedding; these span siliceous, calcareous, and argillaceous rocks that range from very-fine sandstone or grainstone, through siltstone, packstone, and wackestone, to claystone (fine mudstone). Poro-perm systems are various combinations of inter-granular, intra-granular, inter-crystalline, intra-kerogen, intra-pyrobitumen/char, and fracture components. The hydrocarbon fluid property of prime importance to flow is viscosity; density, composition, and resulting PVT behavior (phase, bubble/dew point, gas/oil ratio, *etc*.) are important as they affect viscosity, and production behavior. Stratal architecture defines the spatial relation of intervals that were organic-matter rich and generated hydrocarbons with intervals that have sufficient porosity and permeability to produce. Stratal architecture essentially indicates the amount of secondary migration, which can range from fractions of millimeters in Porous Mudstone reservoirs, to kilometers in 'conventional' tight reservoirs. Lithofacies and stratal architecture are controlled primarily by depositional processes, whereas poro-perm and fluid properties are additionally influenced by subsequent burial and uplift as they affect hydrocarbon generation, retention, and expulsion, fluid migration, diagenesis, and present-day pressure and temperature (Figure 2).
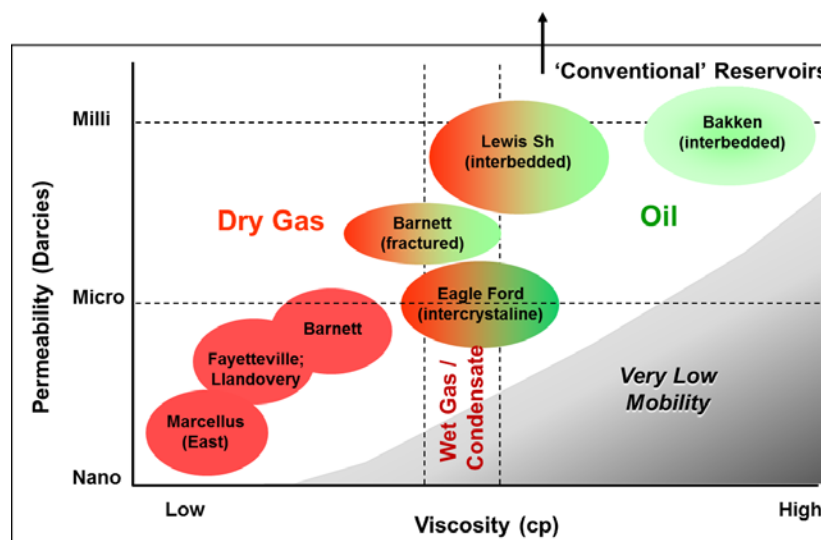
Figure 1 – Diagram illustrates the relative position of representative fine-grained reservoir formations/plays, based on rock permeability and fluid viscosity, and their various hydrocarbon fluid types. Production rates are proportional to the ratio of permeability and viscosity, thus dry gas can flow at significant rates in nanodarcy rock whereas black oil requires much higher permeability rocks for meaningful rates. (For this figure, high viscosity is approximately 1cp—the viscosity of water).

In this paper, we concentrate on the Porous Mudstone ('Source Rock') reservoir class that comprises 'shale-oil' reservoirs at lower thermal maturities and pressure-temperature (P-T) conditions to 'shale-gas' reservoirs at higher maturities and P-T conditions. Both contain a variety of pore types: inter-granular, intra-granular, intra-kerogen, and intra-pyrobitumen/char.
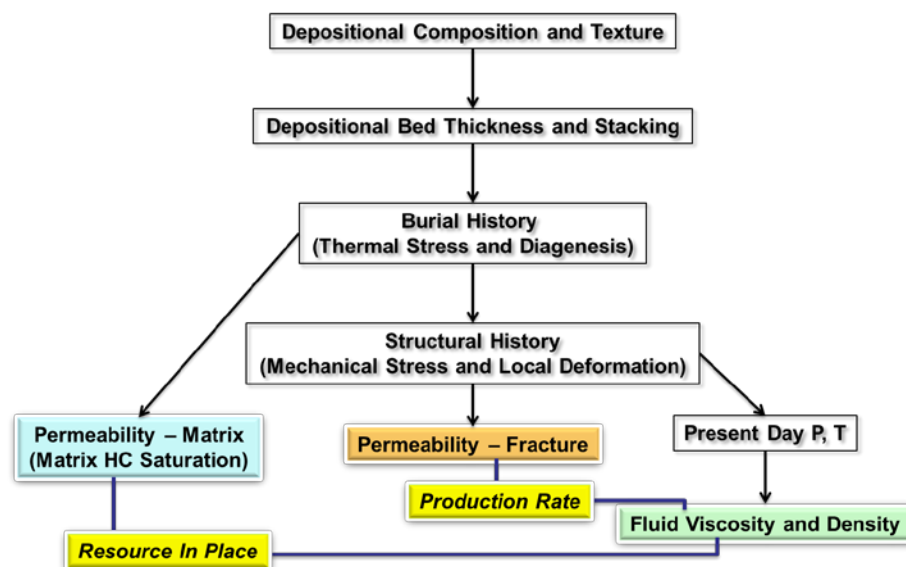
Figure 2 – Geologic controls that lead to current day rock permeability and fluid viscosity and their combined relation to resource in place and production rates.

A few words on nomenclature…
Porous Mudstone/Source Rock reservoirs have some significant differences with coarser siliciclastic or carbonate reservoirs, both in kind and in terminology. Before we enter into a detailed discussion of their characteristics, a few words on the general aspects of these characteristics and the terms we use is in order.

Rocks: There has been significant confusion about terminology when it comes to fine-grained rocks and their organic components (for in-depth details and comparison of definitions and different classifications of fine-grained rocks, see Lazar *et al*., 2010 and references therein). To many people, "shale" means "claystone", which in turn is a rock composed of more than 2/3rds clay-size material. By this definition, however, most "shale" reservoirs are not made of shale. Currently, most effective shale reservoirs have a significant component of silt-sized biogenic silica or carbonate as well as organic matter, and could more accurately be termed "argillaceous chalk", "kerogenous porcelanite", or "organic-matter-rich skeletal wackestone". According to the AGI Glossary (2005), shale is a laminated, indurated, fissile rock with more than 67% clay-sized minerals. Fissility, however, is weathering dependent and not an inherent property of a rock; one can place a fresh piece of a mudstone (hand specimen or core) into a box, open the box a year later and that same piece of rock can exhibit well developed fissility and then be called "shale".

Shale is a term deeply entrenched in our industry, and many will likely continue to use it especially as a class name or as a lithostratigraphic group or formation despite its descriptive shortcomings. *Sensu stricto*, however, we recommend that 'shale' be used only as a field term for fine-grained, indurated, fissile sedimentary rocks. "Mudstone", a term consistent with the use of other sedimentary rock descriptions such as sandstone and limestone, is probably more appropriate as a generic technical name for fine-grained rocks (Macquaker and Adams, 2003; Potter *et al*., 2005; Lazar *et al*., 2010). For a technical description, we recommend naming a particular fine-grained rock based on texture, bedding, and composition (see Lazar *et al*., 2010 for guidelines). In this paper, we use the term "mudstone" for a rock of any composition composed of > 50% grains less than 62.5 microns. We then add terms to specify the composition and bedding characteristics of a particular rock. This approach helps to make it clear that the essential and shared attributes of "Porous Mudstone" reservoir rocks are their texture, and that composition and bedding, although important, are secondary attributes.

Organic Material: There is a similar lack of uniform usage for terms that describe the organic substances found in fine-grained rocks. We use the term "organic material" as a generic class name for material enriched in organic carbon that can have many forms, only some of which generate hydrocarbons and host porosity. Organic material in rocks at surface P-T conditions comprises phytoclasts/macerals, kerogen, bitumen, pyrobitumen, char, and solidified oil ("dead" oil), along with retained liquid hydrocarbons (Figure 3; also see discussion in Tyson, 1995). (Depending on the analytical procedure used, all or some subset of these forms could be represented in a Total Organic Carbon measurement.) **Phytoclasts** are discrete

organic particles of approximately the same size range as the surrounding mineral clasts (after Bates and Jackson, 1987); they primarily represent pieces of algae and bacteria/archaea as deposited, as well as fragments of land plants and fungi. (In coaly rocks, these are called macerals. In this paper, we also use the term "organic matter" for this type of particle.) Kerogen and bitumen are fossilized forms derived from phytoclasts; the difference between kerogen and bitumen is one of degree (of solubility in organic solvents) and not of kind. **Kerogen** is an essentially insoluble solid composed of complex hydrocarbon and hydrocarbon-related molecules in a multipolymeric form. At higher thermal maturity, kerogen can host pores that are in essence the voids left behind by hydrocarbons that were generated and expelled. **Bitumen** is soluble and can be solid or semi-solid with a colloidal structure, or a highly viscous fluid. (There is a spectrum of solubility, depending on the type and strength of solvent.) **Pyrobitumen** is the solid hydrocarbon residue of hydrocarbon generation from bitumen; it is infusible and insoluble, but still retains some capacity to generate hydrocarbons upon further heating. **Char** is the ultimate residue of hydrocarbon generation, with minimal hydrogen content and essentially no remaining potential for generating hydrocarbons. Both pyrobitumen and char can host significant porosity and are quite similar to petroleum coke. **Solidified ("Dead") oil** (as used in this paper) is hydrocarbon that was liquid in the subsurface, but that is solid or very highly viscous at surface conditions due to expulsion of volatiles on the way up the wellbore and in handling and storage.

For the development of porosity, the essential distinction is between material that is solid versus liquid under reservoir conditions—solids being necessary to preserve pores. It appears that there are two main pathways for making organic-hosted pores by generation of hydrocarbons: from kerogen, resulting in "mineral coke", and from bitumen/liquid hydrocarbon, resulting in pyrobitumen and char ("petroleum coke"—these two main paths for generating gas are discussed in Tissot and Welte, 1984). A schematic representation of the evolution of organic matter from photosynthesis, through the oil and gas windows, to post methane generation is shown in Figure 3. With burial and maturation, organic material becomes increasingly more porous and carbon-enriched, as hydrocarbons are generated and expelled. A significant volume of gas is generated from oil retained in the rock.
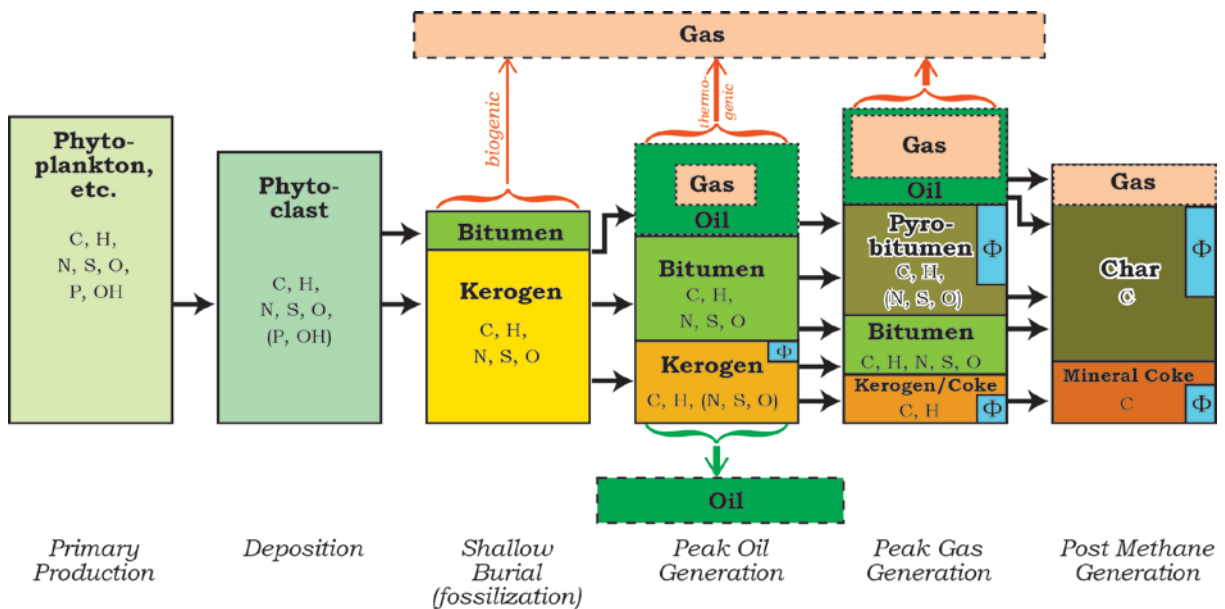

Figure 3: Schematic representation of the evolution of organic matter from photosynthesis, through the oil and gas windows, to post methane generation. Solid outlines indicate solid material, short-dash outlines indicate fluids retained in the rock (and gas dissolved in oil), long-dash outlines indicate expelled hydrocarbons. Blue rectangles indicate porosity hosted by various organic materials; this porosity is filled with hydrocarbon mixtures indicated by the short-dash boxes. The overall size of rectangles roughly indicate relative volume of each component.

Absolute Permeability of 'Shale-oil'/Tight-liquids and 'Shale-gas' Systems – progress, but still evolving

Porosity, fluid saturation, and permeability derived from core can be tied to log response; however, several studies have shown that the results obtained from different core analysis laboratories can vary significantly, reflecting differences in analytical technique, differences in definitions of fundamental rock and fluid properties, or the millimeter-scale variability common in mudstones that make it problematic to select multiple samples with identical attributes (Passey *et al*., 2010). Porosity determination in 'shale' reservoirs is complicated by very small pore sizes and, thus, large surface area (and associated surface water) as well as by swelling clays that have interlayer water.

Previously, it was demonstrated that accurate measurement of porosity and permeability in fine-grained mudstones is quite

challenging (Passey *et al.*, 2010; Luffel and Guidry, 1992; Luffel et al., 1993, Sondergeld et al., 2010; Clarkson et al., 2012). Over the last three years, industry has been active in addressing the differences among absolute porosity and permeability measurements conducted by various service company, university, and operating company laboratories. Significant progress has been made regarding porosity: it has been observed that, through multiple 'round robin' comparisons of various laboratories, total porosity measurements using helium porosimetry by different laboratories are generally within about +/- 1 p.u. of each other, which is good news.

The range of crushed-rock as-received permeability values of 'round-robin' shale-gas samples reported by various laboratories, however, remains unsatisfactory, with differences of 2 to 4 orders of magnitude still reported (Spears *et al.*, 2011; Handwerger *et al.*, 2011). It is beyond the scope of this paper to address whose 'permeability' is "right", but a number of recent papers (Sinha *et al.*, 2013, 2012; Tinni *et al.*, 2012; Suarez-Rivera *et al.*, 2012; Fathi et al., 2012) describe more technical details of various approaches for permeability measurements. The presence of mobile hydrocarbons in 'shale-oil'/tight-liquids reservoir rocks presents an added complexity that imposes additional challenges to obtaining valid and useful permeability measurements. It is anticipated that, within the next year or two, the issue of effective permeability in gas-window mudstones will be resolved and become routine with possible standards for all laboratories to help quality control their systems and workflows.

Porous Mudstone ('Source Rock') Reservoirs

Geological Controls and Factors
Depositional Processes: Most currently producing Porous Mudstone ('shale') reservoirs are mature to overmature oil-prone source rocks (Bohacs, 2007; Passey *et al.*, 2010). Through burial and heating, these reservoirs evolved from organic-matter-rich mud deposited in marine, lacustrine, or swamp environments. Key characteristics of organic-matter-rich rocks that have been investigated extensively in previous work include: total organic carbon (TOC), thermal maturity level, mineralogy, organic matter type, and thickness—all of which translate also into reservoir potential.

The accumulation of organic-matter-rich rocks (ORRs) is a complex function of many interacting processes (as discussed more fully in Bohacs *et al.*, 2005). Successful prediction requires the integration of plate tectonics, geodynamics, and basin structural development with reconstructions of paleo-environmental conditions as the context for process-based models for the occurrence, distribution, and character of potential source rocks or Porous Mudstone reservoirs. Organic-matter accumulation in depositional environments is controlled by complex, non-linear interactions of three main proximate control variables: rates of production, destruction, and dilution. Significant enrichment of organic matter occurs where organic-matter production is maximized, destruction is minimized, and dilution by clastic or biogenic material is optimized, in an area with sufficient accommodation rate to accumulate significant thickness of sediments. The main factors and interactions are illustrated in the following equation:

Equation 1: Controls on Organic-Matter-Rich Rock Character

$$ORR\_Quality = \left[\frac{Production_{H-rich} - Destruction_{H-rich}}{Dilution_{non-H-rich}} \right]$$

Although organic-matter enrichment can be expressed as the relatively simple relation above, it is quite complex in detail because of the interdependencies of the variables (Bohacs et al., 2005):

- *Production = f(Nutrient supply)*
- *Destruction = f(Production of organic matter) + f(Oxidant exposure time) – f(Clastic sedimentation rate < burial-efficiency threshold)*
- *Dilution = f(Clastic sedimentation rate > burial-efficiency threshold) + f(Production of biogenic silica or carbonate relative to protoplasm).*

As Equation 1 indicates, the accumulation of organic matter is ultimately the result of sets of competing rates: it is essential to produce organic matter faster than it is consumed or oxidized. Observations of many organic-matter-rich rocks ranging in age from Cambrian to Recent indicate that ORRs accumulate in a variety of settings and result from appropriate combinations among competing rates of production, destruction, and dilution of organic matter (*e.g.*, Potter *et al.* 1980; Arthur *et al.* 1987; Creaney and Passey, 1993; Huc, 1995; Tyson, 2001; Bohacs 1990, 1998; Werne *et al.* 2002). There are many combinations that can yield rocks enriched in organic material, especially for moderately rich potential source rocks that can serve as Porous Mudstone reservoirs (Bohacs *et al.*, 2005, their Table 1).

Although organic-matter-rich intervals can be hundreds of meters thick, vertical variability in TOC is ubiquitous at scales of

less than a meter and is controlled by depositional, biotic, and diagenetic factors (Bohacs *et al.*, 2005). In general, the fundamental geologic building block of mudstone reservoir systems is the parasequence, and commonly many tens of parasequences comprise the organic-matter-rich formation whose lateral continuity can be estimated using techniques and models developed for source rocks (Bohacs, 1998). Full characterization of these formations requires integration of sample-based analyses with full well-log suites, including high resolution density and resistivity logs and borehole images.

'Shale-oil'/Tight-liquids Systems: 'Shale-oil'/tight-liquids Porous Mudstone reservoirs share many attributes with shale gas reservoirs, but also have some distinct differences—fluid properties become a dominant control on producibility (as discussed above) and significant inter-granular porosity appears to be essential. In terms of rock properties, silica or carbonate that is biogenically produced along with the hydrogen-rich organic matter can form a significant portion of the inter-granular and intra-granular poro-perm system and provide strength ('brittleness') to the rock to sustain fractures (Figure 4). Just as with the organic matter, the ultimate character of the biogenic material in the rock is a function of three sets of competing processes, quite analogous to ORR accumulation:

Equation 2: *Controls on Biogenic-Rich Reservoir Rock Character (RQ = reservoir quality)*

$$RQ = \left[\frac{\left(Production_{H-rich} + Production_{SiO2/CO3}\right) - \left(Destruction_{H-rich} + Dissolution_{SiO2/CO3}\right)}{Dilution_{clay}} \right]$$

In this version of the relation, we additionally consider primary production of both hydrogen-rich material (i.e., phytoclasts/macerals) as well as hydrogen-poor biogenic silica and carbonate. Destruction of the hydrogen-poor material includes dissolution of carbonate and transformation of biosilica. Dissolution is influenced by many factors, but mainly by rates of primary production, burial, and sediment mixing (mostly by burrowing), as well as by mineral composition, molecular weight, reaction rate, and porosity. Equations 3 and 4 indicate typical functional forms and interactions of these factors.

Equation 3: *Controls on dissolution portion of Destruction term for silica portion of system (after Archer et al., 1993)*

$$\Phi \frac{\partial Si}{\partial t} = \frac{\partial}{\partial z}\left(\frac{D_{Si}}{F}\frac{\partial Si}{\partial t}\right) + \left[\left(k_{opal}\right)\left(C_{opal}\right)/M_{opal}\right]\rho\Phi(1-\Phi) \bullet \left(Si_{sat} - Si\right) \bullet H\left(Si_{sat} - Si\right)$$

Equation 4: *Controls on dissolution portion of Destruction term for carbonate portion of system (after Archer et al., 1993)*

$$\Phi \frac{\partial \sum CO_2}{\partial t} = \frac{\partial}{\partial z}\left(\frac{D_{CO_2}}{F}\frac{\partial CO_2}{\partial z}\right) + \frac{\partial}{\partial z}\left(\frac{D_{HCO_3}}{F}\frac{\partial HCO_3}{\partial z}\right) + \frac{\partial}{\partial z}\left(\frac{D_{CO_3}}{F}\frac{\partial CO_3}{\partial z}\right) + R_{org} + R_{cal}$$

where: $\quad R_{org} = \left[\left(k_{orgl}\right)\left(C_{org}\right)/M_{org}\right]\rho\Phi(1-\Phi) \bullet H\left([O_2]\right)$

$$R_{cal} = \left[\left(k_{call}\right)\left(C_{cal}\right)/M_{cal}\right]\rho\Phi(1-\Phi) \bullet \left[1 - \frac{[CO_3]}{[CO_3]_{sat}}\right]^n \bullet H\left([CO_3]_{sat} - [CO_3]\right)$$

C = concentration (dry weight fraction)
D = free diffusion coefficient
F = sediment formation factor (after Ullman and Aller, 1982)
H = Heaviside function (= 0 if supersaturated, = 1 if undersaturated)
k = rate constant ($cm^3\ mol^{-1}\ s^{-1}$)
M = molecular weight
R = reaction rate ($mol\ cm^{-3}\ s^{-1}$)
$[CO_3]_{sat}$, Si_{sat} = apparent saturation value ($mol\ cm^{-3}$)
ρ = density of solid material ($g\ cm^{-3}$)
Φ = porosity

As mentioned above (and discussed more fully in Tyson, 2001; Bohacs *et al.*, 2005; Passey *et al.*, 2010), the controlling parameters for Production, Destruction, and Dilution are not completely independent and are complexly inter-related through physical, biological, and chemical factors. Similarly, the controls on the dissolution portion of Destruction are influenced by

Production and Dilution factors: the first order control is biogenic production of silica and carbonate that contributes to the starting concentrations of solid reactants. Organic-matter type and availability influences biological activity—burrowing is a prime control on sediment mixing rate and on pore-water oxygen and CO_2 concentrations. The organic matter also influences microbial type and activity which in turn influences such key chemical factors as pH, Eh, carbonate alkalinity, and ionic concentrations (*e.g.*, [HCO_3^-]). Dilution also plays a role in dissolution through the type and amount of clay minerals and elements in associated oxy-hydroxides and sesqui-oxides. These components can buffer certain dissolution reactions or hinder others (*e.g.*, Taylor and MacQuaker, 2000). In silica systems, the proportion of clay minerals relative to silica is key in determining whether the silica phase changes (through dissolution-reprecipitation reactions) result in chert or porcelanite amenable to fracturing or in neo-formed clay minerals more challenging to hydraulically fracture and prop. Dilution effects on Porous Mudstone reservoirs comprise both the content of clay minerals (as they affect rock strength, permeability, and wettability) and of biogenic silica and carbonate (as they affect rock strength and organic-matter concentration and connectivity) as well as sediment accumulation rate influence on redox reactions that determine the formation of early cements. Hence, the interaction of the three sets of competing processes is even more intricate and intertwined than that for ORR accumulation alone. In practice, however, the paleo-environmental conditions that lead to significant ORR accumulation commonly also result in biogenic-rich rocks in associated strata (Bohacs *et al.*, 2005; Bohacs and Lazar, 2008).

As importantly, such fluid properties as hydrocarbon viscosity, density, and phase behavior are controlled by composition, which is a function of depositional input and burial history (*i.e.:* P, T, diagenesis), and are critical to resource potential and producibility. Over geological time, fluid density and phase control fluid saturation in the matrix. In a traditional interpretation of reservoir, fluid saturation can be considered in terms of the pressure in the hydrocarbon column required to overcome the capillary entry pressure of the matrix—the hydrocarbon column pressure is equal to $\rho * g * h$ (density*gravity*height of the column), and capillary entry pressure is proportional to surface tension and wetting angle, both of which are influenced by fluid density and phase. This approach has proven effective in such mudstone reservoirs as the Monterey and Kreyenhagen Formations (Schwalbach et al., 2007). In the short term, viscosity and phase affect flow and production rates. Although there are many views of the details of how fluids flow in very low permeability rocks, practically all published relations (*e.g.:* Knudsen, Klinkenberg, Forchheimer) are built on the Darcy-Weisbach equation and include viscosity as a prominent term (*e.g.*, Noman and Kalam, 1990; McPhee and Arthur, 1991; Zeng and Grigg, 2006; Blassingame, 2008). Indeed, these alternate flow models are needed because the fluid is of low viscosity and density (*i.e.*, a gas—*e.g.*, Ziarani and Aguilera, 2012).

Hence, two main classes of attributes affect ultimate mudstone reservoir performance: rock properties (mainly permeability) and fluid properties (mainly viscosity) that are influenced by the full geological history of the reservoir (Figures 1, 2). Overall reservoir permeability includes both matrix and fracture characteristics: Matrix permeability is a function of original depositional composition, texture, bedding, and stratal stacking plus burial history (thermal stress, diagenesis). Fracture permeability is a function of the same controls as matrix permeability along with structural history (mechanical stress). Fluid properties (viscosity, density) are also controlled by the original depositional properties and burial/uplift history, along with present-day reservoir pressure and temperature.

'Shale Gas' Systems: The higher thermal maturities of 'shale-gas' Porous Mudstone reservoirs result in some contrasts with 'shale-oil'/tight-liquids Porous Mudstone reservoirs: they tend to have less smectite (inter-layer water) due to illitization, but develop significant porosity hosted in kerogen, pyrobitumen, and char ('organic material' *sensu lato*). SEM images of ion-beam-milled samples reveal development of a distinct separate nanoporosity system contained within organic material, in some cases comprising > 50% of the total porosity, and these pores tend to be hydrocarbon wet, at least during most of the thermal maturation process (*e.g.*, Passey *et al.*, 2010). Thus, in these cases, the pore volume within the organic material is generally the dominant fraction of the entire porosity of most shale-gas systems (Figure 5). The genesis of these organic-material pores probably represents "coking" of previously liquid hydrocarbons and of kerogen macerals. These pores are contained within the organic material, and therefore might have entirely different wettability than that of the pores in the mineral matrix. The organic-hosted pores could be hydrocarbon wet and are generally where the majority of the free gas resides in high thermal maturity, organic-matter-rich Porous Mudstone reservoirs. For most 'shale-gas' systems, the well log resistivity is relatively high, and most petrophysicists develop empirical models to determine total porosity, generally from crushed-rock type of core analysis. Water saturation can also be calculated in the total porosity system, however, due to the inability to conduct full electrical property measurements of extracted plug samples of mudstone, the values for "m" and "n" used in Archie's equation generally are assumed to be 2, but can be modified if one has sufficient confidence in the crushed-rock determinations of Sw and Sg.

Current shale-gas reservoir systems exhibit a wide range in mineralogy of the inorganic minerals composing the matrix. Although these mudstones all inherently are composed of very fine grained particles, the matrix mineralogy reflects the building-block material available for deposition. The original mineralogy of the sediment can be further altered through chemical diagenesis through cementation and dissolution. Figure 4 illustrates distribution of bulk mineralogy for several

well-known organic-rich mudstones worldwide. Much of the range exhibited in any given formation is reflective of the high degree of vertical heterogeneity observed in most mudstone successions. The plot demonstrates that bulk mineralogy is not a dominant control on shale-gas plays due to the presence of organic–matter hosted pore systems.
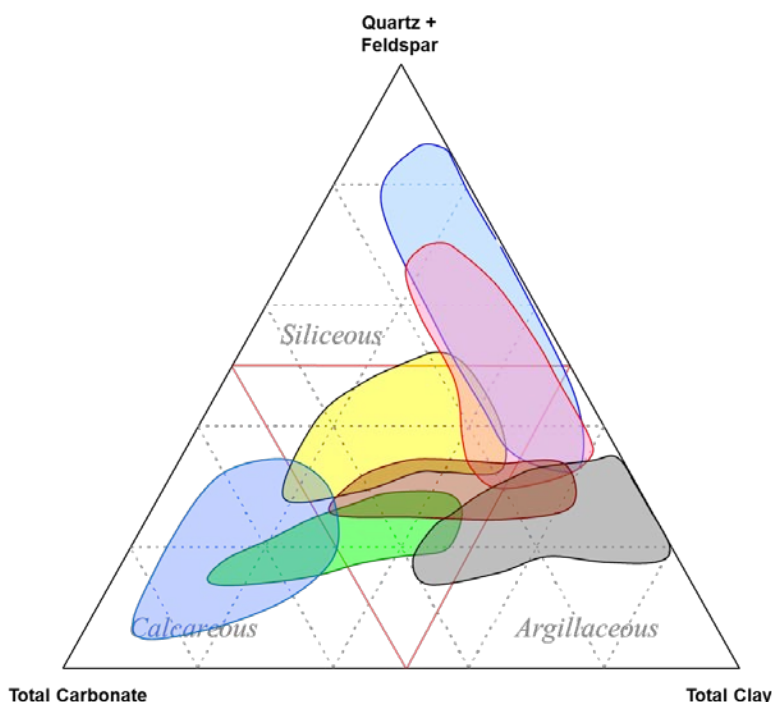

Figure 4 –Variation in matrix composition observed in various 'shale'-gas/tight liquid reservoirs worldwide. Silica or carbonate that is biogenically produced along with the hydrogen-rich organic matter can form a significant portion of the inter-granular and intra-granular poro-perm system and provide strength ('brittleness') to the rock to sustain fractures. Total clay content relative to carbonate and silica is another strong influence on rock strength. Each color corresponds to a particular 'shale'-gas/tight liquid formation.

Porosity-Permeability Systems

Shale-Gas Systems - Porosity Observations: As described in detail by others (e.g., Loucks et al, 2012, 2010; 2009; Potma et al., 2012), a previously unrecognized porosity system appears to occur in organic material (kerogen, bitumen, pyrobitumen, or char) in the gas window— the maturity threshold is likely dependent on organic-matter type. These organic-hosted pores appear to play a key role in the storage and producibility of hydrocarbons. In some silica-rich systems, the organic-hosted pores appear to make up the majority of the porosity visible under SEM, where the original matrix pores between silica-rich grains appears to have been almost completely cemented (see Figure 5). At present, it is difficult to differentiate, in these high-maturity samples, organic material that once was a kerogen maceral from bitumen, pyrobitumen, or char (although there are some subtle features that might allow for differentiation, but this topic is beyond the scope of this paper).

In contrast with the silica-rich shale-gas formation pictured above, in organic-matter and clay-rich mudstones, ion-milled SEM images reveal a fabric dominated by clay platelets, with the appearance of abundant porosity between the clay grains (Figure 6 left). Higher magnification (right figure) indicates that the space between the clay particles is primarily occupied by organic material, which clearly shows organic-hosted pores at even higher magnification. But in addition to the organic-hosted pores, there is considerable interparticle porosity within the clay platelets that is not hosted by the organic material. In this example, analysis of preserved core indicated that the total porosity of the system is about 15 porosity units (p.u.) and that 7 p.u. are occupied by gas (presumably within the organic material) and about 8 p.u. occupied by water (presumably in the intergranular clay porosity and as surface (and possibly interlayer) water.
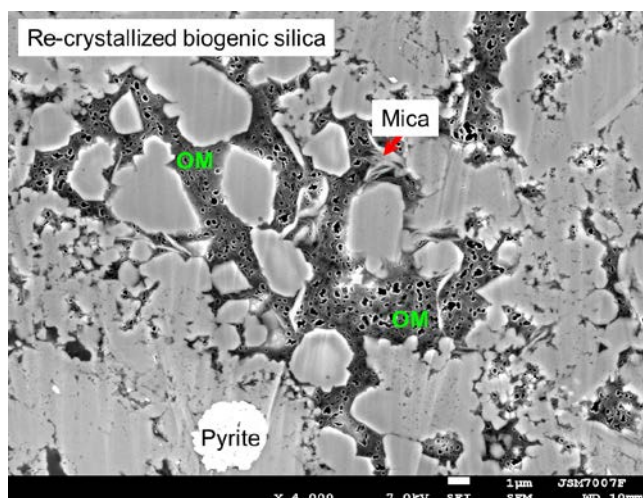
Figure 5 – SEM image of ion-milled section of Barnett Shale. Note that in this view, the majority of the visible porosity is within the organic material and not within the silica-rich matrix.
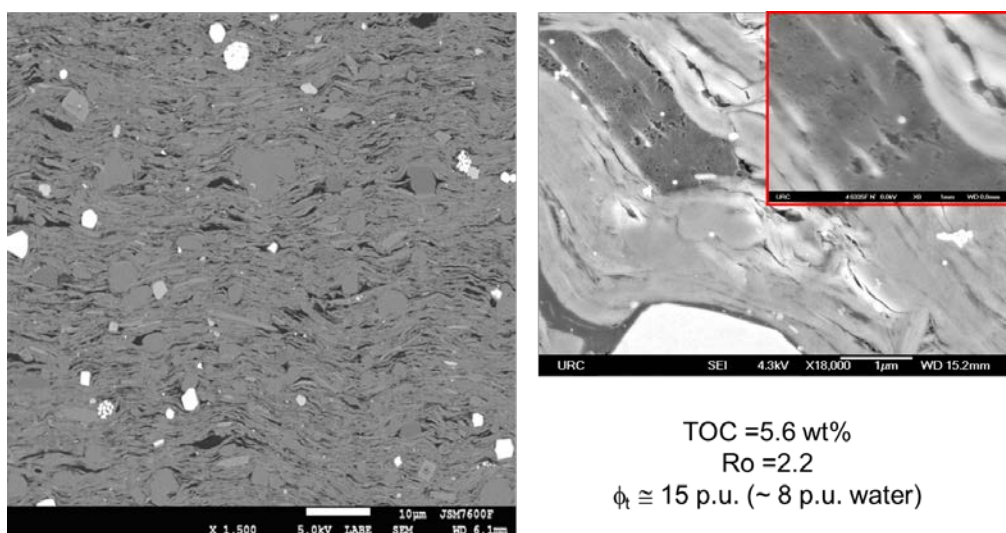

Figure 6 – SEM images of clay-rich and organic-material-rich potential shale gas formation. Note that porosity exists both within the organic material and between the clay platelets.

Although a significant portion of the total porosity can be contained in organic material, in many 'shale' gas formations, porosity associated with mineral matter (e.g., intergranular porosity) can also be significant (*e.g.*, clay-rich mudstones and/or mudstones that have undergone complex diagenetic processes). These types of pores are discussed in the following section on 'Shale oil'/Tight-liquids porosity observations".

Due to the very small size of pores in mudstones (and in the associated kerogen and pyrobitumen/char), quantification of porosity types in mudstones remains a challenge. Detailed examination of pores using a combination of various techniques (*e.g.*, He porosimetry, MICP Mercury Injection Capillary Pressure, and SEM 'point counting') indicates that much of the porosity is likely in very small organic-hosted pores below the resolution of the standard SEM (approximately 3-5 nanometers) (Comisky *et al.*, 2011). The occurrence of these very small pores is the same as proposed by Ambrose *et al.*, (2010) to address more accurate GIP (gas-in-place) calculations. The size range has implications for the role of free versus adsorbed gas in the storage of gas and wet-gas compounds in these organic-hosted pores. Figure 7 schematically illustrates how the size of a methane molecule compares to the diameter of the pore in a hydrocarbon-wetting system, such as an organic-hosted pore. In this figure, even the 'large' 40 nanometer diameter pore was previously considered 'small' for conventional reservoirs. The presence of the very small pores have been known to exist in coals (Sakurovs, et al., 2012) but previously had not been known widely to exist for oil-prone kerogen and generated bitumen. The role of these very small pores in the ultimate producibility of shale-gas systems is unknown, and can be impacted by additional issues of hydrocarbon

flow due to potential blockage of small pores/pore throats by capillary condensation within organic-hosted pores (Chen *et al.*, 2012).
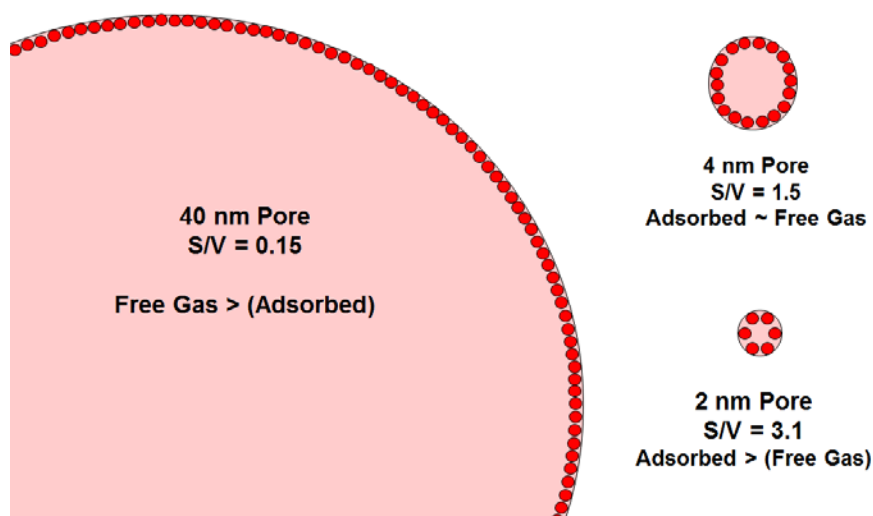

Figure 7 – Schematic illustration of the scale of nanometer-scale pores and the size of methane
molecules (red dots). The red dots along the pore surface indicate residing as adsorbed gas,
which would likely have a greater fluid density than free gas.

'Shale'-oil/Tight-liquids Systems - Porosity Observations: In examining organic-matter-rich mudstones that are in the oil window, it has been noted that abundant organic-hosted pores are most obvious at higher maturity ranges. Previously, it has been reported that 'structured organic matter' (phytoclast/kerogen) exhibits minimal, if any, organic-hosted pore development within the oil window (Hardy *et al.,* 2012; Schieber *et al.*, 2012). An examination of an ion-milled SEM image of a Woodford Shale sample in the oil window demonstrates that no organic-hosted pores are visible in the structured organic matter under SEM (at least down to about 5 nanometers). Thus, in this rock at this maturity, it is unlikely that pores in kerogen particles play a significant role in the producibility of black oil even though the kerogen is saturated with black oil at the molecular level (see also Figure 14 of Passey *et al*., 2010 for additional images of this sample fluorescing under UV light). At lower maturities, there are, however, some features that have the appearance of very large pores (micrometer-scale) that are associated with organic material surrounded by mineral grains (although it is challenging to discern the influence of sample retrieval, handling, and analyses on these features).
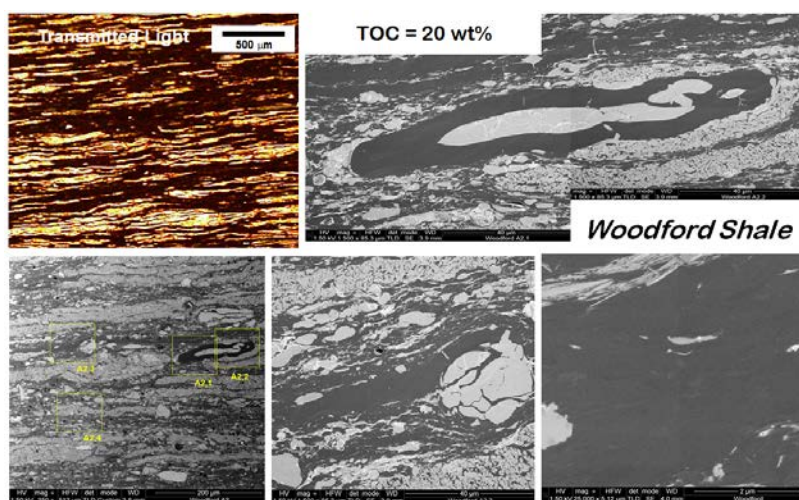

Figure 8 – Transmitted light optical photomicrograph and high magnification SEM images of ion-milled sample
of Woodford Shale. This sample is in the oil-window and no pores are visible in the kerogen
and phytoclasts of *Tasmanites*.

Pores of this size would be essential in the oil window, because larger pores and pore throats are likely required for sufficient mobility because molecules of oil are much larger than that those of dry gas (i.e., methane) (Momper, 1978; Nelson, 2009).

Figure 9 illustrates that methane molecules are typically 1-2 orders of magnitude smaller than organic-hosted pores observed in samples from the shale-gas window. Given that oil molecules are larger and oil more viscous than gas, it is reasonable to expect that larger pores are required for moving oil on a production time frame; thus, it is likely that pores larger than 1-2 micrometers are required.
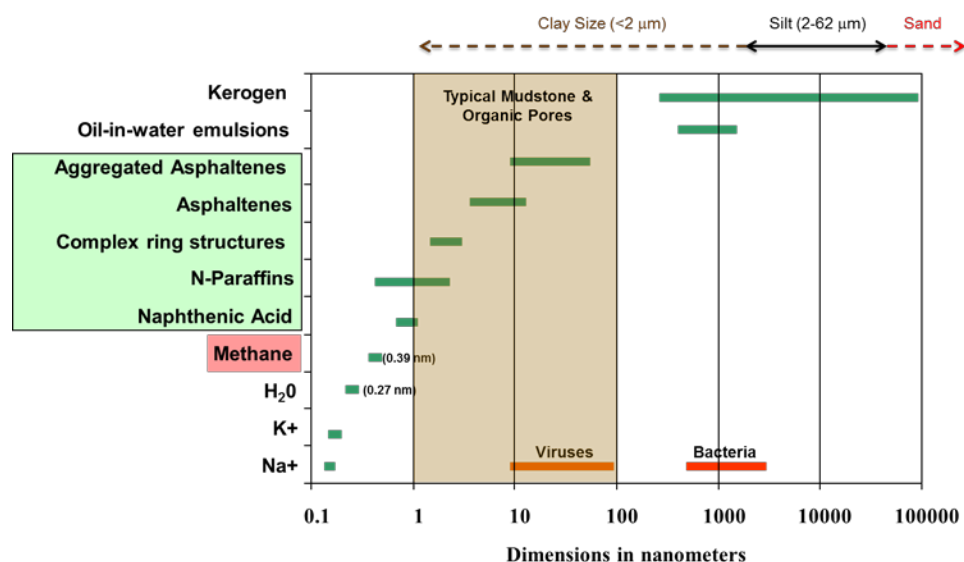

Figure 9 – Comparison of size of various cations, and hydrocarbon molecules with typical clay-, silt-, and sand-size particles. Also shown are the size range of typical mudstone and organic-hosted pores. Note that many compounds found in black oil are much larger than methane and water molecules (after Momper, 1978).

Excluding interbedded and fractured fine-grained reservoirs (such as the Bakken, Monterey, and parts of the Barnett and Woodford Formations), it appears that intergranular, intragranular, and intercrystalline inorganic-hosted pores likely contribute significantly to the storage and producibility of black oil. Figure 10 illustrates that within the Eagle Ford Formation, a significant proportion of the porosity comprises such pores, which typically have dimensions of 1-5 microns, and could be sufficient for storing and producing black oil. Where the thermal maturity of an Eagle Ford sample is higher, organic-hosted porosity is obvious and abundant, as observed in other shale-gas reservoirs. However, in other samples at similar maturities, some organic material does not exhibit organic-hosted pores, probably as a function of the type of organic material and its original hydrogen content (*e.g.*, bitumen/pyrobitumen/char versus kerogen).
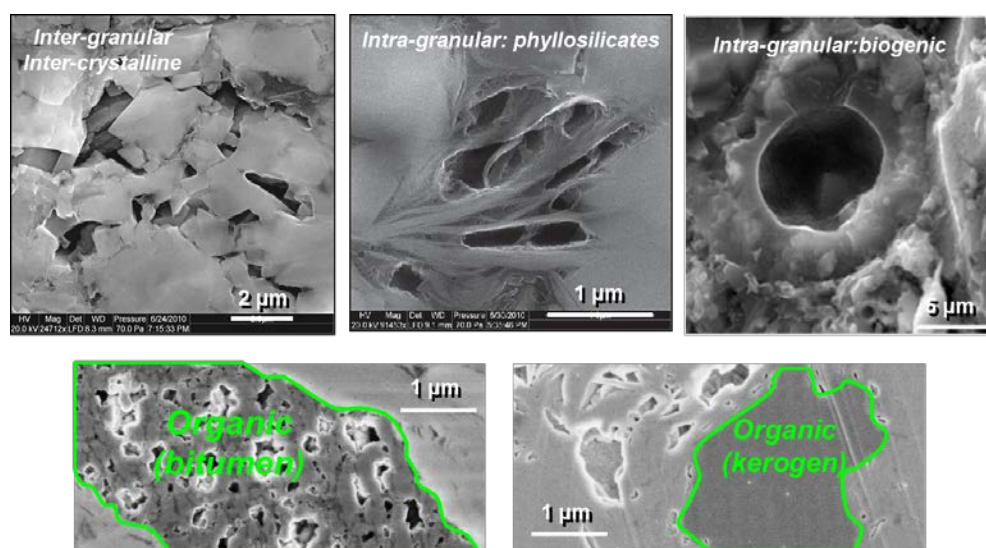

Figure 10 – SEM images showing various types of pores associated with inorganic material, and those commonly present within organic material. Note the large differences in pore size, where the inorganic pores can be 1-2 orders of magnitude larger than typical organic-hosted pores. (top three images from Eagle Ford Shale, Schieber *et al*., 2012; bottom two images from Hardy *et al*., 2012)

Thus, the development of organic-hosted porosity is a complex function of the type, origin, and history of various organic materials; the full range of controls is not yet widely understood. In the oil window, although oil is dissolved within and adsorbed onto kerogen, it is likely that such oil is not easily producible. Hence, plays with additional porosity systems, such as interbedded sandstones/siltstones (*e.g.*, Middle Bakken, Three Forks), layers containing significant interparticle/intraparticle/intercrystalline pores (*e.g.,* Eagle Ford), or fractures (*e.g.*, Monterey, Woodford, Barnett), would tend to work better. (Note that for most fractured formations, the porosity associated with fractures is typically less than 1.0 %BV, so the fractures primarily provide permeability and not necessarily significant hydrocarbon storage.) The various types of porosity commonly encountered in fine-grained reservoirs that are in the oil-window are schematically summarized in Figure 11.
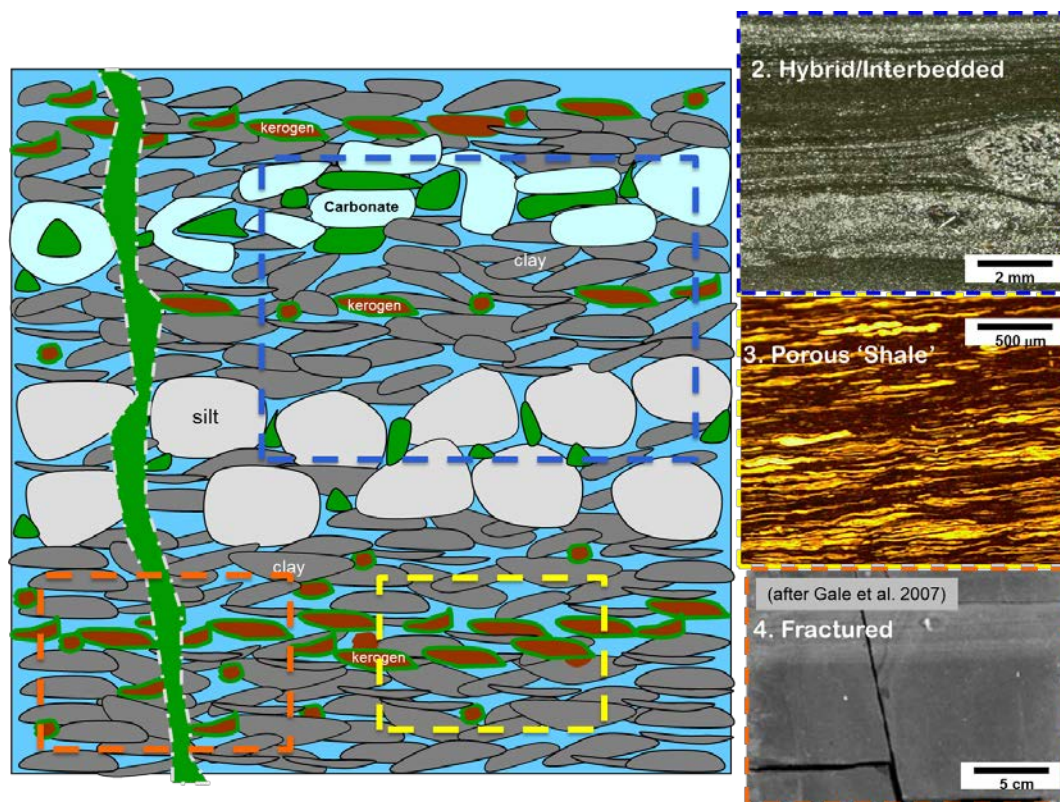

Figure 11 – Schematic summarizing types of pores that can host black-oil in fine-grained reservoirs rocks.
Also, shown are various low magnification photomicrographs and core photographs illustrating
the major types observed (shown here in examples from siliceous mudstones).

Evolution of Porosity-Permeability Systems

Figure 12 summarizes much of our current understanding about how the porosity system evolves for oil-prone organic-matter-rich mudstone from immature, through the oil window, and into the shale-gas window. Intergranular and intragranular pores probably persist through much of entire maturity range, but, depending on mineralogy, the original porosity can be completely cemented (e.g., silica-rich mudstones), some additional porosity can be generated during diagenesis and through re-crystallization (e.g., carbonate-rich mudstones), and for some carbonate-rich rocks, fossil tests can preserve significant amounts of porosity through much of the entire maturity range. Intergranular and intragranular pores are originally water-wet and not all are intruded by hydrocarbons in the oil window. Pores can also be hosted by various forms of organic material at various levels of thermal maturity, from kerogen, through pyrobitumen, to char and mineral coke. In many formations, organic-hosted pores appear largely unaltered through much of the shale-gas window although there is evidence that the density of the remaining kerogen increases with increasing maturity (Alfred and Vernik, 2012). At extremely high maturity, it appears that the remaining organic material expels most of its hydrogen content and transforms into graphite or graphene and related compounds (e.g., Tissot and Welte, 1984); the fate of organic-hosted pores depends on pressure and stress-state history. It is not known exactly how the porosity system evolves as organic material "shrinks" with increasing maturity and expulsion of lighter hydrocarbons.
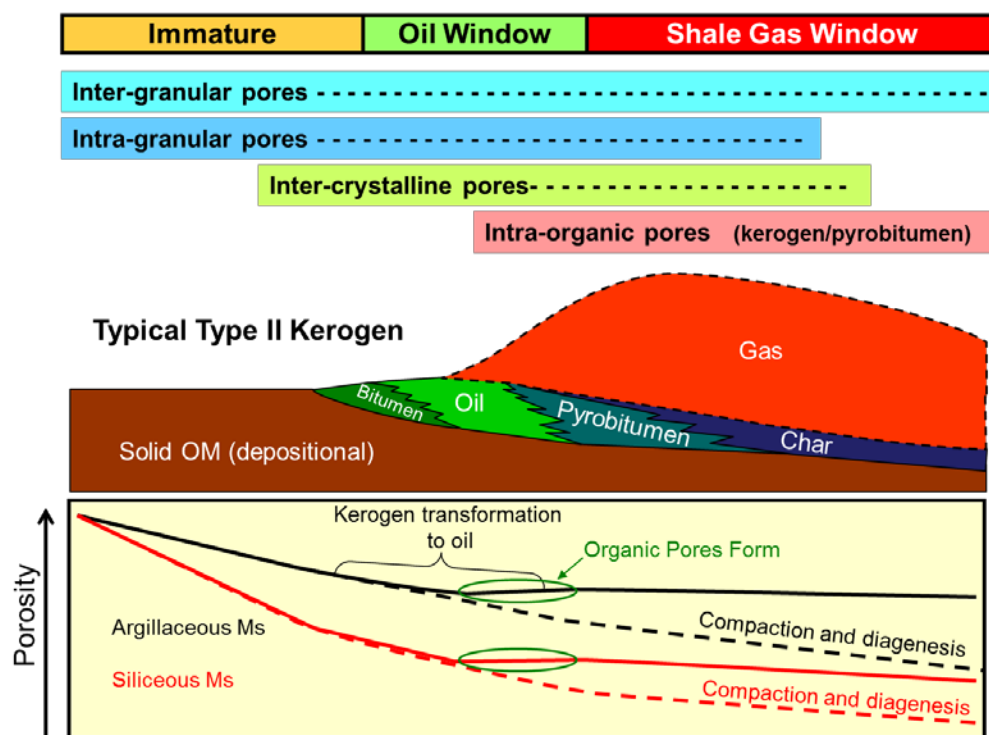
Figure 12 – Summary diagram illustrating how various pore types can evolve as a function of thermal maturity for Type II (oil-prone) kerogen. At very high maturities, organic-hosted pores can occur in depositional organic matter (kerogen) as well as in pyrobitumen and char, although it is commonly difficult to differentiate these various species of organic material.

Conclusions

Our observations and interpretations lead to several general conclusions:

- A spectrum of combinations of rock and hydrocarbon properties can result in meaningful production from fine-grained rocks, effectively spanning 'conventional' tight oil to fractured 'shale' gas reservoirs, in four main families based on dominant porosity-permeability system and stratal architecture.
- The rock and fluid property controls on resource-in-place volumes and production rates all share common geological controls.
- There are many forms of organic material in these rocks, only some of which can generate hydrocarbons and develop significant porosity, but all of which can be represented in a Total Organic Carbon measurement.
- Porous Mudstone reservoirs contain a variety of pore types: inter-granular, intra-granular, intra-kerogen, and intra-pyrobitumen/char— the last two, 'organic-hosted' types, are better developed and connected at higher thermal maturities.
- The size and distribution of organic-hosted pores and their resulting permeability require very low viscosity fluids for significant production rates. Production of higher viscosity hydrocarbons (*e.g.*, black oil, volatile oil) appears to best from rocks with significant inter- and intra-granular pores.

In summary, Figure 1 illustrates how various fine-grained reservoirs can be compared based on the permeability and viscosity of the systems—the combination of which is proportional to flow rates (*e.g.*: D'Arcy's Law). In this illustration, a 'high' viscosity is approximately that of water (e.g., 1 cp). Dry gas appears to be able to be produced from reservoirs that have permeability ranges in the 10's to 100's of nano-Darcies and many shale-gas systems can have permeability values exceeding one (1) micro-Darcy. As the hydrocarbons become more complex (i.e., wet-gas, condensate, and volatile oil), and the fluid viscosity increases, higher permeability is required (and likely larger pores) to produce the fluids at significant rates; a key control is the state of the fluid in the subsurface at reservoir temperatures and pressures. For black-oil reservoirs, even larger pores and higher permeability systems are likely required, and these systems approach 'poor-quality' conventional reservoirs, albeit more complex, and require artificial stimulation to achieve meaningful rates of production. This representation emphasizes the necessity of considering both rock and fluid properties for the entire spectrum of hydrocarbon reservoirs.

A full understanding of the relation of porosity and gas content will result in development of optimized processes for hydrocarbon recovery in shale-gas reservoirs. 'Shale'-oil/Tight-liquids plays require integration of both rock and fluid properties throughout the entire geological history of the reservoir, and as a part of the overall hydrocarbon system. In both

play types, reservoir performance is influenced not only by present-day pressure and temperature conditions, but also the original depositional attributes, peak P-T conditions, and subsequent uplift/exhumation history. Appreciation of the similarities and differences between 'shale-gas' and 'shale-oil'/tight-liquids enables more efficient and effective exploitation of the full range of resource types.

Acknowledgements

Nomenclature

C	concentration (dry weight fraction)
D	free diffusion coefficient
F	sediment formation factor (after Ullman and Aller, 1982)
g	acceleration of gravity ($m\ s^{-2}$)
h	height of hydrocarbon column (m)
H	Heaviside function (= 0 if supersaturated, = 1 if undersaturated)
k	rate constant ($cm^3\ mol^{-1}\ s^{-1}$)
M	molecular weight
R	reaction rate ($mol\ cm^{-3}\ s^{-1}$)
$[CO_3]_{sat}$, Si_{sat}	apparent saturation value ($mol\ cm^{-3}$)
ρ	density of solid material ($g\ cm^{-3}$)
Φ	porosity

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