Relative Gas Volume Ratios for Free Gas and Gas Hydrate Accumulations

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Gas hydrate is widely believed to represent a "compressed" or efficiently-packed form of natural gas, implying that gas hydrate is uniformly more energy dense than free gas accumulations at comparable depths. As first demonstrated by Barth (2005) for the deepwater Bering Sea, this is not necessarily the case. Here we explore this relationship for a range of gas hydrate settings that have been the focus of resource-related exploration and characterization.

The commonly cited "energy density" ratio for methane hydrate is 164:1, indicating that 164 unit volumes of methane at standard pressure (1 atm) and 0° C will be released from 1 unit volume of methane hydrate (assuming 96% of all cages are occupied by gas molecules). In the subsurface, this 164:1 ratio is largely independent of depth because gas hydrate is nearly incompressible at the pressures where gas hydrate is stable on Earth. However, the same is not true for conventional natural gas accumulations. In the case of methane vapor, the ratio of the volume of gas held at a given depth to the corresponding volume that would be released at the surface ranges greatly and is primarily governed by gas compression due to pressure, with additional complexities related to temperature.

The figure shows a comparison of the 164:1 methane density for gas hydrate with the changing energy density as a function of depth for "free"

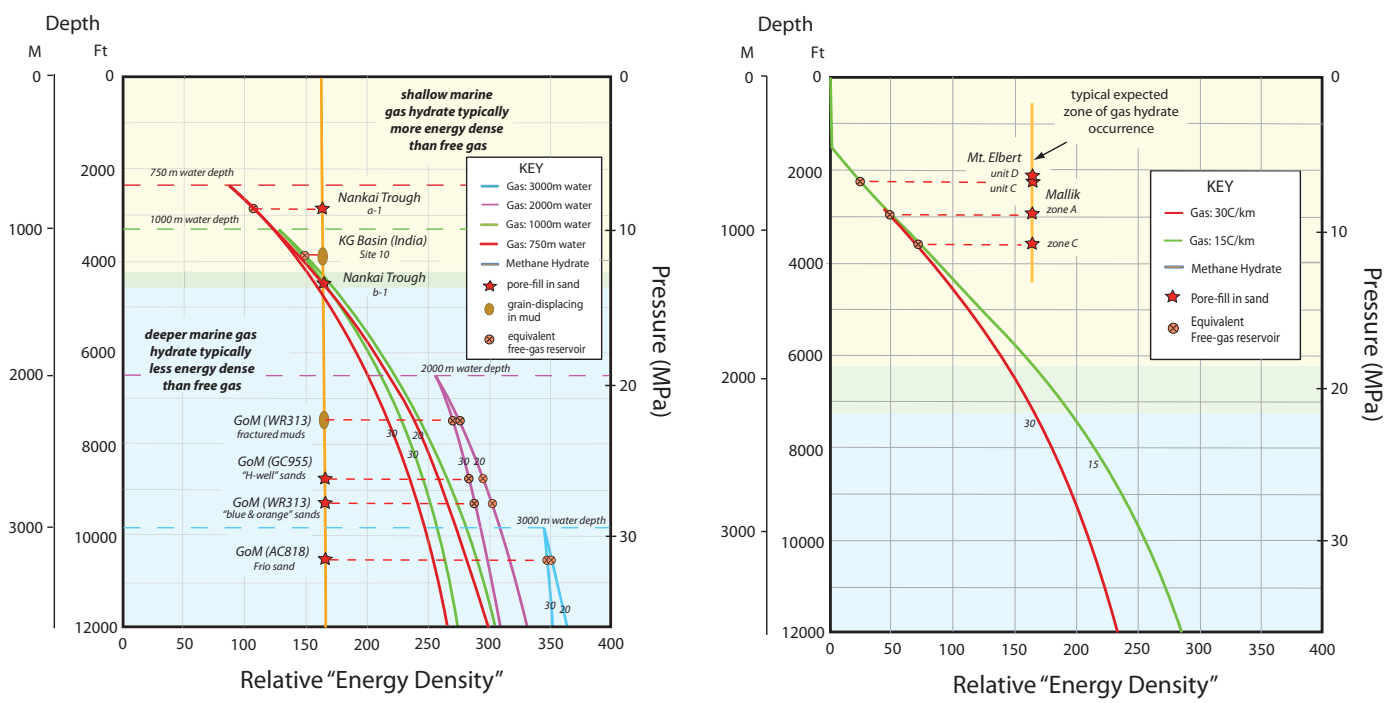

Figure 1: Comparison of energy density for free gas and gas hydrate deposits in marine (left) and permafrost (right) settings. "Relative Energy Density" refers to the ratio of gas held within a unit volume at surface conditions versus at depth. For gas hydrate, this ratio is ~1:164 and largely independent of depth. For gas, this ratio is 1:1 at the surface and increases with depth in response to pressure and temperature. Numbers plotted on the curves ("30", etc.) refer to thermal gradients in ° C/km.

gas accumulations. In the figure on the left, free gas density calculated using the Peng-Robinson equation of state is shown for three water depths and for two representative geothermal gradients. Gas hydrate is shown as the nearly vertical line at a value of 164, with well-documented sub-seafloor gas hydrate accumulations indicated for reference. This figure shows that, assuming hydrostatic pressure gradients, gas hydrate and free gas accumulations have approximately equal "energy density" (energy content per unit volume) at a depth of ~4000 ft below sea-level. In other words, at that total depth relative to sea-level, a 100 ft-thick hydrate accumulation holds as much gas as a 100 ft-thick free gas accumulation, assuming that the two have the same reservoir properties and saturation. Above this depth, gas hydrate is more energy dense, and it becomes relatively more energy dense at shallower depths, ultimately being 164 times as energy dense as free gas at the surface if the hydrate is maintained at stable pressures. At depths of greater than ~4000 feet below sea level, free gas is more energy dense in the marine environment. At present, one of the deeper well-documented marine gas hydrate occurrence is within the Frio sand in Alaminos Canyon block 818. This deposit lies at the base of the gas hydrate stability zone approximately 1,500 feet below the seafloor in just over 9,000 feet of water (see Boswell *et al*., 2009). At this location, methane gas is not compressed within the gas hydrate structure relative to how it would reside in a free-gas reservoir under the same conditions; instead, the hydrate lattice actually works to keep the molecules farther apart than they would be in the free state, therefore lowering the energy density. If this deposit were to be shifted out of hydrate stability conditions without changing its pressure, the released gas would further compress by roughly a factor of two in response to the ambient pressure, thereby significantly reducing the overall potential volume expansion of the pore fluids (including both gas and water, see table). In contrast, gas hydrates at the *B-1* location in the Nankai trough (Kurihara *et al*., 2010) reside very close to the depth at which a gas hydrate and a comparable free-gas reservoir would have roughly equivalent energy densities. Other shallower gas hydrates, such as those in the Nankai *A-1* location or at Site 10 in the Krishna-Godavari basin (Collett *et al*., 2006) are characterized by gas hydrate energy densities that are significantly greater than a free-gas accumulation would be at that depth.

The figure on the right shows similar information for the two best characterized permafrost-associated accumulations, the Mount Elbert site (Alaska: Boswell *et al*., 2008) and the Mallik site (NW Canada: Dallimore *et al*., 2005). At these settings, STP conditions do not exist at the surface, depressing the energy density curves for free gas downward with relation to pressure. In addition, sediment temperatures are higher at shallower absolute depths relative to the surface than in the marine cases due to the lack of a thick overlying water column. As a result, temperatures will exceed those suitable for gas hydrate formation well above the "cross-over" point between free gas and gas hydrate energy density. Therefore, onshore permafrost-associated gas hydrate accumulations can always be considered more energy dense than an equivalent free gas accumulation at the same depth.

The gas volume ratio comparisons have important implications for understanding the potential impact of gas hydrate dissociation, whether natural or induced. Most critically, the nature of the geomechanical and hydraulic response of hydrate-bearing sediments to i*n situ* gas hydrate dissociation will differ for shallow and deep reservoirs. In shallow marine and in permafrost settings, there will be significant volume expansion of

the fluid (gas and water) accompanying dissociation, leading to pressure build-up and potential fracturing under thermally-induced dissociation conditions, unless there are clear pathways for fluid and gas release (Santamarina and Jang, 2009). As shown in the table, the hypothetical change in fluid volumes (assuming *in situ* conversion from gas hydrate to free gas and water at unchanging pressure) declines significantly with burial depth and pressure.

Suggested Reading

Barth, G., 2005. Methane Gas Volume Expansion Ratios and Ideal Gas Deviation Factors for the Deep-Water Bering Sea Basins, USGS Open file report 2005-1451

Boswell, R. *et al*., 2009. Occurrence of gas hydrate in Oligocene Frio Sand: Alaminos Canyon block 818: Northern Gulf of Mexico: JMPG 26 (8), 1499-1512.

Boswell, R. *et al*., 2008. Investigation of gas-hydrate bearing sandstone reservoirs at the Mount Elbert stratigraphic test well, Milne Point, Alaska. ICGH-2008.

Collett, T., *et al*., 2006. Indian national gas hydrate program: Expedition 01 Initial Reports: DVD – Directorate General of Hydrocarbons, India.

Dallimore, S., Collett, T., 2005. Scientific results from the Mallik 2002 gas hydrate production research well program, Mackenzie delta, Northwest Territories, Canada. GSC Bulletin 585.

Kurihara, M., *et al*., 2010. Prediction of production test performance in eastern Nankai Trough methane hydrate reservoirs using 3D reservoir model: OTC 20737.

Santamarina, C., Jang, J., 2009. Gas production from hydrate bearing sediments: geomechanical implications: Fire in the Ice, Summer 2009.

Example location	Gas Hydrate Energy Density	Energy Density of Comparable Free Gas	Potential Volume Change in Fluids (Gas + Water)
Mount Elbert C	164	25	7.36 x
Mallik Zone A	164	70	3.14 x
Nankai Site A-1	164	105	2.36 x
Nankai Site B-1	164	164	1.80 x
WR313 Orange Sand	164	300	1.35 x
AC 818 Frio Sand	164	350	1.27 x

Table 1: Comparison of energy density (as defined above) between comparable gas hydrate and free gas reservoirs. Right hand column indicates potential volume change of pore fluids for in situ *conversion of gas hydrate to free gas and water at unchanging pressure.*