

# Lawrence Berkeley National Laboratory

## Lawrence Berkeley National Laboratory

### **Title**

Toward Production From Gas Hydrates: Current Status, Assessment of Resources, and Simulation-Based Evaluation of Technology and Potential

### **Permalink**

<https://escholarship.org/uc/item/7hm710jd>

### **Author**

Moridis, George J.

### **Publication Date**

2008-02-12

# Toward Production From Gas Hydrates: Current Status, Assessment of Resources, and Simulation-Based Evaluation of Technology and Potential

George J. Moridis, SPE, Lawrence Berkeley National Laboratory; Timothy S. Collett, SPE, US Geological Survey; Ray Boswell, US Department of Energy; M. Kurihara, SPE, Japan Oil Engineering Company; Matthew T. Reagan, SPE, Lawrence Berkeley National Laboratory; Carolyn Koh and E. Dendy Sloan, SPE, Colorado School of Mines

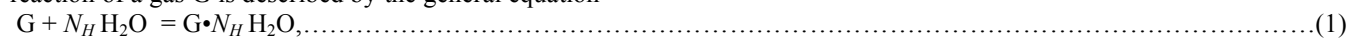
This paper was prepared for presentation at the 2008 SPE Unconventional Reservoirs Conference held in Keystone, Colorado, U.S.A., 10–12 February 2008.

## Abstract

Gas hydrates are a vast energy resource with global distribution in the permafrost and in the oceans. Even if conservative estimates are considered and only a small fraction is recoverable, the sheer size of the resource is so large that it demands evaluation as a potential energy source. In this review paper, we discuss the distribution of natural gas hydrate accumulations, the status of the primary international R&D programs, and the remaining science and technological challenges facing commercialization of production. After a brief examination of gas hydrate accumulations that are well characterized and appear to be models for future development and gas production, we analyze the role of numerical simulation in the assessment of the hydrate production potential, identify the data needs for reliable predictions, evaluate the status of knowledge with regard to these needs, discuss knowledge gaps and their impact, and reach the conclusion that the numerical simulation capabilities are quite advanced and that the related gaps are either not significant or are being addressed. We review the current body of literature relevant to potential productivity from different types of gas hydrate deposits, and determine that there are consistent indications of a large production potential at high rates over long periods from a wide variety of hydrate deposits. Finally, we identify (a) features, conditions, geology and techniques that are desirable in potential production targets, (b) methods to maximize production, and (c) some of the conditions and characteristics that render certain gas hydrate deposits undesirable for production.

## Introduction

**Background.** Gas hydrates are solid crystalline compounds in which gas molecules (referred to as guests) occupy the lattices of ice-like crystal structures called hosts. Under suitable conditions of low temperature  $T$  and high pressure  $P$ , the hydration reaction of a gas  $G$  is described by the general equation



where  $N_H$  is the hydration number. Hydrate deposits occur in two distinctly different geographic settings where the necessary conditions of low  $T$  and high  $P$  exist for their formation and stability: in the permafrost and in deep ocean sediments (Kvenvolden, 1988).

The majority of naturally occurring hydrocarbon gas hydrates contain  $CH_4$  in overwhelming abundance. Simple  $CH_4$ -hydrates concentrate methane volumetrically by a factor of 164 when compared to standard  $P$  and  $T$  conditions (STP). Some modeling suggests that the energy needed for dissociation could be less than 15% of the recovered energy (Sloan and Koh, 2008). Natural  $CH_4$ -hydrates crystallize mostly in the structure I form, which contains 46  $H_2O$  molecules per unit cell. Structure I hydrates have a  $N_H$  ranging from 5.77 to 7.4, with  $N_H = 6$  being the average hydration number and  $N_H = 5.75$  corresponding to complete hydration (Sloan and Koh, 2008). Natural gas hydrates can also contain other hydrocarbons (alkanes  $C_\nu H_{2\nu+2}$ ,  $\nu = 2$  to 4), but may also comprise lesser amounts of other gases (mainly  $CO_2$ ,  $H_2S$  or  $N_2$ ).

Gas hydrates were first discovered in laboratory studies ca. 1800, but it was as late as 1965 that mankind first recognized that they may be common in nature, and that the age of some natural gas hydrate systems may be on the order of millions of years (Sloan and Koh, 2008). Although there has been no systematic effort to map and evaluate this resource on a global scale, and current estimates of in-place volumes vary widely (ranging between  $10^{15}$  to  $10^{18}$   $m^3$  at standard conditions), the consensus is that the worldwide quantity of hydrocarbon gas hydrates is vast (Milkov, 2004; Klauda and Sandler, 2005). Given the sheer magnitude of the resource, ever increasing global energy demand, and the finite volume of conventional fossil fuel reserves, gas hydrates are emerging as a potential energy source for a growing number of nations. The attractiveness of gas hydrates is further enhanced by the environmental desirability of natural gas (as opposed to solid or liquid) fuels. Thus, the appeal of gas hydrate accumulations as future hydrocarbon gas sources is rapidly increasing and their production potential clearly demands technical and economic evaluation.

The past decade has seen a marked acceleration in gas hydrate R&D, including both a proliferation of basic scientific endeavors as well as the strong emergence of focused field-based study of gas hydrate productivity, primarily within national gas hydrate programs. Together, these efforts have helped to clarify the dominant issues and challenges facing the extraction of methane from gas hydrates. Among the most important developments is the increasing focus of studies in the lab on gas hydrates bearing sediments (as opposed to crystalline gas hydrate), the dramatic improvements in tools available for sample collection and analysis, the emergence of robust numerical simulation capabilities, and the imminent transition of gas hydrate resources from the era of astronomical in place numbers to the more relevant assessment of potential recoverability (Boswell, 2007). We have gone from thinking of marine gas hydrates as being controlled primarily by pressure and temperature conditions to a fuller understanding of the complexities of gas hydrate geological systems, including new insights into the effects of solubility, salinity and heat flow (Ruppel et al., 2005; Paull et al., 2005), reservoir lithology, and rates and

migration pathways for both gas and water. Taking advantage of this new data is a new marine gas hydrate resource assessment under way by the U.S. Minerals Management Service of the U.S. Department of the Interior in the Gulf of Mexico (Ray, 2005) that is expected to appear early in 2008

Going forward, the attempt to commercially produce gas from geologic hydrate deposits will face major challenges. Critical data gaps, such as information on the mechanical and hydraulic properties of hydrate-bearing media are being actively addressed. Furthermore, significant inroads are now being made into our understanding of hydrate behavior under different potential production scenarios. Nevertheless, critical challenges remain that are compounded by the complexity of dealing with a solid compound that releases gas only through an endothermic reaction, as opposed to a simple fluid withdrawal that characterizes production from conventional reservoirs. In addition, there is the difficulty of operating in the hostile Arctic and deep marine environments where gas hydrates are encountered.

Gas hydrates are often compared to coalbed gas resources, which were also considered to be an uneconomic resource in the not too distant past (Collett, 2007). However, once the resource was geologically understood, the reservoir properties defined, and the production challenges addressed, coalbed gas became a viable fuel in its own right and an important part of the energy mix in the United States, where it accounts for almost 10% of the natural gas production. Past experience with the development of other unconventional energy resources clearly shows that the evolution of gas hydrate into a producible source of energy will require a significant and sustained research and development (R&D) effort. Our paper discusses the current states of this R&D effort and of the corresponding knowledge.

**Objective.** The objective of this review paper is to review the state of knowledge on the subject of gas production from hydrates. This includes (1) an assessment of the resource and its global distribution, (2) a discussion of current policies, focus and priorities, (3) a synopsis of the technical advances that have addressed some of the early knowledge gaps in hydrate science that are relevant to production, (4) a review of the proposed production technologies and strategies (as dictated or constrained by the deposit conditions), (5) an analysis of current production predictions, (6) a summary of guidelines, criteria and recommendations for the selection of hydrate deposits as production targets and evaluation of the corresponding production methods, and (7) identification of remaining challenges and knowledge gaps at this early stage of the hydrate exploitation endeavor.

Note that, in this review paper, we do not address the subject of geophysics, and its potential role in the detection of hydrates, evaluation of the resource, and monitoring of the dissociation-fueled gas production process. The subject is sufficiently important and complex to merit its own separate review.

**Methods of Production from Gas Hydrates.** Gas can be produced from hydrates by inducing dissociation, which also releases large amounts of H<sub>2</sub>O (Eq. 1). The three main methods of hydrate dissociation are: (1) depressurization, in which the pressure  $P$  is lowered to a level lower than the hydration pressure  $P_e$  at the prevailing temperature  $T$ , (2) thermal stimulation, in which  $T$  is raised above the hydration temperature  $T_e$  at the prevailing  $P$ , and (3) the use of inhibitors (such as salts and alcohols), which shifts the  $P_e$ - $T_e$  equilibrium through competition with the hydrate for guest and host molecules (Makagon, 1997). Long-term production strategies often involve combinations of the three main dissociation methods (Moridis and Reagan, 2007a,b).

### **Occurrence, Research Activities and Priorities, and Prospective Production Targets**

**Magnitude and Global Distribution of the Hydrate Resource.** Knowledge of the occurrence of *in situ* gas hydrates is very incomplete, and is obtained from both indirect and direct evidence. There have been 23 locations where irrefutable evidence of hydrates has been seen through direct recovery of hydrate samples: 3 in the permafrost and 20 in ocean environments (Sloan and Koh, 2008). In permafrost regions, evidence of gas hydrate is provided two ongoing R&D programs (discussed below) and by analysis of industry 3-D seismic data and data obtained during the drilling and logging conventional oil and gas wells. The ability to prospect for gas hydrate deposits using this data has recently been demonstrated in the Prudhoe Bay region of the Alaska North Slope (Inks et al., in press). In the marine environment, the bulk of the data supporting the interpretation of gas hydrates at the majority of locations in indirect indicators (such as Bottom simulating reflections) on relatively low-quality 2-D seismic data. However, direct gas hydrate detection and characterization from marine 3-D data has recently been shown by Dai et al., (in press) and the use of 4-component ocean bottom seismic also shows great promise (Backus et al., 2006; Bunz and Mienert, 2005)

Given the relative abundance of marine gas hydrate resources, these occurrences will likely be the primary targets for future R&D activities. However, given the favorable economics of conducting long-term field programs in the Arctic (as opposed to the deep water, it is expected that arctic R&D activities will also continue. Two countries, the U.S., and Japan, are making considerable R&D investments in the Arctic, under the reasoning that the information gained on the behavior of gas hydrate bearing sand reservoirs can be readily transferred to the study of marine resources at a later date.

**Estimates of Gas Trapped in Hydrates and Related Uncertainties.** Table 1 lists the estimates of natural gas in hydrates in the geosphere's gas hydrate stability zone (GHSZ). These estimates range from the maximum values of Trofimuk et al. (1973),  $(3.053 \times 10^{18} \text{ m}^3 \text{ STP of CH}_4)$ , based on the assumption that hydrates could occur wherever a satisfactory  $P$ - $T$  regime exists, to the minimum values of Soloviev (2002)  $(2 \times 10^{14} \text{ m}^3 \text{ STP})$ , accounting for limiting factors such as CH<sub>4</sub> availability,

limited organic matter, porosity  $\phi$ , the thermal history of various regions, etc.). All the estimates in Table 1 (except that of Klauda and Sandler, 2005) involve extrapolation of a limited amount of fairly well known, localized geological data to a global level. The Klauda and Sandler estimate is based on a state-of-the-art model that involves (1) a new *ab initio* thermodynamic model that includes the effects of pores and salt, (2) estimates of the locus of the intersection of the geothermal gradient with the phase boundary (obtained from measured local temperatures and gradients in the world oceans), and (3) measured local organic sediment contents that (4) served as inputs to the methanogenesis mass transfer model of Davie and Buffett (2003). The model enables prediction of most recorded occurrences of hydrates, and reasonable explanations for the remaining exceptions (Sloan and Koh, 2008). The large amount of hydrates predicted by Klauda and Sandler includes both very deep hydrates and very dispersed hydrates, many of which are not accounted for by the other models or are not discovered by sampling due to dissociation. When only continental hydrates are considered, Klauda and Sandler predict  $4.4 \times 10^{16} \text{ m}^3$  (STP) of gas in hydrates.

None of the estimates of natural gas hydrates are well defined, and therefore they are all speculative to a certain extent. However, even the most conservative estimates suggest enormous amounts of gas in hydrated form, the magnitude of which can be appreciated by comparing them to the current rate of  $10^{12} \text{ m}^3$  STP of gas-equivalent annual energy consumption in the United States. All estimates are comparatively large relative to estimates of the conventional gas reserve of  $1.5 \times 10^{14} \text{ m}^3$  of methane (Radler, 2000). Kvenvolden (1988) indicated that his estimate of  $1.8 \times 10^{16} \text{ m}^3$  of methane in hydrates may surpass the available, recoverable conventional  $\text{CH}_4$  by two orders of magnitude, or a factor of two larger than the  $\text{CH}_4$ -equivalent of the total of all fossil fuel deposits.

The only systematic assessment U.S. hydrate resources to date has been by Collett (1995). He assigned probabilities to 12 different factors (geological attributes correlated with the existence of hydrates) to estimate the 50% probability (mean) estimate of hydrate resources within the United States at  $9 \times 10^{15} \text{ m}^3$  of  $\text{CH}_4$  (with the 95% probability estimate at  $3 \times 10^{15} \text{ m}^3$  and the 5% probability estimate at  $1.9 \times 10^{16} \text{ m}^3$ ), i.e., the mean hydrate value indicates 300 times more hydrated gas than the gas in the total remaining recoverable conventional resources.

**Geographic Occurrences.** In terms of global distribution, the amount of hydrates in the ocean surpasses that in the permafrost by two orders of magnitude (Sloan and Koh, 2008). This oceanic amount is disproportionately large, considering that the oceans and the permafrost comprise 70% and 7%, respectively, of the earth's surface. The estimates of the oceanic hydrate resources are so large compared to those in the permafrost (Table 2) that a 1% error in the ocean approximations could encompass the entire permafrost hydrate reserves. Kvenvolden (2005) compiled 89 hydrate sites shown in Figure 1 (Sloan and Koh, 2008). At those locations hydrates were either:

1. Recovered as samples (23 locations),
2. Inferred from (a) Bottom Simulating Reflector (BSR) geophysical signatures (63 locations), (b) decrease in pore water chlorinity (11 locations), well logs (5 locations), and slumps/pockmarks (5 locations – note that there is skepticism as to whether some of these slumps are indicative of hydrate occurrence), or
3. Interpreted from geologic settings (6 locations).

A measure of the dearth of direct knowledge on the global distribution of hydrates, as well as on the properties of hydrate-bearing sediments, can be gleaned by attempting to compare this meager list of sampled (or even merely geophysically investigated) locations that represents the entirety of the accumulated data-base of natural hydrates, to the huge body of information on conventional oil and gas reservoirs, or even to the large (and rapidly increasing) data-base of information on unconventional resources such as coalbed methane (Warner, 2007).

**Policies, Focus, Activities, and Priorities.** The following review focuses on those studies that are most relevant to the assessment of gas hydrate resource potential:

**Policies, Institutional Support, and Research Activities.** By the early 1990s, it was clear that the potential implications of gas hydrates to the future balance of energy, especially in countries with limited conventional oil and gas resources (Boswell, 2007). Japan took a leading role in the effort to explore the potential of geologic hydrate deposits as an energy source when the Japanese Ministry of International Trade and Industry (MITI) established a research program in 1995, which led to the drilling and installation of the first well designed to investigate marine gas hydrate deposits from a resource perspective (Takahashi et al., 2001). This exploration well was drilled from November 1999 to February 2000 in the Nankai Trough offshore Japan at a water depth of 945 m, at a location where the BSR seismic signature indicated a high probability of hydrate (Uchida et al., 2004; Tsuji et al., 2004; Matsumoto et al., 2004). One of the most important accomplishments of this pioneering effort was the development of a methodology to evaluate hydrate occurrence while drilling a well (Takahashi et al., 2001; JNOC-TRC, 1998). The initial MITI program was succeeded by a larger multi-well exploration program (Matsumoto et al., 2004), and is probably the most advanced program in the world in terms of proximity to commercial production.

In the U.S., gas hydrate studies related to resource issues had begun in 1980s with small program within the U.S. DOE and the USGS. The DOE program ceased in 1990, although the USGS continued to make significant contributions, including the 1995 release of an estimate of  $9 \times 10^{15} \text{ m}^3$  STP ( $= 3.2 \times 10^{17} \text{ STP ft}^3 = 320,000 \text{ TCF}$ ) of domestic gas hydrate resources via the world's first systematic gas hydrate resource assessment. Spurred by this information, and other factors, in 2000, the U.S. Congress restarted the U.S. national program by enacting the Methane Hydrate Research and Development Act (MHR&D



Act). This legislation authorized substantially increased funding and directed the U.S. Department of Energy, the U.S. Geological Survey (USGS), the Minerals Management Service, the National Oceanic and Atmospheric Administration (NOAA), the Naval Research Laboratory, and the National Science Foundation to work together to uncover the physical nature, economic potential, and environmental role of naturally-occurring methane hydrates. Over the first 5 years of the MHR&D Act, hydrate science advanced significantly, both in terms of knowledge of natural hydrate occurrences, hydrate physical/chemical properties, and in the tools available to researchers.

Working from a solid foundation of knowledge obtained from earlier studies (Sloan and Koh, 2008; Boswell, 2007), researchers gained a greater understanding of the complexity of hydrate accumulations through laboratory work (Waite et al., 2002; Durham et al., 2003; Winters et al., 2004; Kneafsey et al., 2005; Gupta et al., 2006), numerical simulation analyses (Moridis and Reagan, 2007a,b; Moridis et al., 2007a; Moridis and Sloan, 2007), and national and international collaborative field experiments (Dallimore and Collett, 2005) (see discussion in following sections of this paper), and began the development of the precursors to tomorrow's hydrate exploration and evaluation technologies. By 2005, it was clear that, given certain reservoir conditions, production of methane from hydrate was technically feasible and potentially commercially viable through specially tailored application of existing technologies (Boswell, 2007). In 2005, the U.S. interagency R&D program began implementing the second 5-year authorization of the MHR&D Act, which saw the ongoing transition of the effort from one based primarily on studies in the lab to a more integrated effort focused on collection of data in the field.

**Synopsis of Global Research Activities.** In the US, research activities include laboratory experiments and simulation studies (Boswell, 2007), in addition to field studies that focus on onshore Alaska and the offshore Gulf of Mexico — i.e., sites of proven exploration targets for gas hydrates in the US (Collett, 1995; Collett, 2004; Collett, 2007). There, documented prolific petroleum systems coexist with critical drilling and transportation infrastructure that may allow gas hydrate prospects to be drilled and produced from existing installations. Major federal-industry partnerships have been formed in both the Gulf of Mexico and on the North Slope of Alaska (Collett, 2004).

It is likely that the first US domestic production from hydrates may occur in Alaska, where gas from onshore hydrates will either support local oil and gas field operations, or be available for commercial sale if and when a gas pipeline is constructed. However, it is not possible to completely discount the possibility of first US domestic production of gas from hydrates occurring in the Gulf of Mexico because, despite of the substantially increased complexity and cost of offshore operations, there is a higher probability of available pipeline capacity and easier access to markets.

Japan has a rigorous research plan and an advanced exploration program that has led the drilling of 36 wells in gas hydrate-bearing turbiditic sand reservoirs in the Nankai Trough off Japan's east coast (Takahashi and Tsuji, 2005). Fujii et al. (2005) described the variety of gas hydrate occurrence found in the Nankai region, and Kurihara et al. (2005) discussed the relative economic favorability of gas hydrates in different geologic settings. The Japanese effort is probably the most advanced in terms of approaching commercial production, which is expected to begin around 2016. Japan has also collaborated with Canada and other nations to conduct scientific studies and initial gas hydrate production tests in the Canadian Arctic. Canada has established a large gas hydrate research and development program that resulted in the Mallik production field test (Dallimore and Collett, 2005), the most significant to-date development in the quest for gas production from hydrates (see later discussion).

The government of India is also funding a large national gas hydrate program to meet its growing gas requirements. Earlier seismic data (acquired on the Indian continental margin) and gas hydrate occurrences that were accidentally discovered during drilling for conventional oil and gas resources (Collett, 2004) provided the impetus for a hydrate-focused scientific expedition in the summer of 2006. This expedition confirmed large hydrate deposits at four offshore locations, from which a large number of hydrate-bearing sediment cores were obtained. Most notable was the 130-meter thick fractured shale occurrence in the Krishna-Godowari basin that contained gas hydrate concentrations previously unseen in shale-dominated reservoirs (Collett et al., 2006).

China has pursued gas hydrates R&D for more than a decade (Fan et al., 2005) and conducted its initial drilling and coring program in the South China Sea in early 2007. That expedition found saturations of gas hydrate up to 40% in undeformed, clay-dominated sediments at a number of sites (Zhang, et al., 2007). Like the India expedition before it, these results were totally unexpected, and indicated that, given adequate sources of gas, hydrates are remarkably effective at filling any available pore space.

Korea has established a significant research program that aims to assess the potential hydrate resources in the Korean East Sea. Preliminary surveys conducted by the Korea Institute of Geoscience and Mineral Resources (KIGAM) between 2000 and 2004 suggest that there is a significant potential for gas hydrate occurrence in the Ullung Basin (Park, 2006), and numerical simulation studies have raised intriguing possibilities about the production potential of these deposits (Moridis et al., 2007b). In late 2007, news reports emanating from the drilling and coring program in Korea's East Sea reported several 100-meter thick occurrences that appear to be similar to the thick fractured shale deposit discovered offshore India in 2006.

Other countries (e.g., Norway, Russia, Mexico, Taiwan, Vietnam, Malaysia) have either embarked on, or are investigating the viability of, government-sponsored research programs to investigate the potential of gas production from national hydrate deposits. This list is only expected to continue to grow. In Europe, research programs like Hydratech and Hydramed have received funding from E.U. sources, however, these programs have tended to focus primarily on scientific and environmental issues.

A major contributor to the advance of gas hydrate science has been a series of field expeditions carried out under the Integrated Ocean Drilling Program (IODP) and its predecessors. IODP efforts included the initial discovery of marine gas hydrate offshore Guatemala in 1982, as well as seminal expedition offshore Peru, at the Blake Ridge (offshore S. Carolina), in the Nankai Trough, and at Hydrate Ridge (offshore Oregon). The most recent Expedition, X311, conducted a systematic sampling of gas hydrate within the accretionary wedge sediments offshore Vancouver Island. This expedition produced an array of important findings, including major new insights into the importance of gas hydrate solubility/methane saturation in pore waters, and the major control that reservoir lithology can play in determine degree of gas hydrate concentration (Reidel et al., 2005).

Given the difficulty and the large costs of conducting field studies on hydrates, significant effort is invested in international collaborative projects that combine the talents and resources of the participants. The most well known (and probably the most important, in terms of knowledge generated) was the 2002 Mallik project, conducted at that site in Canada's Mackenzie Delta (Northwest Territories) by an international consortium that included seven organizations from five countries (Japan, Canada, the United States, India and Germany) as well as the International Continental Scientific Drilling Program. Current international collaborative projects include the Mallik 2007-2008 project (Dallimore et al., 2007) (Japan and Canada), as well as other bilateral collaborations, e.g., US-India (Collett et al., 2006) and US-China (see later discussion).

**Focus and Priorities.** As in the case of conventional hydrocarbon production, it is logical to expect that the first gas recovery from hydrate resources will occur where there is relatively easy site access and the gas hydrate is concentrated (Collett, 2007). It is obvious that such sites and deposits constitute the first targets on which the attempt to produce gas from hydrates must be focused. While the following discussion is based on the conditions and properties of US deposits, and the results and experiences from the US research effort, the approach and concepts apply universally.

The recently published Interagency R&D Roadmap (Boswell et al., 2006) recognizes that the wide range of geological settings for gas hydrate implies a variety of gas hydrate occurrences. The analysis of Boswell and Collett (2006) used relative prospects for future production as the criterion to identify several key tiers of gas hydrate resource categories within the context of a gas hydrates *resource pyramid* (Figure 2). This depiction can accurately display the relative size and producibility of the different types, with the most promising resources at the top and the most technically challenging at the base (Boswell and Collett, 2006). The pyramid shape reflects the natural tendency for the most abundant elements of a resource group to also typically be the most difficult to profitably extract. Figure 2 also includes an accurately scaled (with regard to relative size) schematic resource pyramid for all domestic non-hydrate natural gas resources.

At the peak of the Gas Hydrates Resource Pyramid (those resources that are closest to potential commercialization) are gas hydrates that exist at high saturations within quality reservoirs rocks under existing Arctic infrastructure (Figure 2). This resource is currently estimated to be in the range of  $9.4 \times 10^{11}$  m<sup>3</sup> STP (= 33 TCF) of gas-in-place (in the "Eileen" trend of Alaska's North Slope). Modeling studies suggest that as much as  $3.4 \times 10^{11}$  m<sup>3</sup> STP (= 12 TCF) of that volume may be technically recoverable. The second-from-the-top tier of hydrate resources is that of less well-defined accumulations that exist in similar geologic settings (discretely trapped, high-saturation occurrences within high-quality sandstone reservoirs) on the North Slope, but away from existing infrastructure. The current USGS estimate for total North Slope resources is approximately  $1.7 \times 10^{13}$  m<sup>3</sup> STP (= 590 TCF) gas-in-place (Collett, 2005).

The next most challenging (third) tier of resources includes gas hydrates of moderate-to-high concentrations that occur within quality sandstone reservoirs in the marine environment. Because these resources are usually burdened by the likely high costs of extraction from deep water, the most favorable accumulations are those found in the Gulf of Mexico in the vicinity of oil and gas production infrastructure (Boswell, 2007). The scale of this resource is not well known, but is the subject of an ongoing assessment by the U.S. Minerals Management Service, which has recently revealed the occurrence of significant volumes of sandy sediments within the shallow section (Ray, 2005). Examples of this category of resource have been documented from the Gulf of Mexico (Smith et al., 2006), as well as from the Nankai Trough offshore Japan (Fujii et al., 2005) and by the recent IODP Expedition 311 offshore Vancouver Island (Reidel et al., 2005).

The fourth tier involves massive deposits of gas hydrate, generally found encased in fine-grained muds and shales. Most promising among this group appear to be those with elevated  $S_H$  primarily because of extensive structural disturbance of the sediment. Such fractured-reservoir accumulations may be common in certain areas, with thick sections exhibiting massive vein fills, high concentrations of small hydrate nodules, smaller vein fills, or massive layers parallel to bedding planes (Boswell et al., 2007). However, unlike the sand/sandstone systems where grain-supported reservoirs result in high matrix permeability and for which well-based production concepts are more plausible, extraction of methane from these shale-encased fractured accumulations is expected to be problematic because of significant geomechanical challenges that may affect the integrity of the formation and the well stability (Rutqvist and Moridis, 2007). Major technological advancements beyond current production systems will be needed before production from such deposits becomes feasible.

In order of decreasing producibility, the fifth tier of occurrences involves massive gas hydrate mounds that lie exposed at or near the seafloor and extend to unknown depths (Boswell and Collett, 2006). These features are possibly very dynamic and may be common, but their contribution to the hydrate resource is unknown. Their potentially limited magnitude (as a fraction of the total hydrate mass) notwithstanding, recovery of methane from such features is practically impossible using conventional well technology (because of their proximity to the ocean floor and the practically limitless supply of water), and

may be very difficult if subsea mining technologies are attempted (because of the likelihood for significant disturbance of sensitive sea-floor ecosystems).

At the very base of the gas hydrate resource pyramid (sixth tier) are those finely-disseminated accumulations, typified by the Blake Ridge accumulation offshore the Carolinas (Borowski, 2004), in which large volumes of gas hydrate are relatively evenly distributed through vast volumes of fine-grained and relatively undeformed sediment at low (~2-4% average, with a maximum estimate of 5%-12%) saturations. Such resources may represent the bulk of the world's global gas hydrate in-place resource (in the hundreds of Tcf gas-in-place). Unfortunately, the prospects for economic recovery of natural gas from this highly disseminated resource are very poor with current technologies (Moridis and Sloan, 2007).

**Hydrate Deposits That Are Production Targets.** From the previous discussion, it is obvious that hydrate deposits that are being considered as production targets must have the following attributes:

- Confirmed presence of high hydrate saturation (preferably by coring and well logging, or by geophysical methods at a minimum),
- Occurrence within sediments of sufficient reservoir quality to support well-based production methods,
- Site accessibility through proximity to existing infrastructure, and
- Access to gas markets through pipeline availability.

Such potential targets are limited because these requirements further restrict the possible choices from among the scant deposits for which data are available. In this section we discuss the features and attributes of hydrate deposits (permafrost or oceanic) that are either known or likely targets for gas production, and we analyze the geologic and engineering factors that control their ultimate resource potential.

**Permafrost Deposits.** The discussion in this section follows closely the analysis of Collett (2007), which is the most thorough analysis of the subject. It is generally believed that thermal conditions conducive to the formation of permafrost and gas hydrate have persisted in the Arctic since the end of the Pliocene (about 1.88 Ma). Maps of present-day permafrost indicate that about 20 percent of the land area of the northern hemisphere is underlain by permafrost. Geologic studies (Molochuskin, 1978) and thermal modeling of subsea conditions (Osterkamp, 1993) also indicate that *relic* permafrost (Collett, 2007) and gas hydrate may exist within the continental shelf of the Arctic Ocean. In practical terms, onshore and near-shore gas hydrate can only exist in close association with permafrost. Thus, the map in Figure 3 depicts not only the distribution of onshore continuous permafrost and the potential extent of relic sub-sea permafrost, but also the maximum possible extent of occurrence of onshore and near-shore gas hydrates. Because of relatively easier access, data from permafrost deposits are of better quality and represent a disproportionately large fraction of the entire hydrate database. Note that permafrost deposits represent the two top tiers of the hydrate resource pyramid of Figure 2, indicating their relative desirability compared to oceanic accumulations. There are three permafrost deposits under consideration as production targets, as discussed in this section.

**Mackenzie Delta, Canada – Mallik Gas Hydrate Accumulation.** This is likely the best-characterized gas hydrate accumulation in the world. The assessment of gas hydrate occurrences in the Mackenzie Delta-Beaufort Sea area was made originally on the basis of data collected during the past three decades of conventional hydrocarbon exploration in the area (Judge et al., 1994), and were refined with data from three dedicated scientific drilling programs (Dallimore and Collett, 1995; Dallimore et al., 1999; Dallimore and Collett, 2005) that included the collection of gas-hydrate-bearing core samples. This gas hydrate field is overlain by 600 m of permafrost, and is located within a sequence of Tertiary sediments (Collett, 2007). At least 10 discrete gas hydrate layers, with a total thickness of over 110 m and high hydrate saturation  $S_H$  (occasionally exceeding 80%), were identified from well-log analysis in the 900 m to 1,100 m interval (Dallimore et al, 1999; Dallimore and Collett, 2005). The estimates of the amount of gas in the hydrate accumulations are in the  $2.8 \times 10^{10}$  -  $2.8 \times 10^{11}$  m<sup>3</sup> STP (= 1 to 10 TCF) range (Majorowicz and Osadetz, 2001; Osadetz and Chen, 2005), making the Mallik field as one of the most concentrated gas hydrate deposits in the world.

Because of the success of the earlier (1998) Mallik 2L-38 gas hydrate research well program, the Mallik site (Figure 4) became the test site of two additional gas hydrate production research programs: (1) The Mallik 2002 Gas Hydrate Production Research Well Program (Dallimore and Collett, 2005), and (2) the 2006-2008 JOGMEC/NRCan/Aurora Mallik Gas Hydrate Production Research Program (Dallimore et al, 2007). The Mallik 2002 Gas Hydrate Production Research Well Program involved an international consortium (comprising the Japan National Oil Corporation, the Geological Survey of Canada, the U.S. Geological Survey, the U.S. Department of Energy, the GeoForschungZentrum-Potsdam, the Indian Ministry of Petroleum Geology and Natural Gas, Gas Authority India Ltd, and the International Continental Scientific Drilling Program), conducted the first fully integrated field study and test of production from hydrates, and yielded unique data that provided a detailed analysis of the geology, geochemistry, geotechnical and microbiological properties of gas hydrate bearing sediments (Collett, 2007). Over 150 m of high quality gas hydrate cores collected during the Mallik 2002 program provided additional insights into the macroscopic and microscopic properties of the reservoir sediments (Figure 5).

The studies originating from the Mallik 2002 test included investigations of (a) the kinetics of gas hydrate dissociation, (b) petrophysical properties and initial  $S_H$  of the hydrate-bearing media (HBM), (b) the HBM thermal and hydraulic properties, (c) the HBM geochemistry, (d) the HBM geotechnical properties such as compressive strengths and stress regime, and (e) the capability of geophysical methods to accurately quantify the hydrate distributions by using a variety of surveys

(surface, downhole, cross-hole seismic studies and advanced well log surveys, in addition to fiber optics for high-definition determination of the transient geothermal regime).

Short-term depressurization experiments monitored the HBS response, investigated the feasibility of depressurization-induced gas production from hydrates, and indicated higher effective permeability of the HBM than previously thought. A longer (5-day) experiment of gas production by thermal stimulation involved the circulation of warm water in a 17m-thick section of highly concentrated hydrates (Figure 6), and resulted in continuous gas production at varying rates that peaked at 1,500 m<sup>3</sup>/day (Figure 7). These results confirmed earlier predictions that gas production from hydrates at the Mallik site by means of thermally induced dissociation was technically feasible (Moridis et al., 2005b).

The extensive data sets that obtained from the production tests allowed (a) the calibration of several hydrate reservoir models through a history-matching (inverse modeling) process that minimized deviations between observations and predictions, thus providing the first indications of the model validity, (b) the determination of important properties and parameters of the HBS and of the kinetic dissociation reaction, and (c) a rational assessment of the long-term production response of a gas hydrate accumulation (Moridis et al., 2005b; Kurihara et al., 2005a,c). The long-term predictions of production indicated the advantage of depressurization (over thermal stimulation) as a viable method for hydrate dissociation and commercial gas production, and further demonstrated the superiority of methods combining depressurization and thermal stimulation (Moridis et al., 2005b; Kurihara et al., 2005c). The substantial differences in the long-term predictions of the models were not unexpected (given the short duration of the experiment and the almost chaotic behavior of gas wells immediately after the initiation of production), and served to underscore the need for longer-term tests.

The 2006-2008 JOGMEC/NRCan/Aurora Mallik Gas Hydrate Production Research Program (Dallimore et al., 2007) is a continuation of the 2002 test. The primary objective of this research program is to conduct and monitor long-term tests of gas production from hydrates. The 2007 activities involved instrument and equipment installation, in addition to a successful short-term drawdown production test at a 12-m-thick hydrate-bearing section near the base of the stability zone (Dallimore et al., 2007; Collett, 2007). This research program is still in progress.

*North Slope, Alaska, USA – Eileen Gas Hydrate Accumulation.* The geology and petroleum geochemistry of the rocks on the North Slope of Alaska, and the subsurface temperature data needed to assess the distribution of the gas hydrate stability, are described in considerable detail in a number of publications (Bird and Magoon, 1987; Collett, 1993). The CH<sub>4</sub>-hydrate stability zone in northern Alaska, as mapped in Figure 8, covers most of the North Slope.

The first direct confirmation of gas hydrate on the North Slope was provided by data from a single well (the Northwest Eileen State-2 well, located in the northwest part of the Prudhoe Bay Field), in which studies of pressurized core samples, downhole logs, and production testing had confirmed the occurrence of three gas-hydrate-bearing stratigraphic units (Collett, 1993). Analysis of downhole log data from an additional 50 exploratory and production wells in the same area provided additional indications of hydrate occurrence in six laterally continuous sandstone and conglomerate units (A to F), which are all confined to the geographical area shown in Figures 9a and 9b. Collett (2007) indicated that the hydrate units appear to trap down-dip several large free-gas accumulations (Figures 9a and 9b; Units A through D). The volume of gas within the Eileen Gas Hydrate Accumulation (Collett, 2007) is estimated at about twice the volume of known conventional gas in the Prudhoe Bay Field (Collett, 1993), and ranges between 1.0x10<sup>12</sup> and 1.2x10<sup>12</sup> m<sup>3</sup> STP (Collett, 2007).

A project funded by the MHR&D Act involves collaboration of the BP Exploration (Alaska - BPXA), Inc., the DOE, and the USGS and aims to determine the viability of the North Slope hydrates as an energy source (Mount Elbert Science Team, 2007). Analysis of geophysical surveys and well log data led the team to the installation of a well in 2007 at a previously undrilled, fault-bounded accumulation named the “Mount Elbert” prospect. to acquire critical reservoir data needed to develop a longer-term production test program.

The well was drilled (Figure 10) to a depth of 915 m using chilled oil-based drilling fluid to avoid the inhibitor-induced dissociation caused by salts and alcohols in conventional muds. A remarkable achievement was the recovery of significant lengths of core of the hydrate intervals (Figure 11), which were used for subsequent analyses of pore water geochemistry, microbiology, gas chemistry, petrophysical properties, and thermal and physical properties. After a battery of well log surveys was completed, a Schlumberger Modular Dynamic Testing (MDT) was conducted in two reservoir-quality sandy hydrate-bearing sections with high  $S_H$  (60% to 75%). Gas was produced from the gas hydrates in each of the tests. This study has yielded one of the most comprehensive datasets yet compiled on a naturally occurring gas hydrate geologic deposit (Collett, 2007).

Presently, the project research partners are in the process of fully analyzing and integrating the data collected from the well, including re-calibration of the initial geological and seismic models for the site. These data will then be used to determine if, where, and when to proceed into the next phase of the project — currently envisioned as a long-term production test to determine reservoir deliverability under a variety of production/completion/operation scenarios. Long-term predictions of production under a variety of scenarios are being used in a DOE-sponsored code comparison study for the cross-validation of several numerical codes (Wilder et al., 2007), and will be used during the analysis of the project’s long-term production test options

*West Siberia, Russia – The Messoyakha Field.* The Messoyakha Field, a gas field located in the northern part of the West Siberian Basin (and at the apex of the resource pyramid in Figure 2), is often used as an example of a hydrocarbon accumulation from which gas has already been produced from in-situ natural gas hydrates. Production data and other pertinent geologic information have been used to deduce the presence of gas hydrates within the upper part of the

Messoyakha field (Makogan, 1981). It has been suggested that the production history of the Messoyakha field demonstrates that gas hydrates are a readily producible source of natural gas, and that production can be started and maintained by conventional methods (simple depressurization using a standard well design). The presence of hydrates was inferred from the evolution of pressure over time—as production began from the lower free-gas portion of the Messoyakha field in 1969, the measured reservoir pressures followed predicted decline relations, but began to deviate from expected values in 1971. This deviation has been attributed to the release of gas from dissociating gas hydrates. Cumulatively, it is estimated that about 36% (about  $5 \times 10^9$  m<sup>3</sup> STP) of the total produced gas originated from gas hydrates (Makogan, 1981). Unfortunately, incomplete and/or inaccessible data from the Messoyakha field and the existence of plausible alternative theories for the pressure deviations (Krason and Finley, 1992; Collett and Ginsburg, 1998) do not allow the unequivocal consideration of Messoyakha as a hydrate-supported gas reservoir. Had such data been available and had the contribution of hydrates to the production stream been confirmed, the Messoyakha field would have been by far the most important system in our consideration because it would have provided irrefutable evidence of the technical and economic feasibility of long-term production.

**Oceanic Deposits.** The most favorable oceanic deposits will be those with high gas saturation in high-quality reservoirs. The challenges facing commercialization of marine gas hydrates will likely be higher than those in the Arctic, given the higher costs of operating in deep water, and the likely reduced reservoir quality of deep marine sands. However, the presence of established gas gathering and marketing systems in regions like the Gulf of Mexico should also be considered. And even where such systems do not exist, pursuit of marine gas hydrate will continue as many of the most motivated national programs (India, Korea, Japan) do not have the Arctic gas hydrate option available. The two oceanic deposits that serve as models for the evaluation of marine gas hydrate prospects are described below.

*Offshore Japan – Nankai Trough.* This area has probably experienced the largest investment and most advanced field research activity because of the intensive Japanese effort to evaluate the potential and feasibility of gas production from hydrates. Following the discovery of hydrates and the drilling of an exploration well at a water depth of 945 m in 2000 (Takahashi et al., 2001), a multi-well exploration program was conducted in 2004 at 16 locations in three different sites (Kumano Basin, Second Atsumi Knoll and Offshore Tokai) at water depths of 720 m to 2,033 m (Figure 12) that had been selected on the basis of the BSR signature (Takahashi and Tsuji, 2005).

A total of 32 wells were drilled, and a comprehensive evaluation research and test program was implemented, which included logging while drilling (16 wells), wireline logging (2 wells), and coring. The latter was done for visual determination of the occurrence of hydrate in the sediment (3 wells), sample acquisition for studies on sedimentology and hydrate origin (3 wells), and acquisition of high quality hydrate-rich samples for laboratory studies (6 wells).

The experimental program focused heavily on the practicalities and challenges of well construction in hydrate sediments, and involved evaluation of well designs appropriate for oceanic hydrate deposits (Figure 13), cementing to minimize gas leakage, hole caliper measurement while- and after drilling, measurement of formation and fracture pressures, monitoring of bottomhole pressure and temperature while drilling, and successful horizontal drilling (the first such attempt in the world) in the unconsolidated shallow formations typical of hydrate deposits (Takahashi and Tsuji, 2005). Following successful completion of this phase of the research program, all wells were plugged and abandoned. Analysis of the acquired geological/ petrophysical information has led to the refinement of the hydrate resource estimates in the Eastern Nankai Trough. As for future plans, there is only scant (and mostly anecdotal) information, but an offshore production test appears to be the next logical step (Takahashi and Tsuji, 2005).

*Gulf of Mexico – Oligocene Frio Formation* This first documented case of highly-saturated gas-hydrate bearing sand in the Gulf of Mexico was described by Smith et al., (2006) from Alaminos Canyon Block 818 of the Gulf of Mexico (Figure 14). Log data from a specially designed exploration well in about 2750 m (9000 ft) of water at the site indicated the presence of an 18.25-m (60-ft) thick sandy hydrate-bearing layer (10,530 to 10,590 ft drilling depth) at a relatively high temperature (about 21 °C), with a high porosity  $\phi$  (about 0.30), Darcy-range intrinsic permeability  $k$ , and high  $S_H$  (Figures 15 and 16). Thus, this deposit belongs to the third tier in the resource pyramid of Figure 2. Initial estimates of  $S_H$  derived from analyses of the resistivity and p-wave velocity data (Collett and Lee, 2006) indicate a range from 0.6 to over 0.8 (Figures 15 and 16). Preliminary calculations indicated that the base of the gas hydrate stability zone at this location occurs at or slightly below the base of the hydrate (Smith et al, 2006; Collett and Lee, 2006).

The Tigershark data are particularly valuable because they describe a promising target for gas production (as indicated by the high  $S_H$  and the thermodynamic proximity of the HBL to the bottom of the hydrate stability zone), and because of the paucity of data on marine hydrate deposits. Preliminary simulations with synthetic data (describing hydrate reservoirs under the Tigershark conditions) indicate that such systems can reach gas production rates well in excess of  $2.8 \times 10^5$  m<sup>3</sup>/day = 10 MMSCFD (Moridis and Reagan, 2007a,b).

### The Role of Numerical Simulation

As in every attempt to evaluate conventional oil and gas reserves, the assessment of the production potential of hydrates involves predictions of the complex system behavior. The reliability and accuracy of these predictions hinges on the following three factors: (1) the availability of robust numerical simulators that cover the spectrum of the dominant processes and phenomena, (2) knowledge of the parameters and relationships that describe quantitatively the physical processes

(usually obtained from laboratory experiments and/or from field tests either by direct measurement or through history-matching) and the thermophysical properties of all the components of the system under investigation, and (3) the availability of field and laboratory data for the validation of the numerical models. The complexity of the coupled processes involved in the dissociation reaction do not permit the use of analytical models either for direct predictions or for the verification of the numerical models except under limited conditions, i.e., at early times and after significant approximations.

Thus, the role of numerical simulation is critically important, and is the only tool that allows the assessment of the gas production potential of hydrates as there is no possibility of prediction without it. It allows the design of laboratory and field experiments, can provide answers (or, at a minimum, general behavior trends) to very complicated problems at a very reasonable cost before necessitating substantial investments for operations, and allows investigation of a wide range of alternative (*what-if*) scenarios that would be impossible to explore otherwise. Note that even if there are no field or laboratory data for code validation and only very sketchy data describing the properties and physical processes in the system are available, numerical simulation can provide very important insights (provided the underlying physics are correct and representative of the simulated processes) because it makes it possible to determine technical feasibility, to establish envelopes of possible solutions, to determine sensitivity to particular parameters and processes, and to identify promising target zones of hydrates for development.

**Code Availability.** The ability to numerically simulate the behavior of geologic hydrate reservoirs has improved substantially over the past 5 years in terms of both code availability and capabilities (Boswell, 2007). There are currently several numerical models that can simulate the system behavior in hydrate-bearing geologic media. The most commonly used simulators are the following:

- (a) The TOUGH+HYDRATE code (Moridis et al., 2005a), and its earlier, open-source version that is distributed by the National Energy Technology Laboratory under the name HydrateResSim (NETL, 2007)
- (b) The MH21 code developed by a Japanese team including the Japan Oil Engineering Company, the National Institute for Advanced Industrial Science and Technology and the University of Tokyo (Kurihara, 2005b)
- (c) The STOMP-HYD code developed by the Pacific Northwest National Laboratory (Phale et al., 2006)
- (d) A hydrate-specific variant of the commercial simulator CMG-STAR3 (Computer Modeling Group, STAR3)
- (e) The Hydrsim simulator developed by the University of Calgary (Hong and Pooladi-Darvish, 2005)

There are a few other simulators of hydrate behavior in porous media (Sun and Mohanty, 2005; Pawar et al., 2005), but these are not widely used. Codes (a) and (b) were calibrated against the data from the thermal dissociation test at the Mallik site (a process that provided an initial basis in the validation effort) and showed good agreement with observations, but exhibited significant deviations when predicting long-term production performance. Since that time, both codes were substantially enhanced. Codes (a) through (e) are participating in a code-comparison study sponsored by the US DOE (NETL, 2007), and most are capable of simulating the behavior of hydrates and reservoir fluids during common dissociation scenarios. Recent independent studies of designing and analyzing laboratory experiments involved predictions and calibrations (Tang et al., 2007) that increased confidence in the models. While the behavior of the various codes can be similar over a wide range of problems (thus providing a foundation for the claim of cross-validation), measurable differences exist. In the absence of reliable and well-documented data sets from field experiments (i.e., an indisputable baseline for comparison), it is not possible to claim that any of these codes has been fully validated. The impression among the participants of the code-comparison study is that the models generally account for the important physics of the problem, and that validation and calibration (rather than adequacy of the numerical code capabilities) will be a constraining factor in the assessment of the hydrates as an energy resource.

**Data Needs for Simulations in Support of Assessment of the Hydrate Production Potential.** These are divided into three different types: (a) data requirements that are common to all reservoir simulations, (b) those that stem from the presence of the solid hydrate in the pores and/or fractures of the geologic media and its interference with the flow of reservoir fluids, and (c) data needs that are unique to hydrates, and are related to their phase behavior and thermodynamic properties. In this section we discuss each type of data need.

**Data Needs Common to All Simulations of Subsurface Flow and Transport.** These include data needs related to space discretization (adequately detailed to describe heterogeneity), distribution of the thermal and hydraulic properties of the hydrate-free media and of the gas and aqueous phases, timing information (e.g., maximum timestep size, maximum number of timesteps, duration of simulation, etc.), and parameters that determine computational options (e.g., method of upstream weighting in multiphase flow, method of solution of the matrix equations, convergence criteria), execution control (e.g., determining when to force a premature cessation of the simulation), and output options. This type of data need includes the thermophysical properties of reservoir fluids in hydrate deposits, i.e., the properties of water (NIST, 2000) and of the CH<sub>4</sub>-H<sub>2</sub>O real gas mixture (e.g., Peng and Robinson, 1976). All these needs are well known and/or very basic (as they are routinely an issue in non-hydrate simulations), pose no special challenge in the attempt to model hydrate-bearing systems, and will not be further discussed.

**Data Needs Related to The Presence of Hydrates in The Pores of the Geologic Media.** Such data involve relationships and parameters that are defined and usually known in hydrate-free media, but which must be amended to describe the effects of the solid hydrate on the composite hydraulic, thermal and geomechanical behavior of HBM. These effects are not

considered in standard simulations, and quantitative relationships (and the corresponding parameters) need to be included for an accurate representation of the physics.

**Hydrate Effects on the Composite Thermal Properties.** These properties include the composite thermal conductivity  $k_{\theta}$  and specific heat  $C_{\theta}$ . Laboratory (Moridis et al., 2005c) and field data (Dallimore et al., 2005) clearly indicate that the conventional approach of estimating  $k_{\theta}$  as the weighted average (Bejan, 1984) of the contributing phases, i.e., gas, aqueous, solid grains, ice and hydrate, is inaccurate. By history-matching laboratory data, Moridis et al. (2005c) determined the relationship

$$k_{\theta} = k_{dry} + (\sqrt{S_A} + \sqrt{S_H})(k_{wet} - k_{dry}) + \phi S_I \lambda_I \dots\dots\dots(2)$$

which is an extension of an earlier  $k_{\theta}$  model (Somerton et al., 1973; 1974) used extensively in geothermal studies, and which adequately describes the data. The computation of  $C_{\theta}$  poses far fewer challenges, as a saturation- and density-weighted average appears to describe well the system behavior (Moridis et al., 2005c). However, the subject is far from exhausted, and there is significant room for more studies to be conducted, and new  $k_{\theta}$  and  $C_{\theta}$  relationships to be developed.

**Hydrate Effects on the Flow (Hydraulic) Properties.** These are the wettability-related properties, and include the phase relative permeabilities  $k_{rel}$  and capillary pressures  $P_{cap}$ . Laboratory studies to determine the effect of solid phases (i.e., hydrate and ice) on the effective permeability of porous media—from which the phase relative  $k_{rel}$  permeabilities may be extracted—are in progress (see discussion in a subsequent section), but the results have not yet reached the refereed literature. This is an issue of the highest priority because of the strong dependence of gas recovery from hydrates on the effective permeability of HBM (Kurihara et al., 2005b; Moridis and Reagan, 2007a,b), and accurate quantitative descriptions to obtain reliable estimates.

In the meantime, the  $k_{rel}$  and  $P_{cap}$  relationships (functions of saturation) used in hydrate simulations are theoretical extensions of conventional multi-phase flow models. Moridis et al. (2005a; 2007a) proposed two alternative models to describe the wettability processes (relative permeability and capillary pressure) in hydrate- and/or ice-bearing media. The first general model is the *Original Porous Medium* (OPM) model, and is based on the treatment of (a) the medium porosity as unaffected by the emergence of hydrates and/or ice (although subject to change due to changes in pressure and temperature), (b) the intrinsic permeability of the porous media as unchanging during the evolution of the solid phases, and (c) the fluid flow as a relative permeability issue controlled by the saturations of the various phases in the pores. The second general model is the *Evolving Porous Medium* (EPM) model, which considers the evolution of the solid phases (hydrate and ice) as tantamount to the creation of a new porous medium with continuously changing porosity and intrinsic permeability, the pore space of which is occupied only by the two fluid phases (aqueous and gas). Within the OPM and EPM models,  $k_{rel}$  and  $P_{cap}$  are computed using standard relationships.

**Hydrate Effects on the Composite Geomechanical Properties.** These are important in coupled geomechanical studies of production from HBM because of (a) their possible adverse effects on flow properties and (b) concerns about wellbore stability and formation structural integrity. Natural hydrates usually occur in unlithified, unconsolidated media that are prone to subsidence and yielding during production because dissociation removes the strong cementing effect of hydrates. The currently available literature is scant (Durham et al., 2003), but the subject of geomechanical response of HBM is the focus of significant attention (not only as related to production, but also as a geohazard in the installation of offshore structures) and the subject of several investigations in several countries (see discussion in a subsequent section). It is expected that significant new information will become available in the next few years as the results of the various studies in progress begin reaching the peer-reviewed literature.

**Data Needs Unique to Hydrates.** These include the thermophysical properties of hydrates, as well as their thermodynamic properties and phase behavior. Obviously, assessments of the production potential of hydrates may be compromised if incorrect phase relationships are used. The specific data needs are described in detail below.

***P–T Relationships and Phase Diagram.*** These are of critical importance, as they define the dissociation behavior of the hydrate. If a pure CH<sub>4</sub>-hydrate is involved, then the *P* vs. *T* relationships (and the corresponding phase diagram) are well defined. There are two relationships describing the *P–T* relationship along the 3-phase (aqueous + hydrate + gas, or ice + hydrate + gas; Lw-H-V and I-H-V, respectively) equilibrium lines. The first is the regression equation of Kamath (1984)

$$P = \exp\left(e_1 + \frac{e_2}{T}\right) \dots\dots\dots(3)$$

where *P* is in KPa, *T* is in K,

$$e_1 = \begin{cases} 38.980 & \text{for } 0^{\circ}\text{C} > T_c \geq 25^{\circ}\text{C} \\ 14.717 & \text{for } -25^{\circ}\text{C} \geq T_c > 0^{\circ}\text{C} \end{cases}, \quad e_2 = \begin{cases} -8533.80 & \text{for } 0^{\circ}\text{C} > T_c \geq 25^{\circ}\text{C} \\ -1886.79 & \text{for } -25^{\circ}\text{C} \geq T_c > 0^{\circ}\text{C} \end{cases} \dots\dots\dots(4)$$

The second relationship (shown in Figure 17) covers a wider temperature range (from –124 °C to 48 °C, allowing its use in experiments where liquid N<sub>2</sub> is used to stabilize the hydrate), and is a general regression expression derived by Moridis (2003) based on data from several researchers reported in Sloan (1998). Figure 17 shows the entire phase diagram, i.e., all the phase co-existence regimes defined by the *P–T* relationship.

The picture becomes far more complicated if composite hydrates (i.e., hydrates produced from more than one gas) are involved. In this case it is not possible to assume that the composite hydrate is a mixture of individual pure hydrates that behave independently because such an assumption would violate the laws of thermodynamics and would produce erroneous

results. Composite hydrates behave as solid solutions, and a 1% C<sub>2</sub>H<sub>6</sub> in a CH<sub>4</sub>-hydrate is sufficient to change the equilibrium pressure by about 40%. Thus, complete  $P$ - $T$ - $X$  relationships need to be used to describe composite hydrates. For implementation in numerical simulators, these  $P$ - $T$ - $X$  relationships need to be described by fast parametric functions. Such functions are unavailable because only a very limited (practically infinitesimal) part of the possible hydrate-forming gas mixtures has been studied experimentally, and the complexity of deriving even interpolation-based parametric relationships increases with the number of gases  $n_G$  (requiring regression of  $n_G - 1$  variables).

The only possible option in this case is the use of statistical thermodynamics (Sloan and Koh, 2008), which is very powerful, can be used to determine a wide range of other thermophysical properties of the composite hydrate, and has been verified against laboratory experiments. However, this model is unsuitable for use in fully implicit numerical simulators because of the tremendous computational load it imposes (requiring a minimization of the Gibbs energy at every attempt at computation). Unless and until simple and general parametric  $P$ - $T$ - $X$  relationships become available, the only possibilities are either (a) the implementation of the statistical thermodynamics approach using powerful computational platforms (such as clusters and supercomputers), or (b) the use of statistical thermodynamics to develop hydrate-specific parametric  $P$ - $T$ - $X$  relationships on a case-by-case basis, which can then be implemented in numerical simulators. Fortunately, the hydrates that have been investigated as possible production targets in field studies up to now (i.e., Mallik, Mount Elbert, Nankai Trough) are over 99.5% CH<sub>4</sub> (Dallimore et al., 2005; JNOC-TRC, 1998).

**$\Delta H^0$  -  $T$  Relationships and Phase Diagram.** The relationship between the heat of dissociation  $\Delta H^0$  and temperature is also critical, given the fact that heat transport appears to be by far the dominant mechanism controlling dissociation (Kowalsky and Moridis, 2007). As in the  $P$ - $T$  relationship, under three-phase conditions (Lw-H-V and I-H-V)  $\Delta H^0$  can be computed from the simple equation of Kamath [1984] as,

$$\Delta H^0 = C_1 + C_2 T \dots\dots\dots(5)$$

where  $\Delta H^0$  is in cal/gmol,  $T$  is in K,

$$C_1 = \begin{cases} 13,521, & \text{and} \\ 6,534 \end{cases} \quad \text{and} \quad C_2 = \begin{cases} -4.02 & \text{for } 0^\circ\text{C} > T_c \geq 25^\circ\text{C} \\ -11.97 & \text{for } -25^\circ\text{C} \geq T_c > 0^\circ\text{C} \end{cases} \dots\dots\dots(6)$$

As can be seen,  $\Delta H^0$  is a weak function of temperature. More recent studies with advanced instrumentation (Gupta, 2007) indicate that  $\Delta H^0$  is practically temperature-insensitive over a wide range of temperatures. The current practice is to extrapolate equation (5) beyond its validated temperature range.

**Kinetics of the Hydration/Dissociation Equation.** The main equation describing the kinetics of the CH<sub>4</sub>-hydrate reaction was proposed by Kim et al. (1987), and was then modified by Clarke and Bishnoi (2002) to assume the form:

$$Q_H = -K_0 \exp\left(\frac{\Delta E_a}{RT}\right) F_A A (f_{eq} - f_v) \dots\dots\dots(7)$$

where  $K_0$  is the intrinsic hydration reaction constant [kg m<sup>2</sup> Pa<sup>-1</sup> s<sup>-1</sup>],  $\Delta E_a$  is the hydration activation energy [J mol<sup>-1</sup>],  $R$  is the universal gas constant [8.314 J mol<sup>-1</sup> K<sup>-1</sup>],  $F_A$  is an area adjustment factor (dimensionless),  $A$  is the surface area participating in the reaction [m<sup>2</sup>],  $f_{eq}$  is the fugacity at equilibrium at temperature  $T$  (Pa), and  $f_v$  is the fugacity in the gas phase at temperature  $T$  (Pa). While the form of equation (7) is widely accepted, some additional values for  $K_0$  and  $\Delta E_a$ —other than those of Kim et al. (1987) and Clarke and Bishnoi (2002) that had been derived from experiments involving hydrate particles in water systems without any porous media—have been proposed (e.g., Moridis et al., 2005b; 2005c; Tang et al., 2007).

However, Kowalsky and Moridis (2007) showed that, while kinetics play an important role in short-term dissociation processes lasting a few minutes to a few hours (e.g., the dissociation of an unpressurized hydrate-bearing core as it ascends to the surface and is transferred to storage), they are not important in realistic, long-term gas production schemes. Their predictions of long-term production based on the kinetic and the equilibrium reaction models practically coincided, and indicated that mass and heat transfer are the dominant (and practically the only) limitation. These results are in agreement with earlier studies (Pawar et al., 2005; Hong and Pooladi-Darvish, 2005), and are exceptionally important because they remove the possibility of a potentially significant obstacle (i.e., kinetic limitation) in the quest for gas production from natural hydrate deposits. A related computational benefit is the reduction of the size of the matrix equations (the equilibrium model requires one less degree of freedom, and, thus, one less equation per cell), resulting in faster executions.

**Thermophysical Properties of the Solid Hydrate.** These include the density, specific heat and thermal conductivity, and their relationships to  $P$  and  $T$ . Sloan (1998) and Sloan and Koh (2008) provide updated lists of constant values of these properties, and more recent data have become recently available. However, because of the very narrow temperature range of hydrate existence in natural systems targeted for dissociation-induced gas production (based on our experience, at no time exceeding 25 °C) and the relative insensitivity of these properties to  $P$  and  $T$ , an attempt to introduce  $P$ - $T$  dependence would result in a second- or third-order effect. This being the case, the reliability of the production predictions will be unaffected if well-documented constant values are used in the simulation, provided that accurate models are available to describe the composite HBS behavior.

**Laboratory Studies in Support of Numerical Simulations.** Some of the hydrate-related data needed as inputs to numerical simulations of production predictions are obtained from targeted laboratory experiments. Here we discuss important laboratory studies (recent and/or in progress) that yield such data for use in simulators.



*Thermal Properties of Hydrates and HBS.* The thermal properties of CH<sub>4</sub>-hydrates (pure and in porous media) have been investigated by several research groups. Waite et al. (2002) measured directly the  $k_{\theta}$  of four porous mixtures of quartz sand and CH<sub>4</sub>-hydrate at  $S_H = 0, 33\%, 67\%,$  and  $100\%$ . Kumar et al. (2004) and Gupta et al., (2006) employed inverse modeling to determine the thermal properties of a porous methane hydrate plug. Rosenbaum et al (2007) used a novel single-sided transient plane source technique to determine the thermal conductivity and thermal diffusivity of a compacted methane hydrate sample over the temperature range of 261.5-277.4 K and at gas-phase pressures ranging from 3.8 to 14.2 MPa.

Moridis et al. (2005c) used inverse modeling to determine the composite thermal conductivity of silica sand CH<sub>4</sub>-hydrate samples by analyzing laboratory results consisting of  $T$ - $P$  data, as well as X-ray CT scans that provided a density map of the sample. The use of X-ray CT scans is deemed essential in the laboratory studies because without them it is easy to misinterpret localized phenomena (such as the expected significant heterogeneity in the dissociation pattern) as volume-averaged processes. Thus, the data sets to be used in history matching of hydrate laboratory experiments should include images of phase distributions and dissociation fronts.

*Relative Permeability of HBS.* Using a vertical packed sand column under gravity drainage, Jaiswal (2004) formed CH<sub>4</sub>-hydrate and measured  $k_{rel}$  in hydrate-bearing consolidated Oklahoma 100 mesh sand and core samples from a North Slope formation. In a study that is still in progress, Kneafsey et al. (2007) and Seol et al. (2006) used flow measurements through horizontal samples of HBS (involving silica sands and silts) to measure their absolute and effective permeabilities, thus determining  $k_{rel}$  endpoints. Additionally, data from a waterflood and the corresponding x-ray CT scans (Figure 18) are being analyzed by means of numerical inversion (history-matching) to deduce the  $k_{rel}$  behavior. CT scanning allows for attribution processes to specific locations, rather than to the bulk.

*Capillary Pressure of HBS.* Researchers at Lawrence Berkeley National Laboratory are conducting experiments to describe the  $P_{cap}$  vs. saturation relationships of HBS involving hydrate-bearing silica sands. These are difficult and time-consuming tests that are challenged by the requirement that they be conducted exactly at conditions of hydrate equilibrium without allowing phase changes. The scant limited field data that are available (including a  $P_{cap}$  estimated from a history matching effort of the Mount Elbert MDT test data, not yet published) suggest that the porous media in desirable hydrate accumulations are characterized by high  $k, \phi$  and  $S_H$ , and by low  $P_{cap}$ . An issue of particular interest is whether the presence of hydrate significantly influences  $P_{cap}$ . The results of this study could be very important because a high  $P_{cap}$  can adversely affect gas production from hydrates (Moridis et al., 2007a).

*Geomechanical Properties of HBS.* Knowledge of the geomechanical properties of hydrate-bearing sediments is critical, because of the serious implications for wellbore stability and formation structural integrity during hydrate dissociation (in response to production or simple thermal loading), which can result in reduction in (and possibly loss of) production and damage to wellbores supported by hydrate-bearing sediments. The problem is accentuated in marine environments because the proximity of HBS to the ocean floor and the large compressibility of marine sediments can compromise the stability of structures such as platforms with catastrophic economic and safety consequences, and even more so along the continental slope, where underconsolidated and possibly overpressured zones developed during hydrate dissociation can trigger submarine landslides. Initial geomechanical investigations focused on pure compacted CH<sub>4</sub>-hydrates (Durham et al., 2003). Geomechanical properties of laboratory-formed and natural samples have been measured in the GHASTLI apparatus by USGS researchers (Waite et al., 2004; Winters et al., 2004). Masui et al. (2005) conducted some pioneering geomechanical studies using hydrate-impregnated Toyoura sand, developed stress and strain relationships, and defined the relationship between  $S_H$  and various geomechanical properties (e.g., modulus of elasticity, Poisson's ratio, internal friction angle, etc.). Investigations of geomechanical properties of sediments containing tetrahydrofuran hydrate have been conducted at Georgia Tech (Lee et al., 2007; Yun et al., 2007). Current investigations of the geomechanical strength of methane HBS are being performed at Lawrence Berkeley National Laboratory in a specially designed apparatus that permits the concurrent analysis of coupled geomechanical, geophysical and flow processes, and x-ray CT scans (Figure 19.)

*Geophysical Properties of HBS.* Geophysical methods appear to be the most promising (and cost-effective) techniques to remotely detect hydrate deposits, and to monitor their changes in the course of gas production. Helgerud et al. (1999) measured elastic wave properties of marine HBS. Using their GHASTLI apparatus (Winters et al., 2004), USGS researchers are conducting studies that measure the elastic wave properties of HBS. In a related experiment that is currently in progress, LBNL researchers are measuring the elastic wave properties of HBS using the geomechanical test cell (Figure 19) and a low frequency resonant bar apparatus.

## Gas Production Strategies

**Classification of Gas Hydrate Deposits.** Natural gas hydrate accumulations are divided into three main classes (Moridis and Collett, 2003) based on simple geologic features (Figure 20). Note that, while this classification is simple, it is quite effective as it can provide insights into the optimal production method. Class 1 accumulations are composed of two layers: the Hydrate-Bearing Layer (HBL) and an underlying two-phase fluid zone containing free (mobile) gas and liquid water. There are two kinds of such deposits: the first involves water and hydrate in the hydrate zone (Class 1W, gas-poor system), while the second involves gas and hydrate (Class 1G, water-poor system). In this class, the bottom of the hydrate stability zone (i.e., the location above which hydrates are stable because of thermodynamically favorable  $P$  and  $T$  conditions) coincides with the bottom of the hydrate interval. For a given temperature, this is the most desirable class because it is the easiest to destabilize

and release gas. Class 1 accumulations are sometimes referred to as “Hydrate-Capped Gas Reservoirs” (Gerami and Pooladi-Darvish, 2006).

Class 2 deposits comprise two zones: (1) an HBL, overlying (2) a zone of mobile water (hereafter referred to as WZ). Class 3 accumulations are composed of a single zone, the hydrate interval (HBL), and are characterized by the absence of an underlying zone of mobile fluids. In Classes 2 and 3, the entire HBL may be well within the hydrate stability zone and can exist under equilibrium or stable conditions. A fourth class (Class 4), pertains specifically to oceanic accumulations, and involves disperse, low-saturation hydrate (<10%) deposits that lack confining geologic strata (Moridis and Sloan, 2007).

In the following sections we discuss the specifics of production from each of the first three classes of deposits. Although interest in this subject has only recently begun and the available literature is limited, sufficient progress has been attained to be able to discern appropriate production practices and conditions to maximize potential production.

**Gas Production From Class 1 Deposits.** Of the three main dissociation methods, depressurization-based production strategies appear well suited to the conditions of Class 1 deposits (and are possible the only long-term practical option) because of their simplicity, technical and economic effectiveness, and the fast (practically immediate) response of hydrates to the rapidly propagating pressure wave (as opposed to the much slower response to thermal stimulation). Because of the strongly endothermic nature of the dissociation reaction and the rapidity of dissociation under depressurization, care must be taken to limit the formation of solid phases (i.e., secondary hydrate and ice) in the vicinity of the producing well, which may have adverse effects on the fluid permeability regime and, consequently, on gas production. Thus, the top of the production (perforated) interval must be located at a sufficient distance from the nearly impermeable initial hydrate interface (Moridis et al., 2007a). Otherwise, the resulting steep  $P$  and  $T$  gradients can lead to secondary hydrate formation, which can choke the well (Kurihara et al., 2005). Although this may appear counterintuitive in a depressurization process, it is necessary because spatially uniform and gentle  $P$  and  $T$  gradients (as opposed to steep localized fronts) can significantly enhance long-term production from gas hydrates (Moridis et al., 2007a).

Practically all the studies focusing on production from Class 1 deposits are based on depressurization. Hong and Pooladi-Darvish (2005) applied constant- $P$  depressurization (i.e., a constant bottomhole pressure) at a well at the center of a small ( $r_{max} = 200$  m) Class 1G cylindrical reservoir, and analyzed the sensitivity of the continuously declining production to various properties and operational conditions (Figure 20). They reported that, at the end of the first year of production, about 48% of the produced gas had been replenished by hydrate-originated  $CH_4$ . As expected, production was marked by a continuous (and significant) decline in  $T$  because of continuous reservoir cooling caused by the endothermic dissociation. The most important observations from this study are the confirmation of the technical feasibility of production from hydrates using conventional technology, and that heat transfer was the dominant mechanism controlling dissociation (kinetics having practically no effect). Their results also indicated increasing contribution of dissociation to the production stream with an increasing permeability  $k$  and a decreasing bottomhole pressure  $P_w$  (factors that can be affected by the choice of production target or operation practices). Kurihara et al. (2005b) investigated a cylindrical Class 1G deposit produced under constant- $Q$  (rate) conditions, and, while they indicated that gas production from such a system was expected to be “huge”, he did not provide any data documenting quantitatively the contribution of dissociation to the production stream at the end of the year-long simulation period.

Moridis et al. (2007) conducted a study of long-term (10 to 30 years) of constant- $Q$  ( $= 0.81944$  ST  $m^3/s = 2.5$  MMSCFD) production from both Class 1W and 1G hydrate deposits that had the attributes of a permafrost system. Single vertical wells were used, and the well spacing was 100 ha ( $r_{max} = 400$  m). To describe the contribution of gas released from hydrate to the production stream, they introduced the concepts of *Rate Replenishment Ratio* (RRR or R3) and *Volume Replenishment Ratio* (VRR or VR2). RRR is defined as the fraction of the gas production rate at the well(s) that is replenished by  $CH_4$  released from hydrate dissociation. VRR is defined as the fraction of the cumulative gas volume produced at the well(s) that is replenished by hydrate-originating  $CH_4$ . These two parameters provide a measure of the hydrate system response and the effectiveness of dissociation as a gas-producing method. Review of the RRR in Figure 21 (Class 1W) demonstrates the effectiveness of depressurization and the technical feasibility of gas production from Class 1 hydrates. After attaining a maximum of 0.62, RRR begins to decline because of occlusion of the hydrate body by high-saturation hydrate shells that are effectively impermeable. This is a result of a very strong capillary pressure in the presence of hydrate (a very conservative approach), and the resulting  $S_H$  is so high that the remaining fluids are immobile. As a result of the high capillary pressure, hydrate lensing is observed (Moridis et al., 2007a). The VRR in Figure 21 reaches a maximum of 0.46 (i.e., 46% of the cumulative gas produced until that time is replenished from hydrate dissociation) before it begins to fall as occlusion reduces dissociation (reaching a respectable 0.43 after about 3700 days of production).

The evolution of the hydrate saturation distribution over time, the hydrate lensing, and other interesting phenomena (including the development of a honeycomb of wormhole-like dissociation patterns, all the result of capillarity) are shown in Figure 22, which also shows the destruction of the hydrate through dissociation. Figure 23 shows the corresponding spatial distribution of the gas saturation. Of particular interest is the evolution of an upper dissociation interface at the top of the hydrate zone, above which gas accumulates (See Figures 22 and 23). This upper interface is caused by heat flows from the overburden (as the geothermal gradient is reversed because the hydrate becomes progressively colder as dissociation advances), and highlights the importance (if not necessity) of impermeable upper boundaries during production from

hydrates. Note that (a) it is possible to continue production from the gas zone, and (b) to destroy the nearly impermeable hydrate lenses by injection of warm water injection in localized applications.

Production from a Class 1G deposit (with all other properties identical to the class 1W problem) appears to be simpler and faster. The VRR increases continuously over the 30-year production period, reaching a maximum of about 0.74, while the corresponding RRR is 0.54. The desirability and the great production potential of such deposits are obvious. It appears that the Messoyakha accumulation in Siberia (see earlier discussion) belonged to this Class (Makagon, 1981). In this case, because of high initial permeability, some concentration of hydrate, occlusion and lensing does occur, but does not hinder dissociation, which proceeds until the hydrate is practically exhausted (Figure 25). Note the emergence of the upper dissociation interface, which is a universal feature of hydrates under production (Moridis et al., 2007a; Moridis and Reagan, 2007a;b). Additional important issues that need to be raised are that (a) production from both Class 1W and 1G deposits involves conventional technologies, and (b) production from Class 1 hydrates necessitate continuous heating of the wellbore to prevent hydrate formation and plugging (Moridis et al., 2007a).

**Gas Production From Class 2 Deposits.** As in the case of production from Class 1 deposits, depressurization-induced dissociation (based on fluid removal through wells) appears to be the most promising gas production strategy in Class 2 deposits (Figure 26) because of its simplicity, technical and economic effectiveness, and the fast (practically immediate) response of hydrates to the rapidly propagating pressure wave. Because of the low effective permeability of the HBL, the well has to be completed partly in the WZ, and it is from there that the bulk of the produced fluids originate during the early stages of production. The effectiveness of depressurization is further enhanced by the near-incompressibility of water (which expands the volume over which depressurization is sensed by the HBL), and by the large heat capacity of water. The latter plays a significant role in providing part of the heat needed to support the strongly endothermic hydrate dissociation reaction as warmer water flows from the outer reaches of the formation toward the well.

Although thermal stimulation can be effectively used in conjunction with depressurization for localized applications (to destroy secondary hydrate and ice, as is discussed in detail in subsequent sections of this paper), pure thermal stimulation does not appear to be a promising dissociation method because it is slow and inefficient. Additionally, it has very large energy needs (dictated by the high thermal inertia of subsurface media), and is inherently wasteful because of (a) increasing heat losses through the boundaries, and (b) the need to raise the temperature of not only the hydrate but also of the inert phases (i.e., the porous medium and the non-hydrate phases), which constitute the dominant portion of the mass of a given formation volume. If the heat-transfer mechanism is advection (e.g., warm water injection), then the injected fluid may have adverse effects on the relative permeability of the released gas. Heat transfer is significantly slower and less efficient if it is based on conduction, (e.g., through electrical heating). The use of inhibitors is not recommended either because of (a) rapid reduction in effectiveness caused by the dilution of the inhibitor by the H<sub>2</sub>O released from dissociation, (b) the cost of chemical inhibitors, and (c) the potentially adverse consequences of halite precipitation with salt-based inhibitors.

**Well Design.** A new well configuration was designed (Moridis and Reagan, 2007a) to maximize production from Class 2 deposits and alleviate a persistent problem of substantial secondary hydrate (and occasionally ice) formation in a narrow zone ( $r < 10$  m) around the well (Moridis and Reagan, 2007a). The well design denoted as “Phase 1” (see Figure 27) is used during the initial stages of production. The base case involves a production (perforated) interval that begins at the HBL base and extends 5m into the WZ. The decision to locate the perforated interval into the WZ below the hydrate zone is based on the very low permeability in the HBL (caused by the high  $S_H = 0.70$ ) and to ensure sufficiently high flow rates at the well. During Phase 1, the outer wellbore surface is heated. This heating causes thermal dissociation of the hydrate and leads to the creation of a cylindrical dissociation interface around the well that can communicate with the production interval because of locally enhanced permeability. Electrical heating may be used (at least initially) if the  $S_H$  of the undisturbed HBL is sufficiently high to make flow difficult, but warm water injection (injected at the upper part of the wellbore) may be used at a later time (Phase 2). This allows the replacement of the slow and inefficient conduction during thermal heating by the much faster and efficient advective heat transfer mechanism.

The unique feature of this well design is that the outer wellbore heating prevents the formation of secondary hydrate around the wellbore. This is important because it is expected to provide a continuous flow pathway from both the cylindrical and the evolving upper horizontal dissociation interfaces to the perforated interval. Such access is by no means guaranteed without outer wellbore heating. The expectation is that fluid withdrawal using this well design will result in maximum gas release and production by maximizing the total dissociation area and access to the three interfaces (i.e., the cylindrical, the upper and the lower horizontal ones). As the cylindrical and the lower horizontal dissociation interfaces continue to recede during dissociation, it is possible to expand the production interval upward into the HBL (from its initial upper limit at the base of the hydrate zone) and reap the benefits of a longer perforated interval.

The well may be further modified at a later stage (Phase 3, usually when less than 35% of the original hydrate remains) when there is significant gas accumulation at the top of the reservoir. Despite high volumes and large volumes, this gas cannot be recovered by using a conventional well perforated at the top of the formation because, after an initial short, high-rate, production period (lasting from hours to weeks), the well is blocked by secondary hydrate and/ice. The problem is alleviated by modifying the well according to the design shown in Figure 27, which involves alternating thin zones (about 1 m) of gas production and warm water injection. The warm water is injected at a low rate ( $< 1$  kg/s) at a relatively low temperature (the reservoir is already cold because the well begins operating at a time corresponding to an advanced stage of

dissociation), and either prevents the formation of secondary hydrate or ice through mixing with the incoming fluid stream, or destroys pre-existing hydrate and ice blockages by thermal stimulation. This well configuration does not exceed current technical capabilities. Note that a Phase 3 well may not be always needed.

**Evaluation of Production Potential.** Fluids are withdrawn from the well at a constant mass rate  $Q_M$ . In the oceanic Class 2 hydrate deposit in the example discussed here (with properties and conditions representative of those at the Tigershark formation, see earlier discussion),  $Q_M = 19.2 \text{ kg/s} = 10,000 \text{ BPD}$ . A universal characteristic of production from Class 2 deposits is the variable  $Q_M$ : as production advances, cavitation (i.e., rapid pressure drop) occurs at the well either because secondary hydrate and/or ice are obstructing flow (in which a short term warm water injection may be appropriate) or because the increasing amount of lower-density gas arriving at the well cannot sustain the prescribed  $Q_M$ . Thus,  $Q_M$  has to be reduced (note the drop in the see-saw appearance of the gas production rate  $Q_P$  curve in Figure 28) to continue production, but the reduction in  $Q_M$  does not necessarily result in a lasting decline in  $Q_P$ . The latter recovers rapidly, and then exceeds the level at the last cavitation (see Figure 28). Inspection of  $Q_P$  in Figure 28 shows that it proceeds in cycles marked by cavitation events. During each cycle, gas production increases continuously, while water production decreases (Moridis and Reagan, 2007a). Note that, unlike Class 1, all the gas produced here originates from hydrates and is easy to track.

In the left panel of Figure 28, Stage IV corresponds to the introduction of the Phase 3 well design. The same figure also shows that (a)  $Q_P$  reaches levels as high as  $4.8 \times 10^5 \text{ m}^3/\text{day}$  (=17 MMSCFD), and (b) the average gas production  $Q_{avg}$  over the 5,660 day period of simulation (when both the hydrate and the gas are exhausted) is about  $2.2 \times 10^5 \text{ m}^3/\text{day}$  (=7.8 MMSCFD), but (c) gas production is encumbered by a long initial lead time during which little gas is produced. Actually, when the initial  $Q_M = 38.4 \text{ kg/s}$  (20,000 BPD), then the maximum  $Q_P$  exceeds  $5.7 \times 10^5 \text{ m}^3/\text{day}$  (=20 MMSCFD), and  $Q_{avg} = 3.0 \times 10^5 \text{ m}^3/\text{day}$  (=10.5 MMSCFD) over a 4,700-day production period (Moridis and Reagan, 2007a). The obvious conclusion is that the highest possible initial  $Q_M$  that the system can sustain must be used to maximize production. The important observation from the right panel of Figure 28 is the very high recovery, which can exceed 100% (the extra originating from solution gas). Of course, the level of recovery may be limited by economic and geomechanical considerations. These results indicate the very significant gas production potential of hydrates such as the Tigershark deposit.

Production from Class 2 deposits (and the corresponding water-to-gas ratio  $R_{WGC}$  decreases) with an increasing (a)  $Q_M$ , (b) hydrate temperature (which defines its stability for a given pressure), and (c) intrinsic permeability. Lower initial hydrate saturations lead initially to higher gas production and a lower  $R_{WGC}$ , but the effect is later reversed as the hydrate is depleted (Figure 29). Note the continuous decline of  $R_{WGC}$  over time, which is a universal feature of the depressurization-based production from Class 2 deposits indicating the continuously declining water production in proportion to the gas production. This observation is valid under any of the conditions and production methods (Moridis and Reagan, 2007a). An additional important point is the rapid improvement in performance at early times. This is in stark contrast to the reality in conventional gas reservoirs, in which  $R_{WGC}$  invariably increases over time. The obvious conclusion is that hydrate deposits reserve their worst performance for the initial stages of production, but then they rapidly and continuously improve over time.

The  $S_H$  distribution in Figure 30 shows the gradual destruction of the hydrate, and attests to the efficiency of the well design to keep the pore space in the vicinity of the wellbore free of secondary hydrates and ice that can obstruct flow. Note again the evolution of the upper dissociation interface, as the hydrate recedes. Gas saturation reaches very high levels at this location (Moridis and Reagan, 2007a), and highlights the necessity for upper permeability barriers if gas production from hydrates is to become possible. Absence of such barriers will inevitably lead to gas escaping through the permeable overburden toward the ocean floor, with possibly undesirable consequences if such releases cannot be contained.

Analysis of the gas production potential of (a) an oceanic Class 2 deposits in the Ulleung Basin of the Korean East Sea (Moridis and Reagan, 2007c) and (b) a permafrost deposit in the North slope show similar patterns (Figure 31). Although the Ulleung Basin deposit is assumed to be substantially thicker than the Tigershark one (50m vs. 18m), it produces less gas because it is much colder and less permeable. The permafrost deposit is 15 m thick, but is colder than the Tigershark one (12 °C) and lacks the beneficial effect of the salt (an inhibitor) on dissociation. The most important observation is that all these Class 2 deposits (oceanic and permafrost) appear to be able yield gas at rates of several MMSCFD.

In a study of marine Class 2 deposits with permeable overburden and underburden, and/or with a deep water-zone, Moridis and Kowalsky (2005) determined that the production rates were too low to justify considering such accumulations as viable targets. Both a single well and a multi-well (five-spot, with warm water injection) system were tested. The production rate was higher in the case of single-well production because, in the five-spot pattern, the (a) gas produced from the thermal dissociation of hydrate caused by the warm water re-injection is very slow to reach the production well, and (b) the water injection does not allow a significant pressure drop, thus reducing the driving force of the depressurization-induced dissociation near the production well. The main reasons for the limited potential of these deposits are (a) the ineffectiveness of depressurization as the driving force of dissociation in the absence of confining layers, (b) the availability of practically limitless amounts of water in the vicinity of the HBL, necessitating large water production rates for an effective pressure drop, (c) the challenge of focusing and directing water flow through the HBL (easily bypassed if higher permeability pathways through the enveloping boundary layers are available), and (d) the adverse relative permeability to gas flow, as gas attempts to emerge as a mobile free phase in a fast-flowing water-saturated geologic medium.

**Gas Production From Class 3 Deposits.** While depressurization-induced dissociation appears to be the most promising strategy in gas production from Class 1 and Class 2 deposits, the situation is far less clear in Class 3 accumulations because

of the absence of a hydrate-free (and, consequently, relatively permeable) zone underneath the HBL from which fluids can be removed to induce depressurization of the overlying hydrates.

Thus, the attractiveness of depressurization is challenged by permeability limitations in Class 3 deposits. In such deposits, the only method to induce dissociation by depressurization is via flow through the HBL. However, the low effective permeability  $k_{eff} = k_{eff}(t)$  of the solid hydrate inhibits large flow rates, leading to low rates of dissociation and gas production, and a localized system response that is expected to be limited to the area around the production well.

**Constant- $Q$  depressurization.** Simple comparison of the total area available for dissociation reveals that, even at a very early stage, depressurization-induced gas production from Class 3 deposits under constant  $Q_M$  production appears to lag significantly behind that from Classes 1 and 2. This is because the pressure disturbance cannot access the base or top of the HBL. This realization provides a potential insight into gas production from Class 3 hydrates: a plausible strategy to maximize  $Q_P$  would be to transform a Class 3 into Class 2 deposit through adoption of processes that enhance dissociation along the base of an HBL and development of a water zone. Increased hydrate saturation  $S_H$  is expected to progressively exacerbate the problem of low  $Q_P$  because of a reduction in  $k_{eff}$ . Additionally, if a high  $Q_M$  rate is imposed at the well and/or  $S_H$  is high in the HBL, ice can form because of the strongly endothermic hydrate dissociation reaction and Joule-Thompson cooling near the wellbore where gas velocities are high. Ice formation, especially when combined with secondary hydrate formation, can have a severe adverse effect on permeability.

For the reasons discussed above, depressurization by imposing a constant  $Q_M$  at the well appears to be a possibility when (a) the intrinsic permeability  $k$  of the HBL formation is high, (b) the initial  $S_H$  is moderate (i.e.,  $S_H < 0.5$ ), (c) the capillary pressure  $P_{cap}$  is weak, and (d) the irreducible aqueous and gas saturations ( $S_{irA}$  and  $S_{irG}$ , respectively) are relatively low. Selection of this type of production presupposes knowledge that  $k_{eff,0}$  (initial  $k_{eff}$ ) of the HBL is capable of delivering the prescribed  $Q_M$ , and that the potential formation of secondary hydrate near the well does not lead to  $k_{eff} < k_{eff,0}$ . Such knowledge may not be available *a priori*. Generally, it is not advisable to use constant- $Q$  depressurization for gas production in Class 3 hydrate accumulations.

**Constant- $P$  depressurization.** Constant-pressure production involves the maintenance of a constant pressure  $P_w$  at the well, which acts as an internal boundary. The flow rates  $Q_M$ ,  $Q_P$  and  $Q_W$  under constant- $P$  production are not constant but vary over time because they are controlled by the time-dependent phase mobilities at the well and the pressure differential between the well and its surroundings.

Constant- $P$  production is applicable to a wide range of formation permeabilities, is uniquely suited to allow continuous rate increases to match increasing permeability (the result of the dissociation-caused reduction in  $S_H$ ), and may be the only reasonable alternative when  $S_H$  is high. An additional and very significant advantage of constant- $P$  production is the elimination of the possibility of ice formation (with its detrimental effects on permeability and  $Q_P$ ) through the selection of an appropriate  $P_w$ . This is ensured by selecting a  $P_w > P_Q$ , i.e., the  $P$  at the quadruple point  $QI$  (see Figure 17).

A possible drawback is that constant- $P$  production may lead to large initial  $Q_W$ , which, however, decreases over time. An additional potential drawback is that, by selecting a  $P_w > P_Q$ , both  $Q_P$  and the corresponding cumulative volume of produced gas  $V_P$  is reduced because the pressure differential  $\Delta P = P_0 - P_w$  (the driving force of flow, dissociation and gas production) is not maximized. This is less of a problem in deeper and warmer oceanic accumulations, in which the initial pressure  $P_0$  can be high, than in shallower oceanic accumulations and in the relatively shallow permafrost deposits. This complication can be resolved by (a) maximizing  $\Delta P$  by selecting a  $P_w$  slightly above  $P_Q$ , and (b) varying  $P_w$  over time, keeping initially  $P_w > P_Q$  until  $Q_P$  is significantly reduced (because of depressurization of the entire deposit) and then reducing  $P_w$  to levels below  $P_Q$  (and as low as the atmospheric). This is possible because, by the time  $P_w$  is reduced to below  $P_Q$ ,  $S_H$  is expected to be sufficiently low as to either eliminate the possibility of ice formation upon continuing dissociation, or to limit the possible ice saturation  $S_I$  to levels which result in permeability reduction that is not prohibitive for gas production. Note that the final  $P_w$ , at which a considerable  $Q_P$  is observed, may be well below the normal abandonment pressure of conventional gas reservoirs.

**Thermal stimulation.** Pure thermal stimulation and inhibitor effects face considerable challenges as a method for large-scale gas production from Class 3 deposits. The reasons for their shortcomings were discussed in detail in the discussion of production from Class 2 deposits. It is possible that either may be used for localized, short-term and limited scale applications in conjunction with depressurization.

**Evaluation of Production Potential.** Figure 32 shows that the maximum gas production rates in this example (based on the properties of, and the favorable conditions of, the 18m-thick Tigershark accumulation, see Moridis and Reagan(2007b)) when exposed to two types of thermal stimulation (warm water circulation and electrical heating). The  $Q_P$  in both cases is orders of magnitude below those observed in the Class 1 or Class 2 deposits, and cannot satisfy minimum economic viability conditions under any circumstances. These results confirm the ineffectiveness of pure thermal stimulation, and preclude its use as a production method (Moridis and Reagan, 2007b).

When gas is produced from the Class 3 accumulation by means of constant- $P$  depressurization,  $Q_P$  follows a cyclical pattern that includes a long rising segment, followed by a short precipitous drop (Figure 33).  $Q_P$  reaches a maximum level of  $Q_P = 4.3 \times 10^5$  ST m<sup>3</sup>/day of CH<sub>4</sub> (= 15 MMSCFD). During the 6,000-day production period, the hydrate was exhausted, and a total of  $V_P = 1.37 \times 10^9$  ST m<sup>3</sup> (=  $4.84 \times 10^{10}$  ST ft<sup>3</sup>) of CH<sub>4</sub> were produced at an average rate  $Q_{avg} = 2.3 \times 10^5$  ST m<sup>3</sup>/day (= 8.10 MMSCFD). The water mass production rate  $Q_W$  shows an exponential-like decline with time (Figure 33) from a large initial level of  $Q_W = 23$  kg/s (12,200 BPD) to an average of about  $Q_W = 2.5$  kg/s (= 1,300 BPD) after  $t = 1,000$  days. Even at its highest, this  $Q_W$  level is manageable, and so is the cumulative mass of produced water  $M_W$ . Production from Class 3

hydrates by constant- $P$  depressurization is at its most challenging upon initiation, and the picture continuously improves with time.

In contrast to production from Class 2 deposits with the same initial conditions, which is characterized by long lead times of low production  $Q_P$ , constant- $P$  production from Class 3 deposits begins in earnest from the moment depressurization is applied. These results clearly indicate that there is nothing intrinsically prohibitive in the production from Class 3 hydrates, and provide convincing evidence that the earlier impressions of low production potential of such hydrate deposits were the result of inappropriate production methods. Thus, gas can be produced from Class 3 hydrates at high rates over long times using conventional well technology.

The precipitous  $Q_P$  drops (see the oscillations in Figure 33) occur when a traveling dual barrier (composed of concentric cylindrical structures formed from secondary hydrates) evolves and restricts flow to the well (Figure 34). This dual barrier is caused by the pressure regime and dissociation patterns (Moridis and Reagan, 2007b), and is a unique feature of constant- $P$  production from Class 3 hydrate accumulations.

As in Class 2 deposits, dissociation in Class 3 accumulations is characterized by (a) the evolution of an upper dissociation interface at the top of the hydrate layer (caused by heat flows from the upper boundary) in addition to the lower dissociation interface at the bottom of the HBL, and (b) gas accumulation below the base of the overburden because of continuing dissociation and buoyancy-driven gas rise to the top of the formation. The gas accumulation pattern has particularly important (and potentially severe) implications for gas production from oceanic deposits because lack of a confining overburden could lead to gas loss through percolation through the overburden and release at the ocean floor.

As in Class 2 deposits, processes and phenomena that occur within a narrow zone around the well control gas production from the entire hydrate deposit in the Class 3 case. This critical zone has a radius  $r_c < 15\text{--}20$  m, and fine discretization must be used in its simulations if these near-well phenomena are to be captured and described (Moridis and Reagan, 2007b). Dissociation and flow patterns are uniform and smooth along the entire area of the horizontal interfaces for  $r > r_c$  (Figure 35).

$Q_R$  increases (and the corresponding  $R_{WGC}$  decreases) with an increasing (a) hydrate temperature (which defines its stability for a given pressure), and (b) intrinsic permeability (Moridis and Reagan, 2007b). Lower initial hydrate saturations lead initially to higher gas production and a lower  $R_{WGC}$  (due to the greater  $k_{eff}$  of the initial hydrate mass) but the effect is later reversed as the hydrate is depleted more quickly (Figure 36).

The effect of heterogeneity in permeability  $k$  appears to be beneficial to gas production from Class 3 deposits (Kurihara et al., 2005). Thus, a higher  $Q_R$  is observed with an increasing level of heterogeneity in  $k$  (Figure 37, panel A), which is evident in the  $S_H$  distribution of panel B in Figure 37. Finally, in an interlayered system of sandstone and mudstone strata,  $Q_R$  decreases with a decreasing mudstone permeability (as expected, because of decreased communication between successive hydrate layers). Of particular interest is the observation that fracturing has very little effect (Kurihara et al., 2005b).

**Geomechanical Issues.** Geomechanical changes brought about by dissociation can have a significant impact on production, including porosity and permeability reduction (as the cementing hydrate dissociates, and more stresses are transferred to the generally unconsolidated sediments in HBS), subsidence, formation yielding/failure, and wellbore stability (Rutqvist and Moridis, 2007). It is possible that geomechanical considerations may prevent production from otherwise promising hydrate deposits if conventional oilfield technology is to be used. Generally speaking, the subsidence of unconsolidated hydrate-bearing sands ( $<5\%$ , the rule of thumb of acceptable consolidation to maintain wellbore stability) is manageable, while the subsidence of clayey HBS is sufficiently large to result in formation failure and wellbore instability (see Table 3), even if the issues of low permeability and slurry production are not considered.

### Desirability of Potential Hydrate Targets

Although the available body of information on production from hydrates is rather limited, there is sufficient information to begin identifying particular features, properties, conditions and production methods that are linked to a higher gas production potential and increase the desirability of hydrate deposits, and to use this information to develop a set of guidelines for the selection of promising production targets.

**Desirable Features and Conditions.** These include the following:

- Large permeabilities and porosities, which are almost invariably associated with sandy and gravelly formations. These are usually associated with low capillary pressure and low irreducible gas and water saturations, leading to relatively high permeability to gas and aqueous flow
- Field evidence has shown that such reservoirs, if they contain any gas hydrate at all, are typically highly saturated ( $60\% < S_H < 85\%$ ), with the degree of saturation being largely determined by intrinsic reservoir quality. However, if such cases can be found, production would likely benefit from medium-high hydrate saturations ( $30\% < S_H < 60\%$ ) that provide significant volumes of movable pore fluids to enable effective reservoir depressurization. The effect of  $S_H$  on gas production is not monotonic, but a complex function of  $S_H$  and the timeframe of observation. A lower  $S_H$  has the advantage of higher effective permeability, mild depressurization over long periods because the pressure disturbance extends over a larger volume of the reservoir, generally earlier evolution of gas and larger production rates (Moridis and Reagan, 2007a,b). The disadvantages of a lower  $S_H$  include large early water production rates and early exhaustion of the resource.

Higher hydrate saturations exhibit slower evolution of gas and lower production rates, reach a maximum  $Q_P$  later, but yield larger amounts of cumulative gas.

- The most desirable targets can be easily identified from the inspection of the phase diagram. These are characterized by a large  $T$  and  $P$ , in addition to their proximity to the Lw + H + G (3-phase coexistence) equilibrium line (allowing easier destabilization). Additionally, the larger  $T$  provides a larger source of sensible heat to support the endothermic dissociation process, and a larger  $P$  allows a larger pressure drop before the evolution of ice, leading to larger production rates. Thus, (a) hydrates that occur along this line (where  $P = P_e$  and  $T = T_e$ ) are very desirable, and (b) the desirability increases with an increasing equilibrium  $P$  (and, consequently,  $T$ ). This indicates that Class 1 hydrates (in which the bottom of the hydrate exists at the bottom of the stability zone) are obvious targets because the effort to destabilize them and effect dissociation and gas release is minimal (the additional advantage of having a source of free gas). The same can be said for Class 2 and Class 3 hydrates that exist just above the equilibrium line. The production potential decreases as the stability of the hydrate deposit at its initial conditions (as quantified by the pressure differential  $\Delta P = P - P_e$  at the prevailing reservoir  $T$ ) increases. In practical terms: we target the deepest, warmest reservoirs that are as close as possible to equilibrium conditions. In addition, the deeper reservoirs will also be those with the most overburden, and therefore the less prone to geomechanic impacts at the surface or at the seafloor.
- For reservoirs with the same hydraulic properties,  $S_H$ , and at a given  $P$ : the warmest possible reservoir is the most desirable. For reservoirs with the same hydraulic properties,  $S_H$ , and at a given  $T$ : The reservoir with the lowest possible  $P$  is the most desirable. In general, it is not possible to know *a priori* the relative production potential of a reservoir at equilibrium vs. a deposit at a higher  $P$  and  $T$  but further removed from equilibrium.
- In terms of deposit Classes: Based on current evidence, Class 1 appears to be the most promising target for gas production because the thermodynamic proximity to the hydration equilibrium point at the highest possible temperature requires only small changes in pressure and temperature to induce dissociation. Additionally, the existence of a free gas zone provides a significant economic advantage because it guarantees gas production even when the hydrate contribution is small. Three-phase coexistence (gas, aqueous and hydrate) at the bottom of the hydrate interval is a unique characteristic of Class 1 deposits, which indicates that such permafrost accumulations have about the same  $P$  and  $T$  at the hydrate interface if the geothermal gradient does not exhibit significant local variations. Class 1 deposits with thick gas zone are probably characterized by early gas production, lower water production, but also by later and slower hydrate dissociation (the larger free gas zone is slower to respond). Thinner gas zones may enhance dissociation, but they may also lead to greater water production. Within Class 1: Class 1 G is clearly a more desirable target.
- Class 2 and Class 3: Class 2 can attain high rates, but is also burdened by longer lead times of very little gas production; Class 3 may yield gas earlier and can attain significant production rates, but there is indication that those are lower than in Class 2. The relative merits of these two types will likely be determined by site-specific reservoir quality issues, among which the thickness of the water zone in Class 2 deposits can be dominant.
- All classes: The difficulties of site access notwithstanding, deeper and warmer ( $>14$  °C) oceanic accumulations appear to be more productive than permafrost ones because permafrost deposits have (a) a lower temperature (not exceeding 14 °C), limiting the sensible heat available for dissociation and (b) a lower pressure, limiting the depressurization effectiveness, in addition to (c) lacking the beneficial dissociating effect of salt in oceanic hydrates.
- All classes: The importance of impermeable or near-impermeable upper boundaries cannot be overemphasized.
- In terms of production method: Depressurization appears to have a clear advantage in all three classes. Thermal stimulation can only be considered for localized applications (i.e., destruction of secondary hydrate and/or ice) in the vicinity of the well, while inhibitors appear to make economic sense only when used to prevent hydrate formation in the wellbore. In practical terms, if depressurization does not appear to be effective, the deposit is not a desirable target.

**Undesirable Features and Conditions.** At this early stage in the quest of gas production from hydrates, accumulations characterized by the following features are to be completely avoided as production targets:

- Class 4 deposits, or any deposits in which the enclosing media is undeformed clay sediments: Earlier studies by Moridis and Sloan (2007) have indicated the hopelessness of such deposits under any combination of conditions and production practices.
- Fine sediments (i.e., rich in silts and clays), deformed fractured systems, as well as hydrates in veins and nodules (i.e., hydrate associated with displacement of, or extrusion into, soft sediments, as opposed to hydrates in the pores) despite high gas hydrate saturations, due to geomechanical instability and restriction of fluid flow.
- In Class 2 deposits: Well configurations involving a perforated interval that penetrates the water zone but does not extend substantially into the HBL. Such wells do not allow access to the gas bank developing above the upper dissociating interface, and result in generally low rates (Moridis and Reagan, 2007a).

- In Class 2 deposits: Constant- $P$  production does not seem to be a promising production strategy because it can lead to early breakthrough and massive water production. However, such an approach can be used in a short-term flow test to determine the HBL properties.
- In Class 2 deposits: Deep water zones, and/or permeable overburden and underburden, can drastically reduce gas production from Class 2 deposits. Additionally, the use of multi-well (5-spot) systems involving simultaneous depressurization (at the production well) and thermal stimulation (through warm water injection) appears disappointing (Moridis and Kowalsky, 2005).
- In all Classes: Permeable upper boundaries.
- In all Classes: Pure thermal dissociation methods and/or inhibitor methods have high cost and limited (and continuously eroding) effectiveness.
- In all Classes:  $S_H$  that are so high that the remaining fluids are below their irreducible saturation levels. Such hydrates may not be prone to easy depressurization-induced dissociation. Additionally, knowledge on the behavior of such systems is minimal or nonexistent.
- In all Classes: Fracturing appears to have limited effect on increasing productivity from hydrate deposits (Kurihara et al., 2005b).

## Conclusions

We can draw the following conclusions from this study:

- (1) Gas hydrates are a vast resource with global distribution in the permafrost and in the oceans. Even if a conservative estimate is considered and only a small fraction is recoverable, the sheer size of the resource is so large that it demands evaluation as a potential energy source. Although formidable difficulties exist, the development of hydrates into an energy source appears to have acquired its own global dynamic, with increased levels of international awareness, several national and international programs investigating the feasibility of the endeavor, and heightened levels of activity. Parallels can be drawn from the development of coalbed methane, which, after properly studied and understood, has graduated from being a safety hazard to becoming an increasingly conventional resource that now constitutes 10% of the U.S. gas production.
- (2) There is a concerted international effort (and remarkable cooperation) to determine the technical and economic feasibility of production from gas hydrates. However, it is noteworthy that this effort is currently led by governments, with industry providing a supporting role.
- (3) Production from gas hydrates faces significant challenges because of the hostile environments in which they exist. The difficulty of access, coupled with the significant cost of related work, and the need to have the first attempt at producing gas from this unconventional source be a success (lest failure condemns a large and worthy effort), have led to the development of a rational approach to prioritize potential targets. By need and design, the first attempts to produce gas from hydrates will be limited to the few relatively well-characterized sites with proven resources.
- (4) Because of its power, flexibility, and low-cost (compared to actual field studies), numerical simulation plays a critical role in the effort to assess the production potential of hydrates. While the dearth of field data has not allowed the full validation of numerical codes, the consensus of the scientists involved in the effort is that the models generally account for the important physics of the problem, and that validation and calibration (rather than adequacy of the numerical code capabilities) will be a constraining factor in the assessment of the hydrates as an energy resource.
- (5) A review of the data needs for the implementation of the numerical models indicates that, while knowledge gaps exist, these are being addressed, or can be adequately addressed by sensible approximations. In the case of critically important data, the problem can be addressed by sensitivity analyses that can bound the potential solutions.
- (6) Literature review provides strong indications that gas hydrates from a variety of types of deposits (even ones considered unproductive a few years ago) can yield large amounts of gas at high rates over long periods using conventional technologies. Even when new well designs are proposed, these are well within the current technological capabilities. This bodes well for the production potential of this unconventional resource.

## Nomenclature

- $C$  = specific heat (J/kg/K)  
 $k$  = intrinsic permeability ( $m^2$ )  
 $k_{\theta}$  = thermal conductivity (W/m/K)  
 $k_{\theta RD}$  = thermal conductivity of dry porous medium (W/m/K)  
 $k_{\theta RW}$  = thermal conductivity of fully saturated porous medium (W/m/K)  
 $N_H$  = hydration number  
 $P$  = pressure (Pa)  
 $Q_M$  = mass rate of fluid withdrawal at the well (kg/s)  
 $Q_P$  = volumetric rate of  $CH_4$  production at the well (ST  $m^3/s$ )



- $Q_R$  = volumetric rate of CH<sub>4</sub> release from hydrate dissociation into the reservoir (ST m<sup>3</sup>/s)  
 $Q_W$  = mass rate of water release into the ocean through the annular gravel pack (kg/s)  
 $r_w$  = radius of the well assembly (m)  
 $r_{max}$  = maximum radius of the simulation domain (m)  
 $R_{WGC}$  = cumulative water-to-gas ratio (kg/ST m<sup>3</sup>)  
 $S$  = phase saturation  
 $t$  = time (days)  
 $STP$  = standard pressure and temperature  
 $T$  = temperature (K or °C)  
 $TCF$  = 10<sup>12</sup> STP ft<sup>3</sup> of gas  
 $V_R$  = cumulative volume of CH<sub>4</sub> released from hydrate dissociation (ST m<sup>3</sup>)  
 $V_P$  = cumulative volume of CH<sub>4</sub> released into the ocean through the annular gravel pack (ST m<sup>3</sup>)

### Greek Symbols

- $\phi$  = porosity

### Subscripts and Superscripts

- $\theta$  = denotes initial state  
 $A$  = aqueous phase  
 $e$  = equilibrium conditions  
 $cap$  = capillary  
 $G$  = gas phase  
 $G\theta$  = initial gas phase  
 $H$  = solid hydrate phase  
 $H\theta$  = initial solid hydrate phase  
 $irG$  = irreducible gas  
 $irA$  = irreducible aqueous phase  
 $P$  = production stream  
 $R$  = rock

### Acknowledgments

G.J. Moridis wants to express his gratitude to Scott Dallimore of the Geological Survey of Canada for his generosity, understanding and forgiving nature, and for his assistance in securing permission to include material from the Mallik 2002 Gas Hydrate Production Research Well Program in this paper. G.J. Moridis's and M.T. Reagan's contribution to this study was supported by the Assistant Secretary for Fossil Energy, Office of Natural Gas and Petroleum Technology, through the National Energy Technology Laboratory, under the U.S. Department of Energy, Contract No. DE-AC02-05CH11231. M. Kurihara wishes to acknowledge the support of the Research Consortium for Methane Hydrate Resources in Japan (MH21 Research Consortium) on the National Methane Hydrate Exploitation Program by the Ministry of Economy, Trade and Industry (METI). The authors are indebted to Stefan Finsterle, John Apps and Dan Hawkes for their thorough review and their insightful comments.

### References

- Backus, M., Murray, M., Hardage, B., and Graebner, R., 2006, High-resolution multi-component seismic imaging of deepwater gas hydrate systems: *The Leading Edge*, v. 25, n. 5., pp. 578-593.  
 Bejan, A., 1984. *Convection Heat Transfer*. New York: John Wiley & Sons. 416.  
 Bird, K.J., and Magoon, L.B., 1987, Petroleum geology of the northern part of the Arctic National Wildlife Refuge, Northeastern Alaska: *U.S. Geological Survey Bulletin* **1778**, 324.  
 Borowski, W.S. 2004, A review of methane and gas hydrates in the dynamic, stratified system of the Blake Ridge region, offshore southeastern North America. *Chem. Geology* **205**, 311.  
 Boswell, R., 2007. Resource potential of methane hydrate coming into focus, *JPSE*, **56**, 9-13.  
 Boswell, R., and T. Collett, 2006. The Gas Hydrate Resource Pyramid, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter*, Fall 2006. (<http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsFall06.pdf>).  
 Boswell, R., R. Amato, R. Coffin, T. Collett, G. Dellagiardino, R. Fisk, J. Gettrust, B. Haq, D. Hutchinson, K. Puglise, P. Ray, and K. Rose, 2006. An Interagency Roadmap for Methane Hydrate Research and Development, U.S. Department of Energy, Office of Fossil Energy, July 2006 (online at: <http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/pdf/InteragencyRoadmap.pdf>)  
 Boswell, R., R. Kleinberg, T. Collett, and M. Frye, 2007. Exploration priorities for marine gas hydrates, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter*, Spring/Summer 2007. (<http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsSpringSummer07.pdf>).  
 Bunz, S., and Meinert, J., 2005, Overpressure distribution beneath hydrate-bearing sediments at the Storegga Slide on the Mid-Norwegian margin, Paper 3007, *Proceeding, ICGH 2005*, v. 3, pp. 755-758.  
 Cherskiy, N.V., Tsaarev, V.P., Nikitin, S.P., 1982. *Petrol. Geol.*, **21**, 65.

- Collett, T., 1993, Natural gas hydrates of the Prudhoe Bay and Kuparuk River area, North Slope, Alaska: American Association of Petroleum Geologists Bulletin, **77** (5), 793-812.
- Collett, T., 1995. *1995 National Assessment of U.S. Oil and Gas Resources* (on CD-ROM) (Gautier, D.L., Goldton, G.L., et al., eds.), USGS.
- Collett, T., 2004. Gas hydrates as a future energy resource. *Geotimes*, November, 2004 ([http://www.agiweb.org/geotimes/nov04/feature\\_futurehydrates.html](http://www.agiweb.org/geotimes/nov04/feature_futurehydrates.html)).
- Collett, T., 2007. Arctic Gas Hydrate Energy Assessment Studies, The Arctic Energy Summit, ANCHORAGE, ALASKA • 15-18 OCTOBER 2007
- Collett, T., and Ginsburg, G., 1998. Gas hydrates in the Messoyakha gas field of the West Siberian Basin -- a re-examination of the geologic evidence: *International Journal of Offshore and Polar Engineering*, **8**(1), 22-29.
- Collett, T., and Lee, M., 2006. Well Log Analysis: Tiger Shark AC 818 No. 1, U.S. Geological Survey, internal memo.
- Collett, T., M. Riedel R. Boswell, J. Cochran, P. Kumar, A. Sethi, and A. Sathe, 2006. International Team Completes Landmark Gas Hydrate Expedition in the Offshore of India, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter*, Fall 2006. (<http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsFall06.pdf>).
- Computer Modeling Group, Steam, Thermal, and Advanced Processes Reservoir Simulator (STARS), online: [www.cmgroup.com/software/stars.htm](http://www.cmgroup.com/software/stars.htm)
- Dai, J., Banik, N., Gillespie, D., and N. Dutta, in press, Exploration for gas hydrates in the Deepwater Northern Gulf of Mexico: model validation by drilling, *Marine and Petroleum Geology*.
- Dallimore, S.R. and Collett, T.S., 1995, Intrapermafrost gas hydrates from a deep core hole in the Mackenzie Delta, Northwest Territories, Canada. *Geology* **23**, 527-530.
- Dallimore, S.R., Uchida, T., and Collett, T.S., 1999, Scientific results from JAPEX/JNOC/GSC Mallik 2L-38 gas hydrate research well, Mackenzie Delta, Northwest Territories, Canada, *Geological Survey of Canada Bulletin* **544**, 403.
- Dallimore, S.R., Collett, T.S., Eds., 2005. Scientific Results from the Mallik 2002 Gas Hydrate Production Research Well Program, Mackenzie Delta, Northwest Territories, Canada, *Geological Survey of Canada Bulletin* **585**.
- Dallimore, S.R. and 2006-08 Mallik Team, , 2007. Community Update on the 2006-2008 JOGMEC/NRCan/ Aurora Mallik Gas Hydrate Production Research Program, Northwest Territories, Canada, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter* Spring/Summer2007. (<http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsSpringSummer07.pdf>).
- Davie, M.K., Buffett, B.A., 2003. A numerical model for the formation of gas hydrate below the seafloor, *J. Geophys. Res.*, **108** (B10), 2495.
- Durham, W. B., et al., 2003. The strength and rheology of methane clathrate hydrate, *JGR*, **108** (B4), 2182.
- Fan., S. Zhang, J., and Wang, J., 2005, Progress of gas hydrate studies in China, Paper 3047, *proceeding*, ICGH2005, v. 3, pp. 1012-1021.
- Fujii, T., Nakamizu, M., Tsuji, Y., Okui, T., Kawasaki, M., and K. Ochiai, 2005, Modes of occurrence and accumulation mechanism of methane hydrate – result of METI exploration test wells “Tokai-oki to Kumano-nada”; Paper 3041, *proceeding*, ICGH2005, v. 3, pp. 974-979.
- Gerami, S., and Pooladi-Darvish, M., 2006. Material balance and boundary-dominated flow models for hydrate-capped gas reservoirs, SPE 102234, 2006 SPE Annual Technical Conference and Exhibition, Texas, U.S.A., 24–27 September, 2006.
- Ginsburg, G.D., Soloviev, V.A., 1995. in *OTC 7693*, 27th Annual Offshore Technology Conference, Houston, May 1–4.
- Gornitz, V., and I. Fung, 1994. Potential distribution of methane hydrate in the world’s oceans, *Global Biogeochem. Cycles*, **8**, 335.
- Gupta, A., 2007. Methane hydrate dissociation measurements and modeling: the role of heat transfer and reaction kinetics, Ph.D. Thesis, Chemical Engineering Dept., Colorado School of Mines, Golden, CO.
- Gupta, A., et al., 2006. Composite thermal conductivity in a large heterogeneous porous methane hydrate sample, *J Phys Chem B.*, **110** (33), 16384-16392.
- Harvey, L.D.D., Huang, Z., 1995. *J. Geophys. Res.*, **100** D2, 2905.
- Holbrook, W.S., Hoskins, H., Wood, W.T., Stephen, R.A., Lizarralde, D., and Leg 164 Science Party, 1996. *Science*, **273**, 1840.
- Hong, H., and Pooladi-Darvish, M., 2005. Simulation of Depressurization for Gas Production from Gas Hydrate Reservoirs, *J. Can. Pet. Tech.*, **44** (11), 39-46.
- Jaiswal, N., 2004. Measurement of Gas-Water Relative Permeabilities in Hydrate Systems, Masters of Science thesis, University of Alaska, Fairbanks, AK.
- JNOC-TRC, *Proceedings of the International Symposium on Methane Hydrates*, Chiba, Japan (October 20-22, 1998)
- Judge, A., Smith, S., and Majorowicz, J., 1994, The current distribution and thermal stability of natural gas hydrates in the Canadian Polar Regions, in *Proceedings Fourth International Offshore and Polar Engineering Conference*, Osaka, Japan, 307-313.
- Kamath, V.A., 1984. Study of heat transfer characteristics during dissociation of gas hydrates in porous media”, Ph.D. dissertation, Univ. of Pittsburgh., Pittsburgh, PA.
- Klauda, J.B., Sandler, S.I., 2005. Global distribution of methane hydrate in ocean sediment, *Energy & Fuels* **19**, 469.
- Kneafsey, T., Tomutsa, L., Moridis, G., Seol, Y., and Freifeld, B. 2005. Methane hydrate formation and dissociation in a partially-saturated sand—measurement and observations. *Proceedings of the Fifth International Conference on Gas Hydrates*, vol. 1, pp. 213–220.
- Krasov, J. and Finley, P.D., Messoyakh Gas Field - Russia: West Siberian Basin, Amer. Assoc. Petrol. Geol., *Treatise of Petroleum Geology, Atlas of Oil and Gas Fields, Structural Traps VII*, p. 197-220 (1992).
- Kumar, P., et al., 2004. Thermal diffusivity measurements of porous methane hydrate and hydrate-sediment mixtures, *J. Geophys. Res.*, **109** (B01207).
- Kurihara, M., H. Ouchi, T. Inoue, T. Yonezawa, Y. Masuda, S.R. Dallimore and T.S. Collett, 2005a. “Analysis of the JAPEX/JNOC/GSC et al. Mallik 5L-38 Gas Hydrate Thermal Production Test Through Numerical Simulation”, in *Scientific Results from the Mallik 2002 Gas Hydrate Production Research Well Program, Mackenzie Delta, Northwest Territories, Canada. Geological Survey of Canada Bulletin* **585**, S.R. Dallimore and T. Collett, Eds.

- Kurihara, M., K. Funatsu, H. Ouchi, Y. Masuda and H. Narita, 2005b. "Investigation On Applicability Of Methane Hydrate Production Methods To Reservoirs With Diverse Characteristics", Paper 3003 presented at the 5th International Conference on Gas Hydrates, Trondheim, Norway, 13–16 June, Proceedings, Vol. 3, 714-725.
- Kurihara, M., K. Funatsu, K. Kusaka, M. Yasuda, S.R. Dallimore and T.S. Collett and S.H. Hancock, 2005c. "Well-Test Analysis for Gas Hydrate Reservoirs: Examination of Parameters Suggested by Conventional Analysis for the JAPEx/JNOC/GSC et al. Mallik 5L-38 Gas Hydrate Production Test Results", in Scientific Results from the Mallik 2002 Gas Hydrate Production Research Well Program, Mackenzie Delta, Northwest Territories, Canada. *Geological Survey of Canada Bulletin* **585**, S.R. Dallimore and T. Collett, Eds.
- Kvenvolden, K.A., 1988. Methane hydrate—a major reservoir of carbon in the shallow geosphere, *Chem. Geol.* **71**, 41-51.
- Kvenvolden, K.A., Claypool, G.E., 1988. *U.S. Geological Survey Open File Report 88-216*, 50.
- Kvenvolden, K.A., 2005. Personal Communication with E. Dendy Sloan, November 28, 2005.
- Lee, J. Y., et al. 2007. Observations related to tetrahydrofuran and methane hydrates for laboratory studies of hydrate-bearing sediments, *Geochem. Geophys. Geosyst.*, **8**, Q06003.
- MacDonald, G.J., 1990. *Climatic Changes*, **16**, 247.
- Majorowicz, J.A., and Osadetz, K.G., 2001, Gas hydrate distribution and volume in Canada, AAPG Bulletin **85** (7), 1211-1230.
- Makogon, Y.F., 1981. *Hydrates of natural gas*: Tulsa, Penn Well Publishing Company, 237.
- Makogon, Y.F., 1987. Gas hydrates: frozen energy, *Recherche* **18** (192), 1192.
- Makogon, Y.F., 1988. Natural Gas Hydrates: The State of Study in the USSR and Perspectives for Its Use, paper presented at the Third Chemical Congress of North America, Toronto, Canada, June 5–10.
- Makogon, Y.F., 1997. *Hydrates of Hydrocarbons*. Penn Well Publishing Co. Tulsa, OK.
- Masui, A., Haneda H., Ogata Y. and Aoki K., 2005, The effect of saturation degree of methane hydrate on the shear strength of synthetic methane hydrate sediments. Proceedings of the 5th International Conference on Gas Hydrates, Trondheim, Norway, Paper 2037, Vol. 2, 657–663.
- Matsumoto, R., Tomaru, H. and Lu, H., 2004. Detection and evaluation of gas hydrate formation in the Eastern Nankai Trough by geochemical and geophysical methods, *Resource Geology* **54**, 53-68.
- McIver, R.D., 1981. *Long-Term Energy Resources*, **1**, Meyer, R.F., Olson, J.C., eds., Boston: Pitman, 713.
- Milkov, A. V., 2004. Global estimates of hydrate-bound gas in marine sediments: How much is really out there? *Earth Science Reviews* **66** (3), 183.
- Molochushkin, E.N., 1978, The effect of thermal abrasion on the temperature of the permafrost in the coastal zone of the Laptev Sea: Proceedings of the Second International Conference on Permafrost, Takutsk, USSR, July 13-28, 1973: National Academy of Sciences, Washington D.C., 90-93.
- Moridis, G.J., 2003. Numerical Studies of Gas Production From Methane Hydrates, *SPE Journal*, **32**(8), 359.
- Moridis, G.J., T. Collett, S. Dallimore, T. Satoh, S. Hancock and B. Weatherhill, 2004. Numerical Studies Of Gas Production From Several Methane Hydrate Zones At The Mallik Site, Mackenzie Delta, Canada, *JPSE* **43**, 219.
- Moridis, G.J. and M. Kowalsky, 2005. Gas production from unconfined Class 2 hydrate accumulations in the oceanic subsurface, Chapter 7, in *Economic Geology of Natural Gas Hydrates*, M. Max, A.H. Johnson, W.P. Dillon and T. Collett, Editors, Kluwer Academic/Plenum Publishers, 249-266.
- Moridis, G.J., Kowalsky, M.B., Pruess, K., 2005a. TOUGH-Fx/HYDRATE v1.0 User's Manual: A Code for the Simulation of System Behavior in Hydrate-Bearing Geologic Media, Report LBNL-3185, Lawrence Berkeley National Laboratory, Berkeley, CA.
- Moridis, G.J., T.S. Collett, S.R. Dallimore, T. Inoue and T. Mroz, 2005b. Analysis and Interpretation of the Thermal Test of Gas Hydrate Dissociation in the JAPEx/JNOC/GSC et al. Mallik 5L-38 Gas Hydrate Production Research Well, in Scientific Results from the Mallik 2002 Gas Hydrate Production Research Well Program, Mackenzie Delta, Northwest Territories, Canada. *Geological Survey of Canada, Bulletin* **585**, S.R. Dallimore and T. Collett, Eds.
- Moridis, G.J., Seol, Y., Kneafsey, T., 2005c. Studies of Reaction Kinetics of Methane Hydrate Dissociation in Porous Media", (LBNL-57298) Proc. 5<sup>th</sup> International Conference on Gas Hydrates, Trondheim, Norway, June 13-16, 2005, Paper 1004, **1**, 21-30.
- Moridis, G.J., and E.D. Sloan, 2007. Gas Production Potential of Disperse Low-Saturation Hydrate Accumulations in Oceanic Sediments, *J. Energy Conversion and Management*, **48** (6), 1834-1849.
- Moridis, G.J., and Reagan, M.T. 2007a. Strategies for Gas Production From Oceanic Class 3 Hydrate Accumulations, *OTC-18865*, 2007 Offshore Technology Conference, Houston, Texas, 30 April – 3 May 2007.
- Moridis, G.J., Reagan, M.T., 2007b. Gas Production From Oceanic Class 2 Hydrate Accumulations, *OTC 18866*, 2007 Offshore Technology Conference, Houston, Texas, U.S.A., 30 April–3 May 2007.
- Moridis, G.J., Reagan, M.T., 2007c. Gas Production From Class 2 Hydrate Accumulations in the Permafrost, *SPE 110858*, 2007 SPE Annual Technical Conference and Exhibition, Anaheim, California, U.S.A., 11–14 November 2007.
- Moridis, G.J., M. Kowalsky and K. Pruess, 2007a. Depressurization-Induced Gas Production From Class 1 Hydrate Deposits, *SPERE*, **10** (5), 458-481.
- Moridis, G.J., M.T. Reagan, S.J. Kim, Y. Seol, and K. Zhang, 2007b. Evaluation of the Gas Production Potential of Marine Hydrate Deposits in the Ulleung Basin of the Korean East Sea, *SPE 118859*, 2007 SPE Asia Pacific Oil & Gas Conference and Exhibition held in Jakarta, Indonesia, 30 October–1 November 2007.
- Mount Elbert Science Team, Alaska North Slope Well Successfully Cores, Logs, and Tests Gas-Hydrate-Bearing Reservoirs, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter*, Winter 2007. (<http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsWinter07.pdf>)
- National Energy Technology Laboratory, The National Methane Hydrates R&D Program Methane Hydrate Reservoir Simulator Code Comparison Study, 2007 ([http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/MH\\_CodeCompare/MH\\_CodeCompare.html](http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/MH_CodeCompare/MH_CodeCompare.html))
- National Energy Technology Laboratory, The National Methane Hydrates R&D Program, Hydrate Modeling - TOUGH-Fx/HYDRATE & HydrateResSim (<http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/rdprogram/ToughFX/ToughFx.html#HydrateResSim>)

- Osadetz, K.G., and Chen, Z., 2005, A re-examination of Beaufort Sea – Mackenzie Delta Basin gas hydrate resource potential using a petroleum system approach: Proceedings of the Fifth International Conference on Gas Hydrates, Trondheim, Norway, June 13-16, 2005.
- Osterkamp, T.E., and Fei, T., 1993, Potential occurrence of permafrost and gas hydrates in the continental shelf near Lonely, Alaska: Proceedings of the Sixth International Conference on Permafrost, Beijing, China, July 5-9, 1993: National Academy of Sciences, Washington D.C.
- Paull, C., Ussler, W., Lorenson, T., Winters, W., and J. Dougherty, 2005, Geochemical constraints on the distribution of gas hydrates in the Gulf of Mexico: *Geo-Marine Letters*, 25; DOI: 10.1007/s00367-005-0001-3.
- Park, K.P., 2006. “Gas Hydrate Exploration in Korea”, Proceedings of the 2nd International Symposium on Gas Hydrate Technology, Daejeon, Korea, Nov. 1-2.
- Pawar, R.J., G.A. Zvoloski, N. Tenma, Y. Sakamoto and T. Komai, T., 2005. Numerical Simulation of Gas Production From Methane Hydrate Reservoirs, Fifth International Conference on Gas Hydrates, Paper 1040, 5th International Conference on Gas Hydrates, Trondheim, Norway, 13–16 June, Proceedings, Vol. 1, 258-267.
- Peng, D.Y., and Robinson, D.B., 1976, A new two-constant equation of state. *Ind. Eng. Chem. Fundam.*, **15**, 59.
- Phale, H.A., T. Zhu, M.D. White and B.P. McGrail, 2006. Simulation Study on Injection of CO<sub>2</sub>-Microemulsion for Methane Recovery From Gas-Hydrate Reservoirs, Paper SPE 100541, SPE Gas Technology Symposium, 15-17 May 2006, Calgary, Alberta, Canada.
- Radler, M., *Oil Gas J.*, 98(51), 121 (2000).
- Ray, P., 2005. Quantitative assessment of marine gas hydrates underway at MMS, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter*, Winter 2005.
- Reidel, M., Collett, T., Malone, M., and Expedition 311 Scientists, 2006, Proceedings IODP, 311: Washington, DC. doi:10.2204/iodp.proc.311.2006
- Rosenbaum, E., et al., 2007. Thermal conductivity of methane hydrate from experiment and molecular simulation, *J Phys Chem B.*, **111** (46), 13194-13205.
- Ruppel, C., Dickens, G., Castellini, D., Gilhooly, W., and D. Lizzarralde, 2005, Heat and salt inhibition of gas hydrate formation in the northern Gulf of Mexico: *Geophysical Research Letters*, 32(4), L04605, DOI: 10.1029/2004GL021909.
- Rutqvist, J., and G.J. Moridis, 2007. Numerical Studies of Geomechanical Stability of Hydrate-Bearing Sediments, *OTC-18860*, 2007 Offshore Technology Conference, Houston, Texas, 30 April – 3 May 2007.
- Sloan, E.D., *Clathrate Hydrates of Neutral Gases*. 2<sup>nd</sup> Edition, Marcel Decker, Inc., New York, NY, 1998.
- Sloan, E.D., and C. Koh, *Clathrate Hydrates of Neutral Gases*. 3rd Edition, Taylor and Francis, Inc., Boca Raton, FL, 2008.
- Smith, S., Boswell, R., Collett, T., Lee, M., Jones, E., 2006. Alaminos Canyon Block 818: A Documented Example of Gas Hydrate Saturated Sand in the Gulf of Mexico, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter*, Fall 2006. (<http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsFall06.pdf>).
- Soloviev, V.A., 2002. *Russian Geol. Geophys.*, 43(7), 648.
- Sun, X. and K.K. Mohanty, 2005. Simulation of Methane Hydrate Reservoirs, SPE 93015, 2005 SPE Reservoir Simulation Symposium, Houston, TX U.S.A., 31 January - 2 February 2005.
- Somerton, W.H., et al., 1973. Thermal behavior of unconsolidated oil sands. SPE-4506, 48th Annual Fall Meeting of the Society of Petroleum Engineers, Las Vegas, NV.
- Somerton, W.H., et al., 1974. High temperature behavior of rocks associated with geothermal type reservoirs. SPE-4897, 44th Annual California Regional Meeting of the Society of Petroleum Engineers, San Francisco, CA.
- Tang, L., X. Li, Z. Feng, G. Li, and S. Fan, 2007. Control Mechanisms for Gas Hydrate Production by depressurization in Different Scale Hydrate Reservoirs
- Takahashi, H., Yonezawa, T., Takedomi, Y., 2001. Exploration for Natural Hydrate in Nankai-Trough Wells Offshore Japan, *OTC 13040*, 2001 Offshore Technology Conference, Houston, Texas.
- Takahashi, H. and Y. Tsuji, 2005. Multi-Well Exploration Program in 2004 for Natural Hydrate in the Nankai-Trough Offshore Japan. OTC 17162, 2005 Offshore Technology Conference held in Houston, TX, U.S.A., 2–5 May 2005.
- Trofimuk, A.A., Cherskiy, N.V., Lebedev, V.S., Semin V.I., et al., 1973. *Geol. Geofiz.*, **2**, 3.
- Trofimuk, A.A., Cherskiy, N.V., Tsarev, V.P., 1977. *Future Supply of Nature-made Petroleum and Gas*, Meyer, R.F., ed., New York: Pergamon Press, 919.
- Tsuji, Y., Ishida, H., Nakamizu, M., Matsumoto, R. and Shimizu, S., 2004. Overview of the MITI Nankai Trough Wells: A milestone in the evaluation of methane hydrate resources, *Resource Geology* **54**, 3-10.
- Uchida, T., Lu, H., Tomaru, H. and the MITI Nankai Trough Shipboard Scientists, 2004. Subsurface occurrence of natural gas hydrate in the Nankai Trough area: Implication for gas hydrate concentration, *Resource Geology* **54**, 35-44.
- Waite, W., deMartin, B., Kirby, S., Pinkston, J., and Ruppel, C., 2002. Thermal conductivity measurements in porous mixtures of methane hydrate and quartz sand, *Geophysical Research Letters*, **29** (24), 2229, doi:2210.1029/2002GL015988.
- Waite, W., Winters, W., and Mason, D., 2004. Methane hydrate formation in partially water-saturated Ottawa sand, *American Mineralogist*, **89**, 1202–1207.
- Warner, H.R. (Editor), 2007. Petroleum Engineering Handbook, Vol. 6 - Emerging and Peripheral Technologies, Society of Petroleum Engineers, 621 p. Wilder, J., Anderson, B., Collett, T., Hunter, R., Kurihara, M., Masuda, Y., McGrail, P. Moridis, G., Narita, H., Pooladhi-Darwish, M. White, M., and Wilson, S., 2007. International methane hydrate code comparison project simulates relevant problems, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter*, Winter 2007. (<http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsWinter07.pdf>).
- Winters, W., Pecher, I., Waite, W., and Mason, D. 2004. Physical properties and rock physics models of sediment containing natural and laboratory-formed methane gas hydrate, *American Mineralogist*, **89** (8-9), 1221-1227.
- Yun, T., J. Santamarina, and Ruppel C., 2007. Mechanical properties of sand, silt, and clay containing tetrahydrofuran hydrate, *J. Geophys. Res.*, **112**, B04106.

Zhang, H., S. Yang, N. Wu, X. Su, M. Holland, P. Schultheiss, K. Rose, H. Butler, G. Humphrey, and GMGS-1 Science Team, 2007. Successful and surprising results for China's first gas hydrate drilling expedition, *Fire In The Ice, NETL Methane Hydrates R&D Program Newsletter*, Fall 2007. (<http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsFall07.pdf>).

**Table 1. Estimates of *In Situ* Methane Hydrates (Sloan and Koh, 2008)**

<b>Year</b>	<b>CH<sub>4</sub> amount 10<sup>15</sup> m<sup>3</sup> STP</b>	<b>Citation</b>
1973	3053	Trofimuk et al.
1977	1135	Trofimuk et al.
1982	1573	Cherskiy et al.
1981	120	Trofimuk et al.
1981	3.1	Mclver
1974/1981	15	Makagon
1982	15	Trofimuk et al.
1988	40	Kvenvolden and Claypool
1988	20	Kvenvolden
1990	20	MacDonald
1994	26.4	Gornitz and Fung
1995	45.4	Harvey and Huang
1995	1	Ginsburg and Soloviev
1996	6.8	Holbrook et al.
1997	15	Makogon
2002	0.2	Soloviev
2004	2.5	Milkov
2005	120	Klauda and Sandler

**Table 2. Estimates of Relative Hydrated Methane in the Permafrost and the Ocean (Sloan and Koh, 2008)**

Permafrost hydrated methane ( $10^{14} \text{ m}^3$ )	Oceanic hydrated methane ( $10^{16} \text{ m}^3$ )	References
0.57	0.5–2.5	Trofimuk et al. (1977)
0.31	0.31	Mclver (1981)
340	760	Dobrynin et al. (1981)
1.0	1.0	Makogon (1988)
7.4	2.1	MacDonald (1990)

**Table 3 – Comparison of geomechanical behavior for different types of host sediments (Rutqvist and Moridis, 2007)**

Parameter	Toyoura sand	Clay	Berea Sandstone
Minimum Compressive Reservoir Stress $\sigma_{min}$ (MPa)	-12	-21	-9
Maximum Compressive Reservoir Stress $\sigma_{max}$ (MPa)	-40	-40	-40
Magnitude of settlement of the ocean floor $U_z$ (m)	0.8	4.3	0.05
Yielding within the HBS	Yes	Yes	No
Borehole instability	Yes	Yes	Yes

Thickness of the hydrate-bearing formation = 18.25 m



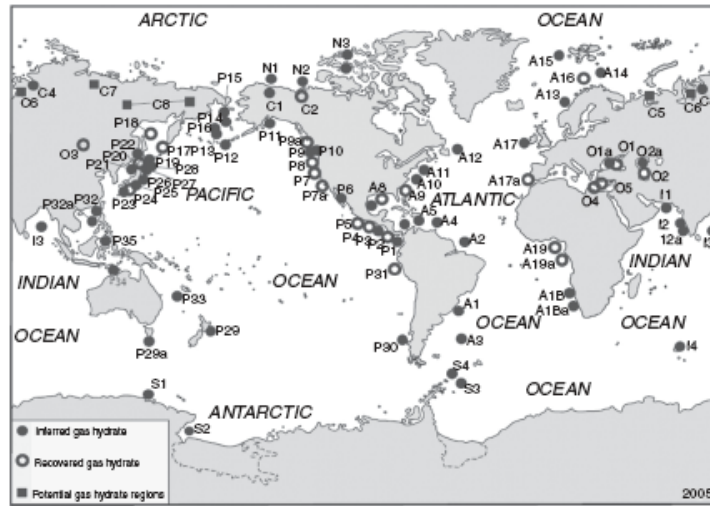


Figure 1 – Inferred (63), recovered (23), and potential (5) hydrate locations in the world (Kvenvolden, 2005).

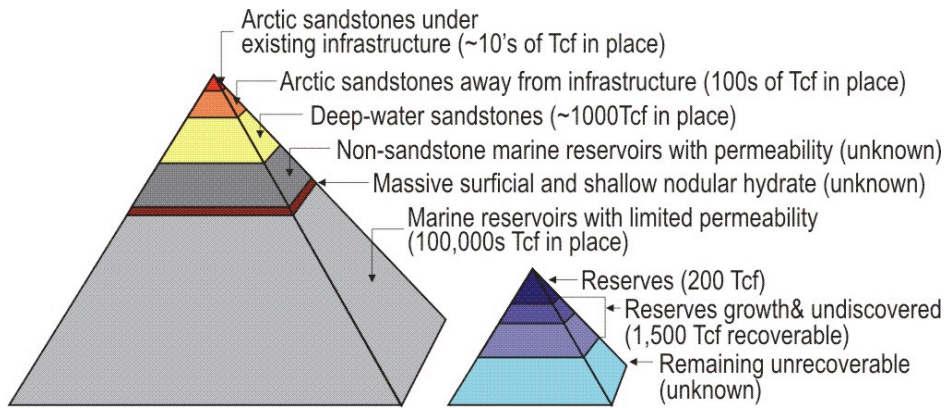


Figure 2 – Gas Hydrates Resource Pyramid (left). To the right is an example gas resources pyramid for all non-gas-hydrate resources (Boswell and Collett, 2006).

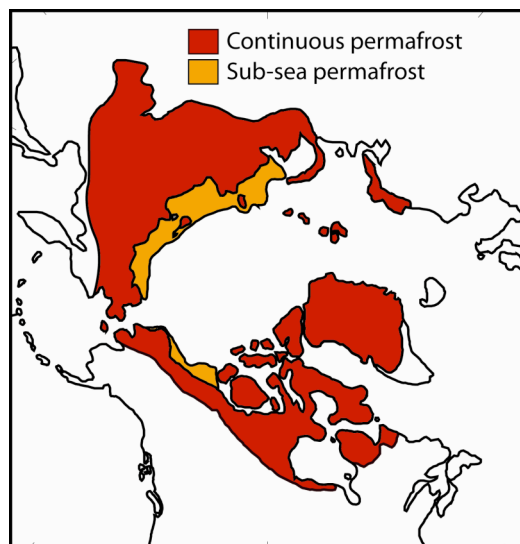
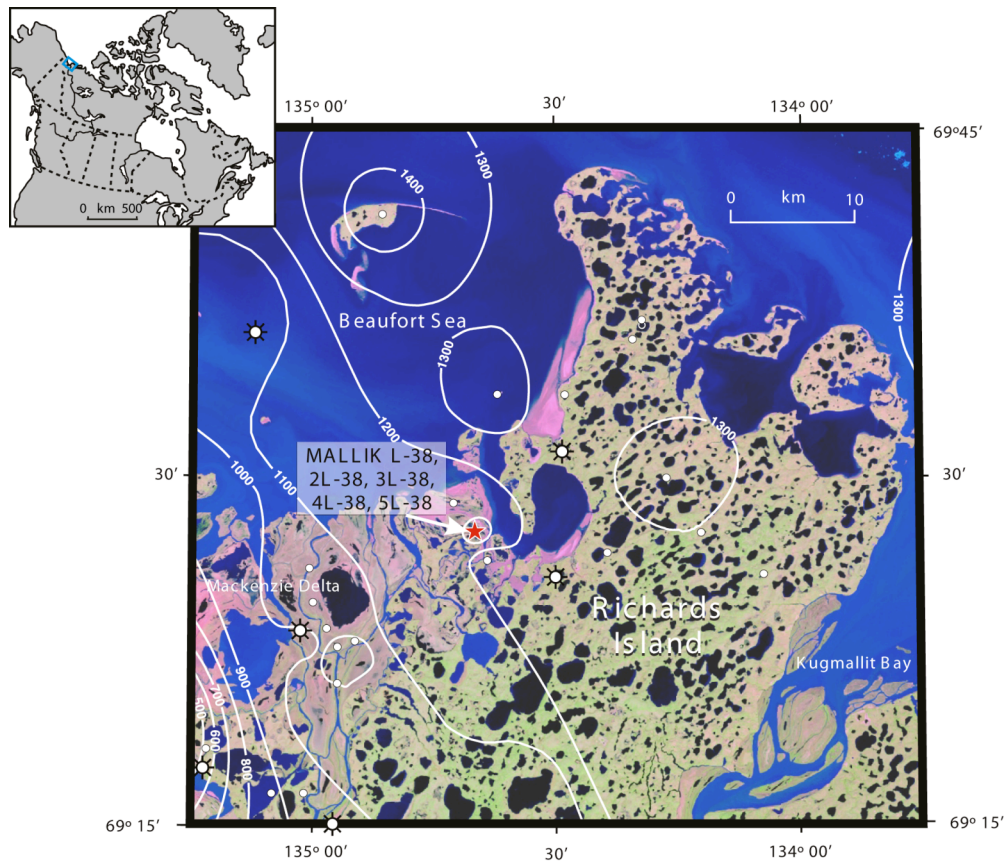
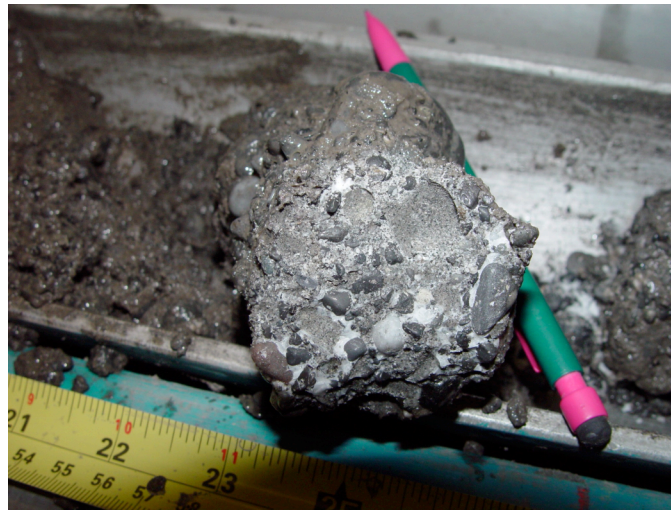


Figure 3 – Distribution of permafrost in the Northern Hemisphere (Collett, 1993).



**Figure 4 – Location of the wells during the 2002 field test at the Mallik site, Mackenzie Delta, Northwest Territories. The base map is a false-color mosaic constructed from a Landsat V image taken July 8, 2002. Contours indicate depth to the base of the gas hydrate stability zone in meters. Symbols include small circles as well locations, larger circles with ticks are wells containing gas hydrate (Dallimore and Collett, 2005).**



**Figure 5 – Photograph of a gas-hydrate-bearing rock core from the Mallik 5L-38 Gas Hydrate Research Well. Note that the gas hydrate is the white material filling the void spaces in this conglomerate (photo courtesy of the Mallik 2002 Gas Hydrate Production Research Well Program - Dallimore and Collett, 2005).**



# Mallik 5L-38 Thermal Test CHFR-RST

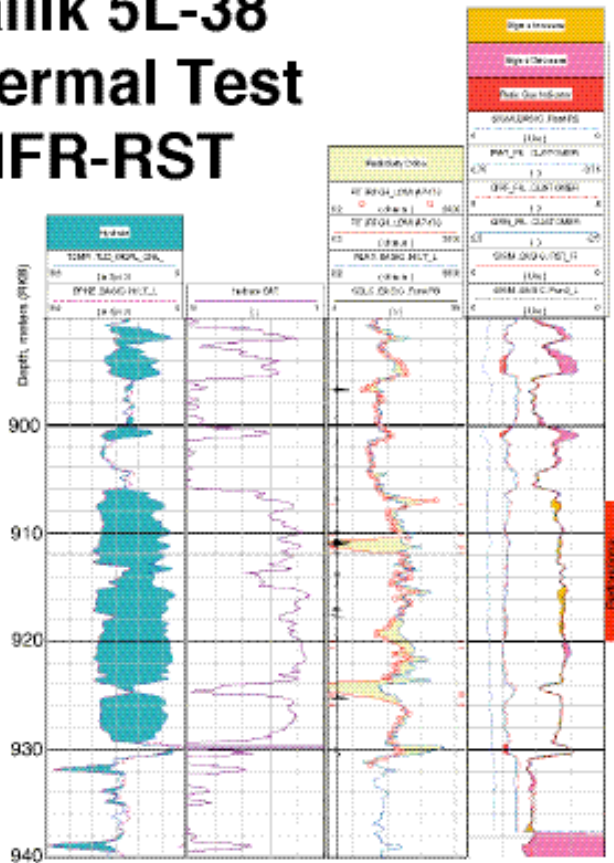


Figure 6 – Geophysical well logs indicating the presence and saturation of gas hydrates in the thermal test zone of the Mallik 5L-28 research well (Dallimore and Collett, 2005).

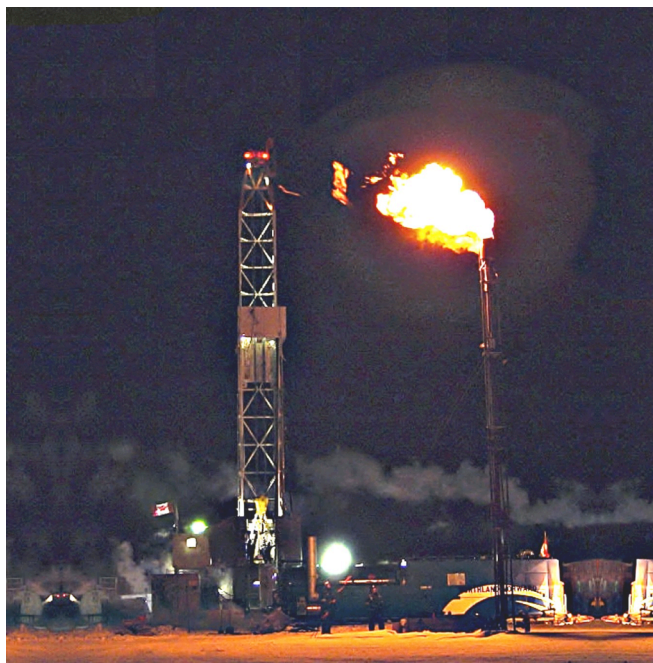


Figure 7 – Photograph of the gas flare from the thermal gas hydrate production test in the Mallik 5L-38 Gas Hydrate Research Well (photo courtesy of the Mallik 2002 Gas Hydrate Production Research Well Program - Dallimore and Collett, 2005).

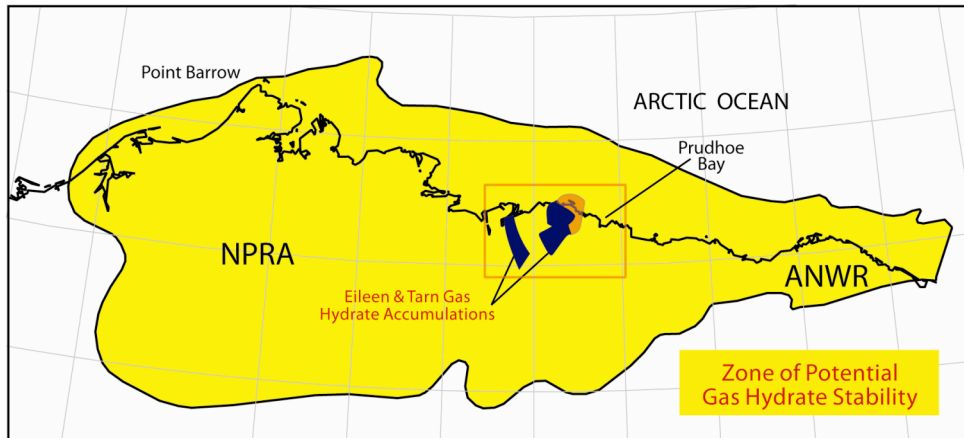


Figure 8 – Map of the Alaska North Slope gas hydrate stability zone. Also shown is the location of the Eileen and Tarn gas hydrate accumulations (Collett, 1993).

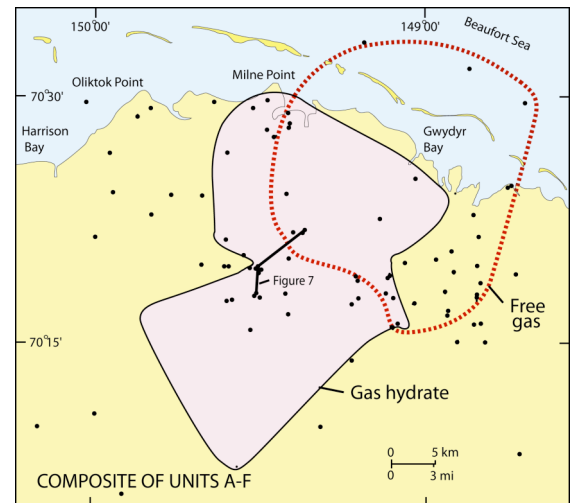
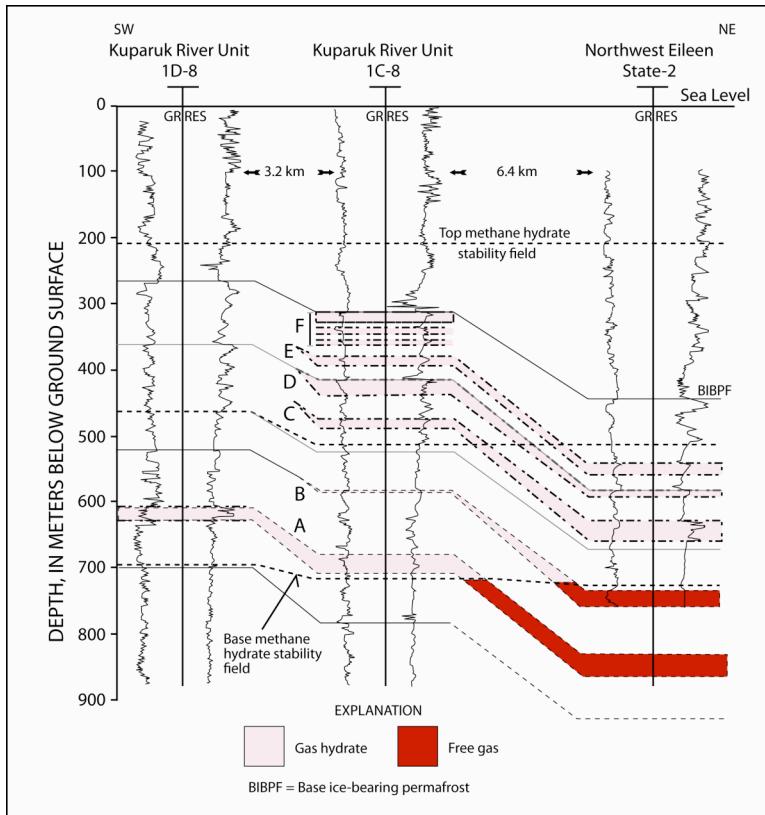


Figure 9 – (a) Cross section showing the lateral and vertical extent of gas hydrates and underlying free-gas occurrences in the Prudhoe Bay-Kuparuk River area in northern Alaska. See Figure 9b for location of cross section. The gas-hydrate-bearing units are identified with the reference letters A through F (Collett, 1993); (b) Composite map of all six gas-hydrate/free-gas units (Units A-F) from the Prudhoe Bay-Kuparuk River area in northern Alaska (Collett, 1993).



Figure 10 – Drilling rig at Milne Point, February 2007 (Mount Elbert, 2007).



Figure 11 – Gas hydrate-bearing sand core and sample from the Mount Elbert deposit (Mount Elbert, 2007).

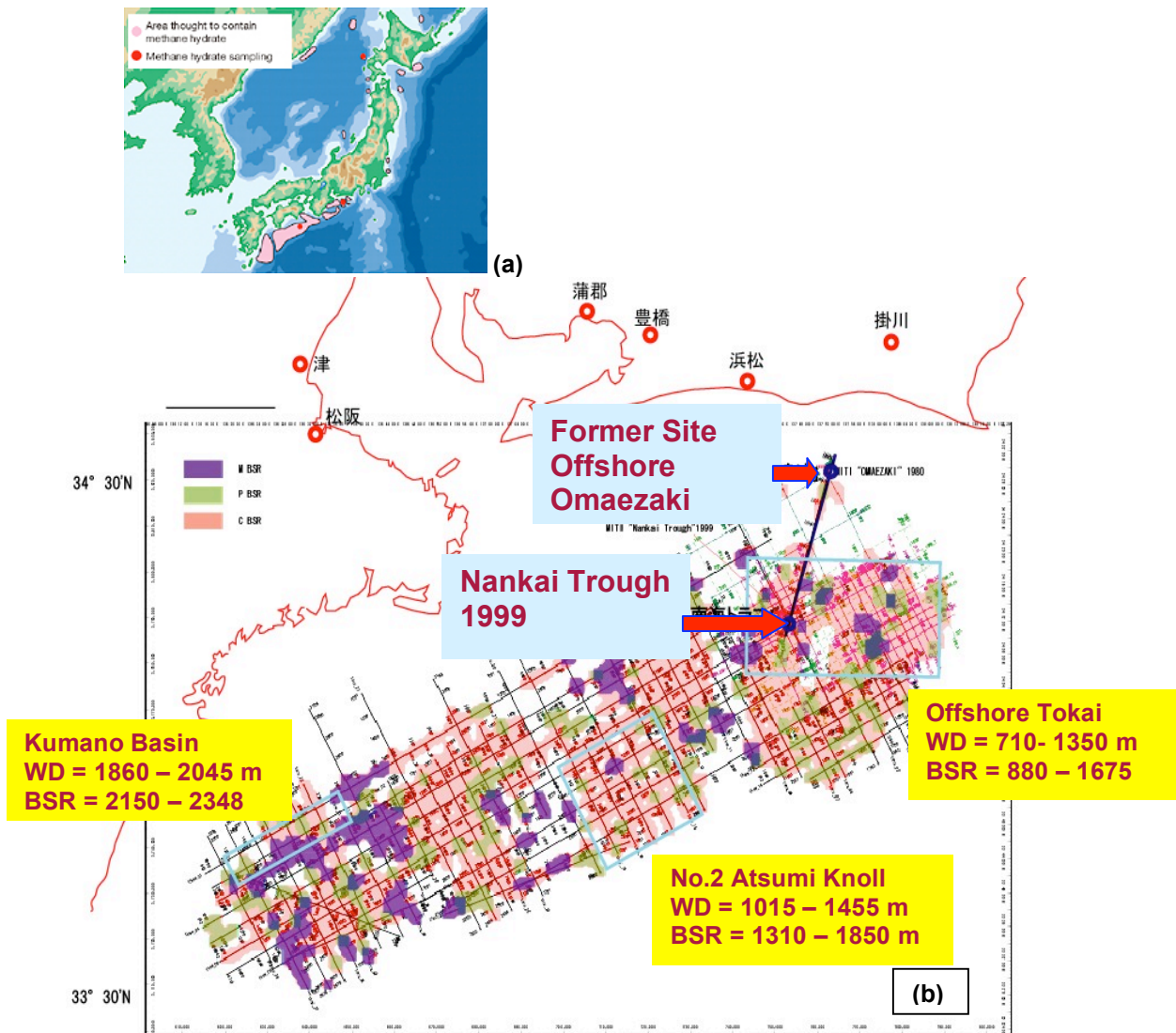


Figure 12 – (a) The hydrate deposit areas in the Nankai Trough region offshore Japan; (b) The drilling sites of the 2004 Drilling Program (Takahashi and Tsuji, 2005).



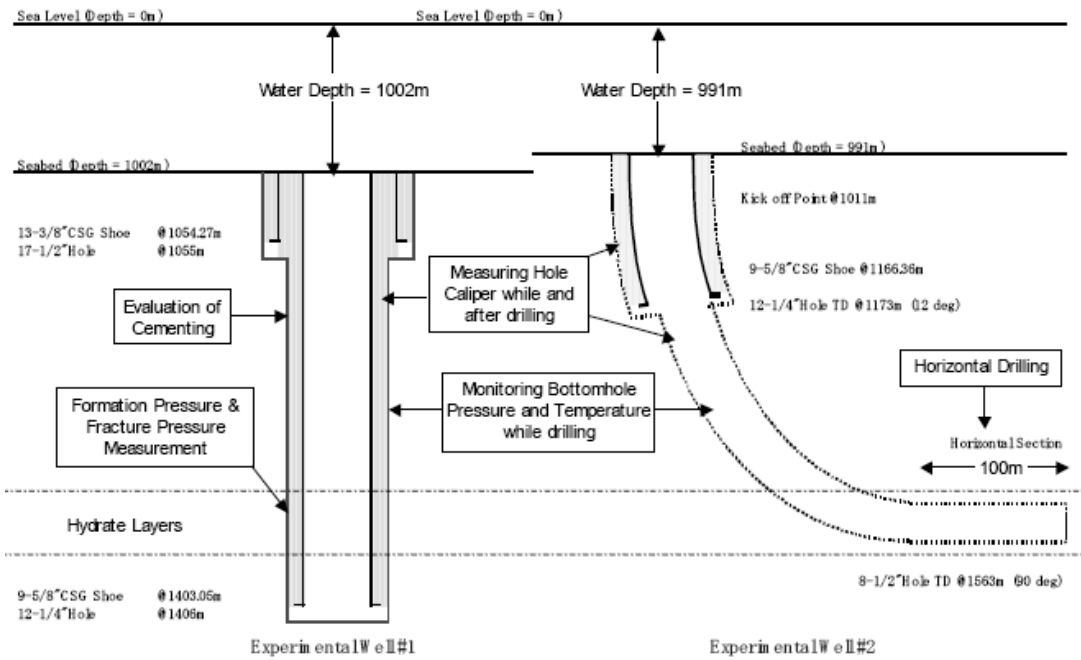


Figure 13 – Two experimental well designs investigated in the 2004 Drilling Program in the Nankai Trough (courtesy of Takahashi and Tsuji, 2005).

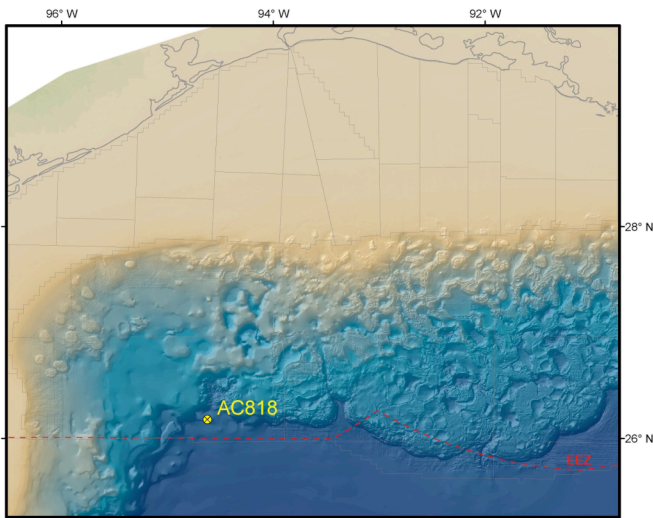


Figure 14 – Approximate location of the “Tigershark” exploratory well in the Alaminos Canyon block 818 (Smith et al., 2008).

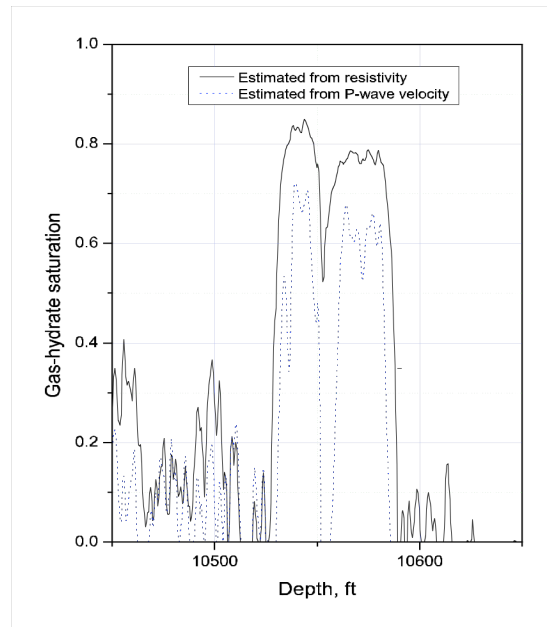


Figure 15 – Hydrate saturation  $S_H$  in Oligocene Frio sand – Alaminos Canyon Block 818 (Collett and Lee, 2006).

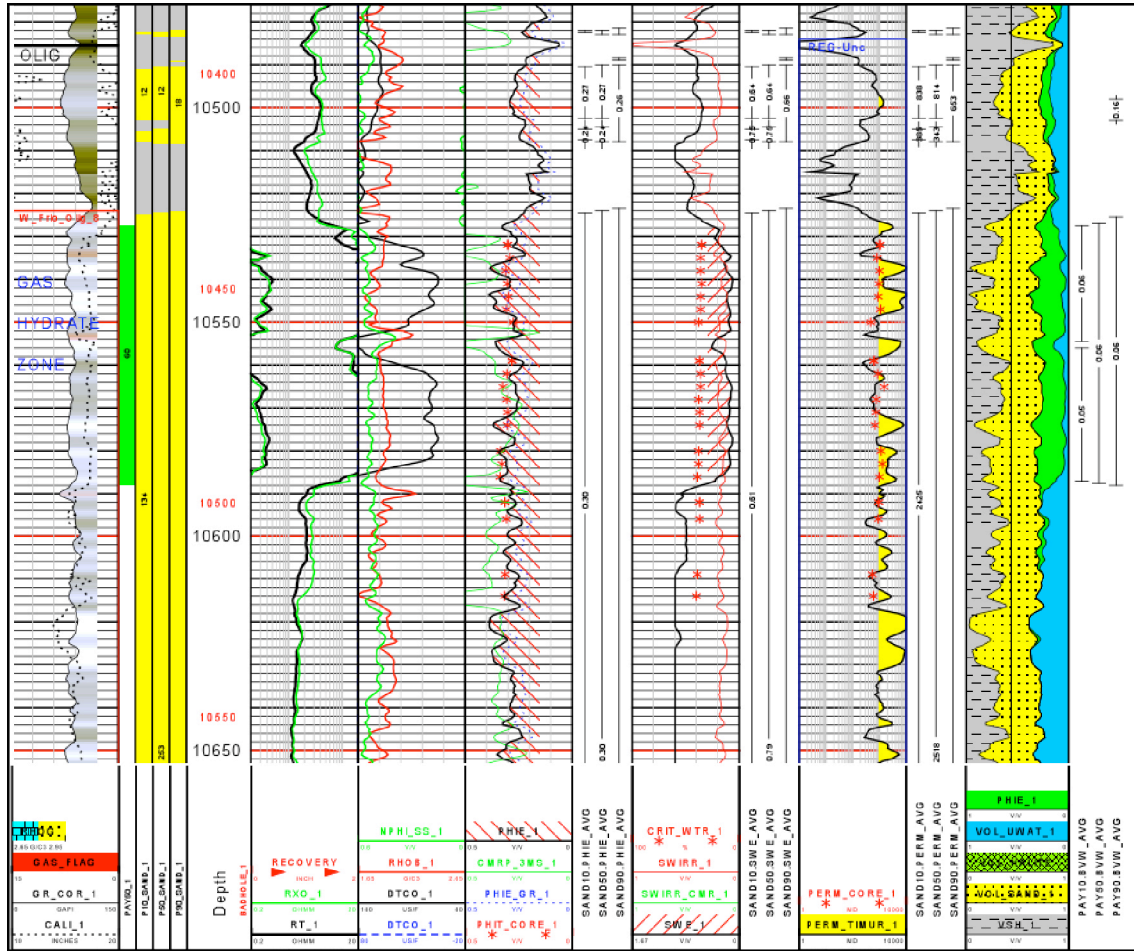


Figure 16 – Well log montage showing data collected over the Frio gas hydrate-bearing sand at Alaminos Canyon Block 818 (from Smith et al, 2006)

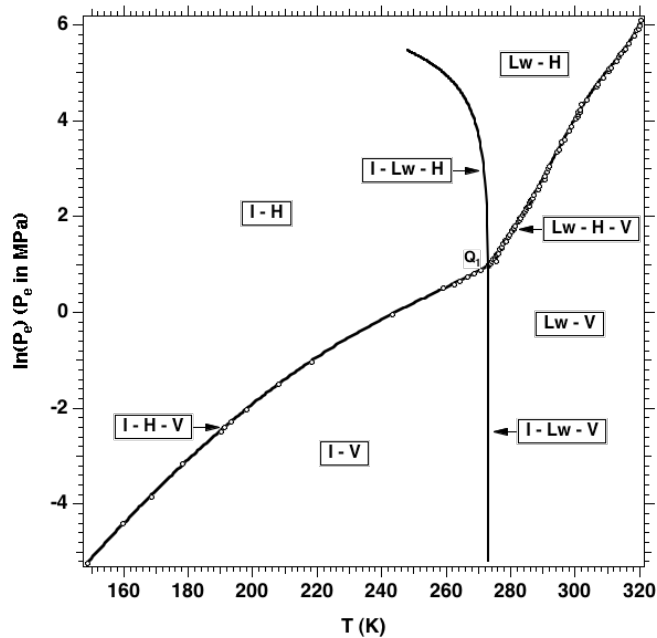


Figure 17 – Pressure-temperature equilibrium relationship in the phase diagram of the water-CH<sub>4</sub>-hydrate system (Moridis, 2003), Lw: Liquid water; H: Hydrate; V: Vapor (gas phase); I: Ice; Q<sub>1</sub>: Quadruple point = I + Lw + H + V

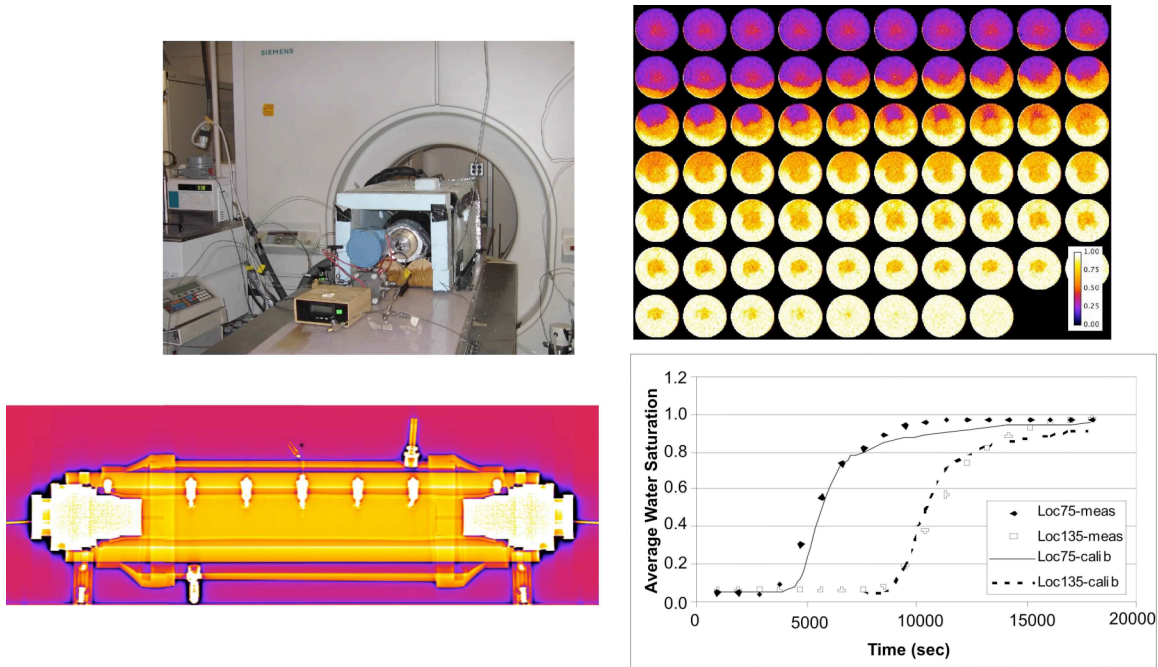


Figure 18 – Relative permeability equipment and method in the LBNL study. Top left – Flow-through x-ray transparent pressure vessel mounted on x-ray CT scanner, Bottom left – x-ray scan of the pressure vessel, Top right – Sequential CT scans of a single hydrate bearing location during a waterflood (higher densities are brighter and show where the water is flowing), Bottom right – Data from scans above and best fit curves.

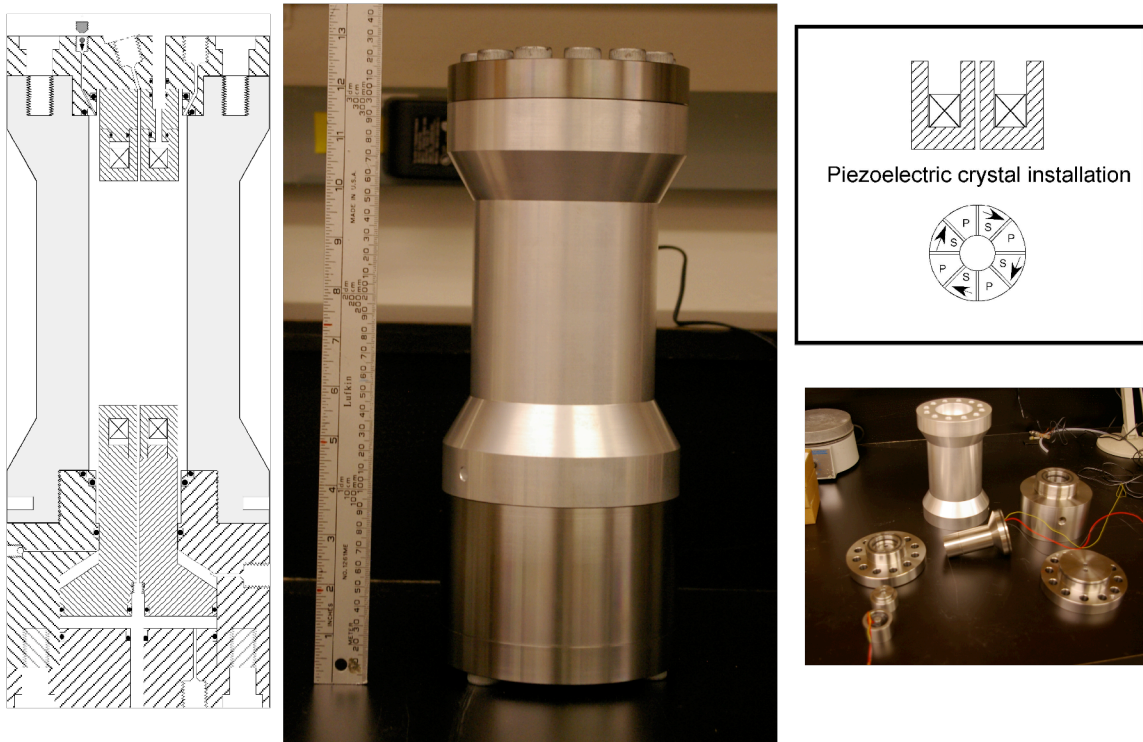


Figure 19 – The LBNL Hydrate Geomechanical Test Cell.

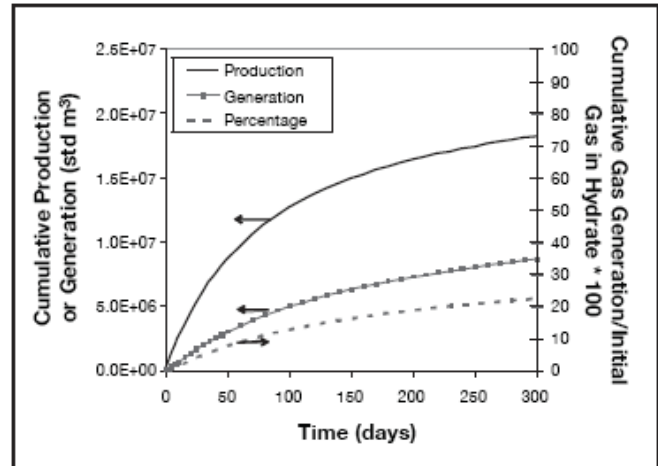
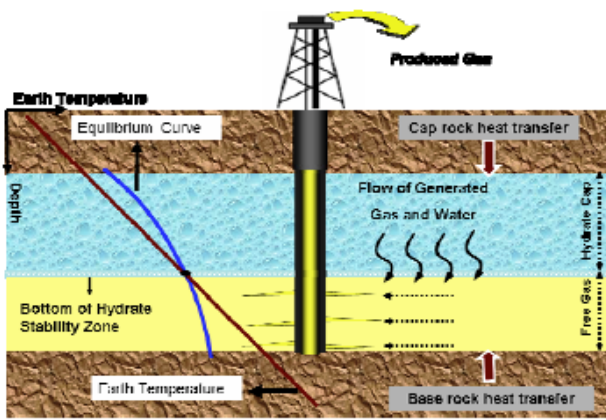


Figure 20 – Left: A schematic of a Class 1 system. Right: Comparison between cumulative gas production and the cumulative volume released from hydrate dissociation (courtesy of Hong and Pooladi-Darwish, 2005).

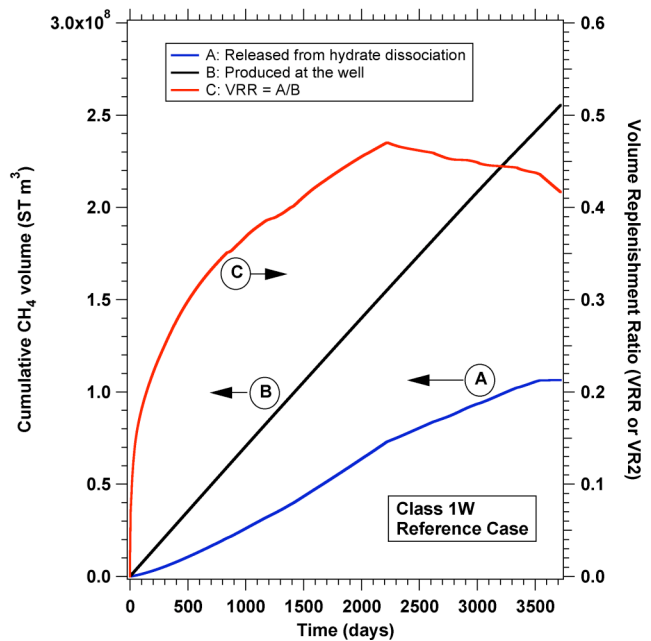
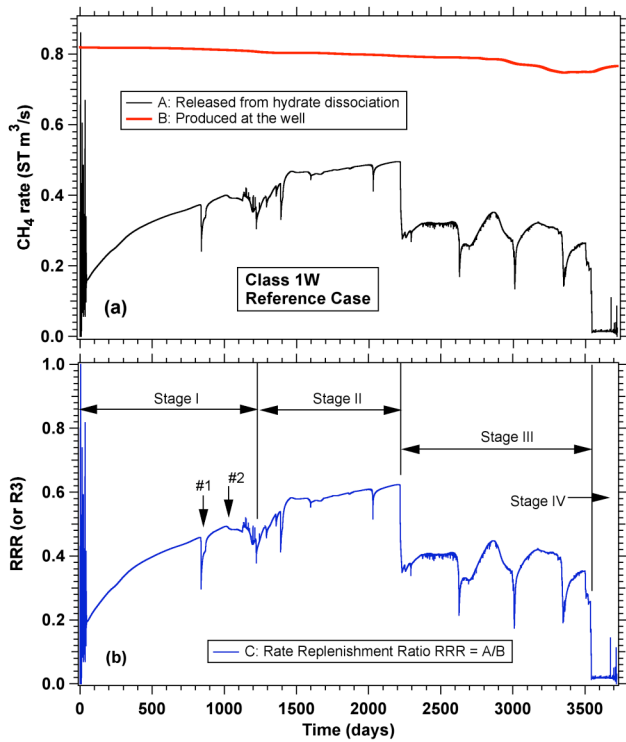


Figure 21 – Left: Evolution of (A) the rate of CH<sub>4</sub> release from hydrate dissociation, (B) the rate of CH<sub>4</sub> production at the well, and (C) the corresponding RRR during long term production from a Class 1W hydrate deposit. Right: Evolution of (A) the CH<sub>4</sub> volume released from hydrate dissociation, (B) the CH<sub>4</sub> volume produced at the well, and (c) the corresponding VRR during long term production (Moridis et al., 2007).



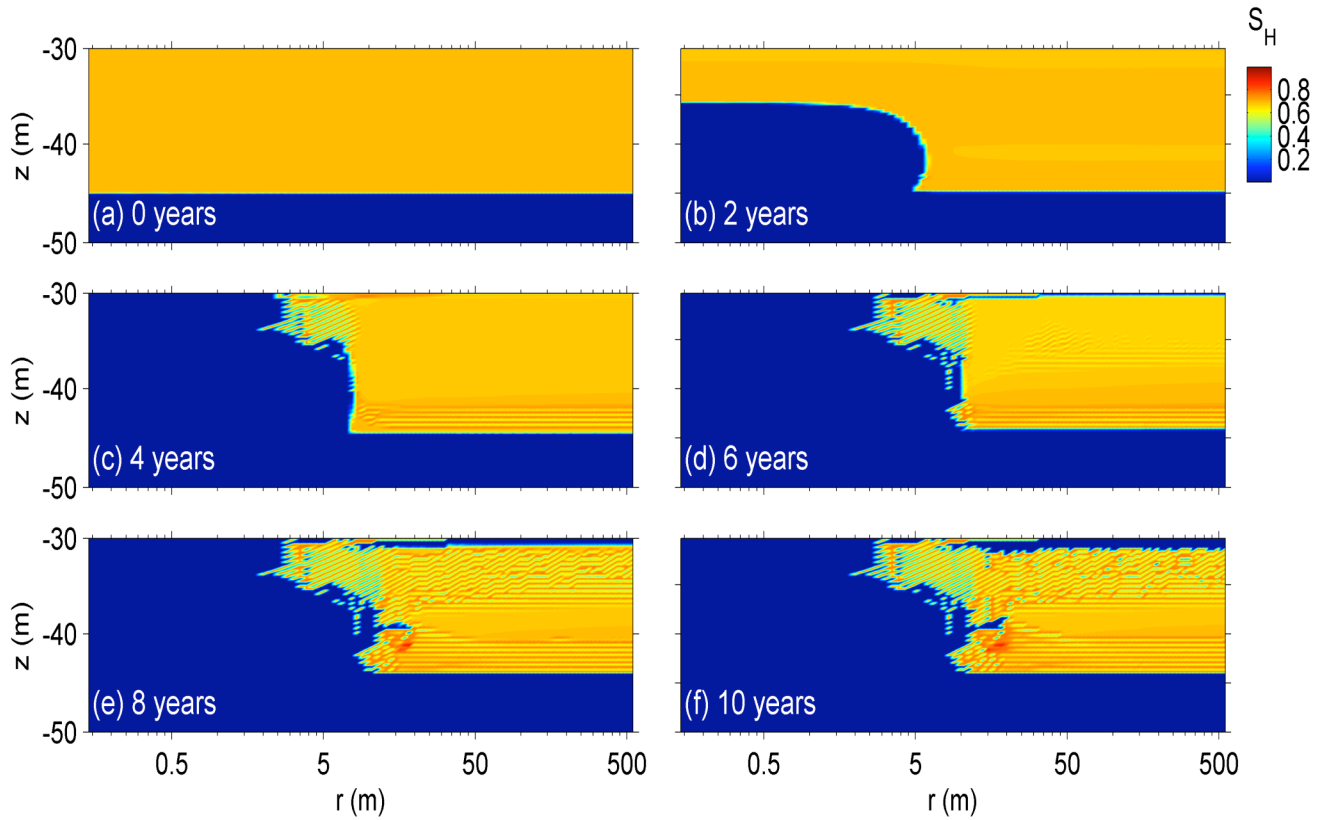


Figure 22 – Evolution of the hydrate saturation distribution in a Class 1W hydrate deposit of Problem 1 during depressurization (Moridis et al., 2007).

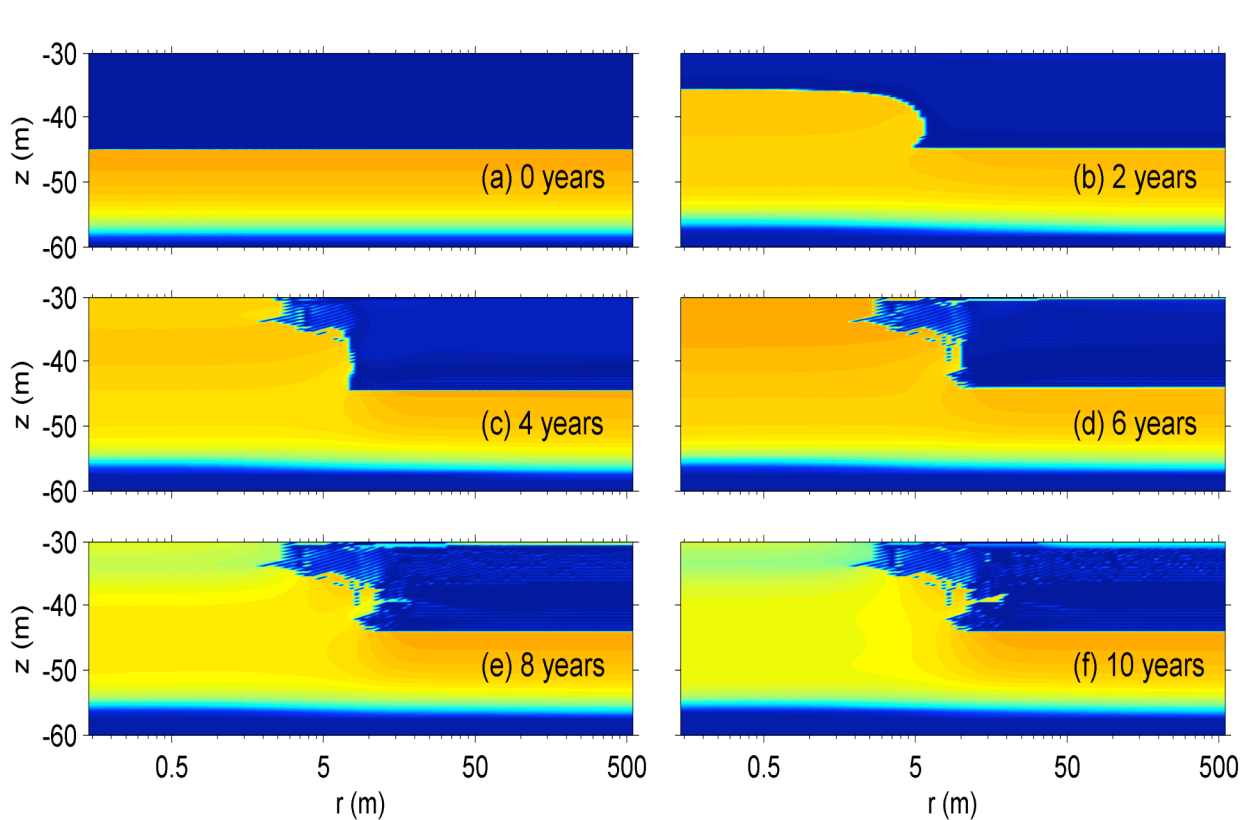


Figure 23 – Evolution of the gas saturation distribution in a Class 1W hydrate deposit of Problem 1 during depressurization (Moridis et al., 2007).

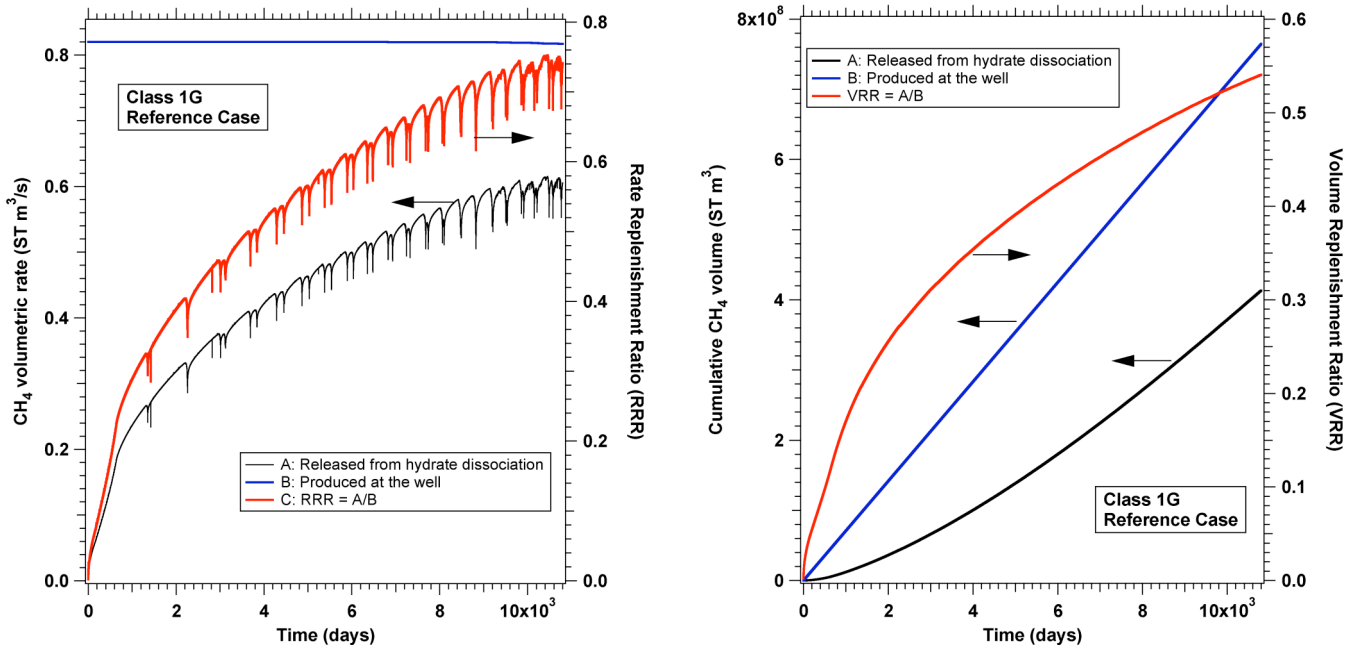


Figure 24 – Class 1G; Left: Evolution of (a) the rate of CH<sub>4</sub> release from hydrate dissociation, (b) the rate of CH<sub>4</sub> production at the well, and (c) the corresponding RRR over the 30-yr production period. Right: Evolution of (a) the cumulative CH<sub>4</sub> volume released from hydrate dissociation, (b) the produced CH<sub>4</sub> volume at the well, and (c) the corresponding VRR over the 30-yr production period (Moridis et al., 2007).

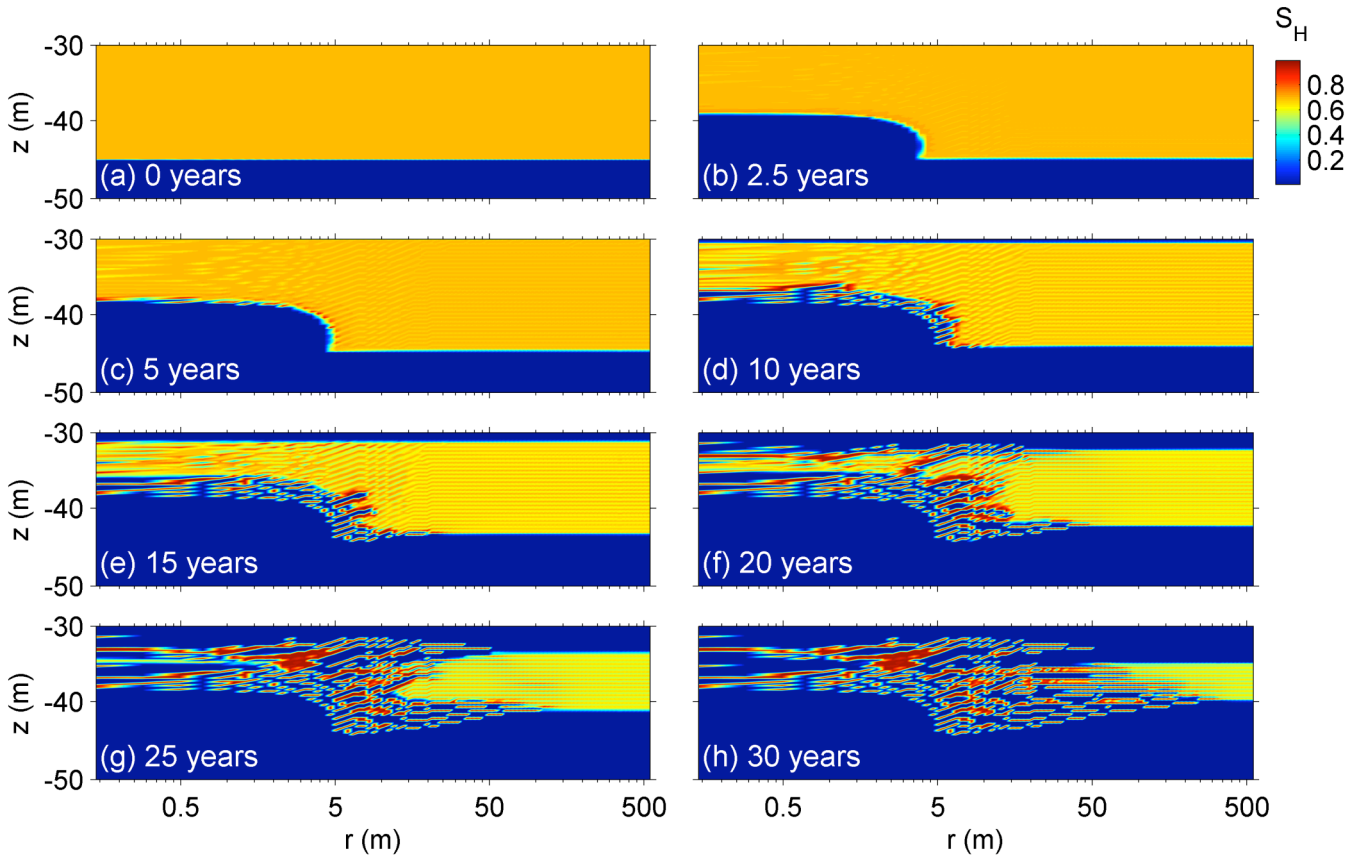


Figure 25 – Evolution of the hydrate saturation distribution in a Class 1G hydrate deposit during depressurization (Moridis et al., 2007).

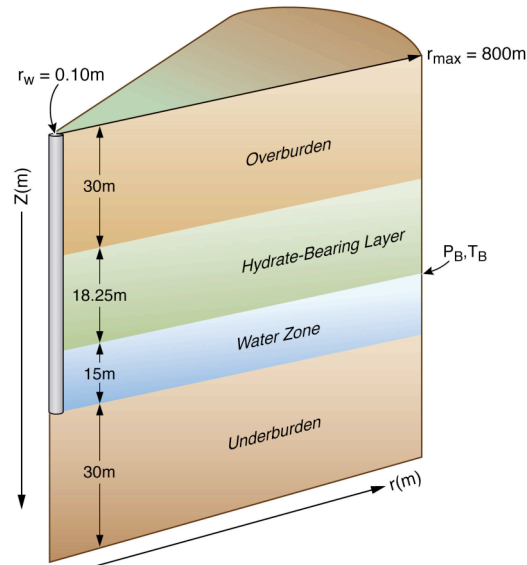


Figure 26 – A schematic of the Class 2 oceanic hydrate deposit simulated in the Moridis and Reagan (2007a) study.

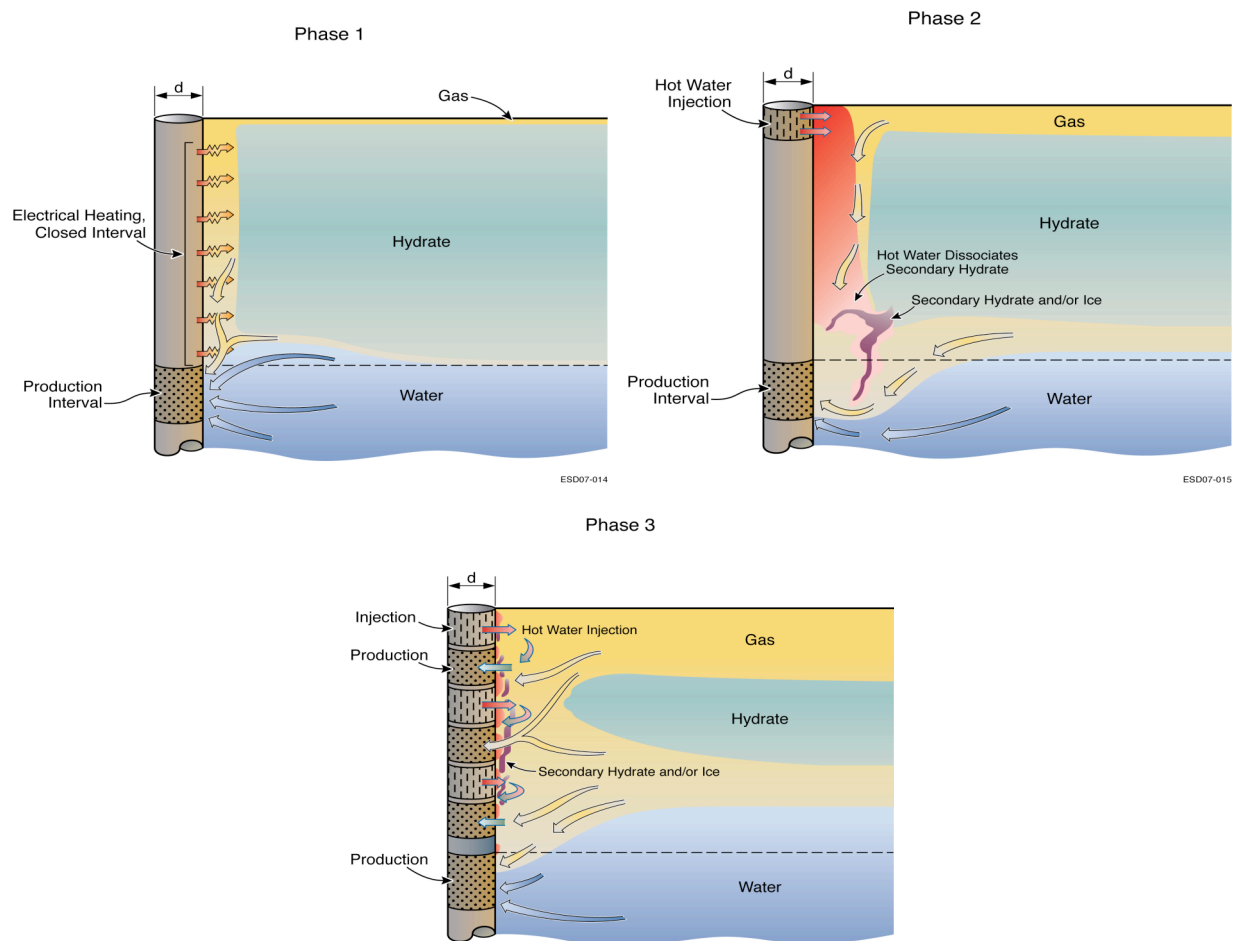


Figure 27 – Proposed well design for production from Class 2 hydrates. Phase 1, initial production stages. The production interval begins at the HBL and extends into the WZ, while the outer surface of the wellbore in contact with the HBL is heated. Phase 2: Well design used in the early and intermediate production. Warm water injected into the formation at the top of the HBL. Phase 3: Well design used in the late stages of production. The system involves thin alternating zones of production and warm water injection (Moridis and Reagan, 2007a).

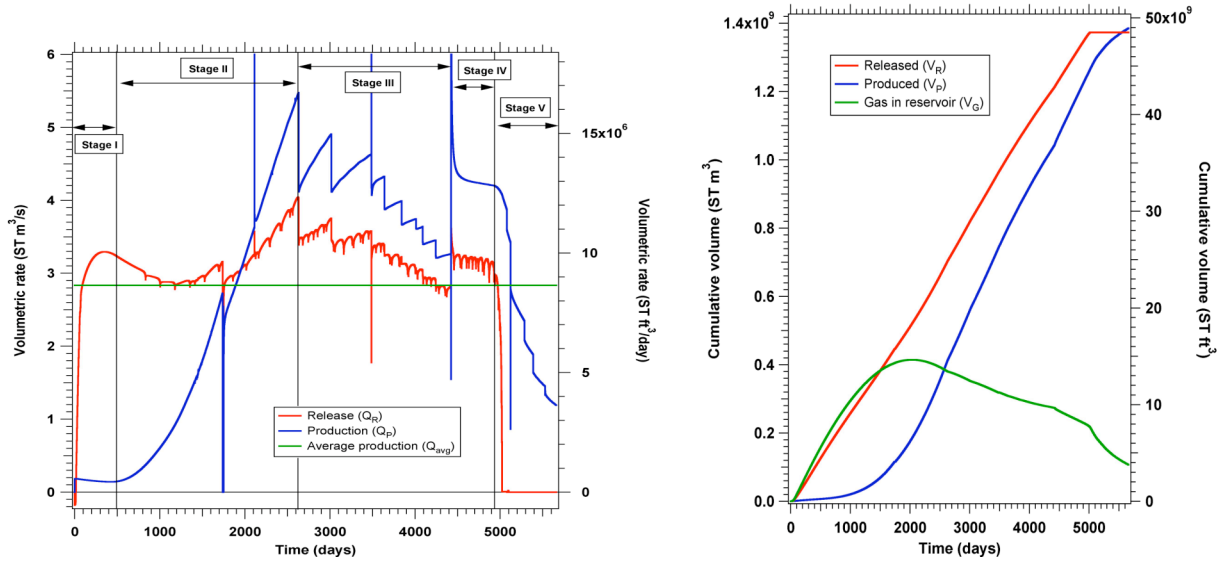


Figure 28 – Left: Rates of (a) hydrate-originating CH<sub>4</sub> release in the reservoir ( $Q_R$ ) and (b) CH<sub>4</sub> production at the well ( $Q_P$ ) during production from a Class 2 oceanic hydrate deposit. The production stages and the average production rate ( $Q_{avg}$ ) over the simulation period (5,660 days) are also shown. Right: Cumulative volumes of (a) hydrate-originating CH<sub>4</sub> released in the reservoir ( $V_R$ ) and (b) produced CH<sub>4</sub> at the well ( $V_P$ ) during production from the same deposit (Moridis and Reagan, 2007a).

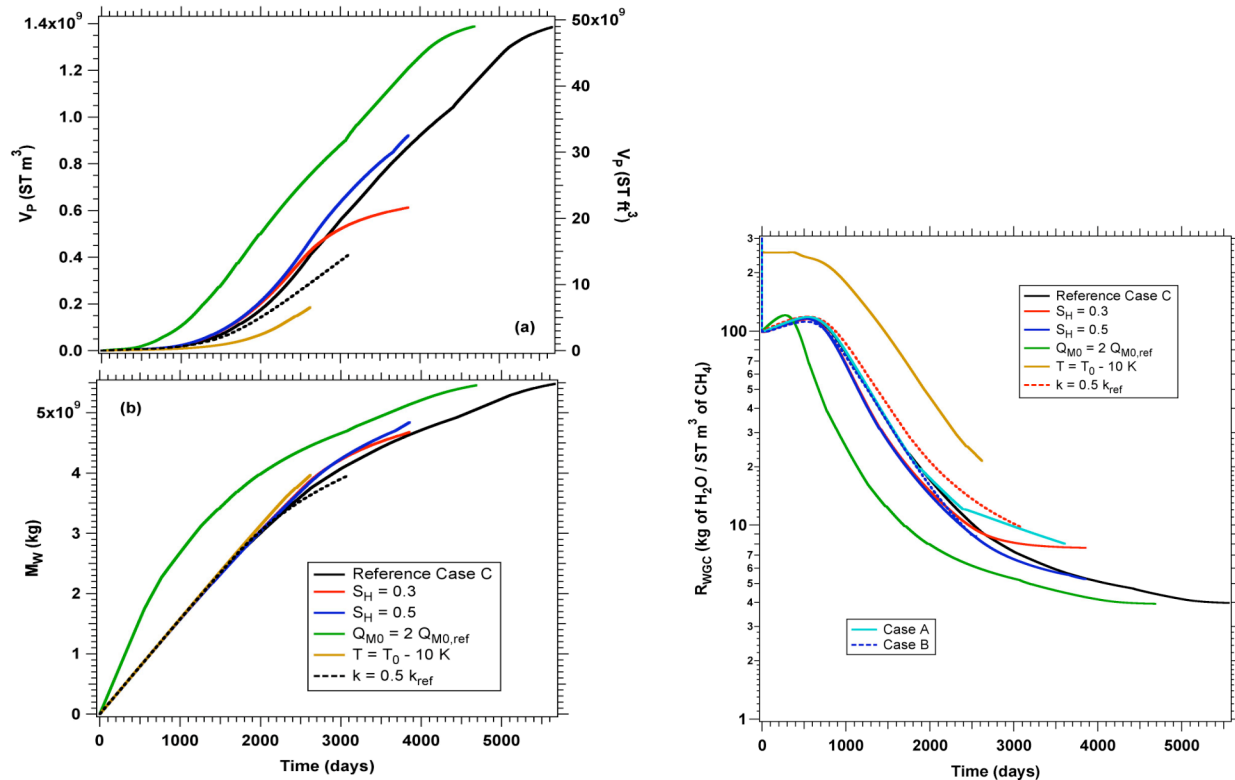


Figure 29 – Sensitivity analysis – Left: effect of various perturbation parameters on the evolution of  $V_P$  and  $M_W$  during production from a Class 2 oceanic hydrate deposit. Right: effect of various perturbation parameters on the evolution of the water-to-gas ratio  $R_{wgc}$  during production from the same deposit (Moridis and Reagan, 2007a).

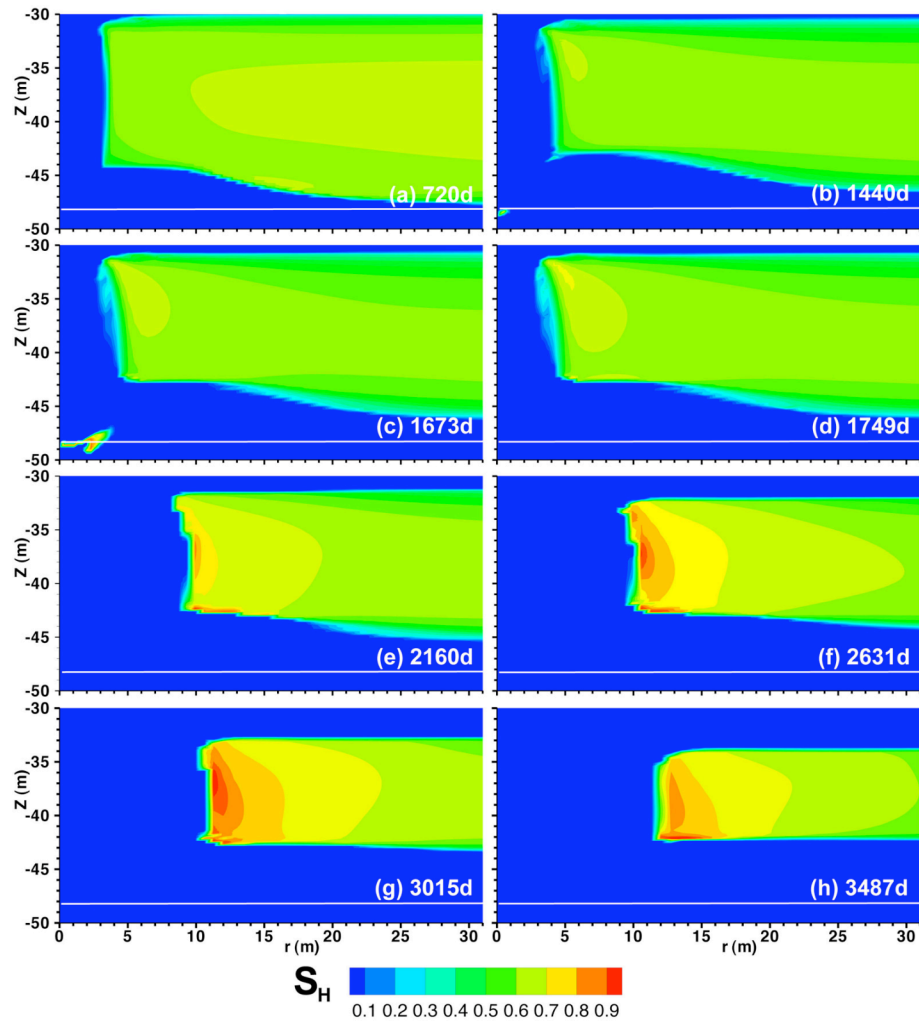


Figure 30 –Evolution of spatial distribution of  $S_H$  during gas production from a Class 2 oceanic hydrate deposit (Moridis and Reagan, 2007a).

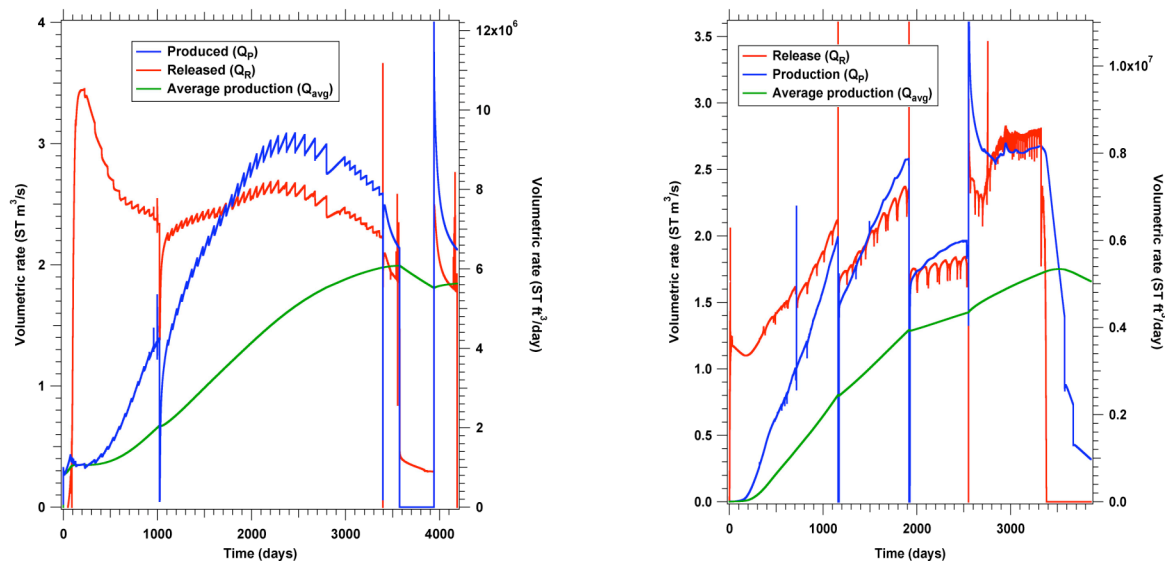


Figure 31 – Rates of (a) hydrate-originating  $\text{CH}_4$  release in the reservoir ( $Q_R$ ), (b)  $\text{CH}_4$  production at the well ( $Q_P$ ), and (c) average gas production rate. Left: Class 2 oceanic hydrate deposit in the Ulleung Basin (Moridis et al., 2007). Right: Class 2 permafrost deposit in the North Slope (Moridis and Reagan, 2007c).

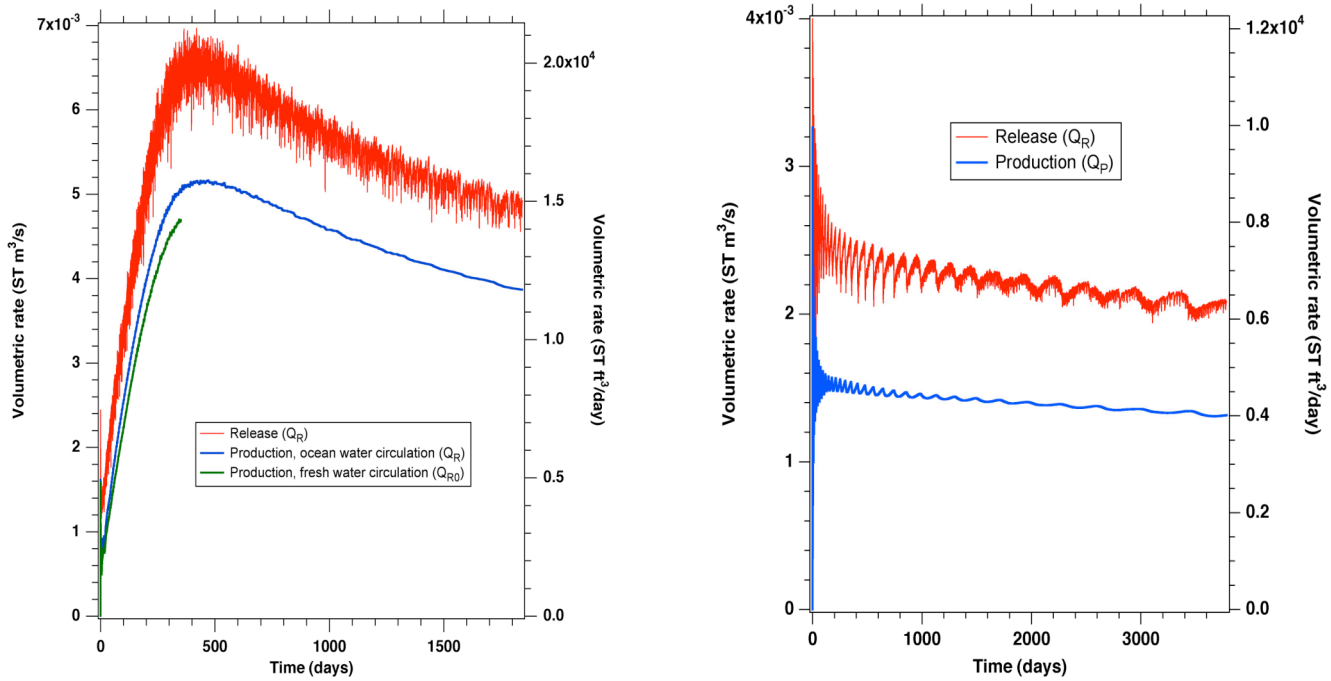


Figure 32 – Rates of (a) hydrate-originating CH<sub>4</sub> release in the reservoir ( $Q_R$ ) and (b) CH<sub>4</sub> production at the well ( $Q_P$ ) during production from a Class 3 oceanic hydrate deposit. Left: Warm water circulation. Right: Electrical heating (Moridis and Reagan, 2007b).

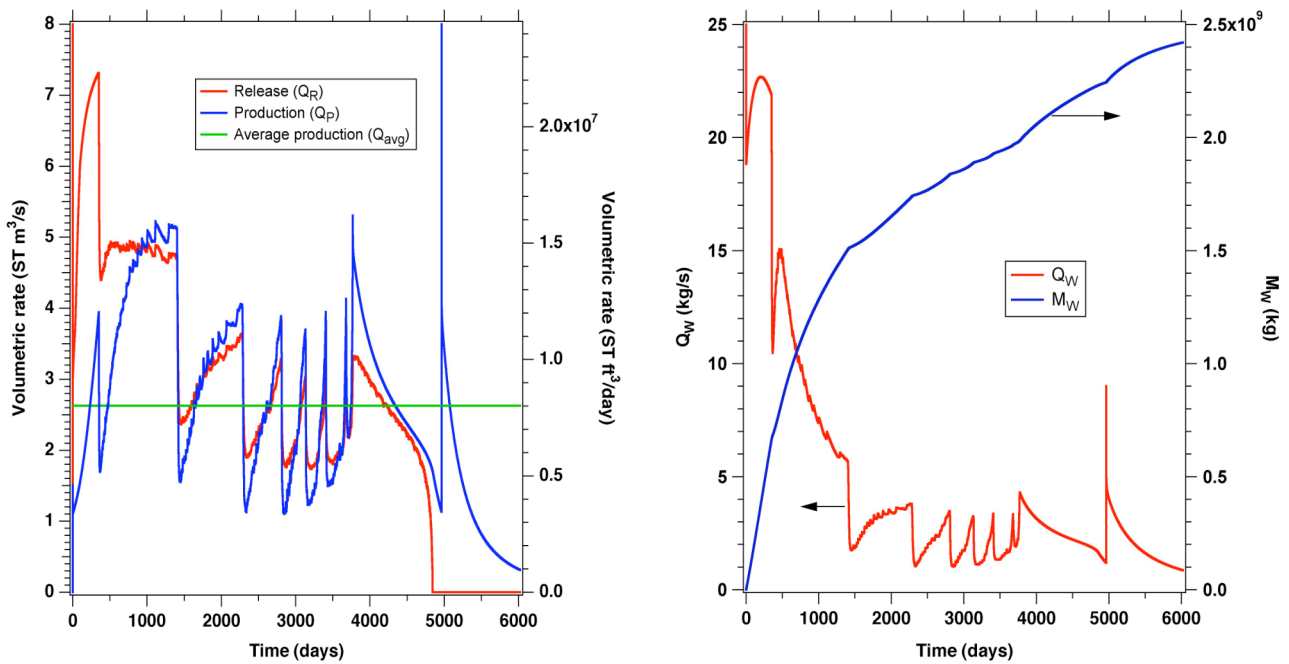


Figure 33 – Left: Rates of (a) hydrate-originating CH<sub>4</sub> release in the reservoir ( $Q_R$ ) and (b) CH<sub>4</sub> production at the well ( $Q_P$ ) during constant-P production from a Class 3 oceanic hydrate deposit. The average production rate ( $Q_{avg}$ ) over the simulation period (6000 days) is also shown. Right: (a) Rate of H<sub>2</sub>O production ( $Q_W$ ) and (b) cumulative mass of produced H<sub>2</sub>O ( $M_W$ ) during production from the same deposit (Moridis and Reagan, 2007b).

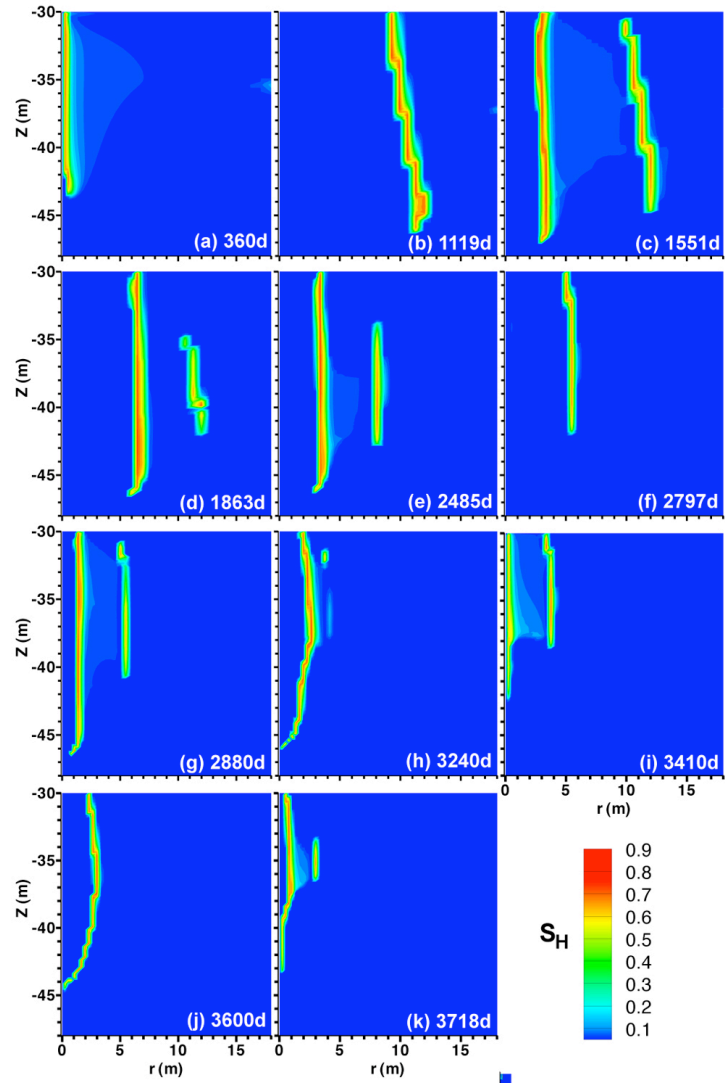


Figure 34 –Evolution of spatial distribution of  $S_H$  during constant-P gas production from a Class 3 oceanic hydrate deposit (Moridis and Reagan, 2007b).

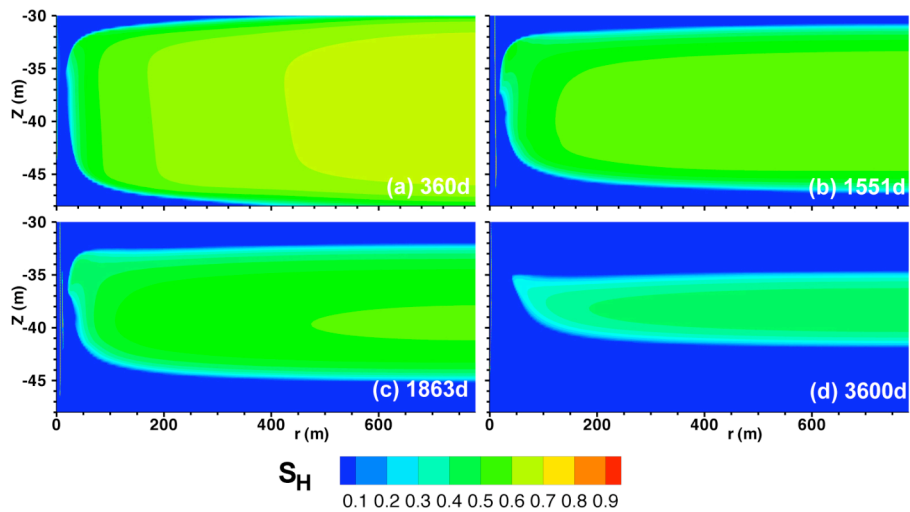


Figure 35 – Evolution of the  $S_H$  distribution over the entire Class 3 hydrate deposit of Figure 34 to demonstrate the uniformity of dissociation away from the critical near-well zone (Moridis and Reagan, 2007b).



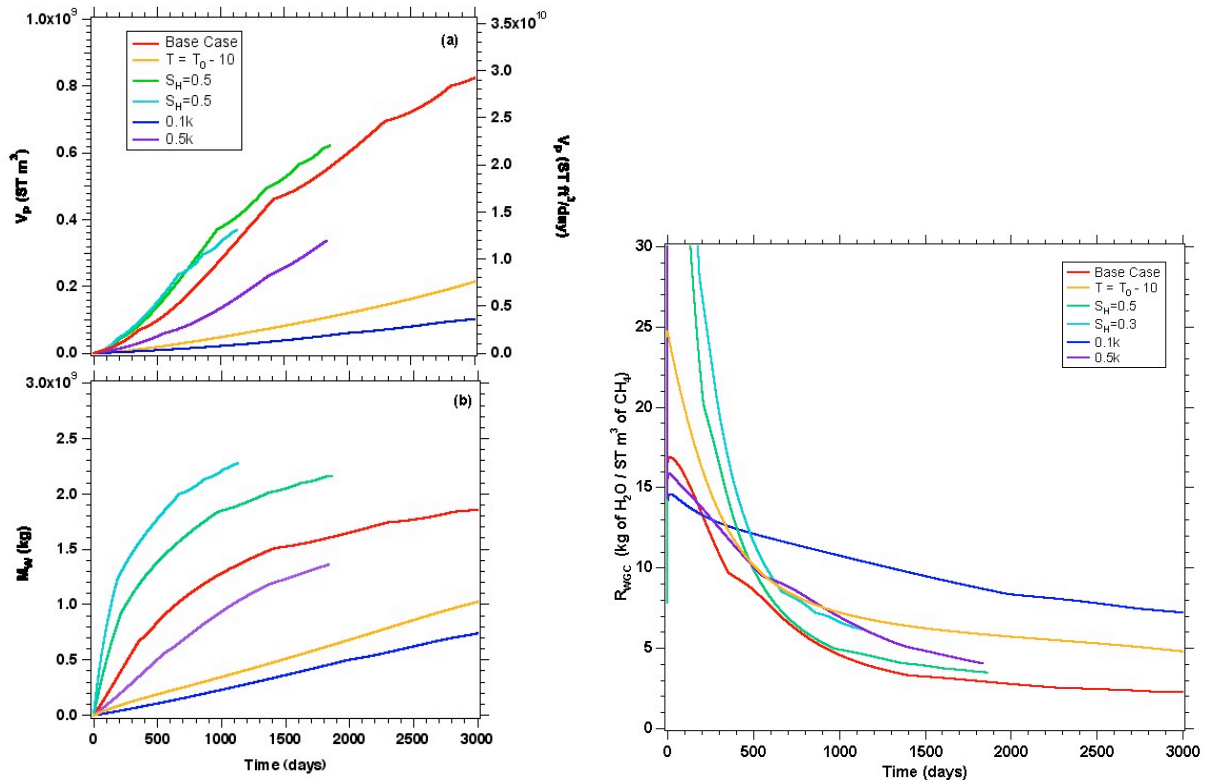


Figure 36 – Sensitivity analysis. Left: effect of various perturbation parameters on  $V_p$  and  $M_w$  during constant-P production from a Class 3 oceanic hydrate deposit. Right: effect of various perturbation parameters on the evolution of the cumulative water-to-gas ratio  $R_{wgc}$  during production from the same deposit (Moridis and Reagan, 2007b).

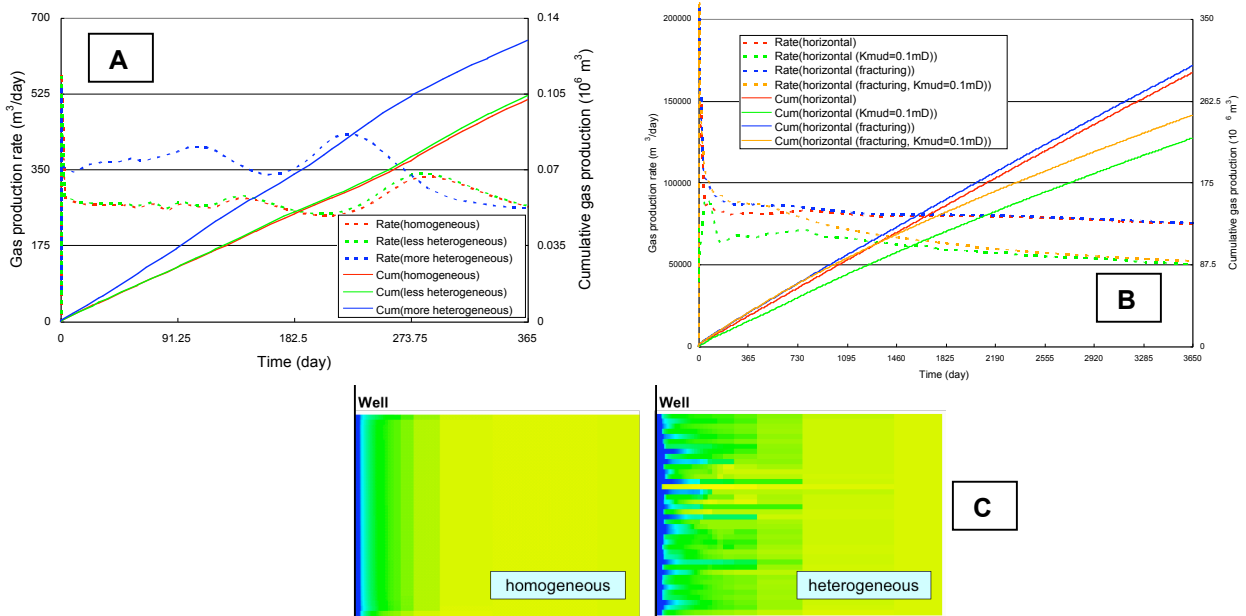


Figure 37 – Sensitivity to heterogeneity in a Class 3 deposit produced at constant pressure. A: Comparison of gas production rates and cumulative production volumes in three problems of various levels of permeability heterogeneity; B: Gas production rates and cumulative production volumes for various mudstone permeability and fracture regimes in a layered system; C:  $S_H$  saturation distribution at the end of the simulation period in the cases depicted in A (Kurihara et al., 2005b).