UNCONVENTIONAL FUELS PART II: THE PROMISE OF METHANE HYDRATES

OVERSIGHT HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES

OF THE

COMMITTEE ON NATURAL RESOURCES
U.S. HOUSE OF REPRESENTATIVES

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OVERSIGHT HEARING ON "UNCONVENTIONAL FUELS, PART II: THE PROMISE OF METHANE HYDRATES."

Thursday, July 30, 2009
U.S. House of Representatives
Subcommittee on Energy and Mineral Resources
Committee on Natural Resources
Washington, D.C.

The Subcommittee met, pursuant to call, at 10:07 a.m. in Room 1334, Longworth House Office Building, The Honorable Jim Costa [Chairman of the Subcommittee] presiding.

Present: Representatives Costa, Lamborn, Holt, Sablan, Heinrich, and Lummis.

STATEMENT OF HON. JIM COSTA, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF CALIFORNIA

Mr. COSTA. Good morning. The Subcommittee on Energy and Mineral Resources will now come to order. This morning we are having a continuum of a series of hearings that we have been holding as we look at various types of fuels, some refer to them as unconventional fuels, and the potential it has as we look at all the energy tools in our nation's energy toolbox to deal with the challenges that we face in the 21st Century. Clearly, a comprehensive energy package, in my mind, involves dealing with the near-term strategies, the mid-term and the longer term. Today's hearing, as it relates to the promise of methane hydrates, is the longer-term strategy as we look at the ability to try to come together with a comprehensive bipartisan energy policy that will take advantage of all the opportunities that I think are there.

Our first hearing on this series dealt with shale gas, a resource that is already considered to be conventional, and it has already become a major part of our nation's energy supply, but the situation a few decades ago was that shale gas was determined to be far more difficult to realize as a part of our energy portfolio. Obviously, in the last several decades, technologies have been developed that took that shale gas that previously was unaccessible and uneconomical, and now it is being utilized as a part of our energy resource. My sense is that potentially methane hydrates may follow in that same category.

Methane hydrates can be thought of roughly as natural gas. As it was explained to me, it is frozen and it is found in many places frozen in ice, not only in terms of the Arctic, but also under the permafrost in the Arctic as well as under oceans on the edges of continents. Our witnesses will testify this morning on its potential as a future source of natural gas for our nation and what that potential is.

The U.S. Geological Survey has estimated that there might be 200,000 trillion cubic feet of natural gas stored in the hydrates. I would hope that our witnesses this morning can try to explain to me what 200,000 trillion cubic feet of natural gas looks like. Clearly, it is bigger than a breadbox, but give us some perspective. Give us some perspective on how our country that uses approximately 23 trillion cubic feet per year, you divide 200,000 by 23, and I guess, as my staff has tried to explain to me, that is kind of what it looks like, but I would like more description from our witnesses.

Of course, the figure is an estimate, and I am told that it is an old one. Just because there is a tremendous amount of methane hydrate does not mean that it is accessible today. What are the challenges of getting it and producing it? Just as we have done with gas from shale, how far away are we in terms of the technologies?

Even if 1 percent of that was recoverable, that would be, I am told, a source of energy for our country for over 80 years' worth of natural gas.

The Subcommittee helped put this together. I want to thank the staff with the Methane Hydrate Research and Development Program that was established over 10 years ago. We are pleased that we can have the status report on where things stand, and more importantly, where we should be going in the future. There have been tremendous strides that have taken place. Wells have been drilled in the Arctic and the Gulf of Mexico to test the ability to locate and produce the gas from these hydrates.

So, we will also hear today about what it might take to make this methane hydrate gas production economical. I am understanding that there are a number of things that have been done by a number of companies in this area. We would like to get an update on that. It seems that shale gas, as I said, was far beyond the horizon just 20 years ago, and while methane hydrates may be viewed in that same way today, hopefully in less than 20 years from now they will not be.

I am optimistic about this potential. I am also interested in hearing—since there are those who believe that as it relates to coastal development of oil and natural gas—although I think the examples we have seen for decades in the Gulf of Mexico, as well as the California coast and other coastal areas in the United States' boundaries—that oil and gas can be and has been produced safely and successfully. I suspect some of the same people who differ with me on that view may have the same attitude toward gas hydrates off the coast, and so how do you overcome that hurdle?

So with that said, I would defer to the Ranking Member of the Subcommittee here for his opening comments, and then we will begin with our witnesses.

[The prepared statement of Mr. Costa follows:]

Statement of The Honorable Jim Costa, Chairman, Subcommittee on Energy and Mineral Resources

Good morning, and welcome to the Energy and Mineral Resources Subcommittee's second hearing on unconventional fuels. Our first hearing in this hearing in this series, on shale gas, dealt with a resource that, while still technically considered unconventional, has already become a major component of our nation's domestic fuel supply. Today's hearing is on methane hydrates, a truly unconventional fuel source, albeit one that has the potential to make a massive impact in the future.

Methane hydrates can be thought of as natural gas frozen in ice. They have a structure where water molecules form a cage around individual molecules of methane, essentially trapping them in a solid state. Because the methane molecules are held together much closer than they would be if they were a free gas, one cubic foot of methane hydrate can release over 160 cubic feet of methane gas.

Originally these substances were thought to just be a laboratory curiosity or a pipeline nuisance. But since they were discovered in nature nearly 50 years ago, they have become viewed as a significant hazard for offshore oil and gas drillers, a potential major player in global climate change, and, most importantly for the purposes of this hearing, possibly the largest source of fossil fuel in the entire world. Estimates from the U.S. Geological Survey peg the amount of gas in hydrate form in the United States to be over 200,000 trillion cubic feet. That sounds large by itself, but is even more impressive when the total amount of conventional natural gas in the United States is estimated to be around 1,700 trillion cubic feet. And in 2008, the nation used about 23 trillion cubic feet. So, in theory, we might have almost 8,500 years worth of natural gas locked up beneath our feet as hydrates.

However, the total resource figure tells us nothing about how much natural gas we would actually be able to get out of these hydrates, which will be highly limited because of economic and technological factors. And the resource estimates themselves are highly uncertain. The Department of Energy and the U.S. Geological Survey, both of whom are here today, have been working for decades to try to answer the questions: How much gas hydrate do we really have? Where is it? And can we get to it in a way that will help provide a new robust source of domestically produced natural gas for this nation.

We do have a good general sense for where methane hydrates are—we know they exist in Arctic regions, beneath permafrost, and also offshore beneath the seabed. These offshore hydrates have been discovered off the coasts of South Carolina and Oregon, and in the Gulf of Mexico. In both the Arctic and the Gulf of Mexico, the indications are that natural gas can be produced from methane hydrates using traditional drilling technology. I understand there were some particularly promising results from the Gulf of Mexico earlier this year, which we will hear more about in the testimony.

The situation now with methane hydrates might resemble how things looked for gas shales just a couple of decades ago. At that time, gas shales were seen as uneconomic and technologically inaccessible—they were truly an unconventional fuel whose time would be far in the future. Those barriers were overcome, and I believe that with continued research, the barriers for production of natural gas from hydrates will be overcome as well in the not-too-distant future. I am extremely optimistic about the promise of methane hydrates, and I look forward to hearing from our witnesses about how that promise might turn into reality.

I now recognize our Ranking Member, Mr. Lamborn, for his opening statement.

Mr. COSTA. The gentleman from Colorado, Mr. Doug Lamborn.

STATEMENT OF HON. DOUG LAMBORN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF COLORADO

Mr. LAMBORN. Thank you, Mr. Chairman, and I commend you for continuing this series of important hearings on the nation's future unconventional energy resources. Today's hearing will focus on the promise of methane hydrates, the development of which was once considered a distant reality because of the technological challenges associated with producing gas from this type of resource.

Like the research and technological advances needed to develop our deepwater oil and gas and onshore shale gas fields, methane hydrate research will allow the United States and other nations to access this important energy resource in the near future. This will be especially important as the United States and other nations' economies begin to improve and energy demand around the world will again continue to rise. Many countries will be looking at the possibility of using methane hydrates to meet their domestic natural gas demands.

I am interested in hearing today about the state of methane hydrate research and the opportunities that this research offers the United States to access this significant domestic energy resource.

However, while the promise of this energy resource is tantalizing, it is important to remember that much of this resource is unavailable for domestic development, even if the technology needed to harvest it were available today.

Domestically, our methane hydrate resources lie off the coast in the Outer Continental Shelf and onshore in Alaska. It has been more than a year since President Bush lifted the moratorium on OCS leasing, and which the Congress in similar manner did not renew, and began work to amend the current five-year leasing plan. However, we are no closer today in being able to access our conventional or unconventional energy resources, such as methane hydrates, for areas previously under moratorium.

By delaying planned development by six months, the Secretary of the Interior has significantly delayed the planning process and hampered the completion of other studies, including an environmental impact statement required to develop a final five-year OCS leasing plan. Meanwhile, environmental allies of this Administration have filed lawsuits which have stopped all development under the current plan for the Chukchi, Beaufort and the Bering Seas of Alaska, the same areas with such great promise for methane hydrates.

Furthermore, the Chairman of the Democratic National Committee has called upon the Secretary of the Interior to stop the planned leasing scheduled for 2011 off the coast of Virginia, the only Atlantic process included in the 2007 to 2012 five-year OCS plan, and an area with significant natural gas prospects.

Meanwhile, Dominion Cove Point LNG terminal in Maryland is receiving liquified natural gas imports from Nigeria and Venezuela, and Elba Island LNG terminal in Georgia is receiving imported gas from Egypt. I would prefer to have the job creation which comes along with domestic leasing rather than the energy dependence and loss of jobs created by importing LNG from other countries.

Allowing access to our domestic conventional and unconventional resources does three important things: It provides an opportunity to create high-paying family wage jobs and unique business development opportunities which stimulate the economy; it provides a strong stream of revenue for Federal, state, and local government treasuries which helps the bottom line on budgets; and it makes us less dependent on foreign sources of energy, which also helps our domestic economy.

Finally, Mr. Chairman, I would like to take this opportunity to also propose that this Committee continue this series of hearings by examining the tremendous promise of oil shale. As you know, Mr. Chairman, I am a strong advocate of oil shale development, and I think we would benefit from holding a hearing to get a clear understanding from this Administration on the status of the oil shale commercial leasing program, including the cancellation of the research development and demonstration leases.

In closing, there are a number of questions I will have about this technology and the promise of methane hydrates, and I am looking forward to hearing from the witnesses.

Thank you, Mr. Chairman, and I yield back.

Mr. COSTA. Thank you, and we look forward to hearing from our witnesses and I will take the gentleman from Colorado's suggestion as it relates to other types of unconventional energy sources, and we will see if we can work that out.

Mr. LAMBORN. Excellent.

Mr. COSTA. Our witnesses this morning are the following: Dr. Timothy Collett, a Research Geologist for the United States Geological Survey; Dr. Ray Boswell, Senior Management and Technology Advisor for the National Energy and Technology Laboratory for the United States Department of Energy; and Mr. Steve Hancock, a Well Engineering Manager at RPS Energy, is that correct? Good, and I pronounced all of your names, I think, properly, I hope. I do want to inform the Subcommittee that we had a hope that a representative from ConocoPhillips would be here as a part of the panel because they have done some work on this. However, a couple of days ago they told us that they would not be able to provide the witness. Obviously, we are disappointed but we hope that in the future they may be able to update us on their efforts in this area with methane hydrates.

So, without further ado, we still have three excellent witnesses, and why don't we begin with Dr. Timothy Collett. I do not know if the three gentlemen here have testified before but, just in case, let me explain the rules.

The rules are that we get to ask the questions and you have to answer them. But beyond that, we give you five minutes for your opening statement. That light there in front of you it is green for four minutes, it becomes yellow for the last minute, and then it turns red after your five minutes has expired, and then your chair drops down if you are still speaking. No, that is not the case, but the Chair does try to be flexible, but we do want you to keep it within five minutes so we can get to the question-and-answer period. Obviously, if you have a longer statement, that will be submitted for the record.

So, again, Dr. Timothy Collett, Research Geologist for United States Geological Survey. What do you want to tell us about methane hydrates?

STATEMENT OF DR. TIMOTHY S. COLLETT, RESEARCH GEOLOGIST, U.S. GEOLOGICAL SURVEY

Dr. COLLETT. Thank you. Mr. Chairman and members of the Subcommittee, thank you for the opportunity to discuss the importance of the energy resource potential of gas hydrates. In this statement, I will discuss the USGS's assessment of the energy resource potential of natural gas hydrates. In our written testimony we also examine the research issues that need to be resolved to safely and economically produce gas hydrates.

Gas hydrates, also known as methane hydrates, are naturally occurring crystal and solids composed of water and natural gas in which solid cages of water trap the gas. Gas and water becomes a solid under certain temperature and pressure conditions within the earth called the gas hydrate stability zone. Gas hydrates are widespread in the Arctic, below permafrost and beneath the sea floor in sediments of the outer continental margins.

The amount of gas contained in the world's hydrate accumulations is enormous, and it is generally believed they hold more natural gas than the world's conventional accumulations. In 1995, the

USGS made the first systematic assessment of the in-place natural gas hydrate resources of the U.S. This study showed that the amount of gas in the hydrate accumulations of the U.S. greatly exceeds the volume of known conventional domestic resources.

Early in 2008, the U.S. Minerals Management Service released the first comprehensive assessment of gas hydrates in the U.S. Gulf of Mexico since the USGS 1995 assessment. The 2008 MMS assessment predicted that gas hydrates in the Gulf of Mexico may hold as much as 21,000 trillion cubic feet of in-place gas. The MMS continues to work on the assessment of gas hydrates in the OCS of the U.S. and also assessing what part of the marine gas hydrate resources can be technically recovered.

In the fall of 2008, with the support of the U.S. Bureau of Land Management, U.S. researchers announced a giant step forward with the completion of the first ever assessment of the amount of gas hydrate that can actually be recovered or technically recovered from gas hydrates. In this landmark study the USGS estimated that more than 85 trillion cubic feet of natural gas could be extracted from the gas hydrates on the north slope of Alaska, which would be one of the largest single sources of natural gas in the U.S.

And I would also like to add in regards to the Chairman's question, put that into context, that would be approximately enough heat or enough energy to heat 100 million U.S. homes for 10 years, so really an extraordinary amount of gas what we determine to be technically recoverable from the north slope if it could be economically produced and exported.

Finally, the USGS has supported gas hydrate research since the early 1980s, and with our Federal partners, including BLM, MMS, and DOE, as well as a number of international research partners in Canada, Japan, India and South Korea, we have made significant contributions to our understanding of the energy resource potential of gas hydrates. The USGS will continue to investigate all aspects of gas hydrates, understand their geological origin, their natural occurrence, the factors that affect their stability, their environmental impact, and possibly the use of this vast new energy resource.

Thank you, Mr. Chairman, for this opportunity to present this information, and I will be happy to respond to any questions you may have.

[The prepared statement of Dr. Collett follows:]

Statement of Dr. Timothy S. Collett, Research Geologist, U.S. Geological Survey, U.S. Department of the Interior

Mr. Chairman and Members of the Subcommittee, thank you for the opportunity to discuss the importance of the energy resource potential of natural gas hydrates. In this statement I will discuss the USGS assessment of the energy resource potential of natural gas hydrates and examine the research and development issues that need to be resolved to safely and economically produce gas hydrates. It is important to note that many different gases form gas hydrates, but methane, which is the main component of natural gas and is used to heat homes and for other domestic purposes, is the most common gas included in gas hydrates and that is why they are often referred to as methane hydrates. It is also important to note that this testimony will focus on the technical and economic aspects of gas hydrate production potential. The environmental impacts from gas hydrate production, including the potential impacts on global climate change, require additional study and analysis as the role of gas hydrates in the total energy mix is further defined and considered.

In 1995, USGS made the first systematic assessment of the in-place natural gas hydrate resources of the United States. That study shows that the amount of gas in the hydrate accumulations of the United States is estimated to greatly exceed the volume of known conventional domestic gas resources. However, gas hydrates represent both a scientific and technologic challenge and much remains to be learned about their characteristics and possible economic production. The primary objectives of USGS gas hydrate research are to: 1) document the geologic parameters that control the occurrence and stability of gas hydrates, 2) to assess the volume of natural gas stored within various gas hydrate accumulations, 3) to analyze the production response and characteristics of gas hydrates, 4) to identify and predict natural and induced environmental impacts of natural gas hydrates, and 5) to analyze the effects of gas hydrate on drilling safety.

Gas Hydrate Occurrence and Characterization

Gas hydrates are naturally occurring crystalline substances composed of water and gas, in which a solid water-lattice holds gas molecules in a cage-like structure. The gas and water become a solid under specific temperature and pressure conditions within the Earth, called the hydrate stability zone. Gas hydrates are widespread in Arctic regions beneath permafrost and beneath the seafloor in sediments of the outer continental margins. The amount of gas contained in the world's gas hydrate accumulations is enormous, estimates of in-place gas within natural gas hydrates range over three orders of magnitude from about 100,000 to 270,000,000 trillion cubic feet (TCF) of gas. By comparison, the conventional global gas endowment (undiscovered, technically recoverable gas resources + conventional reserve growth + remaining reserves + cumulative production) has been estimated at approximately 15,400 TCF (USGS World Petroleum Assessment, 2000). Despite the enormous range of these estimates, and the notable differences between in-place gas-hydrate estimates and the aforementioned estimates of conventional gas, gas hydrates seem to be a much greater resource of natural gas than conventional accumulations.

Even though gas hydrates are known to occur in numerous marine and Arctic settings, relatively little is known about the geologic controls on their distribution. The presence of gas hydrates in offshore continental margins has been inferred mainly from anomalous seismic reflectors that coincide with the base of the gas-hydrate stability zone. This reflector is commonly called a bottom-simulating reflector or BSR. BSRs have been mapped at depths ranging from about 0 to 1,100 meters below the sea floor. Gas hydrates have been recovered by scientific drilling along the Atlantic, Gulf of Mexico, and Pacific coasts of the United States, as well as at many international locations.

Onshore gas hydrates have been found in Arctic regions of permafrost and in deep lakes such as Lake Baikal in Russia. Gas hydrates associated with permafrost have been documented on the North Slope of Alaska and Canada and in northern Russia. Direct evidence for gas hydrates on the North Slope of Alaska comes from cores and petroleum industry well logs, which suggest the presence of numerous gas hydrate layers in the area of the Prudhoe Bay and Kuparuk River oil fields. Combined information from Arctic gas-hydrate studies shows that, in permafrost regions, gas hydrates may exist at subsurface depths ranging from about 130 to 2,000 meters.

The USGS 1995 National Assessment of United States Oil and Gas Resources focused on assessing the undiscovered conventional and unconventional resources of crude oil and natural gas in the United States. This assessment included, for the first time, a systematic appraisal of the in-place natural gas hydrate resources of the United States, both onshore and offshore. The offshore assessment, on which USGS partnered with the U.S. Minerals Management Service (MMS), identified eleven gas-hydrate plays within four offshore provinces. There was one gas-hydrate province identified onshore. The offshore provinces lie within the U.S. 200 mile Exclusive Economic Zone adjacent to the lower 48 States and Alaska. The only onshore province assessed in that study was the North Slope of Alaska. In-place gas hydrate resources of the United States are estimated to range from 113,000 to 676,000 TCF of gas, at the 0.95 and 0.05 probability levels, respectively. Although this range of values shows a high degree of uncertainty, it does indicate the potential for enormous quantities of gas stored in gas hydrates in these accumulations. The mean in-place gas hydrate resource for the entire United States is estimated to be 320,000 TCF of gas and approximately half of this resource occurs offshore of Alaska and most of the remainder is beneath the continental margins of the lower 48 states, underlying the Federal outer continental shelf (OCS). It is important to note that this 1995 assessment does not address the issue of gas hydrate recoverability. The USGS mean estimate of 320,000 TCF (gas hydrate in-place), despite its uncertainty, is more than two orders of magnitude larger than current estimates of natural gas from conventional sources (reserves and technically recoverable undiscovered resources) in the U.S., which is approximately 1,400 TCF.

In the fall of 2008, the USGS completed the first-ever resource estimate of technically recoverable gas from natural gas hydrates. That study found that there is 85.4 TCF (mean value) of technically recoverable gas in gas hydrates on the North Slope of Alaska. This assessment indicates the existence of technically recoverable gas hydrate resources—that is, resources that can be discovered, developed, and produced using current technology. The area assessed in northern Alaska extends from the National Petroleum Reserve in Alaska (NPRA) on the west through the Arctic National Wildlife Refuge (ANWR) on the east, and from the Brooks Range northward to the State-Federal offshore boundary (located three miles north of the coastline). This area consists mostly of Federal, State, and Native lands covering about 44,310 mi2. For the first time, the USGS has assessed gas hydrates, an "unconventional resource," as a producible resource in discrete hydrocarbon traps and structures. The approach used to assess the gas hydrate resources in northern Alaska followed standard geology-based USGS assessment methodologies that have been developed to assess conventional oil and gas resources. In order to use this approach for gas hydrate resources, it was documented through the analysis of three-dimensional industry-acquired seismic data, that the gas hydrates on the North Slope occupy limited but discrete volumes of rock bounded by faults and downdip water contacts. The USGS conventional assessment approach also assumes that the hydrocarbon resource being assessed can be produced by existing conventional technology. The production potential of the known and seismically-inferred gas hydrate accumulations in northern Alaska has not been adequately field tested, but has been the focus of multi-organizational research efforts in Alaska and Canada. Numerical production models of gas hydrate-bearing reservoirs suggest that gas can be produced from gas hydrate with existing conventional technology and this conclusion has been verified by limited field testing. Using a geology-based assessment methodology, the USGS estimated the total undiscovered technically recoverable natural gas resources in gas hydrates in northern Alaska to be between 25.2 and 157.8 TCF (95% and 5% probabilities of greater than these amounts, respectively), with a mean estimate of 85.4 TCF.

In anticipation of gas hydrate production in Federal waters, the U.S. Minerals Management Service (MMS) has recently launched a project to assess gas hydrate energy resource potential on acreage under MMS jurisdiction. The MMS is currently working to assess the resource potential of gas hydrate on the Atlantic OCS and to address the technical recoverability of gas hydrate in the marine environment. Early in 2008, MMS reported on their systematic geological and statistical assessment of in-place gas hydrate resources in the Gulf of Mexico OCS. This assessment integrated the latest findings regarding the geological controls on the occurrence of gas hydrate and the abundant geological and geophysical data from the Gulf of Mexico. The in-place volume of undiscovered gas estimated within the gas hydrates of the Gulf of Mexico was reported as a cumulative probability distribution, with a mean volume estimate of 21,436 TCF. In addition, the assessment reported that 6,710 TCF of this mean estimate are in relatively highly concentrated accumulations within sand reservoirs, with the remainder in clay-dominated sediments.

Gas Hydrate Production

Gas recovery from hydrates is a challenge because the methane is in a solid form and because hydrates are usually widely dispersed in frontier areas such as the Arctic and deep marine environments. Analogous to conventional hydrocarbon production, first recovery of a gas hydrate resource will occur where the gas is concentrated. Proposed methods of gas recovery from hydrates usually deal with dissociating, in-situ, the gas and water from its hydrate (solid) phase by: (1) heating the reservoir beyond the temperature of hydrate formation, (2) decreasing the reservoir pressure below hydrate equilibrium, or (3) injecting an inhibitor, such as methanol, into the reservoir to decrease hydrate stability conditions. Computer models have been developed to evaluate hydrate gas production from hot water, steam injection, and depressurization. These models are based on data from the short term production tests in Canada and Alaska and suggest that gas can be produced from hydrates at sufficient rates to make gas hydrates a technically recoverable resource. Similarly, the use of gas hydrate inhibitors in the production of gas from hydrates has been shown to be technically feasible; however, the use of large volumes of chemicals comes with a high economic and potential environmental cost. Among the various techniques for production of natural gas from in-situ gas hydrates, initial evaluations suggest that the most economically promising method is considered to be depressurization.

The pace of gas hydrate energy projects has accelerated over the past several years. Researchers have long speculated that gas hydrates could eventually be a commercial resource, yet technical and economic hurdles have historically made gas hydrate development a distant goal rather than a near-term possibility. This view began to change over the past five years with the realization that this unconventional resource could be developed in conjunction with conventional gas fields and with existing technology. Research coring and seismic programs carried out by the Ocean Drilling Program (ODP), Integrated Ocean Drilling Program (IODP), government agencies, and several consortia have significantly improved our understanding of how gas hydrates occur in nature and have verified the existence of highly concentrated gas hydrate accumulations at several locations. The most significant development was the production testing conducted at the Mallik site in Canada's Mackenzie Delta in 2002 and 2008. In December 2003, the partners (including the Geological Survey of Canada and USGS, as co-leads, and other partners such as the Department of Energy (DOE)) in the Mallik 2002 Gas Hydrate Production Research Well Program publicly released the results of the first modern, fully integrated field study and production test of a natural gas hydrate accumulation. The Mallik 2002 gas hydrate production testing and modeling effort has for the first time allowed for the rational assessment of the production response of a gas hydrate accumulation. Project-supported gas hydrate production simulations have shown that under certain geologic conditions gas can be produced from gas hydrates at very high rates exceeding several million cubic feet of gas per day.

It is recognized that the Mallik 2002 project contributed much to the understanding of gas hydrates; however, it fell short of delivering all of the data needed to fully calibrate existing reservoir simulators. It was also determined that longer duration production tests would be required to assess more definitively the technical viability of long-term production from gas hydrates. The 2006-2008 Mallik Gas Hydrate Production Research Program was conducted by the Japan Oil Gas and Metals National Corporation (JOGMEC), Natural Resources Canada (NRCan), and the Aurora College/Aurora Research Institute to build on the results of the Mallik 2002 project with the main goal of monitoring long-term production behavior of gas hydrates. The primary objective of the 2006-2007 winter field activities was to install equipment and instruments to allow for long term production gas hydrate testing during the winter of 2007-2008. The following winter (2007/2008), the team returned to the site to undertake a longer-term production test. The 2007/2008 field operations consisted of a six day pressure drawdown test, during which "stable" gas flow was measured. The 2007/2008 testing program at Mallik established a continuous gas flow ranging from about 70,000 to 140,000 ft3/day, which was maintained throughout the course of the six-day (139-hour) test as reported by JOGMEC, NRCan, and the Aurora College/Aurora Research Institute. The 2006-2008 Mallik production test is a significant event in our understanding of gas production from hydrates, in that "sustained" gas production from hydrates was achieved with existing conventional technology through simple well depressurization alone.

The potential for gas hydrates as an economically viable resource has been impacted by higher natural gas prices and forecasts of future tighter supply. However, gas hydrates have yet to be produced economically on a large scale. Gas hydrates have been compared to other unconventional resources, which were also considered to be uneconomic in the not too distant past, such as coalbed methane and tight gas sands. Once those resources were geologically understood and production challenges were addressed, these unconventional resources became part of the nation's energy mix.

Safety and Seafloor Stability

Safety and seafloor stability are two important issues related to gas hydrates. Seafloor stability refers to the susceptibility of the seafloor to collapse and slide as the result of gas hydrate dissociation. The safety issue refers to petroleum drilling and production hazards that may occur in association with gas hydrates in both offshore and onshore environments.

Seafloor Stability

Under the ocean floor, the depth to the base of the gas hydrate stability zone becomes shallower as water depth decreases and the base of the gas hydrate stability zone intersects the seafloor at about 1,500 ft, a depth characterized by generally steep topography on the continental slope. It is possible that both natural and human induced changes can contribute to in-situ gas hydrate destabilization by changing the pressure or temperature regime, which may then convert hydrate-bearing sediments to a gassy water-rich fluid, triggering seafloor landslides. Evidence implicating gas hydrates in triggering seafloor landslides has been found along the Atlantic Ocean margin of the United States. The mechanisms controlling gas hydrate-induced seafloor landslides are not well known; however, these processes may release large volumes of methane, a potent greenhouse gas, to the Earth's oceans and atmosphere.

Safety

Throughout the world, oil and gas drilling is moving into regions where safety problems related to gas hydrates may be anticipated. Oil and gas operators have described numerous drilling and production problems attributed to the presence of gas hydrates, including uncontrolled gas releases during drilling, collapse of wellbore casings, and gas leakage to the surface. In the marine environment, gas leakage to the surface around the outside of the wellbore casing may result in local seafloor subsidence and the loss of support for foundations of drilling platforms. These problems are generally caused by the dissociation of gas hydrate due to heating by either warm drilling fluids or from the production of warm hydrocarbons from depth during conventional oil and gas production. The same problems of destabilized gas hydrates by warming and loss of seafloor support may also affect subsea pipelines.

National Research Agenda for Gas Hydrate Energy Development

In 1982, scientists onboard the Research Vessel Glomar Challenger retrieved a three-ft-long sample of massive gas hydrate off the coast of Guatemala. This sample became the impetus for the first national research and development program dedicated to gas hydrates by the United States. Over the next 10 years, the USGS, Department of Energy (DOE), and a number of other organizations compiled data demonstrating the potential for vast gas hydrates accumulations around the world. By the mid 1990s, it was widely accepted that gas hydrates represented an enormous storehouse of gas.

Recognizing the importance of gas hydrate research and the need for coordinated effort, the U.S. Congress enacted Public Law 106-193, the Methane Hydrate Research and Development Act of 2000. The Act called for the Secretary of Energy to begin a methane hydrate research and development program in consultation with the National Science Foundation; the U.S. Departments of Commerce, represented by the National Oceanographic and Atmospheric Administration (NOAA); Defense, represented by Naval Research Laboratory; and Interior, represented by USGS and MMS. In August, 2005, the Act was reauthorized through 2010 as Sec. 968 of the Energy Policy Act of 2005 (Public Law 109-58), and the Bureau of Land Management (BLM) was added to the interagency effort.

It is important to highlight that for two decades prior to this Act the bureaus of the Department of the Interior studied gas hydrates within their various missions using base research funds. This base funded research continues, but in partnership with a variety of organizations. The USGS is investigating many aspects of gas hydrates to understand their geological origin, their natural occurrence, the factors that affect their stability, the environmental impact and the possibility of using this vast resource in the world energy mix. The USGS is investigating the resource potential of gas hydrates around the world in partnership with many organizations: (1) in the Mackenzie Delta of Canada in partnership with an international consortium; (2) on the North Slope of Alaska in partnership with DOE and BP Exploration (Alaska); (3) the DOE/ConocoPhillips gas hydrate production by CO_2 sequestration project, (4) in the U.S. Gulf of Mexico Joint Industry Partnership (JIP) with Chevron, DOE, and others; (5) the DOE/North Slope Borough, Alaska project; (6) in India in partnership with the Indian Directorate General of Hydrocarbons; and (7) Ocean Drilling Program (ODP) Leg 204 and Integrated Ocean Drilling Program (IODP) Expedition 311. Other countries and groups have expressed interest in cooperative activities including Japan, China, South Korea, Taiwan, and others.

A major emphasis of USGS research focuses on the North Slope of Alaska, where USGS is participating in several gas hydrate energy research projects with DOE, BLM and various industry partners. The USGS is analyzing the recoverability and potential production characteristics of onshore natural gas hydrate accumulations overlying the Prudhoe Bay, Kuparuk River, and Milne Point oil fields. With the success of the 2008 technically recoverable Alaska gas hydrate assessment, the USGS and BLM have expanded their cooperative gas hydrate research efforts in northern Alaska to further characterize the potential environmental and economic impact of gas hydrate exploration and development.

Another major emphasis of USGS research is the U.S. Gulf of Mexico. Several Gulf of Mexico hydrate research programs are underway and the most comprehensive study is a Joint Industry Project (JIP) led by DOE in partnership with Chevron which is designed to further characterize gas hydrates in the Gulf of Mexico. Participants include ConocoPhillips, Total, Schlumberger, Halliburton Energy Services, MMS, Japan Oil Gas and Metals National Corporation, and India's Reliance Industries.

On May 6, 2009, the JIP, including DOE, USGS, and MMS research scientists, completed the first-ever drilling project with the expressed goal to collect geologic data on gas-hydrate-bearing sand reservoirs in the Gulf of Mexico. This was an important goal because other resource assessment studies in northern Alaska by the USGS and offshore Japan, have shown that gas hydrates in conventional sand reservoirs are likely the closest to potential commercialization. In 2005, the Gulf of Mexico Gas Hydrate JIP Leg I conducted drilling, coring, and downhole logging operations designed primarily to assess gas hydrate-related hazards associated with drilling through the clay-dominated sediments that typify the shallow sub-seafloor in the deepwater Gulf of Mexico. Upon analysis of Leg I results, the JIP membership decided to expand its effort to assess issues related to the occurrence of gas hydrate within coarser-grained sediments. The 2009 drilling project, named the Gulf of Mexico Gas Hydrate Joint Industry Project Leg II (GOM JIP Leg II), featured the collection of a comprehensive set of logging-while-drilling (LWD) data through expected gas-hydrate-bearing sand reservoirs in seven wells at three locations in the Gulf of Mexico. The semi-submersible drilling vessel Helix Q4000 was mobilized at sea in the Gulf Mexico and drilling was conducted in the Walker Ridge, Green Canyon and the Alaminos Canyon blocks. The LWD sensors just above the drill bit provided important new information on the nature of the sediments and the occurrence of gas hydrate. The full research-level LWD data set on formation lithology, electrical resistivity, acoustic velocity, and sediment porosity enabled the greatly improved evaluation of gas hydrate in both sand and fracture dominated reservoirs.

The two holes drilled at Walker Ridge yielded evidence of a laterally continuous thick fracture-filling gas hydrate section, but more importantly both wells also encountered sand reservoirs, between 40- to 50-ft-thick, nearly saturated with gas hydrate. Gas-hydrate-bearing sands were also drilled in two of the Green Canyon wells, with one occurrence slightly more than 100-ft-thick. Initial interpretation of the Alaminos Canyon drilling results is that the sands appear to exhibit uniformly low gas hydrate saturation over a large area. Nevertheless, the discovery of thick hydrate-bearing sands at Walker Ridge and Green Canyon validates the integrated geological and geophysical approach used in the pre-drill site selection process in order to predict hydrate accumulations before drilling, and provides increased confidence in assessment of gas hydrate volumes in the Gulf of Mexico and other marine sedimentary basins. The presence of significant gas hydrate accumulations as both pore-filling sands and fracture-filling material in shallow muds, make both Walker Ridge and Green Canyon likely locations for future research into energy targets of gas hydrates in marine environments. While the primary goal of this JIP is to better understand the safety issues related to gas hydrates, the results of the program will also allow a better assessment of the commercial potential of marine gas hydrates.

Seismic-acoustic imaging to identify gas hydrate and its effects on sediment stability has been an important part of USGS marine and onshore studies since 1990. USGS work in this area has allowed for prediction of the occurrence as well as the thickness and saturation of gas hydrates ahead of drilling. USGS has also conducted extensive geochemical surveys and established a specialized laboratory facility to study the formation and dissociation of gas hydrate in nature and also under simulated deep-sea conditions.

The USGS, as well as many groups, participate in the IODP, the ODP, and their predecessor the Deep Sea Drilling Project (DSDP)—which have contributed greatly to our understanding of the geologic controls on the formation, occurrence, and stability of gas hydrates in marine environments. The gas hydrate research efforts under IODP-ODP-DSDP have been mostly directed to assess the role of gas hydrate in climate change. In the summer of 2002, ODP Leg 204 investigated the formation and occurrence of gas hydrates in marine sediments at Hydrate Ridge off the Oregon coast. The shipboard scientists successfully deployed new core systems for recovering and analyzing gas-hydrate-bearing sediments at in situ pressure conditions; thus allowing the correlation of sediment properties with seismic, conventional wireline and logging-while-drilling downhole data. IODP Expedition 311 with a USGS co-chief scientist, established a transect of four research drill sites across the northern Cascadia margin off the west coast of Canada. In addition to the transect sites, a fifth site was established at a cold vent with active fluid and gas flow. The most significant findings of the coring and logging programs during IODP Expedition 311 included the observation that gas hydrate is formed mainly within the sand-rich reservoir-quality formations and is virtually absent in the fine-grained and clay-rich sediments. Thus, the presence of gas hydrate is mainly controlled by lithology much like conventional hydrocarbon resources.

BP Exploration (Alaska), DOE, and the USGS have undertaken a project to characterize, quantify, and determine the commercial viability of gas hydrates and associated free gas resources in the Prudhoe Bay, Kuparuk River, and Milne Point field areas in northern Alaska. Under Phase 1 of this project, gas hydrates and associated free gas-bearing reservoirs in the Milne Point oil field have been studied to determine reservoir extent, stratigraphy, structure, continuity, quality, variability, and geophysical and petrophysical property of these hydrocarbon-bearing reservoirs. The objective of Phase 1 is to characterize reservoirs and fluids, leading to estimates of the recoverable gas reserve and commercial potential, and the definition of procedures for gas hydrate drilling, data acquisition, completion, and production. Phases 2 and 3 will integrate well, core, log, and production test data from additional test wells. Ultimately, the program could lead to development of a gas hydrate pilot project with a long term production test, and determine whether gas hydrates can become a part of the Alaska North Slope gas resource portfolio. In 2005, extensive analysis of 3-D seismic data and integration of that data with existing well log data by the USGS identified more than a dozen discrete and mappable gas hydrate prospects within the Milne Point area. Because the most favorable of those targets was a previously undrilled, fault-bounded accumulation, BP Exploration (Alaska) and DOE decided to drill a vertical stratigraphic test well at that location (named the "Mount Elbert" prospect) to acquire critical reservoir data needed to develop a longer term production testing program. The Mount Elbert gas hydrate stratigraphic test well acquired sediment cores, well logs, and downhole production test data. Gas hydrates were expected and found in two stratigraphic zones—an upper zone containing about 45 ft of gas hydrate-bearing reservoir-quality sandstone, and a lower zone containing about 50 ft of gas hydrate-bearing reservoir. Both zones displayed gas hydrate saturations that varied with reservoir quality, with typical values between 60% and 75%. This result conclusively demonstrated the soundness of the gas hydrate prospecting methods developed primarily at the USGS. The Mount Elbert gas hydrate stratigraphic test well project also included the acquisition of pressure transient data from four short-duration pressure-drawdown tests. Each test consisted of a period of fluid withdrawal (thereby reducing formation pressure) followed by a period where the pump is shutoff and the subsequent pressure buildup is monitored. The Mount Elbert press tests confirmed again that gas could be produced from hydrates by simple depressurization and the presence of a mobile pore-water phase even in the most highly gas hydrate-saturated intervals lends itself to higher expected gas hydrate production rates. This project yielded one of the most comprehensive datasets yet compiled on naturally-occurring gas hydrates.

International Gas Hydrate Research and Development Efforts

Many countries are interested in the energy resource potential of gas hydrates. Countries including Japan, India, China, South Korea, and Canada have established large gas hydrate R&D programs, while Norway, Mexico, Columbia, Chile, and others are investigating the viability of forming government-sponsored gas hydrate research programs. It is also not surprising that the most aggressive and well funded gas hydrate research programs are in countries highly dependent on imported energy resources, such as Japan and India.

In 1995, the Government of Japan established the first large-scale national gas hydrate research program, which now plays a leading role in worldwide gas hydrate research efforts. The first five years of the Japan National Gas Hydrate Program culminated in 1999/2000, with the drilling of a series of closely spaced core and geophysical logging holes in the Nankai Trough. In 2001, the Ministry of Economy, Trade and Industry (METI) launched a more extensive project entitled "Japan's Methane Hydrate Exploitation Program," operated by the Methane Hydrate 2001 Consortium, to evaluate the resource potential of deepwater gas hydrates in the Nankai Trough area. This project is intended to promote the technical development and recovery of gas hydrates, and to provide a long-term stable energy supply, with plans for field production testing as soon as 2011 and development of the technologies needed for commercial production by 2016.

The government of India also is funding a large national gas hydrate program to meet its growing energy requirements. One of the primary goals of the Indian National Gas Hydrate Program (NGHP) is to conduct scientific ocean drilling/coring, logging, and analytical activities to assess the geologic occurrence, regional context, and characteristics of gas hydrate deposits along the continental margins of India in order to meet the long term goal of exploiting gas hydrates as a potential energy resource in a cost effective and safe manner. In 2006, the Directorate General of Hydrocarbons (India) and the USGS conducted research drilling off the Indian Peninsula and along the Andaman convergent margin, with special emphasis on gaining an understanding of the geologic and geochemical controls on the accumulation of gas hydrate in these two diverse settings. NGHP Expedition 01 was among the world's most complex and comprehensive methane hydrates field ventures yet conducted. NGHP Expedition 01 established the presence of gas hydrates in the Krishna-Godavari, Mahanadi, and Andaman sedimentary basins. The expedition discovered one of the richest gas hydrate accumulations yet documented in the Krishna-Godavari Basin, recorded the thickest and deepest gas hydrate stability zone yet known in the Andaman Sea, and established the existence of a fully-developed gas hydrate system in the Mahanadi Basin. It is anticipated that future NGHP efforts will likely include drilling, coring, and field production testing.

Production Potential of Gas Hydrates—Technical Challenges

In order to release, or produce, the gas from a gas hydrate, we must change the temperature or pressure conditions controlling its occurrence and stability. The most economically promising method of producing gas from gas hydrates appears to be depressurization of the reservoir. Results from the Mallik and Mount Elbert test wells support this supposition. However, it is important to note that much more information is needed before production of this unconventional resource in these frontier regions becomes economic. For example, gas production is dependent upon the permeability of the host rock, and therefore, the type of sediment in which the hydrate occurs and understanding flow rates and paths is critical to potential production.

Onshore Alaska and the offshore Gulf of Mexico are proven exploration targets for gas hydrates. In the Gulf of Mexico, industry has begun assessing hydrate potential on their oil and gas leases. New and existing industry-Government partnerships are expected to drill hydrate prospects on the North Slope of Alaska in the near future—hence, the first domestic production of hydrates is expected to occur in Alaska, where gas from the hydrates will either support local oil and gas field operations, or be available for commercial sale if and when a gas pipeline is constructed. In both Alaska and the Gulf of Mexico, critical drilling and transportation infrastructure exists, which will allow gas hydrate prospects to be drilled and produced from existing installations.

The timing for expected commercial production of hydrates is uncertain. The DOE has estimated that gas production from gas hydrate could begin no earlier than 2015. In September of 2003, the National Petroleum Council (NPC) reported that we will not likely see significant production from gas hydrates until sometime beyond 2025. Initial production from gas hydrates could occur much sooner, especially in areas such as the North Slope of Alaska or in other countries. Estimates vary on when gas hydrate production will play a significant role in the total world energy mix. It is not currently possible to determine whether hydrates will be able to contribute to the domestic energy supply. The future contribution of this resource will depend not only on further progress in gas hydrate production, but also on research into the environmental impacts of gas hydrate production, which are not fully understood.

Next Steps to Gas Hydrate Production

The immense volume of gas hydrates worldwide may be a significant potential energy resource at some point in the future. Our understanding of these resources, however, is still evolving—we do not yet know if these accumulations exist in sufficient concentration to make them economically viable, nor do we know whether even concentrated accumulations can be developed economically. Additional science-driven production tests will contribute to our understanding of gas hydrate production. It is generally believed that gas hydrates can be produced by standard techniques used today to exploit conventional oil and gas resources. However, it is very likely that new drilling and production technology would contribute to the ultimate producibility of gas hydrates. We know that hydrates must be produced by releasing the gas from the hydrate form by the methods previously described. However, there has only been one industry scale hydrate production test to date (the 2008 Mallik project). Much more information is needed on: (1) the geology of the hydrate-bearing formations, both on a large scale (the distribution of hydrates throughout the world) and on a small scale (their occurrence and distribution in various host sediments); (2) the reservoir properties/characteristics of gas hydrate reservoirs; (3) the production response of various gas hydrate accumulations; and (4) the economics controlling the ultimate resource potential of gas hydrates. The USGS will continue to play a vital role in studying, evaluating, and understanding the geologic and engineering properties critical to the realization of hydrates as a viable energy source. The USGS will also continue to work with other Federal agencies and within domestic and international consortiums to conduct needed gas hydrate production test studies.

Conclusions

Our knowledge of naturally occurring gas hydrates is growing and it can be concluded that: (1) a huge volume of natural gas is estimated to be stored in gas hydrates; (2) production of natural gas from gas hydrates is technically feasible with existing technology; (3) gas hydrates hold the potential for natural hazards associated with seafloor stability and release of methane to the oceans and atmosphere; and (4) gas hydrates disturbed during drilling and petroleum production pose a potential safety problem. USGS research on gas hydrates is focused on: (1) the energy-resource potential they represent; (2) the hazards they might pose to drilling and the environment; and (3) the impact they might have on global climate change. Thus, the USGS welcomes the opportunity to collaborate with domestic and international scientific organizations and industry to further collective understanding of these important geologic materials.

Thank you, Mr. Chairman for the opportunity to present this information. I will be happy to respond to any questions you may have.

Response to questions submitted for the record by Dr. Collett

Questions from Chairman Jim Costa from the State of California

1. Dr. Collett, what have we learned from the Ocean Drilling Program expeditions on the Atlantic and Pacific coasts? Do there appear to be promising gas hydrate resources in those areas? Also, is there any time-frame for getting a better assessment of hydrate resources on the Atlantic and Pacific coasts?

In response to the first part of your question regarding the contribution of the Ocean Drilling Program (ODP) expeditions on the Atlantic and Pacific coasts, I am proud to note that I had the great opportunity to directly participate in both the ODP expedition Leg 164 on the Atlantic margin and ODP expedition Leg 204 on the Pacific margin. These expeditions and other research have provided seismic profiles along the Atlantic margin of the United States, typically marked by large-amplitude seismic reflectors named “bottom-simulating-reflectors—or BSRs. BSRs are believed to be caused in this region by large acoustic impedance contrasts at the base of the gas hydrate stability zone that mark the contact between sediments containing gas hydrates with sediments containing free-gas rather than hydrates. BSRs have been extensively mapped at two locations off the east coast of the United States—offshore South Carolina along the crest of the Blake Ridge and beneath the upper continental rise of New Jersey and Delaware. The most extensively studied gas hydrate deposit on the Atlantic coast of the United States is on the Blake Ridge. ODP Leg 164 was designed to investigate the occurrence of gas hydrate in the sedimentary section beneath the Blake Ridge. The presence of gas hydrates on the Blake Ridge was documented by direct drilling and sampling and analysis of recovered sediment cores and downhole logging data. Although a significant portion of the Blake Ridge appears to be underlain by gas hydrates, the concentration appears to be low. Further, the host sediments are mostly clay, which raises a concern over the production technology required to produce gas from widely disseminated gas hydrate accumulations in clay-rich sediments. Much less is known about the potential gas hydrate occurrences of the northeastern Atlantic margin of the United States.

ODP Leg 204 to Hydrate Ridge, located on the Pacific continental margin offshore Oregon, was the first deep-sea drilling expedition dedicated to providing an understanding of gas hydrate processes in accretionary complexes. Gas hydrate presence was confirmed at most of the sites drilled during ODP Leg 204. The amount of gas hydrate present, when averaged over the entire gas hydrate stability zone, is generally estimated to be low (about 2 percent of the sediment pore space). However, gas hydrate concentrations increase to approximately 20-30 percent near several methane vents that were drilled during the expedition. Geochemical data indicate that most of the gas forming the hydrate deposits associated with vents has migrated from a greater depth and has either a thermogenic or altered biogenic origin. The regionally pervasive gas hydrate occurrences, at relatively low concentrations, on both Hydrate Ridge and the Blake Ridge appear to have formed from gas produced locally through microbial alteration of in-situ organic matter.

The gas hydrate accumulations discovered during ODP Legs 164 and 204 occur at low concentrations and are disseminated in fine-grained, clay-dominated sediments or at high concentrations associated with natural fluid and gas vent sites on the seafloor. On the other hand, gas hydrates occurring at high concentrations are associated with conventional type sand reservoirs, as discovered recently in the Gulf of Mexico, and are believed to represent the most promising targets for future gas hydrate production.

The assessment of hydrate resources on the Atlantic and Pacific coasts was first dealt with by the USGS in the 1995 National Assessment of United States Oil and Gas Resources, which focused on assessing the undiscovered conventional and unconventional resources of crude oil and natural gas in the United States. This assessment included, for the first time, a systematic appraisal of the in-place natural gas hydrate resources of the U.S. onshore and offshore regions. In 1995, the USGS estimated that the amount of gas within the gas hydrates of the United States may be as much as 317,832 trillion cubic feet. More recently, the U.S. Minerals Management Service (MMS) conducted a systematic geological and statistical assessment of in-place gas hydrate resources in the Gulf of Mexico which was reported in the spring of 2008 (http://www.mms.gov/revaldiv/GasHydrateAssessment.htm). It is our understanding that MMS is moving ahead with the assessment of gas hydrate resources for the entire OCS of the United States. We would suggest contacting MMS for more information on their assessment of marine gas hydrate resources on the Atlantic and Pacific margins of the United Sates.

2. Dr. Collett, the permafrost contains a great deal of methane, which is a concern when it comes to climate change because as the Arctic warms as the permafrost thaws, that methane gets released into the atmosphere where it makes warming even worse. Does production of methane from hydrates help remove this methane from the permafrost before it gets released to the atmosphere?

Atmospheric methane, a greenhouse gas, is increasing at a rate such that the current concentration will probably double in the next 50 years. Because methane is 21 times more radiatively active than carbon dioxide, it is predicted that methane will surpass carbon dioxide as the predominant atmospheric greenhouse gas in the second half of the next century. The source of this atmospheric methane is uncertain; however, numerous researchers have suggested that destabilized natural gas hydrates may be contributing to the build-up of atmospheric methane. Recent studies have shown that most of the known gas hydrate deposits occur deep within the Earth both within and below thick sections of permafrost or under oceanic sediments. It appears that most of these gas hydrate accumulations are insulated from any rapid climate changes and are unlikely to be significantly affected by atmospheric temperature changes. However, the relationship between gas hydrate dissociation and the release of potential greenhouse gases is poorly understood and is the topic of ongoing research within the USGS. It should be noted, however, that it is unlikely that the intentional production of gas (methane) from hydrates that are deeply buried beneath permafrost or the world's oceans would have either a positive or negative feedback on the release of methane to the atmosphere. First, the gas hydrates most susceptible to climate change, those occurring near the surface, are not being targeted for production. Second, the total volume of gas that will likely be produced from gas hydrates under any reasonable scenario will only be a small percentage of the total volume of gas contained in hydrates. In the second case, the unintentional release of gas from a producing hydrate deposit has been predicted to be on a scale similar to that experienced with production from conventional gas deposits. Thus, the production of gas hydrates is not expected to either add to or subtract from the volume of methane being released to the atmosphere by either natural or human-induced processes.

3. Dr. Collett, what do we know about the risk of slope instability on the Atlantic continental margins, and the potential threat of submarine landslides and tsunamis because of that?

Gas hydrates as well as free-gas and salt tectonics have been implicated as triggers for major seafloor landslides along the Atlantic Ocean margin of the United States. However, the mechanisms controlling gas hydrate-induced seafloor landslides are not well known. Under the ocean floor, the depth to the base of the gas hydrate stability zone becomes shallower as water depth decreases, and the base of the gas hydrate stability zone intersects the seafloor at about 1,500 feet, a depth characterized by generally steep topography on the continental slope. It is possible that both natural and human-induced changes can contribute to in-situ gas hydrate destabilization by changing the pressure or temperature regime, which may then convert hydrate-bearing sediments to a gassy water-rich fluid, triggering seafloor landslides. Using our new understanding of the geology of the Atlantic margin and a deeper appreciation of the geologic and engineering controls on natural slides, the first landslide-induced tsunami models are being developed.

4. Congress passed royalty relief for gas hydrate production in the Energy Policy Act of 2005. Dr. Collett, have the rules for this royalty relief been issued? And do you believe it is realistic that production will occur prior to the 2018 deadline that is in that legislation?

The USGS did not participate in the rule making process for the gas-hydrate-related royalty relief considerations in the Energy Policy Act (EPA) of 2005. The U.S. Minerals Management Service (MMS) took the lead on the rule making process as included in EPA. MMS determined a rule was not appropriate at this time.

On March 8, 2006, MMS and the Bureau of Land Management (BLM) published in the Federal Register a joint Advance Notice of Proposed Rulemaking. In August 2006, the Secretary completed the required review of further opportunities to enhance production of gas hydrate resources on the OCS and on Federal lands in Alaska through the provision of other production incentives or through technical or financial assistance and delivered the Report to Congress. The report was prepared by the Department of the Interior, MMS, and is based on information within the Federal interagency hydrate working groups (which represent Department of the Interior bureaus—MMS, BLM, and USGS—and the National Energy Technology Laboratory of the Department of Energy). The report also reflected the public comments received on the March 8, 2006, Advance Notice of Proposed Rulemaking.

In summary, the conclusion of the report was that, given the current lack of information about gas hydrate production potential, the ongoing research in progress, and the absence of industry exploration activity, royalty relief would not encourage production of natural gas from gas hydrates at that time, and the report did not recommend specific government production incentives for gas hydrates. The report stated that production incentives, like royalty relief, would be better-suited for encouraging prospect-specific exploration and development of gas hydrate resources if needed once commercial recoverability is established. Additionally, the report recommended that Federal incentives—through technical and financial assistance for research and development programs, database development, education and training, and assistance and collaboration in field testing of production methods—would be the most effective way to help accelerate the process of commercial production of gas hydrate resources.

MMS can provide further information about royalty relief for gas hydrate production, and we recommend you contact them if you have further questions.

In response to the second part of your question that deals with gas hydrate production prior to the 2018 legislation deadline, it is likely there could be limited gas hydrate production from a few areas in the Arctic and possibly the Gulf of Mexico within this timeframe. Thus, with this relatively short deadline, it is unlikely that many companies will be able to take advantage of this proposed gas hydrate royalty relief.

5. Dr. Collett, what kind of other stimuli could we enact to spur the production of methane hydrates?

Reauthorization of the Methane Hydrate Research and Development Act of 2000 is one option to stimulate the development of gas hydrates as an energy resource. Recognizing the importance of gas hydrate research and the need for coordinated effort, the U.S. Congress enacted Public Law 106-193, the Methane Hydrate Research and Development Act of 2000. The Act called for the Secretary of Energy to begin a methane hydrate research and development program in consultation with the National Science Foundation; the U.S. Departments of Commerce, represented by the National Oceanographic and Atmospheric Administration (NOAA), Defense, represented by Naval Research Laboratory, and Interior, represented by USGS and MMS. In August 2005, the Act was reauthorized through 2010 as Sec. 968 of the Energy Policy Act of 2005 (Public Law 109-58), and the BLM was added to the interagency effort. Work conducted under the Methane Hydrate Research and Development Act has had very significant and long lasting impact on our understanding of the energy resource potential of gas hydrates. Under this legislation, through a number of highly successful field drilling and testing programs in northern Alaska and the Gulf of Mexico, the USGS has determined that a huge volume of natural gas is stored with the world's gas hydrate accumulations and that the production of natural gas from gas hydrates is technically feasible with existing technology. However, the USGS has also learned that gas hydrates represent a natural hazard associated with seafloor stability and the release of methane to the oceans and atmosphere. The work carried out by the Department of Energy and other agencies named above under the Methane Hydrate Research and Development Act, coupled with and supported by the research with funding by other agencies such as the USGS, has allowed significant breakthroughs in our understanding of gas hydrates, especially as it relates to becoming a viable part of our domestic energy mix. Information on work being carried out under the Methane Hydrate Research and Development Act can be found at http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/maincontent.htm. Information on work being carried out at the USGS on gas hydrates can be found at http://energy.usgs.gov/other/gashydrates/.

6. Dr. Collett, what is the administration's position on reauthorization of the Methane Hydrate Research and Development Act, which expires next year?

At this time, the Administration does not have a position on reauthorization.

Mr. COSTA. Thank you very much, and you obviously stayed within the timeframe and for that you get extra bonus points.

Dr. COLLETT. I appreciate it.

Mr. COSTA. Our next witness is Dr. Ray Boswell who is the Senior Management and Technology Advisor for the National Energy Technology Laboratory for the United States Department of Energy, and Dr. Boswell, we look forward to hearing your comments.

STATEMENT OF DR. RAY BOSWELL, SENIOR MANAGEMENT AND TECHNOLOGY ADVISOR, NATIONAL ENERGY TECHNOLOGY LABORATORY, U.S. DEPARTMENT OF ENERGY

Dr. BOSWELL. Thank you, Mr. Chairman, and thank you members of the Subcommittee. I appreciate this opportunity to discuss the Department of Energy's research on naturally occurring gas hydrates.

Since 2000, DOE, through the Office of Fossil Energy's National Energy Technology Laboratory—that is where I work—has led the national research program in gas hydrates. The program is conducted through partnerships with private industry, institutions, and universities, and supported using the unique capabilities of DOE's national laboratories and the expertise of collaborating scientists from six other Federal agencies.

DOE also has active ongoing collaborations with many of the world's leading gas hydrate research efforts, including the national programs of Japan, Korea, Canada and India.

The program is driven by the relatively recent recognition that gas hydrates represent a significant global storehouse of methane, a fact with far-reaching implications for our understanding of the environment as well as for the nation's and the world's future energy supplies. In the past few years researchers have documented that gas hydrates occur in a wide variety of accumulations.

Not all gas hydrates are equal, and we have determined that those that form within sandy sediments are the most promising initial resource targets. Sand rich sediments appear critical to enabling both the concentration of gas hydrate to high levels as well as enabling the potential production of the enclosed methane through application of largely existing well drilling and completion technologies.

This refined focus on hydrate-bearing sands has resulted in a series of encouraging research findings in both Arctic and marine settings. Notably, DOE-sponsored field programs in Alaska in 2007 and in the Gulf of Mexico earlier this year demonstrated the occurrence and the ability to remotely detect and assess, prior to drilling, resource quality gas hydrate accumulations through the application of the same integrated geological-geophysical approaches that guide traditional hydrocarbon exploration.

So we now have a much clearer picture of the promise of gas hydrates. The emerging estimates of potentially recoverable resources, such as Dr. Collett was just mentioning, while lower than those incredibly large in-place volumes that had previously framed gas hydrate resource potential, are far more relevant and meaningful that grounded in data from the field now, and they continue to indicate significant potential resources of domestic natural gas from hydrates.

DOE and our research partners are positioned to conduct the next stage of gas hydrate research and development, including extended field testing of alternative production methods and comprehensive drilling and sampling programs for resource evaluation and validation of our exploration models. In addition, DOE understands that acceptance of gas hydrates as a new energy supply option will require a demonstration of an advance understanding of the role gas hydrates play in the natural environment.

To that end, we are supporting a range of studies to document gas hydrates response to environmental changes and the interaction of gas hydrate associated methane with global carbon cycling and global climate.

Despite all the progress of recent years, there is still much to learn about the details of gas hydrate occurrence and behavior in nature. The potential is very large, the uncertainties remain very large. The department looks forward to meeting this challenge and to providing the knowledge and technology that may provide a valuable additional domestic option for meeting future energy demands.

Mr. Chairman, members of the Subcommittee, I would be happy to take any questions you may have. Thank you.

[The prepared statement of Dr. Boswell follows:]

Statement of Dr. Ray Boswell, National Energy Technology Laboratory, U.S. Department of Energy

Thank you, Mr. Chairman and Members of the Subcommittee. I appreciate this opportunity to provide testimony on the status of the United States Department of Energy's (DOE's) research efforts in naturally-occurring gas hydrates.

INTRODUCTION

Since 2000, DOE, through the Office of Fossil Energy's National Energy Technology Laboratory (NETL), has led the national research program in gas hydrates. The program is conducted through partnerships with private institutions and universities, and supported using the unique capabilities of DOE's National Laboratories.

Program planning and implementation is also greatly aided by the expertise of scientists from the Department of the Interior's U.S. Geological Survey (USGS), Minerals Management Service (MMS) and Bureau of Land Management (BLM), the U.S. Naval Research Laboratory (NRL), the National Science Foundation (NSF), and the Department of Commerce's National Oceanic and Atmospheric Administration (NOAA).

Scientific program oversight is conducted through regular external merit reviews, which include a Federal Advisory Committee comprising leaders from industry and academia, and periodic reviews by the National Research Council. DOE also has active, ongoing collaborations with many of the world's leading gas hydrate programs in Japan, Korea, Canada, and India.

The program is driven by the recognition that gas hydrates represent a significant global storehouse of methane—a fact with far-reaching implications for the environment and for the Nation's (and the world's) future energy supplies. DOE is now conducting and supporting a comprehensive suite of field and modeling studies of gas hydrates' link to climate and carbon cycling, greatly elucidating the role gas hydrates may play during changing climates.

Regarding gas hydrates as an energy source, notable recent successes within the program's primary field efforts have confirmed significant accumulations of the most promising gas hydrate resource targets. We have and continue to prepare for the next stage of gas hydrate research and development (R&D) that will include extended testing of alternative production methods, as well as comprehensive resource confirmation and sample collection. While much work remains to be done, results, to date, are consistently encouraging, and the program remains on pace to accomplish its resource and environmental goals.

BACKGROUND

Through the past 50 years, the Nation's available supply of natural gas has steadily expanded to meet growing demands. Key to this expansion is periodic advances in knowledge and technology that enable new and increasingly remote and challenging resources to be commercially developed.

Over the past half-century, technology has provided the ability to safely and efficiently extract natural gas from previously unobtainable resources, including ultra-deep formations, and those "unconventional" formations that do not readily release natural gas, including tight gas formations, coal-bed methane, and shale gas reservoirs. Federally-funded R&D has been a critical part in enabling many of these successes to benefit the Nation. The next resource element poised to be added to this list is gas hydrates, which may be considered a frontier resource.

Gas hydrates form wherever appropriately-sized molecules of gas (most commonly, methane) and water occur together under specific conditions of low temperature and high pressure. These conditions exist on land in areas of permafrost, and within the shallow sediments of continental margins where water depth exceeds roughly 500 meters.

Until the early 1970s, gas hydrates were not confirmed to exist in the natural environment; however, by the late 1990s, a general consensus had emerged that gas hydrates occurred in vast quantities, perhaps housing more organic carbon than all of the world's coal, oil, and natural gas deposits combined. The total resource estimates are astronomical: the most commonly-cited estimate for the global abundance of methane stored in gas hydrate form is 700,000 trillion cubic feet. However, these volumes are poorly constrained.

Recent estimates continue to range over nearly two orders of magnitude, pointing out the immensity of the problem in assessing gas hydrate resources, and the limited data available on the occurrence and fundamental controls on gas hydrates in nature. The implications of the vast scale of gas hydrates in nature, for our understanding of carbon cycling and climate change, are critically important and are the subject of extensive ongoing studies. However, the primary driver for the rapidly accelerating international investment in gas hydrates research is the emerging potential of gas hydrates as an energy resource.

A RECENT PARADIGM SHIFT

A key development in gas hydrates research in recent years is the realization, based on the findings of a series of recent scientific drilling programs around the world, that all gas hydrates accumulations are not created equal. Gas hydrates accumulations range from large, diffuse accumulations in clay sediments, to smaller, discrete, high-concentration accumulations in sand reservoirs. Gas hydrates occur both on the sea-floor as solid massive mounds, as well as buried several thousands of feet below the sea-floor. When considering gas hydrate potential as an energy supply, we now recognize that those deeply-buried deposits housed within coarse-grained (sand) sediments are the most favorable. It is significant as well that these are the deposits that are most highly-buffered from environmental change.

What makes sand reservoirs attractive is their permeability—a measure of the ease with which fluids can move through the sediment. On the one hand, this permeability appears to be critical in enabling gas hydrates to accumulate to very high concentrations, typically 60 percent to 90 percent of the pore space. In addition, reservoir permeability may be the key to enabling methane production from gas hydrate reservoirs using, to a large extent, existing drilling and completion technologies. Numerical simulations conducted in both the United States and Japan have shown that conventional wellbores penetrating sand reservoirs can be used effectively to: 1) impart changes in reservoir conditions that dissociate the gas hydrates in place; and 2) then gather the released methane at rates that make commercial production a possibility. As a result, substantial resources may be available using largely existing drilling and production technologies. More exotic or potentially intrusive approaches, such as deep sea mining or dredging, are not under consideration.

This refined focus is now enabling more targeted technological development, and more sophisticated and relevant assessments of gas hydrate resources. Recently, the USGS, building on several decades of their own efforts, and integrated with DOE-sponsored field data collection and numerical simulation studies, reported a mean estimate of 85 trillion cubic feet (tcf) of technically-recoverable gas resources in hydrate-bearing sands underlying the Alaska North Slope (ANS). In the marine environment, MMS also reported last year that of more than 20,000 tcf of gas in-place in gas hydrate deposits in the Gulf of Mexico, more than 6,700 tcf is contained at high concentrations in sand reservoirs. These estimates, while less than the volumes that had previously framed gas hydrate potential, are far more meaningful, and indicate that significant potential resources of domestic natural gas from hydrates occurs within areas of existing oil and gas production infrastructure. Assessments of resources in other regions of the United States, including Atlantic and Pacific offshore areas, is also underway within the Department of the Interior, but supporting data are notably absent at this time.

STATUS OF THE EFFORT: RECENT ADVANCES AND REMAINING CHALLENGES

DOE's stated goals in gas hydrates research are to provide the knowledge and technology to enable environmentally-sound and commercially-viable production of gas from gas hydrates by 2015 (for arctic resources) and 2020 (for resources in the Gulf of Mexico). We remain firmly on track to accomplish these goals. Prior research within the program has established a strong foundation of fundamental science and experimental modeling capabilities. Completing this will require a continuation of these efforts, as well as a strong commitment to conducting extensive field operations in both arctic and deep-water marine settings.

Key to fulfilling the promise of gas hydrates as a resource is the ability to confirm resource volumes, and effectively explore for the most favorable deposits. In Alaska, efforts by the USGS, in collaboration with the cooperative research program between DOE and BP Exploration Alaska (BPXA), resulted in the recognition of more than a dozen discrete and potentially drillable accumulations within a small area of the greater Prudhoe Bay region, using existing geophysical and geologic data. A logging, coring, and testing program, conducted at the BPXA-DOE-USGS "Mount Elbert" test well in February of 2007, validated these predictions, provided insight into the planning for future production testing, confirmed the ability to safely conduct scientific data acquisition within an operating oil field with minimal impact to operations, and increased the confidence in the broader assessment of gas hydrate resources throughout the ANS.

More recently, a concerted effort within the interagency technical coordination team, enabled by the DOE-sponsored gas hydrates Joint Industry Project (JIP), resulted in the development of a series of gas hydrate-bearing sand prospects in the deepwater Gulf of Mexico. A three-week drilling program conducted by the JIP in the spring of 2009 similarly validated this prospect development, finding highly-concentrated gas hydrates in reservoir-quality sands, as predicted, in 4 of 7 wells drilled. Future work in the Gulf of Mexico includes dedicated coring programs, utilizing specialized devices in development by the JIP, to collect samples of these reservoirs for further detailed studies.

The potential to safely and efficiently produce gas from hydrate reservoirs is also clarifying. For example, results from an independent 2002 test, led by Japan and Canada, determined that the depressurization method (withdrawal of fluids from the well-bore and the formation, reducing pressures below the stability point of gas hydrates) was likely the most effective means to produce gas from gas-hydrate bearing sands. This finding is in agreement with analyses conducted using data obtained at the "Mount Elbert" test well in 2007. Further depressurization tests at Mallik in 2008 and 2009 confirmed relatively high volume, sustainable flow rates over a six-day testing period.

These tests, combined with findings from laboratory studies, have enabled increasingly sophisticated numerical simulations to be conducted, which indicate that commercially viable production rates are possible in certain settings. However, it remains a challenge to predict the long-term behavior of any reservoir, particularly a non-conventional one, based on short-duration tests. Longer-term (up to a year or more) production tests are needed to understand the true deliverability of gas hydrate reservoirs. At present, the only locations where such tests can be feasibly conducted are the known gas hydrate accumulations within the Prudhoe Bay region on the ANS. DOE is currently coordinating with ANS operators on the complex problem of developing such a test within an area of established production.

An additional promising opportunity that has recently emerged is the potential to inject CO_2 into gas hydrate reservoirs, leading to the release of the methane and the sequestration of the CO_2 within hydrate form. DOE has recently established a research agreement with ConocoPhillips to conduct a field trial of this concept on the ANS, building on prior and encouraging laboratory and modeling findings by a ConocoPhillips-University of Bergen (Norway) research team. If successful, this project could provide a sound option for the disposition of CO_2 that comprises a portion of existing conventional gas resources on the ANS.

Ultimate acceptance of gas hydrates as a new energy supply option will also require demonstration of a full understanding of the role gas hydrates play in the natural environment. To that end, DOE is supporting a range of studies to document the processes that impact the stability of gas hydrates, their response to environmental changes, the flow of methane in sediments, and the ability of released methane to traverse the sea-floor and the water column. In addition, we recognize the need to monitor methane movement and geomechanical changes in reservoirs during field tests.

SUMMARY

Research results over the past decade, including drilling and coring programs, experimental studies, and numerical simulations are clarifying the resource potential of gas hydrates. In particular, application of the concepts that guide the assessment and exploration of traditional hydrocarbon resources are now enabling researchers to focus on the most promising gas hydrate occurrences—those reservoired in sandstone formations—yielding a series of encouraging research findings in both arctic and marine settings.

The DOE-led program in gas hydrates R&D is working to integrate and leverage efforts throughout the United States and internationally to enable gas hydrates to become a viable option for meeting future energy demands. The approach is to integrate three distinct lines of research.

- First, utilize the known gas hydrate accumulations on the ANS as a natural laboratory to study issues related to gas hydrate production. Based on the success of the 2007 “Mount Elbert” field program, DOE and its industry partners in Alaska are now poised to conduct a range of scientific production tests using different approaches.
- Second, conduct additional drilling and data collection expeditions in the Gulf of Mexico to confirm resource occurrence, refine exploration technologies, and identify sites for future production testing. That testing will build on the most promising approaches identified in the arctic testing program. With the successful completion of the spring 2009 JIP drilling and logging expedition, this effort is fully on track.
- Third, demonstrate an understanding of gas hydrate’s role in nature and the potential environmental implications of gas hydrate production. To that end, DOE is supporting a broad range of studies to determine the links between gas hydrates, the oceans and the atmosphere, and is committed to ensuring full monitoring of all field testing programs

Despite all the progress of the past several years, there is still much to learn about the details of gas hydrate occurrence and behavior in nature. The research being conducted is wide-ranging, complex, and multi-disciplinary. The current effort is designed to simultaneously advance fundamental scientific understanding of gas hydrates, characterize marine resources, and explore gas hydrate production potential through Arctic field tests.

The Department looks forward to the challenge of completing these strategic activities that, in concert, support a potential global paradigm shift in energy supply.

Mr. Chairman, Members of the Subcommittee, I would be happy to take any questions you may have.

Response to questions submitted for the record by Dr. Boswell

QUESTIONS FROM CHAIRMAN COSTA

1. Dr. Boswell, how much money is the United States spending on methane hydrate research, and is that enough to meet the DOE goals of production from arctic hydrates in 2015 and marine hydrates in 2020?

Answer 1. Six Federal agencies receive funding for methane hydrate research: U.S. Geological Survey (USGS), National Oceanic and Atmospheric Administration, Naval Research Lab, Bureau of Land Management, National Science Foundation, and Minerals Management Service. The Department of Energy (DOE) was appropriated $9 million in FY 2006, $12 million in FY 2007, $15 million in FY 2008, and

$15 million in FY 2009 for methane hydrates research. An additional $1 million was appropriated in FY 2006 and FY 2008 to the University of Mississippi Hydrate Research Consortium (MHRC), a Congressionally Directed Project. In FY 2009, the MHRC received $1.1 million. The Arctic Energy Office, another Congressionally Directed Project, committed a portion of its funds to methane hydrate R&D: $1.85 million in FY 2006, $2.9 in FY 2008 and $1.7 million in FY 2009.

The DOE program goals, with respect to natural gas production from gas hydrates, are to provide the science and technology such that production is commercially feasible by 2015 for Alaska North Slope resources and by 2020 for Gulf of Mexico resources. These goals were developed in collaboration with our Federal research partners in the context of program authorizations provided by the Methane Hydrate Research and Development Act of 2000. The President's request of $25 million in FY 2010 is enough for DOE to work over the next fiscal year toward providing knowledge and technology to enable commercial production of natural gas from hydrates starting in FY 2015 (Alaska) and 2020 (Gulf of Mexico).

2. Dr. Boswell, what is the difference between the long-term production tests that you described us still needing to do and the sorts of tests that have already been conducted in the Arctic and the Gulf? How close are we to doing these production tests?

Answer 2. The critical difference between the few tests that have been conducted thus far and what is needed is time. Given the nature of gas hydrates reservoirs and the lack of any established production history, we believe a series of tests of extended duration (many months to two years) will be required before we can develop a good understanding of potential gas production rates and, therefore, potential commerciality. We intend to conduct such tests first in the Arctic, and then apply the knowledge gained to more challenging marine production tests. This information will add greatly to what has been determined from the three field testing programs (all conducted onshore in the Arctic; two funded primarily by the governments of Japan and Canada; the third funded by the U.S. DOE in partnership with BP), which have been conducted to date.

There have been no production tests conducted or attempted in the marine setting. The three tests that have been conducted have all occurred onshore and have been of very short duration—the longest (conducted by the governments of Japan and Canada in the Northwest Territories in 2007 and 2008) spanned a total of six days. These tests provided critical scientific information on the response of gas hydrate reservoirs to various phenomena, and have enabled us to identify pressure reduction as the most favorable technique. However, they fall well short of the conventional definition of a "production test," which are generally conducted over sufficient time-frames to enable estimation of potential gas deliverability over the multi-year lifespan of producing wells. DOE plans to initiate its production testing program in FY 2010.

3. Dr. Boswell, are we at the point that we can reliably tell from seismic data whether or not methane hydrates are present at a given location?

Answer 3. Our recent efforts in Alaska and the Gulf of Mexico show that we can greatly improve our ability to detect and assess gas hydrate prospects of resource-relevant thickness and concentrations, given access to industry-standard seismic and other datasets. This is perhaps the most critical recent finding in gas hydrates research. In 2006, an effort lead by the USGS delineated potential reservoirs from seismic data in Alaska. These predictions were confirmed by the subsequent 2007 test well drilled by DOE and BP. In 2008, similar predictions were developed for three sites in the Gulf of Mexico. These predictions were then tested by seven wells drilled in the spring of 2009—gas hydrate was expected in high concentrations in sands at five of those locations and at moderate concentrations in two of the locations: in six of the seven wells drilled, initial analysis of log data confirmed the pre-drill predictions.

4. Dr. Boswell, most of the recent work seems to have been done with depressurization. Where do things stand with other technologies, such as thermal injection?

Answer 4. The 2002 test conducted by Japan, Canada, the United States, and other nations at the Mallik site in northwest Canada, combined with subsequent work in the lab and in numerical simulators, has clearly indicated to us that thermal stimulation alone is not effective as the primary means of gas hydrate production. Subsequent short-term tests in Alaska (in 2007) and in Canada (in 2007 and 2008) and associated favorable numerical simulation results indicate that depressurization is the most promising method. However, as optimal long-term well production and operational strategies are developed, thermal injection and other methods will likely play a key role, depending on local conditions. For example, our latest simulations show that periodic thermal stimulation will be necessary to maintain optimal wellbore conditions during depressurization-based production. Therefore, planning for the initial long-term scientific production test in Alaska includes the application (as required by test results) of thermal injection, hydraulic fracturing, and other methods.

5. Dr. Boswell, is there any potential for mining the methane hydrate mounds that appear on the bottom of the sea?

Answer 5. Gas hydrate is known to occur as solid masses, some as large as 10's of feet across, within the shallow deepwater sediment. Portions of these mounds are exposed on the seafloor. Such occurrences likely represent only a small percentage of the projected global gas hydrate resource, with individual mounds likely containing very limited resources. In addition, these sea-floor gas hydrate mounds represent unique and poorly-understood ecosystems. Any potential benefit to be gained from trying to capture these outcroppings as a resource, through mining or dredging, is small compared to the environmental concerns. As such, mining techniques, or any approaches to extraction of seafloor mounds, are not being considered under the current program.

6. Dr. Boswell, one of the witnesses that was supposed to be at the hearing, from ConocoPhillips, was going to discuss technology where they use carbon dioxide to displace methane from the hydrate, which would leave the carbon dioxide behind. Could you provide some detail about that technology, and what its advantages might be if it works as advertised?

Answer 6. The carbon dioxide displacement technology, which has thus far only been studied in a laboratory setting, involves the simple injection of CO_2 into a gas hydrate reservoir via a conventional wellbore. Previous lab studies have shown that exposing methane hydrate to CO_2 results in the spontaneous exchange of the methane and CO_2 molecules. More recently, experiments conducted by ConocoPhillips and the University of Bergen (Norway) showed that, in sand reservoirs, this exchange can happen efficiently and without substantial destruction of the hydrate structure. The initial attempt to test this technology at a field scale is planned to occur as soon as FY 2010, as part of a collaborative project between DOE and ConocoPhillips.

As compared to depressurization-based technologies for gas hydrate production, the potential advantages of the carbon dioxide displacement technology are: 1) the ability to sequester CO_2 while producing methane (a key element for Alaska, in particular, as existing stranded gas resources in the Prudhoe Bay region include 12% CO_2 that will need to be appropriately handled as part of future production); 2) a substantial reduction in associated water production, improving well economics, and simplifying well completions; 3) maintenance of reservoir strength, with reduced risk for sand production and production-related reservoir and ground subsidence; and 4) potential applicability across a wider range of initial pressure and temperature conditions. Among the remaining hurdles are: 1) unknown ability to inject CO_2 at a field scale; 2) potential low rates of methane production; and 3) various issues related to potential sources of CO_2.

7. Dr. Boswell, what kind of other stimuli could we enact to spur the production of methane hydrates?

Answer 7. The most important means to spur the production of methane hydrates is to continue to conduct the needed research and development to demonstrate production potential. The primary barrier to conducting this research at the required pace is the cost of the needed arctic and deepwater field programs. Going forward, as the program begins to conduct these long-term tests, achieving sufficient industry cost-share for these projects will also be an issue, as industry may still prefer to limit direct investment in projects that they deem long-term and high-risk. As a result, some incentives for participation in basic research programs may be warranted.

Mr. COSTA. Thank you, and you too did very well in terms of staying within the five minutes. We will use both of you as examples, good examples.

Our next witness, last but certainly not least, is a gentleman who has firsthand experience, I believe. Mr. Steve Hancock is a Well Engineering Manager at RPS Energy. I am looking forward to your testimony and then the question period on how this is really extracted, because we have a general concept of how we get oil and how we get gas, and how we get it—whether it is onshore or offshore—to where it is refined, but I am still trying to figure out how these hydrates work in that same fashion.

So, Mr. Hancock, you have your five minutes. Please proceed.

STATEMENT OF STEVE HANCOCK, WELLS ENGINEERING MANAGER, RPS ENERGY

Mr. HANCOCK. Thank you, Mr. Chairman, and members of the Subcommittee, and thank you for the opportunity to appear today to discuss the production and economics of gas hydrate development.

Gas hydrate wells will be more complex than most other gas wells due to a number of requirements, including maintaining commercial gas flow rates with high water production, operating at low pressures and low temperatures, controlling sand production into the well bore, and ensuring well structural integrity with reservoir subsidence.

Technologies exist to address all of these issues, but this will add significantly to both capital and operating costs for gas hydrates. Gas hydrates also have one distinct challenge compared to the other unconventional resources, and that is the high cost of transportation to market.

Onshore gas hydrates in North America are located on the north slope of Alaska and in the Mackenzie Delta in Canada. These resources, along with significant volumes of already discovered conventional gas, are stranded without a pipeline to market. In order to compete for pipeline capacity when a pipeline is eventually available, the economics of onshore gas hydrate developments must be attractive at the prevailing gas prices. This fact may delay major onshore gas hydrate development. However, unique circumstances may allow production of gas hydrates for local community or industrial use.

Gas hydrates have also been discovered in the deepwater areas of the Gulf of Mexico and along deep coastal margins throughout the world. Deepwater drilling technology and experience continues to evolve and the worldwide deepwater fleet continues to expand. However, the deepwater environment is still a very high cost and very high risk area of operation. Offshore gas hydrate developments must have strong economic drivers in order to compete with other deepwater exploration and development opportunities.

A number of studies have been conducted to determine the economics of gas hydrate developments. Numerical simulation models calibrated to actual gas hydrate tests were used to develop production forecasts for a variety of reservoir conditions. Commercial field development planning software was used to determine the capital and operating costs for both onshore and offshore locations. The results of these investigations, while preliminary, have been very encouraging.

For onshore gas hydrates, stand-alone development could be economic with a gas price in the upper range of historical North American gas prices, and for deepwater developments stand-alone gas hydrate fields could be economic with a gas price in the upper range as what has been paid for liquified natural gas on the spot market.

Improved understanding of gas hydrate reservoir performance, new technologies to improve production rates and recoveries, and opportunities to reduce costs will improve gas hydrate economics further. However, we do not know everything about gas hydrate production. The small-scale production experiments conducted at both Mallik and the Milne Point projects provided valuable insight. The recent five-day production test conducted at Mallik demonstrated that gas hydrates can be produced with current technology. However to prove gas hydrates as a viable source of natural gas a production test at commercial rates will be required. The long-term production test planned for the north slope of Alaska is an important step in achieving this goal.

Thank you, Mr. Chairman, and I will also be happy to answer any questions you may have.

[The prepared statement of Mr. Hancock follows:]

Statement of Steven H. Hancock, P.ENG., Well Engineering Manager, RPS Energy Canada

Mr. Chairman and Members of the Subcommittee, thank-you for the opportunity to appear before you today to discuss the production and economics of gas hydrate development.

INTRODUCTION

Unconventional oil and gas resources such as heavy oil, coal bed methane, and shale gas, required development of new technologies such as horizontal and multilateral drilling before they could be economically produced. Based on our current understanding of gas hydrate properties and reservoir performance, we theoretically have the technology to drill, complete, and produce gas hydrate wells at relatively high gas rates. So the question has been asked—when will gas hydrates be economic to produce?

There are no simple answers as to the commerciality of any particular gas hydrate accumulation. The economics of any hydrocarbon development can be highly variable due to uncertainties in geology, drilling and facility costs, reservoir properties, markets and commodity prices. Each development must stand on its own merit and unique set of circumstances. We can however examine a number of hypothetical developments to gauge the relative economics of gas hydrates compared to conventional gas. For gas hydrate developments, additional uncertainty must be assumed at this time because there has not been a well test at commercial gas production rates. All gas hydrate production forecasts are based on theoretical numerical simulation models calibrated to small scale controlled experiments conducted at the Mallik (Canada) and Milne Point (Alaska) test wells.

PRODUCTION STRATEGIES

Gas hydrates can be dissociated into natural gas and water by three main methods [1]:

- Depressurization, in which the pressure is reduced below the gas hydrate stability point at the prevailing reservoir temperature;
- Thermal stimulation, in which the temperature is raised above the hydrate stability point at the prevailing reservoir pressure; and
- Injection of inhibitors such as methanol which changes the gas hydrate stability conditions.

Production strategies can use one or a combination of these methods. Depressurization is thought to be the most technically efficient means of production from natural gas hydrate deposits [10], and is the basis for the economic studies reported in this statement.

Most research programs have targeted coarse-grained sand deposits as the most promising reservoirs for the production of gas hydrates. Natural gas hydrate accumulations within these types of reservoirs can exist in a number of ways, including [2, 3]:

- A gas hydrate layer in contact with a free gas layer—this situation has the obvious advantage that the free conventional gas can produced initially, with contribution from the gas hydrate layer starting as reservoir pressure declines

below the stability point. The free gas is theoretically in contact with a large surface area of gas hydrate, which should increase gas hydrate response.
- A gas hydrate layer in contact with a free water layer—dissociation can be initiated by producing the free water layer and dropping reservoir pressure below the stability point. As above, the free water is theoretically in contact with a large surface area of gas hydrate, which should increase gas hydrate response.
- A gas hydrate layer only, with no free water or gas contacts—dissociation can be initiated in the wellbore contact area only.

The onshore gas hydrate developments evaluated in this study compared two gas hydrate reservoirs with single free gas and free water contacts. The offshore gas hydrate study considered a gas hydrate only reservoir

TECHNICAL CHALLENGES

Gas hydrate wells will be more complex than most conventional and unconventional gas wells due a number of technical challenges, including:
- Maintaining commercial gas flows with high water production rates;
- Operating with low temperatures and low pressures in the wellbore;
- Controlling formation sand production into the wellbore; and
- Ensuring well structural integrity with reservoir subsidence.

Technologies exist to address all of these issues, but will add to development costs. Gas hydrate development also has one distinct challenge compared to other unconventional resources, and that is the high cost of transportation to market.

Most gas fields require some compression to maximize reserve recovery, but this typically occurs later in the life of the field after production starts to fall below the plateau rate. For a gas hydrate development, the required pressure to cause dissociation will require the use of inlet compression throughout the life of the field including the plateau production time. This will require a larger capital investment for compression at the front end of the project, and will also result in higher operating costs over the life of the project.

Water production is not uncommon in gas wells, however water rates are typically less than say 10 bbls/MMscf (barrels of water per million standard cubic feet of gas) for water of condensation and/or free water production. Wells that produce excessive amounts of water are typically worked-over to eliminate water production or shut-in as non-economic. The water production from a gas hydrate reservoir could be highly variable, however water:gas ratios in excess of 1,000 bbls/MMscf are possible. This water must be removed from the reservoir and wellbore to continue the dissociation process. On this basis, a gas hydrate development will require artificial lift such as electric submersible pumps or gas lift, which will also increase capital and operating costs over the life of the field. But it is important to highlight that the water in gas hydrate contains no salts or impurities, it is fresh water and may be a valuable coproduced product of a gas hydrate development.

The combination of low operating pressures and high water rates will require larger tubing and flowlines for a gas hydrate development, in order to minimize friction losses and maximize production. Additional water handling facilities and water disposal will also be required. Larger inhibitor volume (such as glycol) will be required to prevent freezing and hydrate formation in tubing and flowlines. Other items such as sand control, reservoir subsidence, downhole chemical injection, possible requirements for near wellbore thermal stimulation, etc., will also require additional capital and operating costs for gas hydrate developments compared to conventional gas developments.

ONSHORE GAS HYDRATE ECONOMICS

Onshore gas hydrates in North America are located on the North Slope of Alaska and on the Mackenzie Delta in Canada. These resources, along with significant volumes of already discovered conventional gas, are stranded without a pipeline to market. In order to compete for pipeline capacity, the economics of onshore gas hydrate developments must be attractive at prevailing gas prices. This may have an impact on the timing of major onshore gas hydrate development, however, unique circumstances may allow production for local community or industrial use. For example, an oil lease on the North Slope in short supply of gas for heating and power generation could make use of gas hydrate production—the produced gas could be used for fuel, and the produced water could be used for waterflood operations to improve oil recovery.

The preliminary economics of two different hypothetical onshore gas hydrate developments are presented in this statement:
- The first case was based on a reservoir in which gas hydrate is underlain by free-gas. The gas hydrate layer in this case had an initial gas in place volume of 1.07 TCF (trillion cubic feet). The free gas layer added an initial gas in place volume of 0.23 TCF, for a total gas volume of 1.30 TCF.

- The second case was based on a reservoir in which gas hydrate is underlain by water. As above, the gas hydrate layer in this case had an initial gas in place volume of 1.07 TCF (with no free gas component).

Gas and water production rates were predicted using the commercial reservoir simulator CMG-STARS (Computer Modeling Group's Steam, Thermal and Advanced Processes Reservoir Simulator).

The field development plan consisted of 5 production wells and 2 water disposal wells. Production was initiated via depressurization in both cases. The capital and operating costs for the various field development plans considered in this evaluation were generated using IHS Energy's Que$tor™ planning software and costing database, plus information from a variety of sources.

Full discussion of these evaluations cannot be presented here. Additional information on reservoir properties, simulation results, capital and operating costs, and detailed economic discussions are presented in [4]. Key results from these investigations are summarized in the following discussion. Note that all prices in this document refer to 2009 United States dollars.

Figure 1 presents the predicted gas production rates for the two cases.

The first case starts out at a plateau or peak rate of 125 MMscf/d (million standard cubic feet per day), and declines thereafter. Note that conventional gas field developments are normally designed around a plateau or peak production rate lasting say two to five years. This is typically the most economic way to develop and produce a gas field considering capital costs and operating life. The high initial production rate is largely due to the free gas below the hydrate layer. After approximately five years, the total field production rate declines as the free gas is exhausted, and the gas production is due largely to gas hydrate dissociation.

The second case starts out at a low gas production rate, and builds slowly to a peak rate at approximately year five and declines slowly thereafter. In this type of reservoir setting, the free water must be produced to initiate gas hydrate dissociation, which itself produces significant water volumes. These water volumes must be produced prior to the start of significant gas production, which results in a slow build-up to peak gas production.

Typical project economic evaluations are based on risked net present value economics. In this procedure, annual capital and operating costs, along with revenues from gas production, are discounted annually from a starting point. Annual discount rates (or internally rates of return) typically range from 10% to 20% to account for cost of capital and risk. Compared to events which occur early in the life of the project, activities in future years are more heavily discounted and thus have less of an impact on the overall project economics.

A gas hydrate only development will characteristically have peak gas production rates occur later in the life of the field, as well as a lower peak production rate and a longer field operating life, compared to a typical conventional gas field. Thus gas hydrate only developments will be somewhat penalized for the expected production characteristics when using net present value economics.

Figure 2 illustrates the sensitivity of internal rate of return to gas price for the two cases considered. This evaluation includes revenues, capital and operating costs, typical frontier royalties, but with no incentives or taxes. In addition, a pipeline tariff to the southern U.S. markets of $2.50/mscf (thousand standard cubic feet) has been assumed.

The first case is reasonably robust as the gas price increases over $ U.S. 6.00/mscf. This is due primarily to the production of free gas early in the project. The rate of return for the second case is somewhat insensitive to increasing gas price, as the discounting on the delayed peak gas production reduces the impact of increasing price. To achieve a rate of return of 15%, the first case would require a gas price of approximately $ 6.50/mscf, and the second case would require a gas price of approximately $12.00/mscf.

Complexities and geologic heterogeneities encountered in any natural settings may either reduce or improve the well performance, which could significantly change project economics. However these preliminary analyses do indicate that the gas price required for a reasonable rate of return for an onshore gas hydrate development is only slightly beyond the peak historical gas prices that have been observed in North America. It is also obvious from these analyses that comparable conventional gas resources will always be more attractive in net present value terms than gas hydrates.

OFFSHORE GAS HYDRATE ECONOMICS

Gas hydrates have also been discovered in the deepwater areas of the Gulf of Mexico and along most of the deep coastal margins throughout the world. Deepwater drilling technology and experience continues to evolve, and the worldwide deepwater fleet continues to expand. However the deepwater environment is still a very high cost and very high risk area of operation. Offshore gas hydrate developments must have strong economic drivers in order to compete with other deepwater exploration and development opportunities.

By all estimates, the majority of gas hydrates considered for production are located in sandstone reservoirs in deepwater environments. In order to understand the economics of deepwater gas hydrates, stand alone field development plan were prepared for a gas hydrate accumulation not in contact with gas or water-bearing reservoirs. The gas hydrate production rates were based on a study conducted in [4] for a deepwater Gulf of Mexico reservoir condition, which used the TOUGH+HYDRATE (Transport of Unsaturated Groundwater and Heat) numerical simulation model. Capital and operating costs were again developed using IHS Energy's Que$tor™ development planning tool and costing database program. For comparison purposes, a similar sized deepwater conventional gas field was developed using the same tools in order to determine comparative economics.

The field development plans for both fields assumed a subsea development in 5000 feet of water. A new purpose built floating production facility plus a 75 mile pipeline are added to standard costs such as compression, dehydration, and separation. Extra costs associated with hydrate gas production, such as artificial lift, reduced platform pressure, and flow assurance are also considered, in addition to sand control. It was assumed that there would be sufficient wells in place to maintain a plateau production rate of 500 MMscf/day, and recover 2.0 TCF of produced gas over a 20 year life. Additional wells were added for both development types to account for structural and drainage issues typically encountered in large areal discoveries.

Figure 3 illustrate the typical gas production profile for the gas hydrate wells studies in [5]. This result follows the previous discussion regarding delayed onset of peak production followed by a decline as the gas hydrate is exhausted. Also as discussed, significant production of water is required to continue the gas dissociation process. Figure 4 illustrates the predicted water to gas ratio for the simulated well. For the first several years, the predicted water volumes are significantly higher than the well could naturally flow with, therefore artificial lift would be required to initiate and assist production through most of the life of the field.

Based on the predicted gas production profile, 48 wells would be required for the deepwater gas hydrate development. For the conventional gas case, it was assumed that 18 wells would be required, but it is noted that this will count could be significantly reduced in prolific offshore gas fields. Figure 5 presents the total gas production forecast for both cases.

Full discussion of these evaluations cannot be presented here. Additional information on reservoir properties, simulation results, capital and operating costs, and detailed economic discussions are presented in [6]. Key results from these investigations are summarized in the following discussion. Note that all prices in this document refer to 2009 United States dollars.

For the comparative analysis, risked cost and production profiles were developed in order to account for greater uncertainty in a gas hydrate development compared to a conventional gas development. Figure 6 illustrates a pre-tax, pre-royalty plot of rate of return versus gas price for the expected results for both the conventional gas and gas hydrate developments.

Given the risks associated with conventional deepwater hydrocarbon developments, the gas hydrate developments probability adds another level of risk which cannot be quantified at this level of investigation. The capital and operating costs developed for this evaluation considered the unique differences between conventional gas and gas hydrate developments and allowed significant contingency to account for these unknowns. While the absolute costs at this level of study have a wide range of uncertainty, the comparative analysis is considered a reasonable indication of the differences between the two types of developments: i.e. while the gas price required to make a gas hydrate discovery economic will be higher than that for conventional gas discovery, the difference in price is measured in terms of dollars, not orders of magnitude. This also again illustrates that on a comparable basis, a conventional gas development will be more attractive than a gas hydrate development in net present values terms.

CONCLUSIONS

The results of these investigations, while preliminary, have been very encouraging:

- For onshore gas hydrates, stand-alone developments could be economic with a gas price in the upper range of historical North American prices, and
- For deepwater gas hydrates, stand-alone developments could be economic with a gas price in the upper range of what India has paid for liquefied natural gas imports on the spot market.

As with all hydrocarbon developments, the economics of gas hydrates will be highly variable, depending upon such factors as well performance, sediment type, gas-in-place, thermodynamic conditions of a reservoir, and the access to existing infrastructure. It is also clear that comparable conventional gas reservoirs will generally be economically more attractive than gas hydrate only reservoirs, suggesting that the production of gas hydrates on a large commercial scale may be delayed.

Unique circumstances may allow production of onshore has hydrates for local community or industrial use, especially where there is some underlying gas. Offshore gas hydrate developments may proceed sooner on the basis that the premium price required may not be onerous when there is no conventional gas competition, and where security of supply may be a major consideration.

Significant scientific and exploration work must be completed before gas hydrates can be considered as a viable source of natural gas. Critical among these tasks remains the validation reservoir and well performance through extended field testing that demonstrates the ability to produce gas hydrates at commercial rates with current technology. The small scale production experiments conducted at Mallik and Milne Point provided valuable insight into gas hydrate reservoir performance. The short term production test recently conducted at Mallik also demonstrated that gas hydrates can be produced with current technology. The long term production test planned for the North Slope of Alaska is an important step in achieving this goal.

Thank you Mr. Chairman, for this opportunity to provide an overview of the production and economics of gas hydrate developments. I would be happy to answer any questions you may have.

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Figure 1: Field Gas Production Rate (MMscf/d) for Onshore Gas Hydrate Study

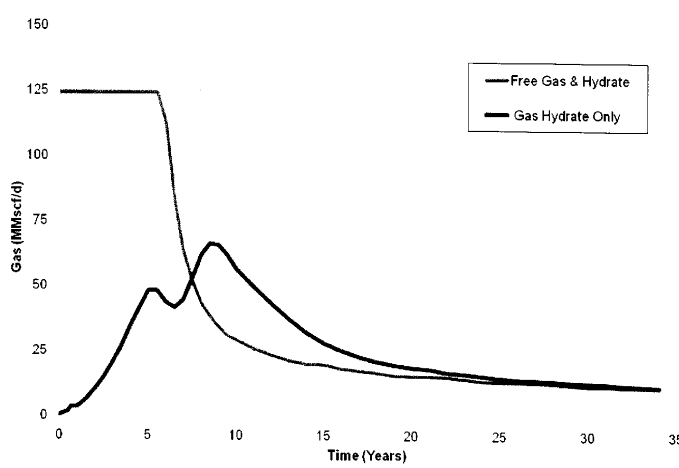


Figure 2: Internal Rate of Return as a Function of Gas Price ($/mscf) for Onshore Gas Hydrate Study

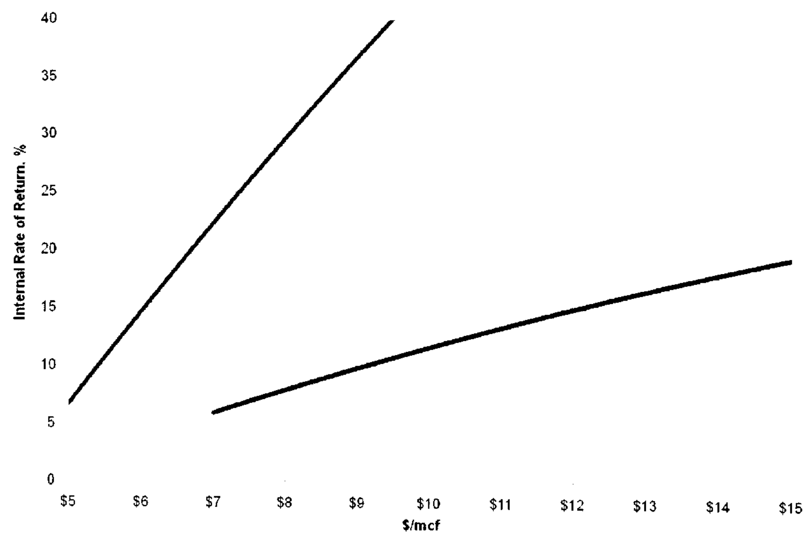


Figure 3: Single Well Gas Production rate (MMscf/d) for Offshore Gas Hydrate Study

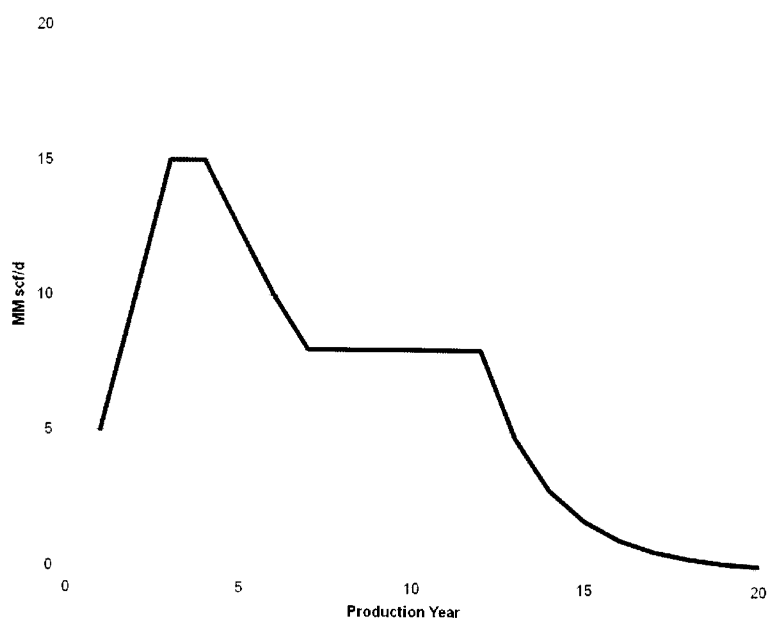


Figure 4: Field Gas Production rate (MMscf/d) for Offshore Gas Hydrate Study

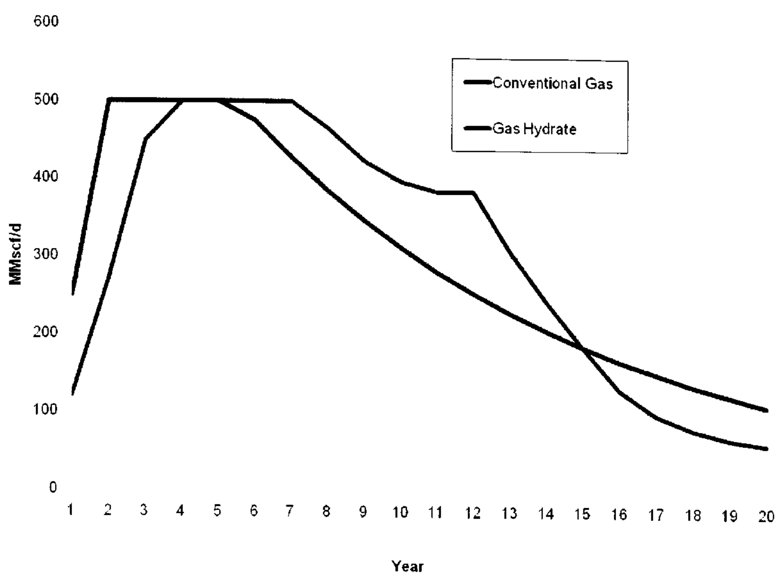


Figure 5: Gas Water Ratio (bbls/MMscf) for Offshore Gas Hydrate Study

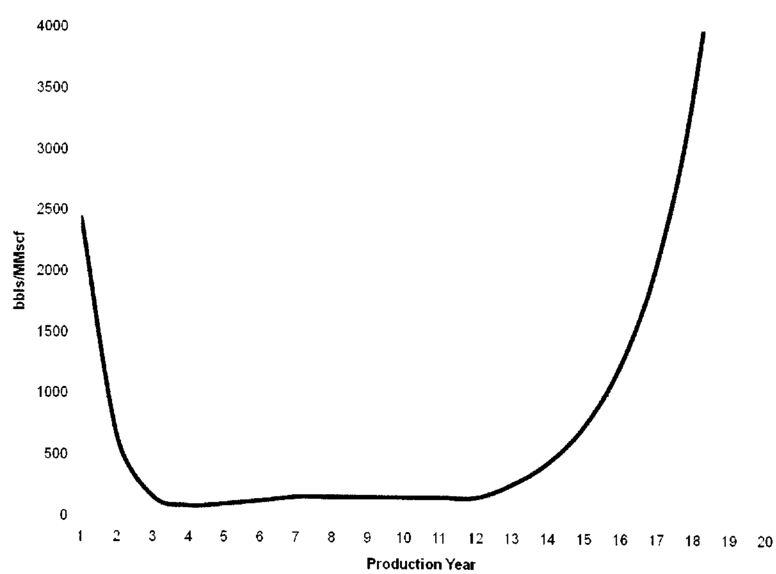
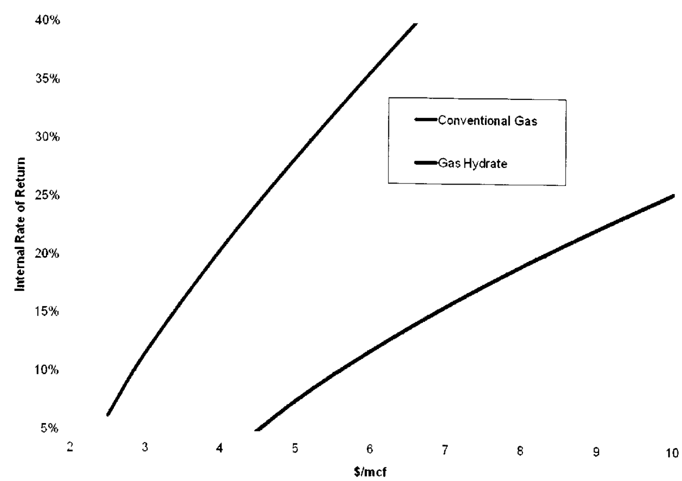


Figure 6: Internal Rate of Return as a Function of Gas Price ($/mscf) for Offshore Gas Hydrate Study



Response to questions submitted for the record by Steven H. Hancock

Questions from Chairman Jim Costa from the State of California

1. Mr. Hancock, what has the industry s financial role been in methane hydrate research efforts? How much money are they putting in now, and at what point would they be able to take over this research entirely?

Answer: I do not have access to any financial data representatives from the USGS and USDOE will be in a better position to address this part of the question.

Most of the large independents and all of the major oil companies conduct research and experimentation on drilling, completions and production technology—once a potential resource becomes a strategic part of their reserves portfolio. The development of heavy oil is a classic example of this, and gas hydrates should follow as similar pattern. As with heavy oil, federally and/or state funded research will be required to prove up the resource potential of gas hydrates. Obviously certain companies such as BP, Chevron, and Conoco-Phillips among others have already identified gas hydrates as possibly being strategically important and have dedicated some resources for research, but the major investigations are still lead by agencies such as the USDOE and USGS. Industry is unlikely to take a lead role until commerciality is proven.

2. Mr. Hancock, how do methane hydrates compare with other unconventional fuels? How would you rank methane hydrates versus things like oil shale, tar sands, etc., in terms of timing and resource potential?

Answer: The unconventional oil and gas hydrocarbons currently being developed in North America have one distinct advantage compared to gas hydrates that being location. Development of shale oil and gas, tar sands, coal bed methane etc. can proceed when the required technology and capital/operating costs are attractive with current market prices.

Unconventional gas projects can generally proceed quite quickly because capital and operating costs are relatively low. Some of the major unconventional gas plays are also close to market, which results in significantly reduced transportation tariffs compared to frontier or offshore gas. This makes it easier for unconventional gas such as tight gas, shale gas, or coal bed methane gas to compete in the North American gas market, even at the low prevailing prices of the current market.

Gas hydrates are located onshore under permafrost in the U.S. and Canadian Arctic regions, and in the deepwater margins around the North American continent there are currently no unconventional developments, oil or gas, in these frontier areas. These areas also contain significant amounts of developed and undeveloped conventional gas resources, much of which is stranded without a way to get to market.

On this basis, gas hydrates will not compete directly with other unconventional gas resources, but rather will have to compete with frontier conventional gas developments. This puts gas hydrates at a distinct disadvantage compared to other unconventional gas resources for access to the larger North American gas market. While a local market use of gas from gas hydrates may be feasible at some point (say fuel for a North Slope industrial requirement or for a town or village), this situation will largely defer the timing of gas hydrate developments until sometime in the distant future.

3. Mr. Hancock, what is the difference between the long-term production tests that you described us still needing to do and the sorts of tests that have already been conducted in the Arctic and the Gulf? How close are we to doing these production tests?

Answer: The short term production tests conducted at Mallik (Canada) in 2002 and Mt. Elbert (Alaska) in 2007 were actually small scale production experiments conducted using advanced logging tools similar to those used in other exploration wells. The test intervals were thin (<3 ft in thickness) and the test durations were short (3-12 hours). The gas production rates were relatively small but measurable. In these tests no gas was produced to surface. The thermal experiment conducted at Mallik did produce gas to surface, but again at relatively low rates. It should be noted that these tests were small scale by design planned to investigate the response of small hydrate layers with known and consistent properties such as pressure, temperature, porosity and hydrate saturation.

During the 2007/8 Mallik flow test, gas was produced to surface and flared over a 5 day period. Again, gas rates were relatively small for this type of test but were still measurable. This test has been the only conventional type of flow test conducted on a gas hydrate well. All of the offshore activities in the Gulf of Mexico have consisted of coring and well logging operations only no testing has been conducted.

Depending upon permeability, short term conventional gas tests can be used to determine reservoir properties several hundred to thousands of feet from the wellbore. Properties such as permeability, pressure, and fluid properties, as well as well productivity and reservoir geometry can be determined from these tests. For the gas hydrate tests conducted to date, the depth of investigation, or distance into the reservoir that has been investigated can be measured in terms of inches or feet. This has provided excellent data regarding the dissociation response and production of gas hydrates in the near wellbore area, and this data has been used to calibrate reservoir simulation models in order to predict long term performance

In conventional gas reservoirs, the gas properties are typically uniform throughout the reservoir, and gas flows from the extreme of the drainage radius of the well (typically 1000 ft. or more) once the well reaches a steady state flowing condition. In a gas hydrate well, gas and water are present and flowing in the reservoir up to the distance where dissociation has taken place past that point the gas remains as a solid in hydrate form. Long term production tests are required to demonstrate that gas hydrate dissociation can be conducted effectively at asignificant distance from the wellbore, and to understand the effects of multi-phase flow of gas and water, pressure response, and temperature or heat flow in the reservoir, combined with the geological complexity in a real life reservoir setting. In addition, a long term test must eventually demonstrate that gas hydrate reservoirs can be produced at commercial gas rates.

For an onshore gas hydrate well drilled from an existing pad, the time required to plan, drill, and complete a well for testing purposes can be accomplished in less than 12 months. A deepwater offshore well test may take more time to execute, especially if subsea equipment is required for a tieback to an existing facility. Arranging funding, agreements, and approvals will add to the timeline, as well as the actual testing time required.

4. Mr. Hancock, you mentioned ranges of prices in your testimonies, but you don t actually provide any numbers. Could you be a little more specific about what sorts of prices would make methane hydrate production economic?

Answer: The work conducted to date on gas hydrate development and economics is considered preliminary at this time. Cost estimates done at this stage of a development plan are typically assumed to have an accuracy of +40% to -25%. Production forecasts used for the gas hydrate developments considered in these studies have been based on theoretical numerical simulation models which have been calibrated only to the short term tests conducted at Mallik and Mt. Elbert. To date there has been no long term or high rate gas tests to demonstrate gas hydrate production potential. Lastly, almost all developments have a degree of geological uncertainty with respect to reservoir extent and variation in properties such as porosity, permeability, and thickness. In addition, proximity to existing infrastructure and processing facilities can have a significant effect on capital and operating costs.

All of these factors contribute to a wide range of uncertainty with respect to capital costs, revenues, and gas recovery, which therefore results in a wide range of gas prices required for the economic development of gas hydrates. In other words there is no single gas price at which gas hydrates can be declared to be economic. Each field development, conventional or unconventional, must stand on its own technical and economic merit.

Many corporations also have widely varying criteria for economic evaluation, and differing risk tolerance. Most of the companies that work frontier or offshore deepwater projects are also large in nature, and have a large inventory of prospects for exploration and development gas hydrates will have to be competitive with these projects in order to attract funds.

Forecasting oil and gas prices have proven to be a difficult task, even for those who specialize in this type of work. While these price forecasts may be interesting for macro type economic studies, most oil companies take a very conservative approach to prices for evaluating the economics of any development. For example, the current price of oil is $70/barrel, and has ranged to well over $100/barrel in the recent past. However, the economics of deepwater developments in the Gulf of Mexico are still typically evaluated with a price forecast of say$35/barrel to $38/barrel. This is done because in addition to the uncertainty discussed above, the stability of commodity prices over the life of a project is also a major risk that must be considered.

The work done on a very few examples of gas hydrate developments suggest that reasonable returns on investment can be achieved with prices in the order of $6.00 to $12.00/thousand standard cubic feet for offshore and onshore projects respectively. However, considering the risks and uncertainties discussed above, sustained gas contract prices in the range of $10.00 to $16.00/thousand standard cubic feet for offshore and onshore projects respectively may be required before gas hydrate projects will proceed. Lastly, fundamental changes in the North American gas market supply picture, as well as advances in technology may have a significant impact on the price range required for gas hydrate development.

5. Mr. Hancock, most of the recent work seems to have been done with depressurization. Where do things stand with other technologies, such as thermal injection?

Answer: Dissociation of gas hydrates can be accomplished by lowering the pressure below the stability point, increasing the temperature above the stability point, or using chemicals (methanol or glycol) to change the stability conditions. Depressurization can be used alone. Thermal or chemical stimulation techniques must be combined with some depressurization in for the well to flow. All of these techniques can be used in conjunction with vertical wells, or high angle, horizontal, or multilateral wells. Fracture stimulations to increase surface contact area with the wellbore may also be used in conjunction with these well types. It should be noted that both the Mallik and Mt. Elbert wells were vertical. Other well types may be considered as part of the long term tests currently being planned.

Pressure drawdown in the wellbore is very easy to control by flowing the well against a low pressure at surface. Artificial lift (downhole pumps or some other method) will be required to remove produced water in order maintain low pressure in the wellbore. Pressure reductions in the reservoir can be effective many hundreds or even a thousand or so feet away from the wellbore can be effectively used to cause gas hydrate dissociation.

Thermal stimulation techniques have been used effectively in heavy oil applications. Steam applied in SAGD (steam assisted gravity drainage) operations or huff and puff (alternate steam injection and oil/water production cycles) are used most commonly. Electrical, including induction and resistance heating as well as microwave, has had some limited success. Heavy oil wells are typically quite shallow and relatively low cost. Thermal conductivity in the reservoir is low therefore steam injection wells must be drilled relatively close to the production wells. Because of the value of the product (oil), heavy oil developments can afford the capital and operating costs associated additional well and thermal operations.

For gas hydrate developments, the value of the product produced (gas) is much lower than the value of the product produced in heavy oil operations on a per volume basis. Therefore gashydrate developments cannot be effectively drilled at the close well spacing that is used in heavy oil. In addition, most of the product heated in the reservoir is actually water (1 cubic feet of gas hydrate releases 0.9 cubic feet of water) which means that much of the heat transferred into the reservoir is wasted. On this basis thermal operations for gas hydrates will probably not be economic.

Likewise chemical usage to cause gas hydrate dissociation will probably not be economic on the basis of the shear amount of chemical required on a reservoir scale. However research in both thermal and chemical stimulation methods will continue, and some elements of both may be incorporated in the long term test currently being planned.

Based on the results of various numerical simulation studies performed on a variety of gas hydrate reservoirs, simple depressurization will be the most effective and economical method of gas hydrate dissociation and production.

6. Mr. Hancock, what sort of difference is there in the cost of production between conventional gas and hydrates?

Answer: Capital and operating costs for gas hydrate developments will be highly variable depending a number of factors including geological model, well productivity, presence of free gas associated with the gas hydrate, and availability of capacity in existing processing plants and pipelines, among others. Thus an absolute comparison of the costs of gas hydrate and conventional gas developments is somewhat difficult.

Only one study has been completed comparing a conventional deepwater gas field to an equal sized deepwater gas hydrate field. Both cases were stand alone developments with sufficient wells to produce the same amount of gas over a 20 year life. For the assumptions used in this study, the capital and operating costs for the gas hydrate development were approximately twice that of the conventional gas field.

On the basis of the studies done to date, gas hydrate developments will have capital and operating costs significantly higher than other unconventional or conventional developments due to well productivity, low operating pressures and temperatures, and high water production rates. Surface facilities for gas hydrate developments will also be higher due to the requirements for larger surface flowlines and inlet facilities (required because of low pressures and water production rates) and the requirement for inlet compression into the processing plant.

7. Mr. Hancock, why do methane hydrate production rates peak in later years, while conventional natural gas wells peak immediately?

Answer: Unconventional hydrocarbons are so called because they are found in formations other than the typical sandstone or carbonate reservoirs i.e. extremely low permeability or tight,reservoirs, shale, or coal beds the hydrocarbons are in their normal fluid condition and can typically flow without undergoing a fundamental change (except of course for bitumen).

The types of reservoirs targeted for gas hydrate testing (and eventual development) are relatively high permeability conventional sandstone reservoirs however the methane gas is locked in a solid gas hydrate crystal so actually the gas is unconventional, not the reservoir.

All gas reservoirs, conventional or unconventional, are capable of their maximum rate on day one of operation. This is because the reservoir pressure is at its maximum (average reservoir pressure declines with production for most reservoirs), the gas that initially flows into the well is in the near wellbore area, and of course the gas is continuous throughout the reservoir. As gas production continues the gas that flows into the wellbore flows through the reservoir rock from greater and greater distances away. Flowing gas through the reservoir rock results in additional pressure loss, and the production rate begins to decline. Some gas wells in high permeability conventional reservoirs can flow at a more or less constant rate or steady state condition for some time, but eventually the production rate will decline. Unconventional gas reservoir production rates typically decline quite rapidly, and may never actually reach any sort of steady state production, although the rate of decline will drop and the wells may produce for many years.

At the start of production for a gas hydrate reservoir, there is no free gas in the reservoir it is all locked up in the hydrate crystals in the pores space of the reservoir rock. The hydrate must first be dissociated, and then the water and free gas can flow to the well. Because water and gas is flowing simultaneously (termed multi-phase flow), the pressure loss through the reservoir will be higher than if just gas only was flowing. Gas and water saturations through the dissociated region will change with time, and gravity will affect the gas and water phases, therefore the flow mechanism will be quite complex.

Gas hydrate dissociation initially occurs in the near wellbore area, and the area where dissociation takes place gradually moves way from the wellbore. If you imagine this dissociation front as the surface area of a cylinder, the surface area of gas hydrate being dissociated increases proportionally to the increasing radius or distance away from the wellbore. Therefore, as this surface area grows, the rate of hydrate dissociation increases, and the rate of gas production also increases. Based on simulation studies, the maximum gas production rate therefore occurs not on days one as with conventional gas reservoirs, but some time into the future, typically years.

8. Mr. Hancock, what kind of other stimuli could we enact to spur the production of methane hydrates?

Answer: Economics, and perhaps a unique opportunity, will determine the timing of the first gas hydrate production. Given the current state of the gas market in North America, royalty and tax relief along with incentives or subsidies may be required to bring forward the timing of the first gashydrate production.

The SEC (Securities Exchange Commission) has very strict rules defining when gas resources such as gas hydrates can be defined as reserves (and can therefore add value). Among other requirements, a demonstration of sustained production at commercial rates is required. Therefore the greatest need at this time in order to spur the production of gas hydrates is an extended well test (or series of tests) that demonstrate long term production capability and that gas hydrates can be commercially produced.

Mr. COSTA. My, my, my, we have to invite these witnesses back.

[Laughter.]

Mr. COSTA. Really. Thank you very much. We do appreciate the concise, precise brevity of your statements, and that is very much appreciated.

Now comes the fun part. We get to ask questions, and let me begin with my first question.

Dr. Collett, how accurate do you think those estimates are in the availability of nationwide methane hydrates? The last estimates were 1995, I think.

Dr. COLLETT. Sure. What is important when we look at the assessments is to understand their evolution much like your question is trying to address. In 1995, we made a very basic assessment based on geologic concepts of our understanding of hydrates at that time, the geologic controls, and tried to forward predict how much gas is in the hydrates—and that is to the molecular count. That is, the amount of gas we feel is in the hydrates is irrelevant, and not linked at all to recoverability. We had no understanding——

Mr. COSTA. And clearly the testimony indicated that based upon where we have identified levels of those hydrates, methane, that some has higher concentrations——

Dr. COLLETT. Right.

Mr. COSTA.—of methane than others.

Dr. COLLETT. And as the evolution of our understanding has moved forward over the last 10 years, or now 14 years, we have focused much more on concentrated gas hydrate accumulations in sand reservoirs, as Dr. Boswell has indicated. The concentrated reservoirs are critical when you start thinking about rate of return, the amount of gas it actually yields from the reservoir per unit time, and the production rate itself.

Mr. COSTA. So the estimates——

Dr. COLLETT. So our assessments have moved away from this kind of molecular calculation of all the gas out there to more closely what gas can actually be produced from hydrates, so we are focusing on only a small part now of that total large number. The large number probably has not changed—you know, the total volume of hydrate—volume of gas and hydrates worldwide—but as you look at the volume of what we think can be producible, our assessments in more recent time has focused on that component.

So last year when we reported our five-year-long study from the north slope of Alaska, we felt our information on Alaska, our knowledge of the hydrates had reached the point that we believe they are technically producible in that environment from sand reservoirs. So, that assessment number at 85 trillion cubic feet, unlike the 200,000 TCF, which you hear for the entire U.S., this is an area on the north slope, we believe that 85 TCF——

Mr. COSTA. Is recoverable.

Dr. COLLETT.—is recoverable.

Mr. COSTA. OK. Dr. Boswell, obviously based on the testimony this morning a lot of work has been done. What do you think is the biggest lesson we have learned about hydrates over this time as it relates to a potential energy source not only as it relates to other conventional energy sources but the other energy tools in our energy toolbox that I spoke of in my opening statement?

Dr. BOSWELL. Thank you for the question.

I think the major thing that we have learned is that our prior conceptions of gas hydrates, which was based on not very much data at all, were very simplified.

Mr. COSTA. Speak more into the microphone.

Dr. BOSWELL. I am sorry. We had some very simplified concepts of gas hydrates just even 5 or 10 years ago, and through a series of field expeditions throughout the oceans of the world we have now realized that gas hydrates in the marine environment take a wide variety of forms. There was a prior conception that gas hydrates in Alaska were one thing and gas hydrates out in the ocean were something different, and people could see how the gas hydrates in Alaska would be produced, but they thought the gas hydrates out in the ocean were widely dispersed, diffused, low concentration, big accumulation but very lean, and no one really had a concept of how you might go about producing them, and that is why hydrates stayed this 30 years off thing in a lot of peoples' minds.

But recently what we have learned is out in the marine environment there are concentrated deposits of gas hydrates and perhaps a significant amount of them, and we have an MMS assessment that suggests there is 6,700 TCF of gas in sand reservoirs, likely at high concentrations, just in the Gulf of Mexico. So that is a smaller number than the 200,000, but it is still a very big number.

So that is probably the main thing that we have learned. The marine resource is no longer this exotic, strange thing that is going to require some brand new technological breakthrough to get to. It exists in accumulations that are not entirely unlike what industry is used to drilling, and we can use technologies existing, well drilling and completion technologies that industry is using.

Mr. COSTA. Before my time expires, thank you. Mr. Hancock, you talked about among the challenges facing on retrieving this methane hydrates the availability of pipeline and the cost. But could you please give us a little more descriptive—I mean, some of us have been to both onshore oil and gas wells and we have been to offshore platforms, and so we have a sense of how they operate. But when you see a methane hydrate, I mean, it is composed, like was said, of molecules in ice, but how do you actually retrieve that gas whether you are onshore or offshore?

Mr. HANCOCK. Actually the process is almost identical to flowing any other conventional oil or gas. You create a pressure drawdown just by removing the water, the hydrostatic head in the well, opening a valve, and doing that the hydrate will disassociate into both gas and water in the formation, in the reservoir, and then you simply produce the gas and the water much as you would in any other well.

Mr. COSTA. And so it comes up and it separates from the water?

Mr. HANCOCK. The gas and water in the reservoir will flow to the well bore. You may need artificial lift to actually produce the water because of the volume, but basically the gas will flow naturally up the well just like every other gas well, and the water, of course, will flow or will be pumped up the well just like any other well that has water production.

The disassociation, the complex understanding of how gas hydrates disassociate, takes place in the reservoir away from the well bore. All the well sees actually is just gas and water.

Mr. COSTA. And the issues with regards to its impact on air quality, CO_2 and other impacts?

Mr. HANCOCK. Basically we are talking about pure methane. No CO_2, no hydrogen sulfite, no heavier hydrocarbons; basically pure methane and essentially fresh water. So the impact will be no different than any other carbon fuel.

Mr. COSTA. And my time has run out but maybe if we come back to it. I guess as intrigued as I am about the potential here, I am also wondering—I am one who supports expansion of offshore oil and gas, but for those who are opposed to it I am wondering whether or not they would have the same reasons to oppose the extraction of methane hydrates because of their concerns of spills, their concerns of platforms, their concerns about the potential impacts of oil and gas that I don't share but, nonetheless, they feel are issues of concern.

Mr. HANCOCK. With gas hydrates or methane hydrates, of course, we are producing methane only. It is the cleanest hydrocarbon that we have. The water that is produced will be slightly saline, but certainly much fresher than sea water. Disposal will require dedicated disposal wells if you're onshore. It will be released to the ocean if you are offshore. But there is no hydrocarbon carryover that you have to worry about or anything like that, and certainly there can be no hydrocarbon spills.

Mr. COSTA. OK. Well, my time has expired, and I will defer to the gentleman from Colorado, Mr. Lamborn.

Mr. LAMBORN. Thank you, Mr. Chairman, and this is fascinating. Were any of you surprised by the production test at the Mallik test well that these good results came about just through the simplest method of production using depressurization?

Mr. HANCOCK. Pleasantly surprised, yes. When we first planned the tests at both the Canadian site at Mallik and in Alaska at Milne Point, the expectation was that we would be measuring gas at extremely low rates, almost too small to measure. But when we did the first experiments, which were just very small-scale pressure drawdown experiments, and pressure depletion is seen as sort of the most economic or easiest way to cause hydrate disassociation, the hydrate response was instantaneous, and that was shocking, to say the least. We expected to be doing something quite different.

So, we actually in the testing process tested it like we would test any other tight gas well, or say a cold-bed methane. It was more a conventional test. So, the response actually was pretty good. We also did a thermal test where again we had a very good response from the reservoir, and both of these have been used to calibrate some of the simulation models that we have used to look at how we would flow these wells on a commercial scale.

Mr. LAMBORN. OK, thank you.

Is the co-produced water associated with methane hydrate reservoirs potable, that is, fit for human consumption?

Mr. HANCOCK. I don't believe it is. The pour water in the reservoir has some salinity. The water released from the hydrate is fresh, but there will be some mixing of those waters so it will not be potable.

Mr. LAMBORN. Would it take much treatment to make it so?

Mr. HANCOCK. If you are talking about desalination, and I am not an expert on that at all, but the salinity will be much less than sea water so theoretically I guess it could be easier.

Mr. LAMBORN. OK. And for anyone of you, how important is the joint partnership with industry in identifying the methane hydrate resources and in developing the technology to produce these resources?

Dr. BOSWELL. It is very important. We conduct our research through cooperative agreements with industry, and that is a requirement for our projects to go forward primarily because they own the land rights and the leases and they have facilities that we need, and they have data that we need. So we have been very fortunate to have BP, ConocoPhillips, Chevron willing to participate with us on this science. Without their help we would have certainly a much tougher time getting to the answers to these questions.

Mr. LAMBORN. Now, did anyone else want to add to that before I go to my next question?

OK, Dr. Collett, two questions. Are there methane hydrates off the coast of California?

Dr. COLLETT. Yes, there is. One of the most interesting ones are these near-surface type hydrate accumulations, what occur in vent sites where there are actually gas seeps, and those are relatively common off the southern coast of California. As you look at the entire California margin, in fact, the entire western margin of the United States, hydrates are well known, particularly a place called Hydrate Ridge offshore Oregon where they actually have been drilled during the ocean drilling program.

So we feel hydrates are almost ubiquitous. They are pretty much uniform to the entire continental margins and most marine basins, but the critical aspect is the nature of the hydrate occurrence, the sand reservoirs versus the disseminated.

The vent sites, I should also add, most of us don't look at the vent sites as any of a potential resource. This is an environmentally very delicate, very sensitive environment. The hydrates we look at as a potential resource are deeply buried, you know, well deep into the sediment column below the hydrate stability field, or in the stability field and below in sand reservoirs. So it is important to understand that sometimes when we see hydrates you see this outcropping nature, but that is not exactly what we are looking at for the resource.

Mr. LAMBORN. Now, for that which might be usable as a resource off the coast of a place like California where fresh water is also——

Dr. COLLETT. Right.

Mr. LAMBORN.—a concern, is the slightly salty yielded water which would be, I assume, easier to desalinate than sea water——

Dr. COLLETT. Yes, I would like to add to that conversation, you know, that question and answer, is that when you look at hydrate itself, the physical nature of hydrates, it has no salt in it at all. The crystalline solid excludes salt. It actually is used in industry procedures as a purification project or product where you can actually purify water by removing all the solids from it. So the hydrate itself has no salt content at all.

What Mr. Hancock was indicating is that the co-produced waters, the non-hydrate bearing waters can be elevated in salt. In most environments we find that those salts aren't highly elevated at all, so there would be a mixing of these components.

So through either complex well completions, focusing on just hydrates, or where you could just produce hydrate water alone, or these co-produced waters need to be dealt with, but in most cases they are going to be very low salinity production streams, and there are actually companies that are looking at hydrates as a potential source of water, of fresh water where it could be an important commodity, maybe even in some environments more important than the gas itself.

Mr. LAMBORN. OK, thank you very much, and thank you all for being here.

Mr. COSTA. All right, the gentleman's time has expired, and the next colleague on our list here is a gentleman who has been voted among the most attractive Members in the Congress. I don't know how you get that designation. I have been trying for years. Mr. Heinrich.

Mr. HEINRICH. Mr. Chairman, you need both your wife and your mother on the selection committee, it helps.

[Laughter.]

Mr. COSTA. Mr. Heinrich.

Mr. HEINRICH. Thank you, Mr. Chair.

I want to get a sense for the geographic distribution of concentrated hydrates where they would be technically recoverable. Do they tend to occur in areas that are geographically separate from some of the other more conventional sources of gas we have had in the past, or would there be cases where they would co-occur at different elevations in the sea floor, different elevations in a sediment column? How does that work, or what is your experience, I should say?

Dr. COLLETT. Our experience is they are closely related, and one reason for that is the reservoir component itself; you know, the sand reservoir where conventional reservoirs occur have the same geologic controls, and this is very important. As you get closer to understanding gas hydrates, we find there are many similarities with conventional gas reservoirs. So the nature of the reservoir itself in the co-existence of hydrates near existing hydrocarbon accumulations because of this depositional environment is consistent.

The other issue is the source of the gas itself within hydrates. It is a very simple concept. If you have a lot of hydrate, you need a significant source of the gas, and oftentimes the gas source for hydrates, the highly concentrated ones, particularly in the Arctic, the Caspian Sea, the Gulf of Mexico, the Black Sea, are areas where you have a thermogenic source coming from depths from the conventional resources themselves also sourcing the hydrates.

So, when we visualize hydrates today, we see hydrates as a continuation of these what we call petroleum systems where they are often closely related to conventional resources.

Mr. HEINRICH. Would we have inadvertently developed some portion of these hydrates in taking conventional gas and reducing the pressure on a hydrate system and have that flow into some of the places that are already producing?

Dr. COLLETT. Right. Yes, one of the particular places where we believe this has taken place is actually since the late 1960s in a field—I actually had the opportunity to work in the late 1980s called the Messoyakha Field in the West Siberian Basin. It has a conventional gas field capped by hydrates, and when that field was brought online as a conventional gas the hydrate disassociated the top of the hydrate cap supporting production over time.

There is also a project that Dr. Boswell could elaborate on, on the north slope of Alaska with DOE in the community of Barrow, one of the native communities, where they are looking at co-production of hydrates in an existing gas field that is being produced since the 1940s called the Barrow Gas Field.

So this could be happening. We don't think it is a common event because most production, particularly marine environments, have been very separated from the hydrate stability field, would have been much deeper. But as we advanced into those deeper water environments and also in these higher Arctic environments, this has probably been a common event, but we are just starting to realize it.

Mr. HEINRICH. So someone who currently holds a lease in one of those areas where you might have co-existence of the hydrates at one elevation and conventional sources at another elevation, they would already have the production rights to potentially produce those hydrates, wouldn't they?

Dr. COLLETT. It is my understanding as a scientist when I have been asked this question and discussed this with BLM and also MMS, there is no official ruling but every discussion about it has made that assumption that would be true. There hasn't been a case where that has been documented and been asked within a lease or the request, but every discussion that has taken place that I have been witness to has indicated that they would be combined.

Mr. HEINRICH. Because we take sort of a bird's eye view to leasing, right? So everything as you look down within——

Dr. COLLETT. Right.

Mr. HEINRICH.—those sections——

Dr. COLLETT. Yes, the center of the earth to the surface of the earth, and it would be hard to imagine as a scientist how to separate them, but again, our experience has not been as such, that a permit has been issued or on a gas hydrate lease, so the official event of that ruling event has never taken place, but every indication has been from all the interested parties that it would be.

Mr. HEINRICH. OK. And I would assume as these disassociate into water and methane, that basically means that the post-production portion of dealing with the fuel is exactly what we do now with methane, so there is not really any technology after production that is different than producing conventional methane or am I wrong about that assumption?

Dr. COLLETT. I think I will defer to Mr. Hancock on that one because I think he——

Mr. HEINRICH. Mr. Hancock.

Mr. HANCOCK. Correct. Once the gas is produced basically it just has to be dehydrated and it is ready for use as a fuel.

Mr. HEINRICH. OK.

Mr. HANCOCK. No other processing.

Mr. HEINRICH. I yield back, Mr. Chair.

Mr. COSTA. I thank the gentleman from New Mexico, and that is very interesting. The next member of our Subcommittee is the gentlewoman from Wyoming, Cynthia Lummis.

Mrs. LUMMIS. Thank you, Mr. Chairman.

This is fascinating. I come from a state that produces a tremendous amount of——

Mr. COSTA. I stand corrected, Ms. Lummis. I apologize.

Mrs. LUMMIS. Thank you. Of cold-bed methane, and so I have some exposure to the recovery of methane through different hydrocarbon sources, so this is wonderful news.

Could you tell me what the next steps are, if there are regulatory mechanisms that the Federal government needs to establish or loosen in order to facilitate the recovery of these resources? And that question is to anyone.

Dr. BOSWELL. I can address what the next steps in terms of science and technology development are.

Mrs. LUMMIS. OK.

Dr. BOSWELL. And certainly the next big step is to conduct an extended term production test, and we have a project underway with the three major—well, with BP, and we are trying to develop a cooperative project with them—ConocoPhillips and Exxon—to conduct an extended test in Alaska, and that is really the next step, and it is also the only place on the planet where such a test can be feasibly executed right now.

And so we have a lot of international interest in that test, a lot of interest in seeing it go forward, and it is a test that we hope to start next year, and it will be an extended term test, at least a year perhaps. That is really the next big thing that needs to be done. There also needs to be more drilling and examination out in the marine environment. Thus far we have been concentrating on the Gulf of Mexico, but there are certainly a lot of gas hydrates elsewhere to look at. So those are the two big things that need to happen science-wise.

Mr. HANCOCK. From an engineering point of view, the next step or the process of steps really needs to demonstrate that we can produce gas hydrates at a commercial rate with the technologies that are available. Based on the information we have now theoretically we think we can. However, we still have to prove that.

Mrs. LUMMIS. And Mr. Chairman, what amount is deemed commercially recoverable for purposes of making a well or a well field cash flow?

Dr. COLLETT. And Steve is looking at me. You know, I think the important aspect when we look at that it is always going to be site-dependent, which your question has already indicated.

Mr. COSTA. Slightly what?

Dr. COLLETT. Site-dependent.

Mr. COSTA. Oh, site-dependent. Oh, sorry.

Dr. COLLETT. And a marine hydrate well is going to be very different than an onshore well on the north slope of Alaska, and I think Mr. Hancock has experienced that. We have actually looked at some of the breakeven or the cost returns in particularly Arctic wells and also in situations in the marine if you wanted to, I think, add that detail.

Mr. HANCOCK. We have looked at a number of scenarios, if you will, for the economics of gas hydrate developments, and as Tim pointed out, each field is unique and each will stand or fall on its own set of circumstance so there is no sort of general price that says, you know, above $7 MCF all gas hydrates are economic. It all is going to depend on a lot of the site-specifics.

But we have looked at developments onshore in the Arctic and, of course, in doing that we have to include a pipeline tariff to come to the main market in the continental U.S., and I don't want to dwell too much on prices. When we first started this work it was really to try to understand will gas hydrates ever be economic.

Mrs. LUMMIS. Yes.

Mr. HANCOCK. We actually have found in doing the work for both onshore and offshore developments that the price required is only a few dollars beyond what conventional gas requires for a similar type development, but those few dollars can make the difference between whether a project goes or doesn't go. So, it can be economic at prices we have already paid in North America, but there is a lot of gas ahead of it, so the commerciality has yet to be sort of proven, and therefore the recovery in terms of how much of the technically recoverable reserves can be economically recovered is open to debate just because of the volatility of gas prices in North America.

Mrs. LUMMIS. Yes. And Dr. Boswell, quickly, I would ask why is Alaska the appropriate platform for the next long-term test? And what cooperation occurred between the government and the private sector in order to complete the 2002 Mallik test?

Dr. BOSWELL. Well, our program is going on two tracks. One track is, is there a significant volume of gas hydrate that makes this a prize worth pursuing, and the other is, if there is, can we produce it, and we have been doing those in parallel, and we have been using the known occurrences of gas hydrates, and Dr. Collett through 20 years in Alaska has pretty much given us a good feeling that there are gas hydrates there, and we know where they are, we know how to find them, so it is a natural laboratory for investigating producibility.

In the marine environment, we don't have that same database, and so we are exploring to see how much is there and where it is. So that, I think, is the answer to your first question. Alaska is the first place where we know where they are, and we can do a test economically also because it is not out in the deepwater.

As far as the Mallik test in 2002, that was a project that was supported by Japan and Canada with a number of international collaborators, including the DOE and groups from India and others.

You asked about the industry involvement in Mallik? I don't believe there was an extensive industry involvement, but Steve and Tim are much more familiar with that project.

Dr. COLLETT. Yes, I was the co-chief scientist on both the first two phases of the Mallik project in Canada. Then there is the Mount Elbert, similar sounded project with BP that Dr. Boswell was involved in two years ago. The Mallik project really started off as a catalyst between the U.S. Geological Survey, the Geological Survey of Canada proposing to Japan who was interested in marine hydrates—again, very poorly understood—come to the Arctic to understand hydrates, and we decided on the Mallik site because of previous industry drilling. Again, this database and insight moved through a series of geologic, then testing programs over now a 10-year period of testing at Mallik of looking at hydrates from a geologic and other perspective.

So, again, very heavily leveraged when you look at the Japanese National Oil Company, the surveys of the two countries, DOE, it is a heavily governmental-leveraged program, and again, it is pretty logical why, is that you have something that is at a pretty high risk resource still. Our knowledge is not well developed, so the industry had been slow to really gain this, but I think particularly Dr. Boswell can add the ConocoPhillips projects in Alaska. Partnered with DOE, the BP projects have all been significant projects to evolve over the last 10 years.

Dr. BOSWELL. Another 30 seconds. The Milne Point project that we had in 2007 was very important because we want to conduct this test, we want to conduct it in the Greater Prudhoe Bay area, and that is a science project coming into an existing business environment, and there is quite a lot of concern by industry on whether we were going to cause a problem—you know, we were going to cause them to lose revenue and things.

So our project up there which we conducted went very well. It didn't cause a single problem, and the demonstration that we could do that, go up there and do that sort of scientific experiment in their back yard is part of the reason why we are getting a lot more interest from industry now to collaborate with us on the upcoming longer term test.

Mrs. LUMMIS. Thank you all for being here. Thanks, Mr. Chairman.

Mr. COSTA. Thank you. The gentlewoman's time has expired.

Mrs. LUMMIS. I snuck that question right under the——

Mr. COSTA. I saw that. Unfortunately, Mr. Holt had to go to the Floor because I was hopeful that he would get a chance to get his questions in.

I am reminded by our panel experts of an old respond when sometimes I am with a large group that if you make answers to questions long enough you discourage further questioning. I hope that is not the strategy with our panel members here.

Mr. Hancock, given the economic considerations here, what do you think is realistic in terms of the industry's ability to start producing natural gas from hydrates?

Mr. HANCOCK. I think realistically you need to try to understand how industry actually selects its projects, and every company has an inventory of prospects and only the top prospects get drilled and developed each year. So until the economics of hydrates actually start to approach the economics of their conventional or unconventional prospects it is going to be difficult to see how industry is going to be driven toward hydrate development at this point in time.

Mr. COSTA. All right, a couple of other quick questions here. We do have Floor debate going on and some other hearings that are taking place concurrently.

Dr. Boswell, how much money is the United States spending on this with DOE, and what is the goals for production of hydrates in 2015, and marine hydrates in 2020?

Dr. BOSWELL. I am sorry. I didn't catch the second half of that question. What are the?

Mr. COSTA. What are the goals for——

Dr. BOSWELL. OK.

Mr. COSTA.—hydrates both production in the Arctic in 2015 and production in marine hydrates by 2020?

Dr. BOSWELL. The amount of money that we spend in the U.S. has historically been probably around $20 million.

Mr. COSTA. How does that compare to Japan?

Dr. BOSWELL. Japan does not officially say how much they spend, but based on the level of their activity I am sure that they are spending at least double that.

Mr. COSTA. OK.

Dr. BOSWELL. Probably triple that.

As far as the goals, our goal is by 2015 to have all the knowledge and technology and the demonstration in place so this is now an option that industry has to consider for meeting demands, by 2015 for the Arctic.

It is going to take more time to do that, of course, in the offshore. The tests are going to be much more expensive, and we just don't know quite as much about it, so that is why that date is further back in time, but it is the same thing. It is demonstrating that there is the ability and the technology that can make commercial production viable.

Mr. COSTA. Because Japan is spending twice as much as we are, does this put us at a competitive disadvantage if in fact would we have to import at some point their technology?

Dr. BOSWELL. We have active ongoing collaborations with Japan that we hope will address that issue. I don't think that it is going to put us at a competitive disadvantage. I think we are spending our money fairly efficiently right now, and the projects that we have in place, if they are able to go forward the way they should, I think will keep us at the head of that curve.

Mr. COSTA. Mr. Hancock, you talked about ranges of prices and I think natural gas—of course, I come from an area in California where we have air quality issues and we are non-attainment areas, as well as in southern California, trying to meet those goals are challenging, and I think gas, natural gas is one of the energy—I call it du jour.

Where does methane hydrates fit in—in terms of its ability to become cost effective?

One of the arguments that I am told is that we don't use more gas is because even though it has been found available and we increase our known finds, that it doesn't compete economically with other forms of energy. Where does methane hydrates fit in—in terms of its break-even point? What price of natural gas do we have to have for the extraction of hydrates ultimately to economically pay off?

Mr. HANCOCK. For gas hydrates onshore to be competitive, return a reasonable rate of return for the people who are investing the money in the development, and I hate to give an exact number, but it is probably closer in the range of the 10 to 12 dollar per MCF where our current market is in the $4 per MCF range in North America.

Mr. COSTA. That is a problem.

Mr. HANCOCK. That is a problem. Offshore, it actually can be slightly lower but the problem is, as the price of gas increases in North America, more and more of the unconventional resources that are already in the Lower 48 states become more attractive and hence we get into the cyclic nature of the gas industry, which right now is at a fairly low point. North America is basically, even though some gas is imported because of heritage-type contracts and things like that, North America is basically self-sufficient in gas.

Mr. COSTA. OK, my time has expired. Any other questions for the witnesses?

I want to thank the members of the panel. I think this was very informative this morning. I am sorry that I was a bit late. As I noted in my opening statement, this is part of a series of hearings that we are holding to try to figure out where all the various energy sources that are available to our country are, and how they fit together as a part of a comprehensive long-term energy plan. So the three of you have been very helpful. We appreciate that.

As customary with the hearing process, the Subcommittee Members will have 10 working days to submit any additional questions that they may have to the three witnesses. We would appreciate, to the degree that those questions are submitted to you, that you provide as effective a response as you did in your opening statements, which was concise and precise and brief. So, we thank you for that, and we thank you for your time.

The Subcommittee is now adjourned.

[Whereupon, at 11:08 a.m., the Subcommittee was adjourned.]

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