National Energy Technology Laboratory

REVIEW OF NON-TECHNICAL ISSUES RELATED TO COMMERCIAL METHANE HYDRATE PRODUCTION
Final Report

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SUMMARY

Methane hydrates have been detected throughout the world around most continental margins. In the United States, deposits have been identified and studied in Alaska, the west coast from California to Washington, the east coast, including the Blake Ridge offshore of the Carolinas, and in the Gulf of Mexico. The U.S. Geological Survey (USGS) estimates that the mean in-place gas resource within the gas hydrates of the U.S. is about 200,000 Tcf.

The purpose of this report is to identify describe, analyze, and report on potential operational, environmental, policy or other issues that could serve to impact the commercial production of methane hydrates. Concern exists that potential issues, or barriers, might constrain or delay bringing natural gas produced from gas hydrates to market. This report attempts to identify those barriers and proposes possible approaches to overcome them to facilitate commercialization of this vast resource in a timely manner. This is intended to complement ongoing methane hydrates research and development (R&D) at the National Energy Technology Laboratory (NETL).

Market clearing national average well head natural gas prices in the range of $4.20 to $4.40 per Mcf represent the target that commercial hydrates will likely have to meet to compete for market share, based on current forecasts of the Energy Information Administration (EIA). Perspectives on future natural gas markets depend on whether the current natural gas market situation is characterized as a short-term market imbalance or the foreshadowing of a long-term *crisis*. In general, traditional sources of North American natural gas supplies will remain challenged in their ability to keep pace with growing demand. Future prices are likely to stabilize at levels considerably higher than in the past, providing a more attractive cost threshold for commercial gas hydrates production to meet. Based on the most recent Annual Energy Outlook of the Energy Information Administration (EIA), the expectation will be that market (Henry Hub) prices in the range of $4.20 to $4.40 per Mcf (2002 dollars) will characterize the 2015 to 2025 time period, with wellhead prices on the North Slope of Alaska in the range of $1.30 to $1.55 per Mcf. However, depending on future North

American gas market scenarios, these prices could be as low as $3.00 per Mcf, or as high as $7.00 per Mcf. The more challenging the outlook for traditional North America natural gas supplies, the better the conditions for the commercial viability for gas hydrates, because future gas prices will be higher, and competing sources of supply will be more limited.

The primary factors influencing the evolution of North America natural gas markets will likely be: (1) the rate of economic growth and its impact on future natural gas demand; (2) the timing of development of a natural gas pipeline from the North Slope of Alaska; (3) the timing and level of expansion of liquefied natural gas (LNG) import capacity in the U. S; and (4) the potential of alternative resources of natural gas supplies; including coalbed methane, additional natural gas resources in Alaska, and in deep formations.

In general, the more existing infrastructure that gas production from hydrates can take advantage of, the less transportation barriers will limit commercial hydrates production. For the most part, particularly in the Gulf of Mexico Outer Continental Shelf (OCS) and North Slope of Alaska, conventional gas resource development will bear most, if not all, of the cost burden of any new gas transportation infrastructure to move produced gas to market. In these areas, gas hydrates generally exist in geographic proximity, and in some cases also in geologic proximity, to sources of traditional gas supplies. Consequently, commercially viability for gas hydrates will depend on the extent to which the gas produced can take advantage of this infrastructure.

On the Alaska North Slope, depending on when an Alaska gas pipeline is built, available transportation capacity could be available for gas produced from hydrates to fill in the 2025 to 2030 time frame, but could be available as early as 2020. Current conventional wisdom foresees gas transportation capacity from the North Slope on line in the 2015 to 2020 time frame. On this timeline, available capacity that hydrates could take advantage of would not be available until between 2025 and 2030.

However, if an Alaska pipeline becomes operational earlier than currently anticipated, such as around 2010 or 2011, available capacity could be available for gas produced from hydrates by as early as 2020. If other uses for natural gas materialize on the North Slope, such as for maintaining pressure in the Prudhoe Bay field and/or perhaps others, or for use to generate steam to help stimulate recovery of the large heavy oil resources on the North Slope, commercial viability could materialize earlier.

In the Gulf of Mexico, considerable infrastructure already exists, and if offshore gas production declines as forecast, as much as much as 1 Bcf per day of underutilized pipeline capacity could be available for transporting gas produced from hydrates between 2010 and 2025. Other potential areas where hydrates may exist, such as the Atlantic and Pacific coasts, where existing natural gas infrastructure, is more limited, would have a higher costs threshold, since new gas supplies would need to bear more of the costs associated with the development of new infrastructure.

Given the current status of U.S. leasing policy in the OCS, and the fact that changes in this policy in the near term are unlikely to occur, it is unlikely that commercial offshore methane hydrates production can occur anywhere except the Gulf of Mexico, or perhaps certain areas onshore and offshore Alaska. Moreover, given the vast amount of hydrates believed to exist in association with the developed areas of the North Slope of Alaska, hydrates on undeveloped federal lands will not likely take place until development and production from the currently developed areas takes place. However, recent actions at both the federal level and by the state of Alaska have helped to clarify that methane hydrates is considered natural gas under existing oil and gas leasing policies and procedures.

From an operational perspective, the factors most likely to influence the location of the first commercial production from gas hydrates are likely to include**:**

- ***Site access***. The first commercial hydrates production will likely take place where access is easy and relatively less costly.
- ***Geologic setting/formation characteristics***. First production will likely take place from a geological setting where the hydrate stability zone (HSZ) occurs in formations that are most like traditional oil and gas reservoirs.
- ***Presence of free gas***. The presence of an appreciable amount of associated free gas, possibly underlying a HSZ potentially serving, at least in part, as a seal for this free gas, could very likely be the primary determinant of initial commercial viability.
- ***Production method***. To gain public acceptance, applications where the development and production method is most similar to conventional methods is the most likely to gain public acceptance. Based on approaches currently under consideration, depressurization, thermal stimulation, or, most likely, a combination of both, will be the processes preferred.
- ***Infrastructure availability***. To support commercial viability, the first large scale production of gas hydrates would need to depend on the availability of existing, likely underutilized facilities and gas gathering and transportation infrastructure.

Recent experimental projects, field tests and simulation studies are providing further confidence that production of gas from hydrates is technically possible. However, much more needs to be understood about the nature of hydrate accumulations and the processes to develop these prospects to produce the gas. Until these processes are further evaluated and demonstrated, our understanding of the potential impacts associated with gas hydrates development and production are purely conceptual.

If the process for developing and producing gas from hydrates is similar to traditional oil and natural gas development and production, most of the environmental and safety issues to be addressed will be essentially the same as those associated with these traditional operations. Drilling waste concerns associated with developing gas hydrates will essentially be the same as those associated with conventional oil and gas drilling, except that the drilling wastes to be managed and disposed will be substantially less, since the hydrates will exist in much shallower settings. Similarly, issues associated with produced water management and disposal are comparable, except that, relative to water produced in association with oil and gas, the water produced from gas hydrates is expected to be at much lower volumes, and of considerable higher (almost pure) quality.

Other considerations associated with producing gas hydrates include gas processing concerns related to the composition of the gas produced from hydrates, and the potential injection of heat or chemicals to help stimulate the dissociation and production of gas from hydrates.

The principal operational concerns associated with drilling to or through a gas hydrate focus on both operational safety and sea floor stability where hydrates may be present. Current operations in both the deepwater and North Slope treat gas hydrates as a hazard to be addressed, not as a resource to be exploited. Hydrates can reform in wells, pipelines, and production facilities, severely impacting drilling and production operations. Gas hydrates can dissociate as a result of oil and gas operations, potentially resulting in hole washouts, sloughing, and collapse of wellbore casings. However, industry and regulatory guidelines on addressing hydrates concerns exist, and new research is adding to the knowledge base concerning the extent and characteristics of hydrates both in marine and Arctic environments.

Some environmental and safety concerns are also uniquely associated with gas hydrates, though these are mostly associated with the characteristics of hydrates in general, and not specifically to the process of commercially producing the gas from the hydrates. Major potential concerns include:

- *Circumstantial evidence exists that indicates that gas hydrates dissociation may have played a role in triggering past seafloor landslides*. Gas hydrates are considered "quasi-stable," and their dissociation can be either slow or quite rapid, depending on the composition of the hydrates, and the rate of change in temperature and pressure conditions. Some researchers have postulated that the formation and dissociation of hydrates at the seafloor can by causally linked to many subsurface and sea floor failures in the Gulf of Mexico and Atlantic OCS.

- *Some hypothesize that changes in global temperature have in the past resulted from major natural releases of methane from hydrates, contributing to atmospheric warming*. The role of methane hydrates in influencing global climate is currently the subject of heated debate within the scientific community. Some claim that methane outgassing from hydrates played a key role in "jump-starting" the erratic climate behavior characteristic of the late Quaternary period, and that a wide range of paleoclimatic and marine geologic data supports this hypothesis. Others do not support this theory, providing evidence that the climate behavior of the time is more likely attributable to changes in the extent of tropical and temperate wetlands and peat bogs.

- *Methane and other gases associated with gas hydrates appear to be the energy source for some, very specialized, seafloor organisms*. These chemosynthetic communities, first discovered in 1984, are just beginning to be understood. These life forms are unique in that they use a carbon (food) source independent of photosynthesis and the food chain associated with photosynthesis. Concerns relate to the potential damage of these communities resulting from seafloor disturbance associated with oil and gas operations, the role that hydrates accumulations here in actually providing their substance, and the overall distribution and abundance of these organisms on the sea floor.

For both environmental and safety considerations, the Minerals Management Service (MMS) is the primary agency responsible for overseeing methane hydrates development and production in the OCS. On North Slope of Alaska, the State of Alaska will be primarily responsible for oversight and regulations associated with methane hydrates development and production on state-owned lands, although even for production on state lands, federal and local permits and authorizations may also be required. *On* ***federal lands***, similar permits, authorizations and consultations are also required, with the ***BLM, the U.S. Fish and Wildlife Service, and EPA having primary oversight and regulatory responsibilities over oil and gas operations***.

To date, very little environmental regulatory consideration has been given to the development of gas hydrates, at either the state or federal level. For the small, pilot-scale demonstrations of hydrates production that have taken place so far, permitting process followed normal procedures, and no special considerations or stipulations were imposed given the fact that hydrates was the target formation. Regulatory agencies have generally taken the position that hydrates development will not occur any time soon, and further consideration will be given to it as its development potential becomes more imminent.

Two federal statutes that could be used by opponents to thwart hydrates development in the federal OCS are the National Environmental Policy Act (NEPA) and the Coastal Zone Management Act (CZMA). Over the past two decades, processes under CZMA have significantly affected siting and permitting of offshore activities, in some cases causing unreasonable delays, or cancellation of major projects. The Environmental Impact Assessment procedures under NEPA could also be used to delay, modify, or thwart new projects in both the offshore and in Alaska. On the other hand, the NEPA process could also be used to help educate the public about the risks and benefits associated with potential development of methane hydrates.

Other interest groups besides environmentalists could also line up to oppose hydrates development**,** including small independent U.S. producers promoting development of more traditional resources, if access to these resources is allowed by government policy, and international interests promoting greater dependence on LNG.

However, despite concerns about hydrates development, most other potential sources of future, long-term natural gas supplies to serve U.S. markets also must overcome significant technical and non-technical barriers. These sources include gas resources underlying federal lands in the Rocky Mountain west, import facilities for LNG, and expanded leasing of oil and gas resources in the OCS. In many cases, the resolution of these issues with those of hydrates development is inextricably linked.

Proactive scientific research, well publicized demonstration projects, and aggressive public education can help facilitate national gas hydrates development. Informed decision making, by both government and private companies can help facilitate the ultimate commercial development of gas hydrates, provided that decisions are based on sound science the realistic balancing of risks and benefits, and the appropriate development or modification of regulatory and oversight procedures to ensure hydrates development proceed with the proper regard for the environment and for human health and safety. The federal government has the responsibility of providing the foundation to accomplish this, and to help make hydrates a future source of energy for the U.S. and the world.

BACKGROUND AND PURPOSE OF REPORT

Background

A gas hydrate is a cage-like lattice of ice, inside of which are trapped molecules of gas, most typically methane (the chief constituent of natural gas), Figure 1. In fact, the name for its parent class of compounds, "clathrates," comes from the Latin word meaning "to enclose with bars." Other gas constituents, such as hydrocarbons like ethane, propane, as well as non-hydrocarbon gases like carbon dioxide and hydrogen sulfide, can also exist within the ice lattice. In this report, the terms "methane hydrates" and "gas hydrates" are used interchangeably and are intended to mean the same thing.

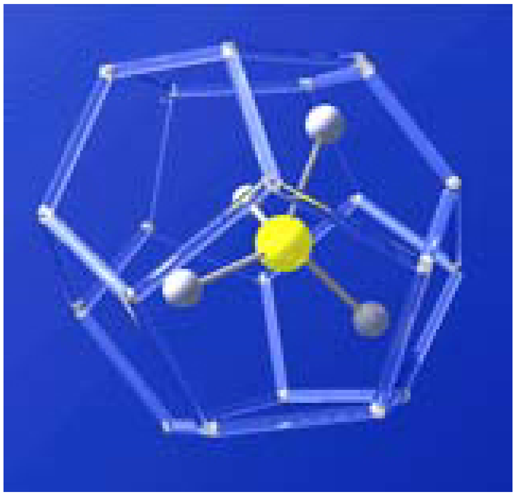
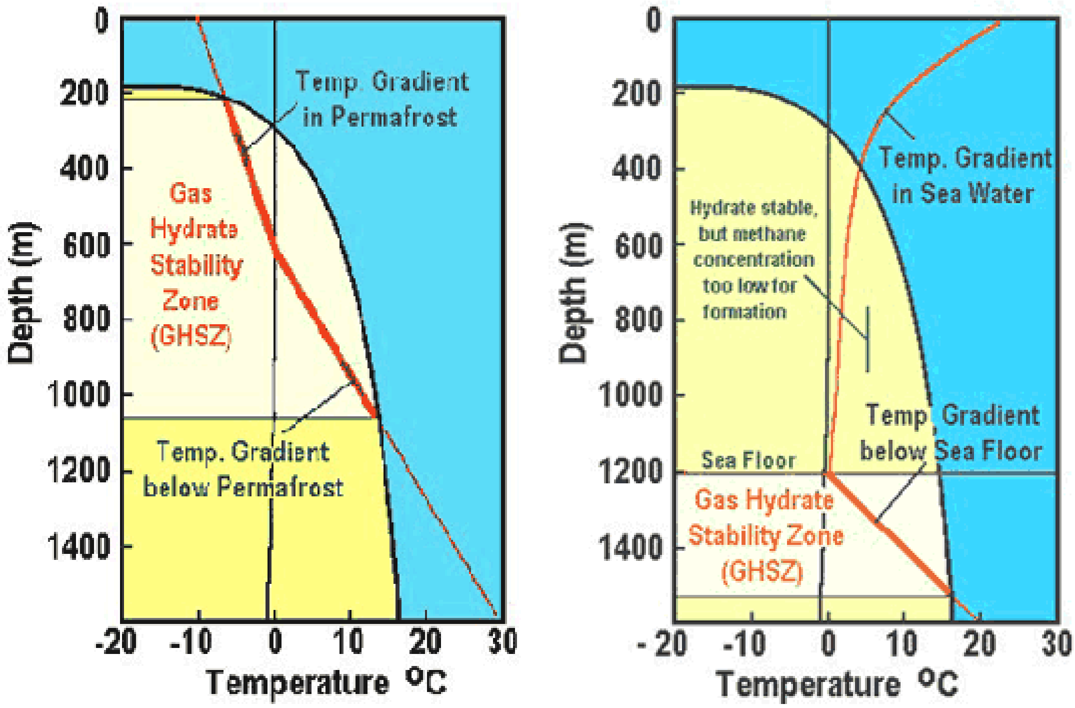


Figure 1: Schematic Representation of Clathrate Structure

Natural gas hydrates generally form in two types of geologic settings: (1) onshore in permafrost regions where cold temperatures persist in shallow sediments, and (2) offshore beneath the ocean floor at water depths greater than about 500 meters, where relatively high pressures dominate. Pressure/temperature relationships for both permafrost and continental margin hydrates are illustrated in Figure 2.

Gas hydrates have been detected throughout the world around most continental margins, Figure 3. In the United States, deposits have been identified and studied in Alaska, the west coast from California to Washington, the east coast, including the Blake Ridge offshore of the Carolinas, and in the Gulf of Mexico, Figure 4.



Arctic Permafrost **Continental Margin**

Figure 2:
Phase Diagrams for Methane Hydrates in Arctic permafrost and Continental Margin Settings

Figure 3:
Location of Worldwide Gas Hydrates Occurrences

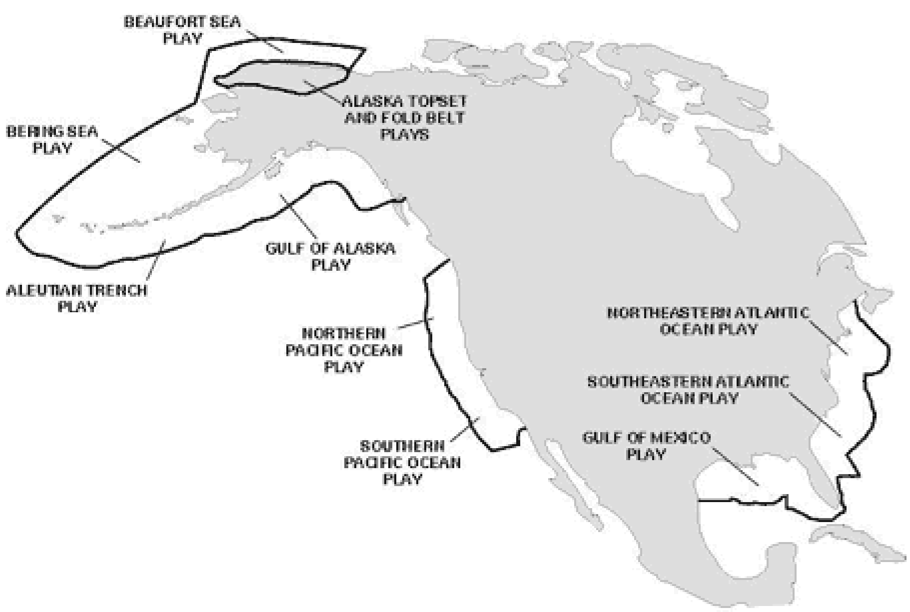


Figure 4:
Location of U.S. Gas Hydrates Occurrences

In 1995, the U.S. Geological Survey (USGS) completed its most detailed assessment to date of U.S. gas hydrate resources. The USGS study estimated the in-place gas resource within the gas hydrates of the U.S. to range from 112,000 to 676,000 trillion cubic feet (Tcf), with a mean estimate of 320,000 Tcf (Table 1).[1]

Subsequent to that work, analysis of core samples taken on the Blake Ridge, collected as part of the National Science Foundation's (NSF) Ocean Drilling Program (ODP), indicated that a downward reduction in the assumed values for hydrate saturation was needed, which would result in a revised, as-yet unofficial, estimate of 200,000 Tcf.[2] This revised estimate has not been reported at the disaggregated level described in Table 1.

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[1] Gautier, D.L., G.L. Dolton, K.I. Takahasi, and K.L. Varnes, *National Assessment of U.S. Oil and Gas Resources, on CD ROM*, USGS Digital Data Series 30, 1985
[2] http://www.netl.doe.gov/scng/hydrate/index.html

Table 1:
Estimated Gas Hydrate Resources in Place in the U.S.

	Mean Resource in Place (Tcf)
Atlantic Coast Province	**51,831**
Northeastern Atlantic Ocean Play	30,251
Southeastern Atlantic Ocean Play	21,580
Gulf of Mexico Province	**38,251**
Gulf of Mexico Play	38,251
Pacific Ocean Province	**61,071**
Northern Pacific Play	53,721
Southern Pacific Play	7,350
Alaska Offshore Province	**168,449**
Beaufort Sea Play	32,304
Bering Sea Play	73,289
Aleutian Trench Play	21,496
Gulf of Alaska Play	41,360
Offshore Provinces Subtotal	**319,602**
Alaska Onshore Provinces	**590**
Topset play -- state lands and waters	105
Topset play -- federal waters	43
Fold Belt Play -- state lands and waters	414
Fold Belt Play -- federal waters	28
U.S. TOTAL	**320,192**

In its hydrates resource assessment, the goal of the USGS was to estimate the volume of U.S. gas hydrate resources using a play-analysis approach, which was conducted on a province-by-province basis, based on relatively limited information. The assessment considered only the *in-place* gas hydrate resources; that is, the amount of gas that may exist within the gas hydrates without reference to its recoverability.

Eleven gas-hydrate plays were identified within four offshore and one onshore petroleum province. Maps of bathymetry, sediment thickness, total organic carbon content of the sediments, seabed temperature, geothermal gradient, and hydrate stability zone served as the primary input to this assessment.[3] Prospects (potential hydrocarbon accumulations) were grouped according to their geologic characteristics into plays. In this appraisal method, geologists make informed judgments about the geologic factors necessary for the formation of a hydrocarbon accumulation and quantitatively assess the geologic factors that determine the typical size of an accumulation.

However, the precise physical locations of such accumulations are generally unknown. Consequently, it is not possible to determine where, within these plays, the gas hydrates accumulations exist.

Consequently, as the next step is this analysis process, several key questions remain to be addressed concerning U.S. gas hydrates resource potential:

- How much of this in-place resource is technically recoverable?
- Of that, how much can be commercial given anticipated future gas markets?
- Where are the most promising prospects for hydrates development?

In anticipation of gas hydrate production in federal offshore waters, the MMS has recently launched a project to estimate the portion of the gas hydrate resource on acreage under MMS jurisdiction that may be technically feasible to produce.[4] The MMS has finalized a methodology for this assessment of recoverable gas hydrate resources that will take a petroleum systems approach. The MMS plans to separately evaluate four play types, using well and seismic data, and then map potential reservoir sands and evaluate any indications of gas and gas hydrate. The goal is to produce a set of three dimensional (3D) maps and probabilities for each of the four play types, presented in a GIS-based format. Plans are for preliminary results to be presented at the Hedberg Research Conference September 2004, with the complete assessment of the Gulf of Mexico due in December 2005.[5]

[3] http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/3_1_01.asp
[4] Anonymous, "MMS Gem Resource Assessment Methodology Outlined" *Fire in the Ice Newsletter*, National Energy Technology Laboratory, Spring 2004
[5] Ray, Pulak, personal communication, July 7, 2004

Nonetheless, even if one percent of this large volume of in-place resource turns out to be recoverable, it will still be significantly larger than prevailing current estimates of technically recoverable natural gas resources in the U.S. Therefore, the potential future commercial viability of the resource needs to be established in light of the future market, regulatory, and policy issues it is likely to confront.

Purpose of Report

The purpose of this report is to identify, describe, analyze, and report on non-technical issues pertaining to methane hydrates, which could serve to impact the commercial production of this resource. Non-technical issues are defined as those operational, environmental, regulatory, marketplace, policy or other issues that could prevent this "exotic" source of natural gas from being commercially developed, if it becomes technically feasible to do so. This report identifies those barriers, and proposes possible approaches to overcome them, that, in parallel with continued technology advancement, would facilitate commercialization of this vast resource in a timely manner. This analysis is intended to complement the ongoing methane hydrates research and development (R&D) program at the National Energy Technology Laboratory (NETL), which has established the goal of commercially producing methane hydrates by 2015.[6]

For purposes of this study, four key assumptions serve to define future U.S. methane hydrate supplies and the potential competitive market conditions under which these resources would be produced commercially:

- *Methane from hydrates will be available in a concentrated form at one or more "point sources"*. High quality (high concentration) methane hydrate areas will be identified as accessible and producible with available technology at the point in time it becomes commercially viable.

[6] http://www.netl.doe.gov/scng/hydrate/index.html

- *Methane from hydrates will be of pipeline quality at a "supply source"*. Methane hydrates are assumed to have an energy content of at least 950 Btu/cubic foot, and will not require further processing to remove impurities.
- *Methane from hydrates will move to market via the North American pipeline system*. Gas produced from methane hydrates will be transportable through the pipeline infrastructure in North America, and this infrastructure will be available (or will be constructed) to bring the gas produced from hydrates to market.
- *Methane from hydrates will be a commodity that will compete in the marketplace with natural gas supplies from all other sources*. For purposes of this assessment, it is assumed that gas produced from methane hydrates would not receive any incentives or subsidy, and would compete in the marketplace with other sources of natural gas supplies, such as liquefied natural gas (LNG), Canadian imports, and other domestic supplies.

The basic approach used for this assessment consisted of three primary steps, as follows:

- First, major forecasts of natural gas supply and demand in North America were examined to specify future levels of demand, the mix of supply sources expected to meet this demand, and the gas prices at which this demand will be met. This characterization of natural gas supply, demand, and prices, at key natural gas market hubs in the U.S., will serve to define the target level of economic viability that potential future sources of gas production from methane hydrates would need to achieve. These prices will essentially establish the "cost levels" at which methane from hydrates would need to compete to enter the market, and provide the targets or thresholds that the R&D program must work toward to realize its commercial production goal.
- Second, potential issues likely to confront methane hydrates development were defined. In this characterization, those issues likely to be unique or specific to methane hydrates development were characterized, along with those faced by all new natural gas supplies (e.g., pipeline facilities, Arctic drilling regulations,

offshore platforms, access to federal lands), that methane hydrates development and production would also face.

- Third, for each issue specific to methane hydrates identified, this report:
  - Characterizes the potential non-technical issues and barriers that could constrain the commercial development of methane hydrates.
  - Assesses the impact of these barriers/issues in terms of increased costs, delayed development, constrained access, etc.
  - Distinguishes these barriers and issues into various categories based on the difficulty in overcoming the barrier or addressing the issue.
  - Suggests possible approaches that could be pursued to overcome, minimize, or mitigate these impacts or address these barriers.

Finally, the overall assessment of traditional natural gas markets is linked to the issues and barriers facing methane hydrate development to determine how they may impact the cost, timing, and performance of future commercial methane hydrates production.

OVERVIEW OF NATURAL GAS SUPPLY, DEMAND AND PRICES

Natural Gas Supply

Domestic production of natural gas is projected in the Energy Information Administration's (EIA's) 2004 Annual Energy Outlook (AEO) to increase steadily from 19.7 Tcf in 2001 to 23.8 Tcf in 2020, and further to 24.0 Tcf in 2025, Figure 5:[7]

- The projected increase in domestic gas production from 2003 to 2015 is primarily due to more rapid development of unconventional gas resources, with offshore and conventional gas production holding relatively constant.
- The projected increase in domestic gas production from 2015 to 2025 (the time period when methane hydrates could be developed as an energy resource) is primarily the result of the completion of the Alaska Natural Gas Pipeline enabling Alaska's gas to reach North American markets.

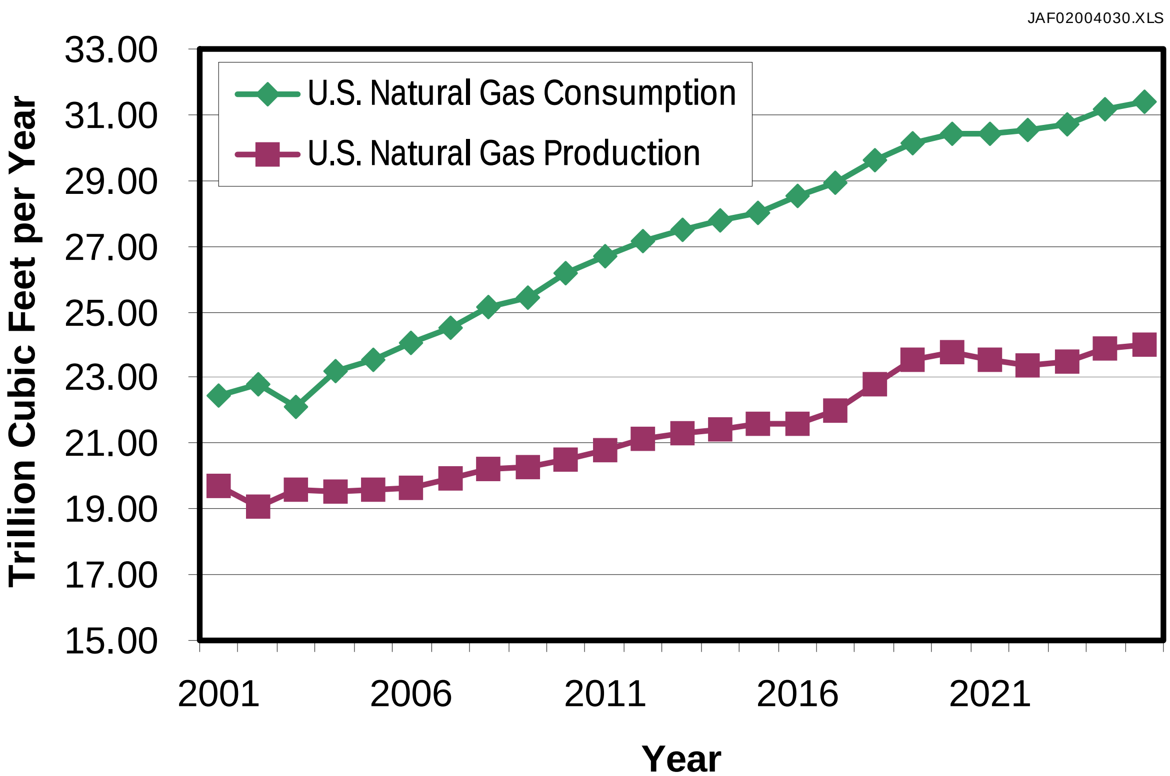

Figure 5: Forecast U.S. Natural Gas Demand and Production to 2025

[7] Energy Information Administration, *Annual Energy Outlook 2004: With Projections to 2025*m DOE/EIA -0383 (2004), January 2004

EIA's 2004 AEO forecasts a significant decrease in projected domestic production relative to its 2003 AEO[8], where domestic natural gas production was forecast to grow to 25.1 Tcf per year by 2020, and to 26.8 Tcf annually in 2025.

Although domestic natural gas production is expected to increase through the year 2025 (in AEO 2004), the demand for natural gas is projected to increase even more. The difference between this faster growing demand and slower growing domestic production is expected to be met by higher natural gas imports:

- Net imports of natural gas increase from 3.6 Tcf in 2001 to 6.5 Tcf in 2020, with decreases in imports from Canada more than offset by increases in LNG imports.
- Net imports of natural gas increase further to 7.2 Tcf in 2025; again all of this increase is associated with LNG.

The publication of AEO 2004 represents a considerable departure from previous EIA forecasts. This departure is in response to growing concerns with respect to the ability of conventional natural gas resources in both the U.S. and Canada to provide the necessary supplies to meet future North American demand. A recent study by the National Petroleum Council (NPC) also includes much lower expectations for domestic and Canadian conventional gas production[9], consistent with the AEO 2004 projections. A more detailed characterization of the implications of the NPC perspectives on future North American natural gas production and consumption, and the role they may play for future commercial gas hydrates production, are discussed in more detail later in this Chapter.

Natural Gas Demand

EIA's 2004 AEO forecasts steady growth in domestic natural gas demand through the year 2025. However, as summarized in Table 2, forecast growth in natural gas consumption is considerably lower in the 2004 AEO compared to that in the 2003 AEO. Based on the 2004 AEO, the demand for natural gas is projected to grow steadily,

[8] Energy Information Administration, *Annual Energy Outlook 2003*, DOE/EIA-0383 (2003), January 2003
[9] National Petroleum Council, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, September 25, 2003

reaching 30.4 Tcf in 2020 and 31.4 Tcf in 2025. This compares to forecast demand growth of up to 34.9 Tcf in 2025 in the 2003 AEO, 3.5 Tcf per year more that the 2004 AEO. NETL's R&D goal for methane hydrates established commercial methane hydrates production between 2015 and 2025,[10] assuming a successful joint DOE and industry R&D and technology demonstration program.

Table 2:
Projections for Natural Gas Demand: Comparison of AEO 2003 and AEO 2004

	Projections for Natural Gas Consumption (Tcf)	
	EIA's AEO 2003	**EIA's AEO 2004**
2001	22.7	22.5
2010	27.1	26.2
2020	32.1	30.4
2025	34.9	31.4

Much of the nearly nine Tcf of growth in natural gas demand between 2001 and 2025, as shown in Table 3, is expected to be in electric power generation and in industrial use of natural gas.

Table 3:
Forecast Consumption of Natural Gas by Sector, AEO 2004

	Consumption of Natural Gas by Sector (Tcf)			
	Electric Power Demand	**Industrial Demand**	**All Other***	**TOTAL**
2002	5.5	7.2	9.7	22.8
2025	8.4	10.3	12.7	31.4
Annual Growth 2002-2025	1.8%	1.5%	1.7%	1.6%

**Includes residential and commercial demand as well as pipeline fuel and lease and plant fuel used for producing, processing natural gas and transporting it to market.*

Again, the growth in natural gas demand in the electric power sector is substantially lower in the 2004 AEO compared to the 2003 AEO. In comparison, the 2003 AEO projected natural gas demand in the electric power sector to be 10.4 Tcf in 2025, 2.0 Tcf more than that forecast in the 2004 AEO. As discussed in more detail below, this is primarily due to higher forecast natural gas prices.

[10] http://www.netl.doe.gov/scng/hydrate/index.html

Geographically, the largest volume of incremental growth in natural gas demand is expected to be in the West-South-Central (Texas, Oklahoma, Arkansas, and Louisiana) and East-North Central (upper Midwest) regions of the country, where large amounts of new gas-fired electric generation facilities have recently come on line or are currently planned. These results are shown in Table 4.

Table 4:
Forecast Consumption of Natural Gas by Census Division, AEO 2004

	Consumption of Natural Gas by Census Division (Tcf)		
	2002	**2025**	**Annual Growth 2001-2025 (percent)**
Pacific	2.8	3.5	1.0
Middle Atlantic	2.4	3.3	1.2
E.N. Central	3.6	5.8	2.1
South Atlantic	2.0	2.6	1.0
E.S. Central	1.1	2.1	2.8
W.S. Central	5.7	7.2	1.0

Natural Gas Prices and Cost Drivers

EIA's 2004 outlook is that average wellhead natural gas prices will be lower for several years (relative to 2001) and then will climb steadily to $4.40 per Mcf by 2025. Table 5 provides EIA's 2004 projections for natural gas wellhead prices (in 2002 $ per Mcf), and compares these to the comparable forecast prices in the 2003 AEO. As shown, natural gas prices are forecast to be $0.50 to $0.65 per Mcf higher over the 2015 to 2025 time frame (the period where commercial hydrates production could possibly first emerge) in the 2004 AEO relative to the 2003 AEO.

Table 5:
Forecast National Average Wellhead Gas Prices in the AEO 2003 and 2004
(2002 $/Mcf)

	2002	2010	2015	2020	2025
(AEO 2004)	$2.95	$3.40	$4.19	$4.28	$4.40
(AEO 2003)	$2.84	$3.40	$3.57	$3.82	$4.03

(1) Offshore Gas Prices

Regional wellhead gas prices will vary considerably from national average wellhead prices, accounting for transportation costs and proximity to markets. Table 6 provides AEO 2004 projections for natural gas wellhead prices for the Gulf of Mexico and the offshore Pacific -- two areas of the Lower 48 offshore with potential for methane hydrate development.

Table 6:
Forecast Wellhead Natural Gas Prices in Pacific and Gulf of Mexico, AEO 2004
(in 2002$ per Mcf)

	2002	2010	2015	2020	2025
Offshore Gulf	$2.66	$3.20	$4.52	$4.52	$4.41
Offshore Pacific	$4.13	$4.00	$4.47	$4.53	$3.83

(2) *Alaska Gas Prices*

Alaska wellhead prices need to account for the cost of the proposed Alaska Natural Gas Pipeline and other costs associated with bringing this gas to market. Using EIA's latest cost estimates, the economics of Alaskan natural gas in the AEO 2004 are based on the following assumptions:[11]

- Assumed cost of pipeline - - $13.9 billion (in 2002 $)
- Assumed pipeline capacity - - 3.9 Bcf per day initially, expanded subsequently to 4.8 Bcf per day
- Cost of transportation, including gas gathering, treatment and a capital risk premium - - $2.87 per Mcf, as summarized below (2002 $):

[11] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2004*, DOE-EIA-0554 (2004), February 2004

- o Local gathering and processing — $0.47/Mcf
- o Transportation from Alaska to Alberta — $1.45/Mcf
- o Price differential -- Alberta to lower-48 states — $0.61/Mcf
- o Additional risk premium in interest costs — $0.34/Mcf

Total Costs $2.87/Mcf

(Alternative cost estimates for this proposal pipeline system are discussed in the next chapter.)

Based on these economics, the potential wellhead price for methane hydrate production from Alaska would be as shown in Table 7.

Table 7:
Forecast Wellhead Natural Gas Prices in Alaska, AEO 2004
(2002 $ per Mcf)

	2002	2010	2015	2020	2025
National Average Wellhead Price	$2.95	$3.40	$4.19	$4.28	$4.40
Less: Transportation and Other Costs		$2.87	$2.87	$2.87	$2.87
Net Alaska Wellhead Gas Prices		**$0.53**	**$1.32**	**$1.41**	**$1.53**

A more in depth discussion of some of the issues associated with an Alaska Natural Gas Transportation System are discussed in the following chapter.

Comparison of AEO 2004 with Other Forecasts

EIA's 2004 AEO forecasts steady growth in domestic natural gas demand and prices through 2025. Other major energy forecasts, such as those published by the NPC, GII (Global Insight, Inc., formerly DRI-WEFA), EEA (Energy and Environmental Analysis, Inc.), EVA (Energy Ventures Analysis, Inc.), DB (Duetsche Bank) and PIRA (Petroleum Industry Research Associates, Inc.) show similar expectations for growth in demand. However, these published forecasts differ considerably in terms of the details associated with their forecasts (Table 8), indicating significant uncertainty associated with future natural gas market trends. The AEO 2004 Reference Case is within the range of projections for total natural gas consumption in the other forecasts throughout the forecast period. The lowest consumption projections are from the NPC Balanced Future scenario, and the highest are from the EVA forecast. All show domestic production providing a decreasing share of total natural gas supply. The two NPC cases generally project the lowest levels of imports, with the highest projected by EVA.

Table 8:
Comparison of Natural Gas Forecasts for Years 2015 and 2025
(All units in Tcf, unless otherwise noted)

			Other forecasts						
Projection	**2002**	**AEO 2004 Reference**	**GII**	**EEA**	**NPC Reactive Path**	**NPC Balanced Future**	**EVA**	**PIRA**	**DB**
					2015				
Lower 48 wellhead price (2002 dollars per Mcf)	2.95	4.19	3.62	4.25	~6.40	~3.60	3.44	3.74	3.03
Dry gas production	19.05	21.62	20.80	21.86	21.55	21.18	21.66	17.89	20.59
Net imports	3.49	6.24	7.01	6.76	5.11	5.12	9.68	8.58	6.67
Pipeline	3.33	3.02	3.65	3.92	2.61	1.94	4.78	3.84	NA
LNG	0.17	3.22	3.36	3.70	2.51	3.18	4.90	4.75	NA
Consumption	22.78	28.03	27.88	28.32	26.67	26.30	31.11	26.58	26.78
					2025				
Lower 48 wellhead price (2002 dollars per Mcf)	2.95	4.40	3.76	NA	~7.10	~3.00	3.69	NA	3.02
Dry gas production	19.05	23.99	20.76	NA	20.90	20.83	24.26	NA	19.04
Net imports	3.49	7.24	9.91	NA	6.31	5.80	11.72	NA	11.16
Pipeline	3.33	2.44	3.61	NA	2.44	1.03	5.26	NA	NA
LNG	0.17	4.80	6.30	NA	3.88	4.77	6.46	NA	NA
Consumption	22.78	31.41	30.75	NA	27.62	26.62	35.89	NA	29.66

NA = not available.
Source: Energy Information Administration, *Annual Energy Outlook 2004: With Projections to 2025*, DOE/EIA -0383 (2004), January 2004

Wellhead natural gas price projections in the AEO 2004 Reference Case are higher than in the other available forecasts (not all forecasts provide wellhead price projections), with the exception of EEA.

The NPC forecasts are discussed in more detail in the following section.

(1) National Petroleum Council

The NPC, at the request of the U.S. Secretary of Energy, recently completed a comprehensive study to examine the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that could affect the potential for North American natural gas demand, supplies, and delivery through 2025.[12] This study built upon the knowledge gained and processes developed in previous NPC studies, enhanced these processes, created new analytical tools and approaches, and identified improvements for future studies.

In conducting its analyses, the NPC concluded that the current domestic policy direction, if not altered, could lead to challenging conditions for natural gas in North America. They assumed that all parties would need to act to ensure that the status quo does not continue. However, to represent the range to which the nation moves beyond the status quo, two scenarios were considered:

- *Reactive Path Scenario*: This scenario assumes continued conflict between policies that tend to support natural gas use, and those that tend to discourage natural gas supply development. Despite this, it assumes that significant pressures will still force the establishment of new policies, implemented reactively, in response to public and political pressure.
- *Balanced Future Scenario*: This scenario assumes that government policies rapidly and proactively evolve to focus on eliminating barriers to market inefficiencies.

In their report, the NPC emphasized that these scenarios and the results for each should not be considered forecasts, but internally consistent frameworks for analyzing policy choices faced by the industry in the years ahead.

The NPC concluded that there has been a fundamental shift in the North American supply/demand balance that will result in higher prices and greater price volatility. In terms of the important issues affecting the first commercial production of

[12] National Petroleum Council, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, September 25, 2003

gas hydrates, the NPC, relative to their previous studies, revised their perspectives in the following key areas:

- Significantly lower expectations for natural gas supplies from Lower-48 and Canadian conventional resources
- Greater demand destruction in the industrial sector due to higher prices
- Lower demand growth for natural gas in the electric power sector
- Considerably faster construction schedule for the Alaska gas pipeline
- Significantly greater volumes of LNG imports into the U.S.

For both its scenarios, the NPC forecasts significantly lower demand growth than the AEO throughout the forecast period, due to lower forecast growth in industrial output and a decline in industrial gas consumption, Table 9. By 2025, forecast consumption ranged from 26.6 to 27.6 Tcf per year, compared to 31.4 Tcf in the AEO 2004.

In terms of forecast natural gas prices, the NPC's Balanced Scenario forecasts natural gas prices comparable to AEO until 2010, where real prices then start to decline due to proactive government policies, from approximately $3.60 per MMBtu in 2010 to $3.00 per MMBtu in 2025. This compares to AEO 2004 forecasts of approximately $3.40 per MMBtu in 2010, growing to $4.35 per MMBtu in 2025. In contrast, the NPC Reactive Path Scenario forecasts prices growing to approximately $6.10 per MMBtu in 2010, continuing to grow to $7.10 per MMBtu by 2025.

U.S. production remained relatively constant throughout the forecast period in the NPC scenarios, while moderate growth in production is forecast in the AEO 2004. The AEO and NPC outlooks for future offshore production were comparable, while the NPC was more pessimistic about Lower-48 onshore conventional and unconventional supplies, Table 10. This is because the NPC estimates of the costs of producing Lower-48 natural gas resources are higher than those assumed in AEO 2004.

Table 9:
Comparison of AEO 2004 and National Petroleum Council Projections
U.S. Consumption, Production, and Imports

	2002	2010	2025
Natural Gas Consumption (Tcf/year)			
AEO 2004	22.78	26.15	31.41
NPC Balanced Future	22.43	24.32	26.62
NPC Reactive Path	22.43	24.73	27.62
U.S. Natural Gas Production (Tcf/year)			
AEO 2004	19.05	20.50	23.99
NPC Balanced Future	18.54	19.45	20.83
NPC Reactive Path	18.54	19.50	20.90
Natural Gas Imports (Tcf/year)			
AEO 2004	3.49	5.50	7.24
NPC Balanced Future	3.61	5.01	5.80
NPC Reactive Path	3.61	5.19	6.31
Natural Gas Wellhead Prices ($/MMBtu, 2002)			
AEO 2004	2.90	3.40	4.35
NPC Balanced Future	3.40	~3.60	~3.00
NPC Reactive Path	3.40	~6.10	~7.10

As a result, the AEO 2004 forecasts higher levels of natural gas imports, mostly from new imports of LNG. However, the AEO 2004 is more optimistic than the NPC concerning the proportional contribution of future natural gas imports from Canada to total U.S. imports, Table 11.

(2) Energy Modeling Forum

Another recent natural gas study of interest is the natural gas market modeling study conducted by the Energy Modeling Forum (EMF) at Stanford University. The EMF was established in 1976 to provide a structured forum within which energy experts from government, industry, universities, and research organizations meet to study important energy and environmental issues of common interest. The EMF forum approach seeks to:[13]

[13] http://www.stanford.edu/group/EMF/approach/index.htm

Table 10:
Comparison of AEO 2004 and National Petroleum Council Projections
Sources of U.S. Natural Gas Production

	2002	2010	2025
Lower 48 Offshore (Tcf/year)			
AEO 2004	4.86	5.42	5.03
NPC Balanced Future	5.09	5.47	5.90
NPC Reactive Path	5.09	5.69	5.15
Lower 48 Incremental (Tcf/year)			
AEO 2004	5.93	7.28	9.17
NPC Balanced Future	5.34	6.53	7.30
NPC Reactive Path	5.34	6.31	7.91
Lower 48 Conventional (Tcf/year)			
AEO 2004	7.83	7.21	7.10
NPC Balanced Future	7.52	6.87	5.58
NPC Reactive Path	7.52	6.89	5.72
Alaska (Tcf/year)			
AEO 2004	0.43	0.60	2.71
NPC Balanced Future	0.46	0.46	1.93
NPC Reactive Path	0.46	0.46	2.00

Table 11:
Comparison of AEO 2004 and National Petroleum Council Projections
Sources of U.S. Natural Gas Imports

	2002	2010	2025
Canadian Imports (Tcf/year)			
AEO 2004	3.59	3.68	2.56
NPC Balanced Future	3.60	3.25	1.29
NPC Reactive Path	3.60	3.50	2.70
LNG Imports (Tcf/year)			
AEO 2004	0.17	2.16	4.80
NPC Balanced Future	0.23	2.06	4.77
NPC Reactive Path	0.23	1.99	3.88

- Improve understanding of an important energy/environment problem by harnessing the collective capabilities of participating experts
- Explain the strengths, limitations and caveats of alternative analytical approaches
- Identify high priority directions for future research.

EMF studies emphasize important corporate and policy decisions rather than methodology. The process identifies the important insights for energy and environmental planning and policy that are learned from a comparison of alternative modeling approaches.

The most recent EMF natural gas study compares alternative approaches for analyzing natural gas and energy markets, highlighting the major implications for corporate and policy decisions.[14] In general, the EMF study provided a much less pessimistic view on the potential of North American supplies to meet the future market demands. Relative to the NPC and EIA forecasts, the participants in the EMF are of the opinion that market forces and new technologies could be much more effective at encouraging increased natural gas supplies. The study concludes that recent volatile natural gas prices do not necessarily foreshadow a long-term crisis in future gas supplies.

By examining a number of different possible future scenarios, the EMF concludes that both private sector and government decision-makers should plan for a range of possible future natural gas market outcomes. Based on the model runs performed by EMF participants over the course of this study, projected natural gas prices could be as low as 58% of prices as of mid-2003, or as much as 118% higher, depending upon forecast models and scenarios. Investments in new natural gas resources and supply technologies, developments in international trade for natural gas, and supportive government policies encouraging a properly functioning and efficient marketplace are critical determinants, the study concludes, to the ultimate outcome for future North American natural gas markets.

(3) <u>EIA Analysis of Restricted Natural Gas Supply Cases</u>

In February 2004, EIA completed a special set of analyses where the 2004 AEO was rerun assuming three different low natural gas supply scenarios.[15] This study was conducted at the request of Representative Barbara Cubin, Chairman of the House

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[14] Energy Modeling Forum, *Natural Gas, Fuel Diversity and North American Energy Markets*, EMF Report 20, Stanford University, September 2003

[15] Energy Information Administration, *Analysis of Restricted Natural Gas Supply Cases*, SR/OIAF/2004-03, February 2004

Subcommittee on Energy and Mineral Resources. The low supply scenarios considered were:

- The natural gas pipeline from the Alaska North Slope to U.S. markets does not get built.
- Inability to permit more than three additional average-sized LNG offloading facilities limits U.S. LNG import capacity to 2.1 Tcf annually.
- No significant increase in production of tight sands natural gas (or other non-conventional gas resources (UGR)), because of no further technological improvements, lower reserves per well, and higher production decline rates.
- Combination of all of the above.

As summarized in Table 12, by 2025, in the two cases where domestic supplies are constrained (No Alaska and No UGR), U.S. production decreases, average wellhead gas prices increase by 2025 (by \$0.20 and \$0.45 per Mcf, respectively), imports increase, and natural gas consumption decreases relative to the AEO 2004 Reference Case.

In the case of restricted LNG imports, by 2025, U.S. consumption decreases, imports decline by one-third, wellhead prices increase by \$0.35 per Mcf, and U.S. production increases modestly.

In the highly unlikely combined case; the circumstances are somewhat dire, where U.S. supplies of unconventional gas are constrained, Alaska natural gas supplies do not get developed, and LNG import terminals do not get built. By 2025, relative to the AEO 2004 Reference case, wellhead natural gas prices increase by over \$1.20 per Mcf, natural gas consumption decreases by 4.5 Tcf per year, and U.S. production decreases by almost 4.0 Tcf per year.

Table 12:
Comparison of U.S. Natural Gas Consumption, Production, Imports, and Wellhead Prices for EIA's Low Supply Scenarios for the Years 2015 and 2025

		AEO2004 Reference	No Alaska Pipeline	Low LNG	Low UGR	Combined
	2002	2015				
Total Consumption (Tcf)	22.7	28.0	28.0	27.6	27.6	26.0
Total Production (Tcf)	19.0	21.6	21.6	22.2	20.7	20.3
Lower 48	12.7	12.3	12.3	12.6	12.9	13.5
Conventional	5.9	8.7	8.7	9.0	5.5	6.2
Unconventional	0.4	0.6	0.6	0.6	2.3	0.6
Alaska						
Net Imports (Tcf)	3.5	6.2	6.2	5.2	6.7	5.5
Canada	3.6	3.2	3.2	3.3	3.1	3.4
Mexico	-0.3	-0.2	-0.2	-0.1	-0.1	-0.0
LNG	0.2	3.2	3.2	2.1	3.7	2.1
Average Wellhead Prices (2002 dollars per Mcf)	2.95	4.19	4.20	4.49	4.28	5.02
	2002	2025				
Total Consumption (Tcf)	22.7	31.4	30.7	30.0	29.7	26.9
Total Production (Tcf)	19.0	24.0	22.7	24.9	20.8	20.2
Lower 48	12.7	12.1	12.3	12.5	12.4	13.2
Conventional	5.9	9.2	9.6	9.6	5.7	6.3
Unconventional	0.4	2.7	0.7	2.7	2.7	0.7
Alaska						
Net Imports (Tcf)	3.5	7.2	7.9	4.9	8.7	6.5
Canada	3.6	2.6	2.8	2.8	2.9	3.5
Mexico	-0.3	-0.1	0.0	0.0	0.4	0.9
LNG	0.2	4.8	5.1	2.1	5.4	2.1
Average Wellhead Prices (2002 dollars per Mcf)	2.95	4.40	4.60	4.74	4.85	5.61

Note: Totals may not add due to rounding

Perspectives on Supply/Demand Influences on Hydrates Development

Fundamentally, perspectives on future natural gas markets depend on whether one believes that the current natural gas market situation is a short-term market imbalance or the foreshadowing of a long-term crisis. In general, traditional sources of North American natural gas supplies will be increasingly challenged in their ability to keep pace with growing demand. Most believe that natural gas prices in the future are likely to stabilize at levels considerably higher that in the past, providing a more attractive cost threshold for the commercial production of gas hydrates to meet.

The only debate is at exactly what levels these prices will likely stabilize. Government policy, the pace of technology development and deployment, and the availability of economically viable alternative sources of energy supply will be critical determining factors influencing how North American natural gas markets evolve. Some of the more important market factors which could potentially influence the commercial viability of gas hydrates are described in the following paragraphs.

(1) Economic Growth

The rate of future economic growth will have a major impact on natural gas demand, and consequently, future prices for natural gas, and thus, the threshold price that gas hydrates must meet to become economically viable. The different forecasts summarized in Table 8 were, among other factors, based on different economic growth assumptions. The AEO 2004 analyzed two alternative economic growth cases, to compare to the Reference Case. The rate of economic growth in these scenarios could result in a 2.0 to 2.5 Tcf per year difference in natural gas consumption over the 2020 to 2025 time period. The high growth scenario results in forecast wellhead natural gas prices $0.40 to $0.54 per Mcf higher than the Reference Case, with the low economic growth case resulting in forecast prices $0.12 to $0.30 per Mcf lower. In the high growth case, natural gas prices are forecast to be as high as $4.70 to $4.95 per Mcf in the 2020 to 2025 time period, while in the low growth case; prices could be as low as $4.00 to $4.30 per Mcf in this time period. (This compares to wellhead prices in the $4.30 to $4.40 per Mcf range for the Reference Case.)

(2) Natural Gas Pipeline from the Alaska North Slope

If a natural gas pipeline from the North Slope of Alaska does not get built by 2025, wellhead natural gas prices could increase somewhat (on the order of $0.20 per Mcf) relative to the Reference Case. However, if the pipeline is not built, natural gas hydrates on the North Slope would not have access to market, and therefore, would also not be economically viable except for possible local use. Offshore hydrates, on the other hand, would have slightly improved prospects for economic viability if a natural gas pipeline from the North Slope is not built.

(3) <u>Expanded LNG Import Capacity</u>

On the one hand, if LNG import capability in the U.S. is constrained, wellhead natural gas prices could increase on the order of $0.30 to $35 per Mcf relative to the Reference Case, reflecting favorably on the relative commercial competitiveness of natural gas hydrates. On the other hand, the environmental and political forces that would be the source of influence resulting in this constrained capacity could also serve to constrain gas hydrates development as well.

(4) <u>Potential Lower-48 Natural Gas Supplies</u>

Again, the impact of lower domestic natural gas supplies on the future commercial viability of gas hydrates depends on the forces contributing to constrained supplies. On the one hand, as shown in Table 11 for the AEO 2004 scenarios, constrained domestic supplies on non-conventional natural gas supplies could result in higher wellhead prices of on the order of $0.45 per Mcf by 2025, improving the relative commercial viability of gas hydrates. AEO 2004 examined two alternative scenarios for oil and gas supply technology, where technological progress was assumed to be 50% faster or slower than that assumed in the Reference Case. In the Slow Technology Growth Case, wellhead natural gas prices were $0.25 to $0.70 per Mcf higher in the 2020 to 2025 time period than in the Reference Case, while in the Rapid Technology Growth Case, wellhead natural gas prices were $0.60 to $0.70 per Mcf lower.

On the other hand, if constrained natural gas supplies are the result of reduced public and private sector investments in R&D, then reduced R&D expenditures will likely also impact the rate of technological improvement that would influence the commercial viability of gas hydrates.

Some of these issues are explored in more detail in the following chapter.

TRANSPORTATION AND MARKET ACCESS ISSUES

Introduction

In the last several years, as evidenced by the changing perspectives of recent natural gas market forecasts, there have been increasing concerns about the adequacy of domestic natural gas supplies to meet future market requirements. Prices throughout 2003 averaged above $5.00 per Mcf, and EIA's Short-Term Energy Outlook (STEO) forecasts[16] that average natural gas prices at the wellhead will remain near or above $6.00 per Mcf through 2005. New supply options, consisting of LNG imports, imports from the Mackenzie Delta in Northern Canada, unconventional gas from the Rocky Mountain West, and gas from Alaska, are being looked to for meeting future market requirements.

From an economic perspective, commercial production from natural gas hydrates in Alaska and Northern Canada, along with the deepwater Gulf of Mexico and possibly other deepwater areas of North America, will depend on significant technology advancements, as well as developer access to the resources, and market access for the production. Moreover, production from gas hydrates must be able to compete with alterative sources of supply to be commercially viable. This section highlights some of the key factors that are likely to influence the nature and timing of the commercial viability of natural gas hydrates in the U.S., relative to other competing sources of supply.

Economics and Timing for the Alaska Pipeline System

One of the main future natural gas supply options requiring high capital costs and long construction lead-times involves bringing natural gas from Alaska to the Lower-48 by a pipeline. A pipeline to transport natural gas from Alaska's North Slope to Lower-48 markets will have a long construction period and operate for many years. Considerable uncertainty characterizes the reported costs, economics, and timing to bring Alaska North Slope gas to Lower 48 markets, and its economics and timing depend upon a wide variety of technological, economic, and political factors that could influence its

[16] http://www.eia.doe.gov/emeu/steo/pub/contents.html

initial entry into service. Various options have been proposed to encourage its construction, though none as of yet have been implemented. Such options include loan guarantees for pipeline construction, Northern Alaska production tax credits, and price guarantees.

Several different projects have been proposed to bring North Slope gas to Lower 48 markets, in some cases by more than one group of developers, Figure 6. The original proposal for the Alaska Natural Gas Transportation System (ANGTS) -- now sometimes called the "Highway Route" or "Southern Route" -- follows the Dalton Highway from Prudhoe Bay to Fairbanks, and then the Alaska Highway to central Alberta. A study by the Prudhoe Bay gas owners concluded that the system would cost US$10 billion $12 billion (depending on capacity) and could profitably deliver gas to Chicago for $3.50/Mcf.[17] Others estimate costs for this pipeline to be as high as $20 billion.[18] The State of Alaska, Yukon Territory in Canada, and most stakeholders advocate this route. Existing regulatory permits and international treaties, subject to review, also authorize this route.

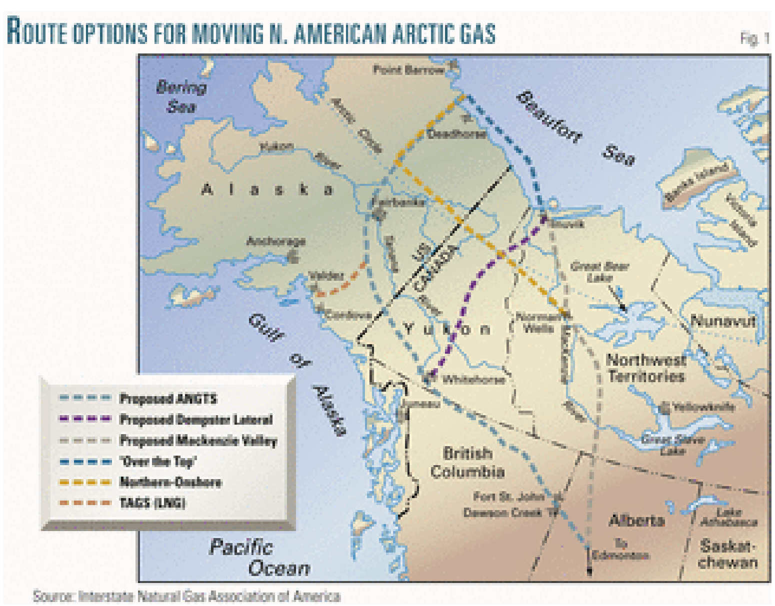

Figure 6: Proposed Alternative Routes for Alaska Gas Pipeline System

[17] Meyers, K., Phillips Alaska, Inc. "The Next Frontier: Alaska North Slope Gas", presentation at Ziff North American Gas Strategies Conference, Calgary, Alberta, Canada, October 16-17, 2000
[18] "BP estimates costs for proposed Alaska pipeline to be $20 bn," *Alexander's Gas & Oil Connections,* Vol. 6, Issue #17, November 9, 2001

A second proposed route, the so-called "Over the Top" route, originally proposed by Arctic Resources Company, may have better economics because of its shorter overall length, but has considerably more difficult logistical, environmental, and political issues to overcome. Its proposed route starts at Prudhoe Bay, and then goes across the Beaufort Sea to the Mackenzie Delta in Canada. At that point, it would hook up with a pipeline from the Mackenzie Delta region to Alberta. Estimated costs of this pipeline range from US$10 to $15 billion.[19]

Variations on each of these two options have been proposed.[20]

In EIA's AEO 2004, the Reference Case assumption is that the Alaska natural gas pipeline to the Lower 48 will become operational in 2018, with an initial capacity of 3.9 Bcf per day, and a subsequent expansion to 4.8 Bcf per day. However, favorable policies and minimal opposition or construction delays could result in the pipeline potentially becoming operational earlier. According to the EIA, based on the economics of Alaska North Slope natural gas production and the anticipated costs for wellhead production (for associated gas), local gathering and processing, transportation to Lower 48 markets, and a substantial risk premium associated with this investment; gas production economics would be favorable for methane hydrates at a market clearing (Henry Hub) natural gas price on the order of $4.20 to $4.40 per Mcf (2002 dollars). Based on this, methane hydrates would initially need to compete with a wellhead natural gas price of about $1.30 to $1.55 per Mcf on the North Slope (see discussion in previous chapter).

The timing of the initial start of a natural gas pipeline from the Alaska North Slope will influence the ability to bring North Slope gas hydrate production to market. Commercial hydrates production on the Alaska North Slope will not likely take place to

[19] Farina, Michael F., RDI Consulting, "New Frontiers – The Potential for Arctic and Northern Canadian Natural Gas Prospects," presentation at Platts – Day of the Trader Conference, Las Vegas, Nevada, December 6, 2001

[20] Williams, Bob, "Alaska Update: Route controversy heats up as push to market Alaskan North Slope gas gathers steam," *Oil and Gas Journal*, August 6, 2001

any great extent until surplus pipeline capacity becomes available, which would likely be minimal until production from proved reserves on the North Slope begins to decline. Early availability of an Alaska pipeline, in general, is favorable for hydrates, because it would permit accessible pipeline capacity for Alaska's methane hydrates to be available earlier than otherwise would be the case.

Other Potential Uses for North Slope Methane Hydrates

Transport through a natural gas pipeline from the Alaska North Slope to Lower 48 markets is not necessarily the only option for North Slope natural gas supplies, including methane hydrates. Other possible alternatives include:

- Use for gas injection for continued reservoir pressure maintenance in the Prudhoe Bay oil field to maintain oil production. Currently, 8 Bcf per day (over 90%) of the natural gas produced from the Prudhoe Bay field is re-injected back into the field to enhance oil recovery.[21] This injection will not continue once a pipeline is built, unless another source of gas for injection on the North Slope is available.
- Use to generate steam for use in producing Alaska's large potential heavy oil resources (16-20 billion barrels of resource in place), such as those in the West Sak Oil Pool of the Kuparuk River, Milne Point and other fields. A small steam injection pilot project to produce these heavy oil resources is currently underway, but considerable additional work will be required to prove the recoverability on these resources.[22,23, 24]
- Use as a source of supply for transport in a conventional or high-pressure gas pipeline that carries the gas from Prudhoe Bay-area fields to a port in southern Alaska, where the gas is chilled to liquefied natural gas (LNG), and loaded on LNG tankers for transport to the Asian Pacific Rim, or perhaps the U.S. Assessments of the economic viability of this option by project proponents are

[21] Alaska Department of Natural Resources, Division of Oil and Gas, *Alaska Oil and Gas Report,* December 2003
[22] Kuuskraa, V.A, and M. L. Godec, *A Technical and Economic Assessment of Domestic Heavy Oil*, report prepared for the Interstate Oil and Gas Compact Commission, 1987
[23] http://www.state.ak.us/local/akpages/ADMIN/ogc/orders/co/co400_499/co406.htm
[24] Williams, Peggy, “Alaska’s North Slope,” *Oil and Gas Investor*, July 2001

not publicly available. Given the glut of current LNG project proposals, this option from the North Slope is unlikely to be competitive.[25]

- Use as a source of supply for a gas-to-liquids (GTL) facility in the Prudhoe Bay area to convert natural gas to middle-distillate (diesel-like) liquids. The GTL product could be pumped in segregated batches through the Trans Alaska oil pipeline and then transported by tankers to the U.S. West Coast. A recent study revealed that incremental construction of several small GTL facilities, allowing for "learning," results in cost reductions for facilities built later. This "incremental" GTL model provided a favorable economic outcome for Alaska gas given current anticipated market conditions, assuming future robust market demand for GTL products.[26] The timing of this, however, remains highly uncertain at this stage.

The economics of and market dynamics likely to impact all of these options remain highly uncertain, and methane hydrates will still need to compete with other natural gas supplies, both on the North Slope and elsewhere, to serve these options.

Economics and Timing for a Canadian Pipeline System

A natural gas pipeline through the Mackenzie Valley is expected to transport 1.2 Bcf per day produced from the Mackenzie Delta in northern Canada to connect up with the current interstate gas pipeline hub in Alberta. According to AEO 2004, this pipeline is forecast to come on line when average Lower-48 wellhead prices exceed $3.41 per Mcf for more than two years. Given these conditions, in the AEO 2004 Reference Case, the Mackenzie Delta pipeline comes on line in 2009.

However, given the significant need for natural gas for producing and upgrading Canadian tar sands, much of the Mackenzie Delta natural gas could very well be consumed by the large syncrude and tar sand plants in Canada. Recent work by the Canadian Energy Research Institute (CERI) has concluded that gas demand for syncrude development could be as high as 1.5 to 2.5 Bcf per day, if two-thirds of the

[25] Sherwood, Kirk W., and James D. Craig, *Prospects for Development of Alaska Natural Gas: A Review*, U.S. Department of Interior, Minerals Management Service, Anchorage Alaska, 2001
[26] Robertson, E.P., *Options for Gas-to-Liquids Technology for Alaska*, INEEL/EXT-99-01023, December 1999

currently proposed projects get implemented.[27] The AEO 2004 Reference Case forecast gas consumption for syncrude development to reach 1.4 Bcf per day by 2025. In either case, this is larger than the expected capacity of the Mackenzie Valley pipeline.

This situation, along with expectations of a decline in Canadian conventional gas production, indicates that Canadian exports of natural gas to the U.S. will likely not "back out" the need for natural gas from Alaska's North Slope, including gas hydrates.

Economics and Timing for Offshore Pipeline Systems

In the Gulf of Mexico OCS, considerable pipeline infrastructure already exists. However, the 2004 AEO forecasts that offshore natural gas production will decline by as much as 1 Bcf per day between 2010 and 2025. This implies that up to this much underutilized pipeline capacity could be available for transporting gas produced from hydrates in the Gulf OCS, should producing this gas prove to be economically feasible, and assuming that new, less costly natural gas resources in the Gulf OCS are not discovered.

The economics of transporting gas produced from hydrates will depend upon the relative location of the producing hydrates to available underutilized infrastructure. As mentioned previously, the locations of economic accumulations of natural gas hydrates have not been identified; so it is currently not known where they will be located relative to existing infrastructure. Nonetheless, given the extensive infrastructure that already exists, the incremental costs associated with transporting hydrates-based production would likely be manageable.

Other potential areas where hydrates may exist in the offshore, such as the Atlantic and Pacific coasts, have more limited existing natural gas infrastructure available to utilize. Even if existing moratoria for leasing and development in these areas are lifted (see discussion in Chapter IV), and hydrates production in these areas becomes commercially feasible, substantial pipeline infrastructure investments may be

[27] Canadian Energy Research Institute, *Oil Sands Supply Outlook: Potential Supply and Costs of Crude Bitumen and Synthetic Crude from Canada, 2013-2017*, CERI Media Briefing, March 3, 2004

necessary to bring the produced gas to market. Moreover, substantial conventional gas resources may also exist in these areas,[28] so should leasing someday be reinstated in the future, gas produced from hydrates would unlikely have to bear the full costs of supporting the development of this infrastructure.

Competing LNG Supplies

The most-likely largest, single, long-term market competitor to methane hydrates will be imports of LNG:

- The AEO 2004 anticipates that LNG imports will reach 4.8 Tcf in year 2025, compared to 0.2 Tcf annually in 2002.
- The NPC natural gas study projects comparable estimates for LNG imports of nearly 14 Bcf per day, or nearly 5 Tcf annually in 2025.

Much of the higher supply expectations for LNG stem from the significant recent reductions in LNG transportation and processing costs. Many in industry expect these costs to decline further, by up to 30% from today's levels, placing increased pressure on competing gas supply sources. With these lower costs, LNG imports from Trinidad and other supply sources to east coast terminals are already economic. In addition, several new LNG receiving terminals are being planned for the West Coast of Mexico, paving the way for LNG imports from Indonesia, Australia, and other Far East sources.

The average wellhead prices required for triggering new LNG production in the U.S. and the Bahamas vary by location, ranging from $3.62 to $4.58 per Mcf (2002 dollars) according to EIA.[29] This then, represents roughly the cost cap for potential gas production from hydrates in the Gulf of Mexico OCS, delivered to shore. The maximum wellhead price (and thus production cost) for methane hydrates from the Alaska North Slope, or any source of natural gas supply for Northern Alaska, given these same assumptions, would be in the range of $0.75 to $1.70 per Mcf allowing for project risk and an acceptable return on investment.

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[28] U.S. Department of Interior, Minerals Management Service, *Outer Continental Shelf Petroleum Assessment,* 2000

[29] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2004*, DOE-EIA-0554 (2004), February 2004

However, as described later in this report, considerable barriers exist that could constrain the construction of future LNG facilities in the U.S. In the February 2004, EIA study of low natural gas supply scenarios,[30] discussed in Chapter II, one scenario assumed that industry was unable to build more than three additional average-sized LNG offloading facilities in the future, limiting U.S. LNG import capacity to 2.1 Tcf annually. Under this scenario, U.S. consumption decreases, natural gas imports decline by one-third, wellhead prices increase by $0.35 per Mcf, and U.S. production increases modestly.

Other Potential Competing Sources of Supply

In addition to methane hydrates, there are a number of other possible sources of future natural gas supplies that, if proven to be legitimate sources of future supply, could compete with gas hydrates to serve North American natural gas markets in the long-term. Moreover, some sources of supply that many now believe to be in dramatic decline may stabilize and continue to be a secure source of supply for many years to come. Some of the more important of these potential sources of supply are described below.

(1) Canadian Coalbed Methane

One potential source of supply that can offset the current production decline in Canada, at least to some extent, is Canadian coalbed methane. However, there remains considerable uncertainty and debate about the ultimate recoverable resource potential for coalbed methane in Canada. The Alberta Geological Survey estimates that coalbed methane resources in place in Canada are over 500 Tcf.[31] The Canadian National Energy Board (NEB) estimates from 60-80 Tcf is recoverable.[32] Depending on how much natural gas supply potential could be possible, Canadian coalbed methane could compete for future market share with gas hydrates.

[30] Energy Information Administration, *Analysis of Restricted Natural Gas Supply Cases*, SR/OIAF/2004-03, February 2004
[31] http://www.ags.gov.ab.ca/activities/CBM/coal_and_cbm_intro.shtml#Coal_Rank
[32] National Energy Board of Canada, *Canada's Energy Future: Scenarios for Supply and Demand to 2025*, July 3, 2003

(2) *Additional Gas Resources in Alaska*

Of the nearly 40 Tcf of natural gas remaining in developed and known undeveloped fields in Alaska, approximately 27 Tcf is generally considered to be potentially available for export at near today's prices, pending construction of a gas pipeline from the North Slope. Another 200 Tcf of conventional undiscovered natural gas resources could exist in the onshore and Federal offshore in Alaska, including the National Petroleum Reserve – Alaska (NPR-A), the Alaska National Wildlife Refuge (ANWR), the Foothills of the Brooks Range, and federal submerged lands on the Beaufort and Chukchi shelves. Another 60 Tcf of unconventional gas potential (primarily attributable to coalbed methane) is represented in the USGS estimates of undiscovered resource potential for Alaska, but are currently not determined to be economic to develop. [33]

(3) *Deep Gas Formations*

Deep formation gas (existing in formations below 15,000 feet) represents about 9% of current U.S. natural gas production. Very little of this domestic resource has been characterized to date. For example, in 2000, of the 28,050 oil and gas wells drilled in the U.S., only 574 were drilled deeper than 15,000 feet.[34] Estimates of deep gas resources remaining to be discovered in the U.S. vary considerably, a function of various assessment methodologies, geographic and geologic definitions, and sources of data. The USGS, which is somewhat in the middle of the range, estimates undiscovered deep gas resources to be 114 Tcf.[35]

Similarly, substantial potential is believed to exist in deep formations in the offshore Gulf or Mexico, despite that fact that little of this resource has been characterized to date. For example, in the OCS, of the 35,000 wells drilled to date in water depths less that 200 meters, only 1,842 were drilled deeper than 15,000 feet.

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[33] Sherwood, Kirk W., and James D. Craig, *Prospects for Development of Alaska Natural Gas: A Review*, U.S. Department of Interior, Minerals Management Service, Anchorage Alaska

[34] American Petroleum Institute, *Basic Petroleum Data Book*, Volume XXI, Number 1, February 2001, Table III-3

[35] Dyman, Thaddeus S., Schmoker, James W., and Root, David H., "USGS assesses deep undiscovered gas resource," *Oil and Gas Journal*, Vol. 96, No. 16, April 20, 1998

Nonetheless, the MMS currently estimates that technically recoverable natural gas resources in deep formations in the shallow water Gulf of Mexico could be as much as 55 Tcf.[36]

Perspectives on Transportation/Market Access Influences on Hydrates

The two primary factors affecting the future commercial viability of methane hydrates will be access to market and the costs and potential for competing sources of supply. In general, the more existing infrastructure that gas production from hydrates can take advantage of, the less transportation barriers will limit commercial hydrates production. For the most part, particularly in the Gulf of Mexico OCS and North Slope of Alaska, conventional gas resource development will bear most, if not all, of the cost burden of transportation infrastructure to move produced gas to market. In these areas, gas hydrates generally exist in geographic proximity, and in some cases also in geologic proximity, to sources of conventional gas supplies. Consequently, commercially viability for gas hydrates will depend on the extent to which the gas produced can take advantage of this existing infrastructure.

On the Alaska North Slope, available transportation capacity for gas produced from hydrates will depend on when an Alaska gas pipeline is built. In this regard, capacity could be available as early as the 2020, but could be delayed to 2030 or after. However, if other uses for natural gas materialize on the North Slope, commercial viability could be realized earlier. Based on this, methane hydrates would initially need to compete with natural gas delivered to the pipeline on the North Slope at about $1.30 to $1.55 per Mcf. Anticipated competitive costs for LNG would also place the threshold cost for gas produced from hydrates in this range.

In the Gulf of Mexico OCS, considerable pipeline infrastructure already exists, but based on current forecasts of production decline in the Gulf OCS, as much as one Bcf per day of underutilized pipeline capacity could be available for transporting gas

[36] U.S. Department of the Interior, Minerals Management Service, "Deep Shelf Gas May Be More Abundant in Gulf than Earlier Forecast Probabilistic Estimate Increases by 175%" press release issued November 19, 2003

produced from hydrates between 2010 and 2025. Wellhead prices in the Gulf OCS could be in the range of $3.40 to $4.60 per Mcf (2002 dollars), depending on the extent of new pipeline investments that will be required to connect the gas produced from hydrates to available pipeline infrastructure, and the costs of competing sources of supply, most prominently LNG.

Other potential areas where hydrates may exist, such as the Atlantic and Pacific coasts, where existing natural gas infrastructure, is more limited, would have a higher cost threshold, since new gas supplies would need to bear more of the costs associated with the development of new infrastructure.

Finally, other possible sources of natural gas supplies other than gas hydrates, if proven to be legitimate sources of future supply, could also compete with gas hydrates to serve North American natural gas markets. These sources of supply will be subject to the same market dynamics and access issues as gas hydrates.

LEASING, OWNERSHIP AND TAXATION ISSUES

The natural gas supply/demand outlook summarized in Chapter II characterizes current views on the future demand for natural gas in North America, the sources of natural gas supplies that will likely meet this demand, and the prices likely to characterize the marketplace. To define the most likely source of first commercial supplies of methane hydrates, the market dynamics defined by this outlook must be considered in combination with the location of prospective methane hydrates resources, the likely costs associated with developing resources in the various locations (or perhaps, the cost targets these resources would have to achieve to be commercially viable), and potential barriers that development of the resources in the various locations would need to overcome. In this chapter, those issues likely to influence leasing, ownership, and taxation of production from methane hydrates resources are discussed.

Access to Offshore Methane Hydrates Resources

Identifying likely sources of first commercial production of hydrates in the U.S. will depend on the extent to which the industry is permitted access to these resources. As described in Chapter I, the vast majority of potential methane hydrates resources in the U.S. exist in the offshore outer continental margins. However, most of this area is currently off-limits to all oil and gas exploration and production activities in the U.S., including any activities targeting gas hydrates. Only areas of the Gulf of Mexico and selected areas off the coast of Alaska are currently available for leasing.

Based on the gas hydrates resource assessment described in Chapter 1, approximately 40% of the total U.S. gas hydrates offshore resource in place, and 75% of the total Lower-48 offshore resource in place, is believed to exist in regions that are currently subject to leasing moratoria, as shown in Table 13.

Moreover, as described in Chapter I, except in rare instances, the precise physical locations of hydrate accumulations within these assessment regions, or plays, are unknown. Consequently, it is not possible, at this time, to specify precisely where within these plays gas hydrates exist.

Table 13:
Estimated Gas Hydrate Resources in Place in the U.S. that are Accessible and Off-Limits to Leasing

	Mean Resource in Place (Tcf)	Currently Accessible to Leasing (Tcf)	Currently Under Leasing Moratoria (Tcf)	Notes
Atlantic Coast Province	**51,831**	**0**	**51,831**	
Northeastern Atlantic Ocean Play	30,251	0	30,251	
Southeastern Atlantic Ocean Play	21,580	0	21,580	
Gulf of Mexico Province	**38,251**	**38,251**	**0**	
Gulf of Mexico Play	38,251	38,251	0	(1)
Pacific Ocean Province	**61,071**	**0**	**61,071**	
Northern Pacific Play	53,721	0	53,721	
Southern Pacific Play	7,350	0	7,350	(2)
Lower -48 Offshore Provinces Subtotal	**151,153**	**38,251**	**112,902**	
Percent of Total		**25%**	**75%**	
Alaska Offshore Province	**168,449**	**146,953**	**21,496**	
Beaufort Sea Play	32,304	32,304	0	
Bering Sea Play	73,289	73,289	0	
Aleutian Trench Play	21,496	0	21,496	
Gulf of Alaska Play	41,360	41,360	0	
Total All Offshore Provinces	**319,602**	**185,204**	**134,398**	
Percent of Total		**58%**	**42%**	

Notes:
1. The portion of this associated with the Eastern Gulf of Mexico may be off limits
2. The portion of this associated with producing leases may still be accessible

A review of the history of leasing policy in these offshore regions is instructive in highlighting some of the barriers that offshore hydrates leasing and development would have to confront, and can provide some insight on the likely sources of first commercial hydrates production in the U.S.

In 1982, the Minerals Management Service (MMS) was created as a bureau within the U.S. Department of Interior (DOI) to manage OCS mineral resources in an environmentally responsible manner. One of MMS's first steps was to introduce the concept and practice of area-wide leasing, which greatly expanded the available OCS areas of interest to industry. Prior to the institution of area-wide leasing, industry would nominate tracks for leasing, and then DOI would determine which of these tracts would be made available. Area-wide leasing increased the number of blocks considered in lease sales, and facilitated more exploration in frontier areas, such as the deep water offshore.

However, accelerated leasing in the Gulf of Mexico was offset in the early 1980s by legislation that established leasing moratoria in the Central and Northern California OCS. This was followed by the first pre-leasing moratorium for the North Atlantic. In 1988, a drilling ban was issued for 73 existing leases in the Eastern Gulf of Mexico, which was later expanded to include the North Aleutian Basin, and existing leases off the coast of North Carolina. In 1990, offshore moratoria and drilling bans were extended and expanded to include all of the offshore West Coast and Atlantic, and the Eastern Gulf of Mexico (south of 28^{o} N. latitude) until after 2000. In 1998, these moratoria were extended to 2012.

Today, because of these moratoria, only about 15% of the OCS acreage in the U.S. is currently available for leasing, and the current MMS Five-Year Leasing Plan for 2002-2007 offers no "new" areas for offshore leasing.

The histories of each of the four main areas of OCS leasing are described below.

(1) *Gulf of Mexico*

On August 20, 2003, DOI celebrated the 50th Anniversary of the Outer Continental Shelf Lands Act (OCSLA), as it reviewed bids for the Western Gulf of Mexico Lease Sale 187. This lease sale was the 100th offshore oil and gas lease sale conducted in the Gulf of Mexico. According to Secretary of Interior Gale Norton, "Over the past 50 years, lease sales … have produced about 14 billion barrels of oil and about 150 trillion cubic feet of natural gas. They have also provided oil-in-kind to help fill the Strategic Petroleum Reserve, created thousands of jobs, and generated $145 billion in revenue from federal offshore collections."[37]

However, not all of the Gulf of Mexico OCS is currently accessible for leasing and development, Figure 7. Leasing in the Eastern Gulf of Mexico has been constrained throughout this thirty-year period. Recent events concerning leasing in the Eastern Gulf include the following:

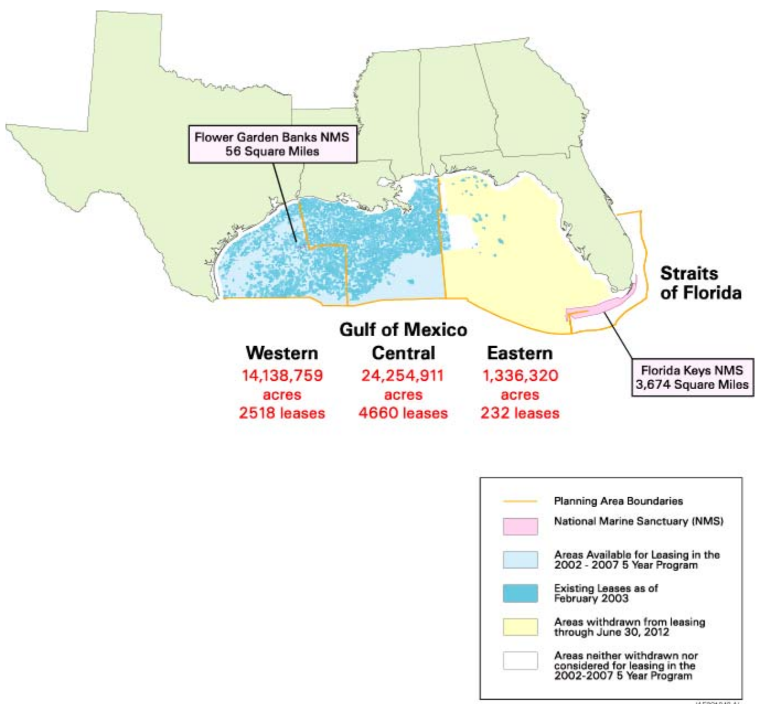

Figure 7:
MMS Lease Areas and Lease Status in the Gulf of Mexico Planning Area

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[37] U.S. Department of the Interior, Minerals Management Service, Office of Public Affairs, "Secretary Norton Celebrates 50th Anniversary of Outer Continental Shelf Lands Act at Western Gulf of Mexico Lease Sale 187" press release issued August 20, 2003

- *Chevron—Destin Dome Block 56*. In 1999, the Environmental Protection Agency (EPA) opposed Chevron USA's proposed natural gas drilling project in the Gulf of Mexico 26 miles south of Florida's Pensacola Beach. In a letter to the National Oceanic and Atmospheric Administration (NOAA), EPA said that it agreed with a State of Florida appeal that the drilling plans for Destin Dome violate the state's Coastal Management Plan. In May 2002, the federal government agreed to pay about $115 million to several oil companies, including ChevronTexaco, Conoco Phillips, and Murphy Oil, to buy out seven of nine leases in the Destin Dome Unit. A second agreement settled litigation brought by several of the oil companies that sued the federal government over alleged improper regulatory hurdles that delayed Destin Dome's development. Murphy Oil kept the two other Destin Dome leases, but those were suspended until 2012.

- *Eastern Gulf of Mexico Lease Sales*. The highly politicized Lease Sale 181 in the Eastern Gulf of Mexico pitted the Administration of President George W. Bush, which originally supported full leasing in the Eastern Gulf, against Jeb Bush, his brother and the Governor of Florida.[38] Originally, President Bush proposed to override state law, which forbids drilling off the Florida coast, to open up the Eastern Gulf for leasing. The initial area for Sale 181 was a 6-million-acre expanse about 15 miles off the coast of Florida -- a tract excluded from federal moratoria on new offshore oil leases that applies elsewhere -- containing an estimated 240 million barrels of oil and 1.8 Tcf of natural gas. In July 2001, prior to the scheduled sale, the President reduced the area to 1.5 million acres and moved the sale's boundaries out of sight of Florida beachgoers. In the revised sale area, drilling can occur no closer than 100 miles offshore from Pensacola and 285 miles from Tampa.

The December 2001 sale, though still opposed by environmental groups, Governor Bush, U.S. Senator Bill Nelson (D-FL), and many other government officials,

[38] Durham, Louise S., "Bush Brothers Face Off: Florida's 'Back Yard" on Front Burner," *AAPG Explorer*, June 22, 2001

proceeded ahead. Since then, thirteen exploration plans have been filed on leases issued as a result of the sale. In addition, a second sale took place in December 2003 in the western part of the Eastern Gulf (Lease Sale 189) and attracted over $8 million in high bids, a modest turnout from MMS's perspective, where 16 bids on 14 tracts were received.[39]

As discussed above, the portion of the hydrates resource which corresponds to areas current off-limits to development is unknown.

(2) <u>Atlantic Coast</u>

The MMS has conducted 10 lease sales in the Atlantic OCS, where 9,240 blocks were offered, and 433 leased, Figure 8. Currently, there is a moratorium on new leases and offshore oil and gas exploration is not allowed in the Atlantic OCS. This moratorium has broad, bipartisan support, and most Atlantic states oppose oil and gas development off their coasts.

In 1981 and 1983, MMS issued leases to drill offshore North Carolina, in an area known as the Manteo Exploration Unit, to a partnership including Mobil Oil, Marathon Oil, Chevron, Conoco and others. To date, no drilling has taken place, in large part due to grassroots opposition. Coastal grassroots organizations are opposed to any type of offshore drilling off the Atlantic Coast, regardless of the technology involved or product likely to be produced (oil or natural gas). These groups remain organized and sufficiently funded to oppose any drilling that may be proposed. Sources of this opposition include:

[39] U.S. Department of the Interior, Minerals Management Service, Office of Public Affairs, "Modest Interest in Eastern Gulf of Mexico Sale 189: Sale Attracts $ 8,376,765 in High Bids" press release issued December 10, 2003

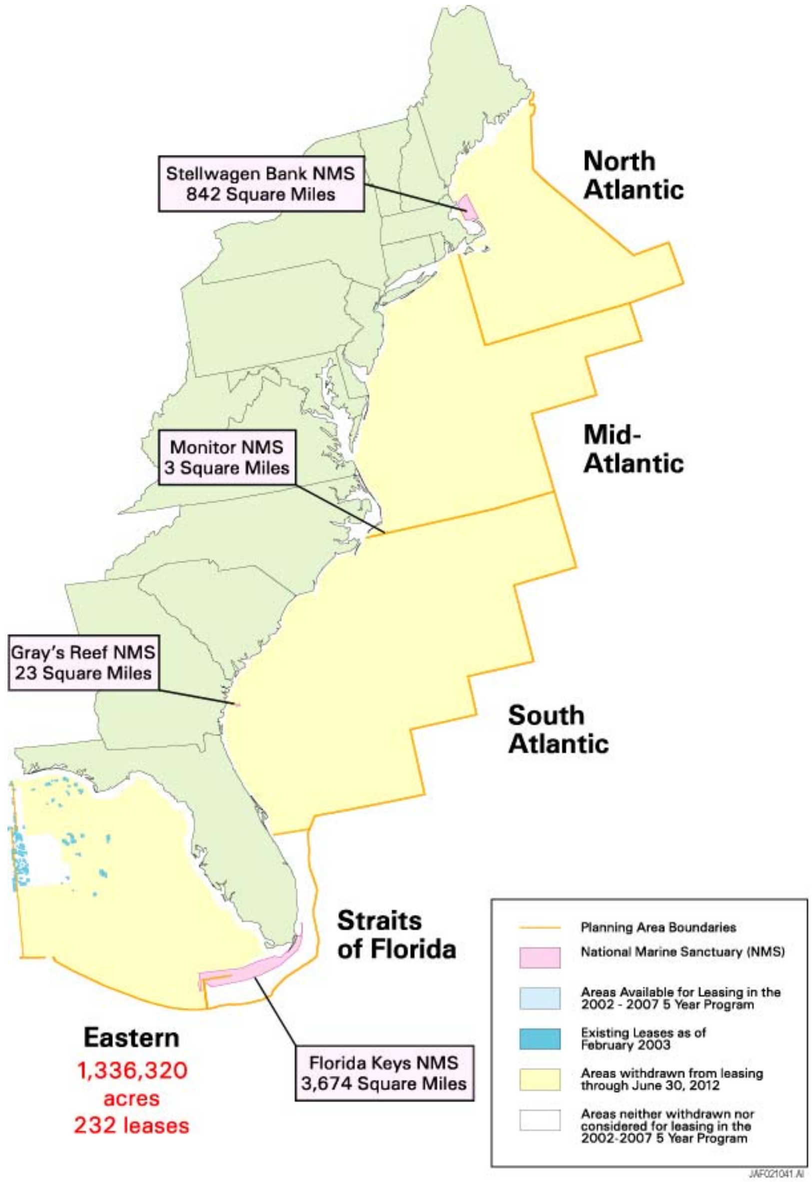

Figure 8:
MMS Lease Areas and Lease Status in the Atlantic Planning Area

- *North Carolina Coastal Federation,* a non-profit organization that seeks to provide citizens with the assistance needed to take an active role in the management of North Carolina's coastal water quality and natural resources.
- *Cape Hatteras Coast keeper,* one of three Coast keepers within the North Carolina Coastal Federation. Coast keepers are full time advocates who are dedicated solely to protecting the coast.
- *LegaSea,* a grassroots citizens group on the Outer Banks supported by Greenpeace and the National Resources Defense Council.

- *Surfrider Foundation,* a non-profit environmental organization dedicated to the protection and enjoyment of the world's oceans, waves and beaches for all people, through conservation, activism, research and education.

MMS has settled all litigation on leases issued off North Carolina, resulting in the relinquishment of 32 leases, while preserving the Manteo Unit for possible future exploration.

A chronology of key events in the history of oil and gas leasing in the Atlantic OCS is summarized in Table 14.

(3) Offshore Pacific

Currently, there are 79 active leases in the Pacific OCS, Figure 9. All of them are located off the coast of Southern California. These leases, containing 38 discovered fields, were developed beginning in the late 1960s, and continued through the early 1980s. Some gas hydrates potential may be associated with these leases, but not enough information exists today to speculate on how much.

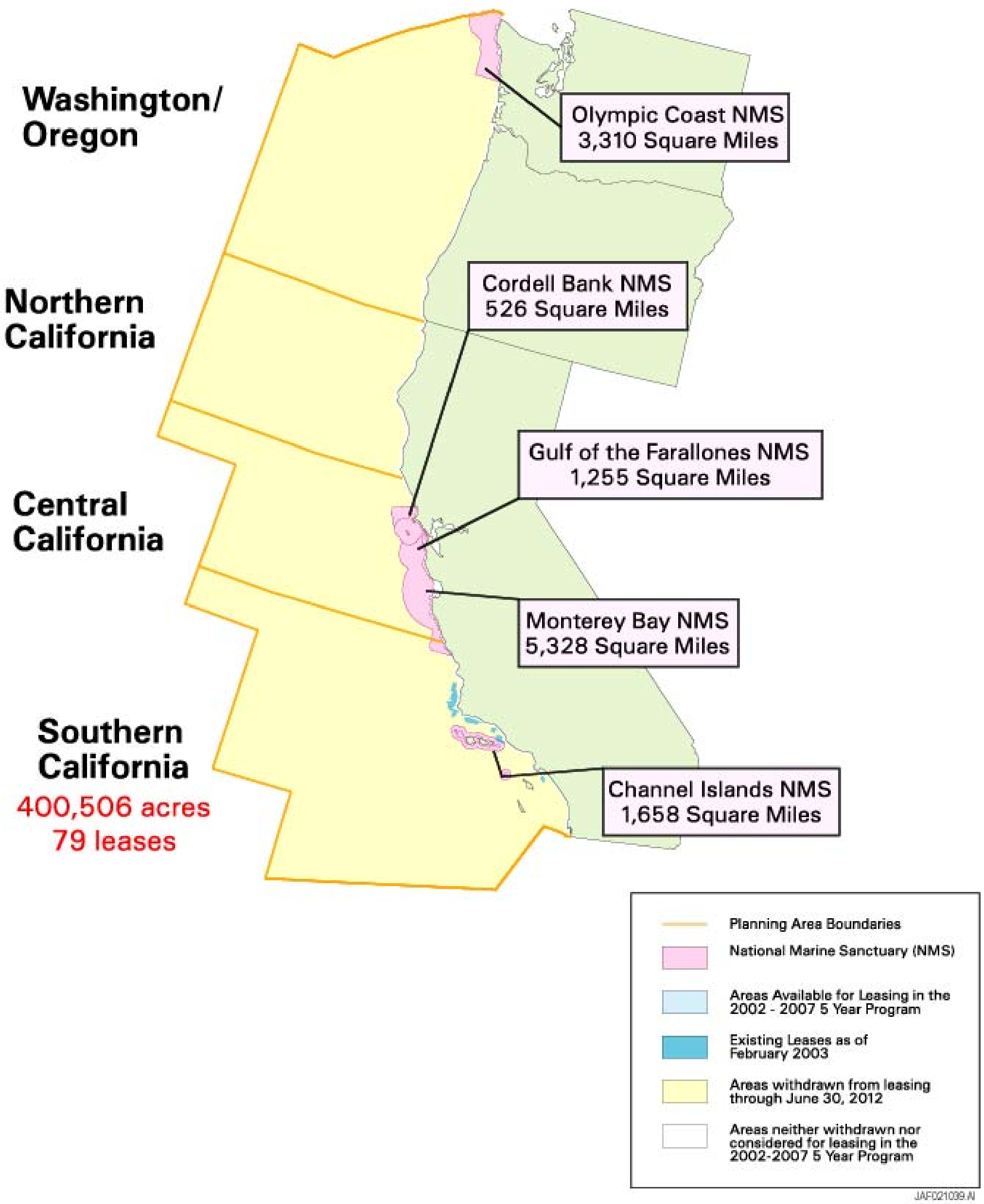

Figure 9:
MMS Lease Areas and Lease Status in the Pacific Planning Area

Table 14:
Key Events Related to Offshore Oil and Gas Leasing off the Atlantic Coast

September 1981 & 83	Manteo Leases Issued. $296 million paid for original 21 leases. In addition, Mobil/Marathon paid $234 million in bonuses for 5 leases.
April 1982	Chevron USA Files Exploration Plans on Manteo Block 510
July 1982	MMS Approves Chevron's Manteo Block 510 Plan
August 1988	Exploration Plan Filed by Mobil on Manteo Block 467
Fall 1988	North Carolina Governor Jim Martin appoints advisory task force.
November 1988	Local residents learn that oil companies led by Mobil had applied for permit to sink an exploration well off Hatteras. State of North Carolina tells residents they should have voiced concerns during the lease sale. Residents meet with Congressman Walter Jones, Sr. (NC) and Chairman House Merchant Marine Committee who does not know details of what Mobil wanted to do.
March 1989	Exxon Valdez spills 11 million gallons of oil into the Prince William Sound
July 1989	MOU Signed between MMS, Mobil and North Carolina
1990	President Bush places a 10-year moratorium on new oil and gas drilling off most of the U.S. coast except North Carolina. Angers NC Gov. Martin who joins with LegaSea.
May 1990	Manteo Unit Approved by MMS
June 1990	MMS Releases Final Environmental Report on Mobil Exploration Plan
August 1990	Congress Passed the Outer Banks Protection Act, establishing an environmental panel to review adequacy of leasing, exploration and production data for offshore North Carolina. The Act prohibits further leasing off North Carolina, as well as approval of exploration or development activities, until Secretary of Interior certifies to Congress that data is adequate.
September 1990	MMS Conditionally Approves Mobil Exploration Plan
November 1990	North Carolina Rules that the Proposed Mobil Exploration Plan and EPA Discharge Permit were Inconsistent with its Coal Zone Program
December 1990	Mobil Appeals North Carolina Coastal Zone Ruling to the Dept. of Commerce
1992	NC Environmental Sciences Review Panel submits report to Department of Interior. Interior Secretary agrees to conduct two studies the panel recommends: socioeconomic study; and benthic (effects of discharges on bottom-dwelling organisms).

Table 14: (continued)
Key Events Related to Offshore Oil and Gas Leasing off the Atlantic Coast

September 1994	US Dept. of Commerce Refuses to Override North Carolina's November 1990 Ruling
January 1995	Mobil and Marathon Appeal Commerce Override Refusal in Federal Claims Court
April 1996	Congress Repeals Outer Banks Protection Act Drilling could be allowed on block 467 if the consistency review is favorable. Manteo Unit lease blocks still suspended because of litigation.
1996	NC Coastal Resources Commission amends state's coastal energy policies (effective August 1998) to clarify criteria needed for consistency review.
July 1997	Federal Claims Court Rules in Favor of Mobil/Marathon On "Taking" Questions; $156 million settlement (Appeals Court later overrules judgment)
1997	Chevron announces intention to drill
1998	LegaSea writes to churches, etc., urging them to call Senator Helms saying that they did not want the oil industry. Concern over oil workers bringing gambling, drugs, prostitution, etc.
February 1998	Chevron Discusses Plans to Drill/Workshop held
June 1998	President withdraws from leasing all unleased areas in Atlantic OCS through 2012
April 1999	Chevron files for Relinquishment of all its Rights, Titles, and Interests in 6 Manteo Unit Leases
December 1999	Amerada Hess Surrenders its Interest in 4 Manteo Leases and Currituck Block 777
June 2000	US Supreme Court Rules in Favor of Mobil/Marathon that a "Taking" Occurred. US government pays Mobil and Marathon $156 million in return for breaking the 1982 lease contracts.
July 2000	District Court Judge Dismisses Mobil's Litigation Against Commerce/North Carolina - Unit SOO Terminated Primary Term Clock Commences on Remaining Leases (8)
August 2000	Unit Operator (Mobil) formally notified by MMS that the Suspensions of operations (SOO) for the leases in the Manteo Unit had terminated and the primary term for the remaining 8 leases would expire on July 26, 2002
November 2000	Conoco and partners file relinquishments on the last 8 remaining active leases located in the Atlantic OCS

Thirty-six of these leases are currently undeveloped. MMS has directed the suspension of operations for these undeveloped leases indefinitely. The undeveloped leases are generally dispersed throughout the area in which production has been occurring for over 30 years, and some development of the producing leases is continuing. Projects have been proposed for a number of the undeveloped leases. California officials want the Administration to buy back undeveloped leases as it has done in Florida. Secretary Norton has said that the companies should be allowed to drill. Their plans, under review when California brought suit against MMS, have been essentially tabled.

Lessees of the undeveloped leases filed suit in January 2002 against the U.S. Government for breach of lease obligations and are pursuing damages. The case is still pending.

The existing moratorium on new oil and gas leasing took effect in June of 1991, by an Executive Order of then President Bush. In July 1998, President Clinton extended this order until June 30, 2012. On April 1, 2003, the Bush Administration announced that it had decided against asking the U.S. Supreme Count to overturn two lower court rulings upholding the State of California’s authority to review and decide on future drilling along its coast. While drilling is not banned, new development is unlikely, due to strong, bipartisan public and state government opposition. Key organizations leading this opposition to leasing include the Natural Resources Defense Council, California Coastal Coalition, California Public Interest Research Group (CalPIRG), Environmental Affairs Board, Environmental Defense Center, Sierra Club, Surfrider Foundation, Wilderness Society, and local residents.

A chronology of key events in the history of oil and gas leasing in the Pacific OCS is summarized in Table 15.

(4) Offshore Alaska

In the Alaska OCS, lease sales have historically occurred in Cook Inlet, the Gulf of Alaska, Norton Sound, and in the Bering, Beaufort and Chukchi Seas, Figure 10.

Currently, 68 leases are active in the Beaufort Sea off the Northern coast of Alaska, and two are active in Cook Inlet in the south. A Beaufort Sea Sale Lease was held September 24, 2003. Bids totaling over $10 million were submitted on 34 tracts covering approximately 181,000 acres.[40] Lease sales are also planned for Cook Inlet in 2004 and 2006. In April 2003, industry was asked whether they were interested in planned oil and gas lease sales in the Norton Basin, Chukchi Sea, and Hope Basin, and no interest was indicated.

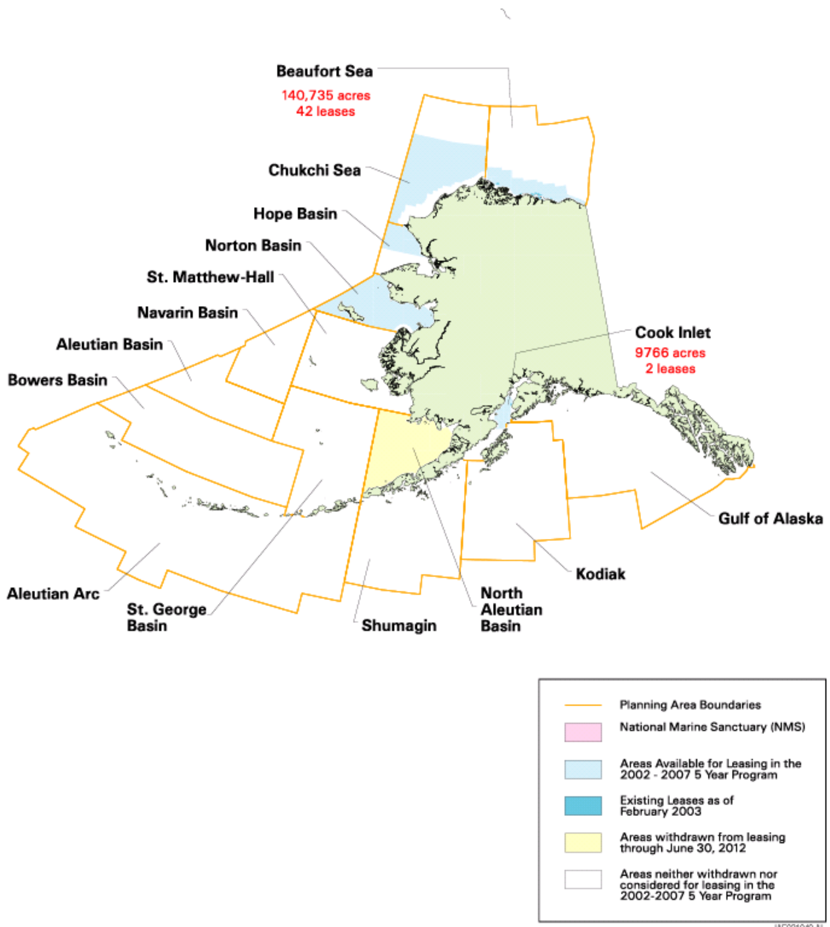

Figure 10:
MMS Lease Areas and Lease Status in the Alaska Planning Area

Despite little opposition to leasing in the Alaska OCS, citizen resistance to specific offshore development projects nonetheless exists. On the North Slope, the Inupiat Eskimos, though supportive of onshore oil development and its economic

[40] U.S. Department of the Interior, Minerals Management Service, Office of Public Affairs, "Oil and Gas Interest Continues in Alaska's Beaufort Sea," press release issued September 24, 2003

Table 15:
Chronology of California's Opposition to Offshore Drilling

1935: Redondo Beach voters ban drilling – By a vote of the people in 1935, Redondo Beach enacts a ban precluding offshore drilling and onshore drilling which held for twenty years.

1969: Santa Barbara blowout – Union Oil's Platform “A” accident in federal waters resulted in an uncontrolled loss of well control, or blowout, which for weeks coated more than 150 miles of California's most pristine and popular beaches with a 660-square-mile mat of thick, black tar, mixed with dead birds and dying marine life, launching the modern-day environmental movement and helping to inspire the first Earth Day. Official estimates of the volume of the spill ran as high as 780,000 barrels, with Coast Guard estimates of the size of the spill set at 100,000 barrels.

1969: Hickel Preserve established – Interior Secretary Walter Hickel, in response to outcry in Santa Barbara after the blowout and spill, uses his secretarial authority to add a 34,000-acre buffer zone to the 21,000-acre federal ecological preserve that the Johnson Administration had established in 1968. These zones are seaward of the state sanctuary that runs thirteen miles from Summerland to Coal Oil Point along the Santa Barbara coastline.

1981: First congressional moratorium – California Congressional Delegation, working with Members of Congress from other states, creates first-ever bipartisan legislative “moratorium” to protect Northern California offshore drilling tracts as part of the fiscal year 1982 Interior Appropriations Bill, effectively cutting off the funding to the Department of Interior for leasing activities.

1986-1990: Local communities enact onshore facilities ordinances – Twenty-four city and county governments enact, by a vote of the people or by a vote of the city council or county commissioners, local land use ordinances which either ban outright, or submit to a vote of the public, any proposed onshore support facilities for offshore oil drilling. In seventeen communities, these measures were enacted by popular votes that prevailed by margins ranging from 53 percent to 85 percent, with the average margin for adoption being 72 percent.

1991: **President George H. W. Bush drilling deferrals** – After more than a year of public hearings, President Bush, by Executive Action, deferred any new offshore drilling leases along the California coast until after the year 2002, citing the lack of adequate scientific data needed to ensure that the environment can be protected from adverse impacts of drilling.

1994: California Legislature bans new oil leasing in state waters – The California State Legislature passes, and Governor Pete Wilson signs into law, a permanent ban on new offshore oil leasing in state waters.

1998: President Clinton's offshore drilling deferrals – President Clinton, by Executive Action, extends the previous Bush Deferrals for California and other sensitive coastal areas until the year 2012.

Table 15: (continued)
Chronology of California's Opposition to Offshore Drilling

1999: Governor Davis acts to stop drilling on active-but-undeveloped leases on the Central California coast – Governor Gray Davis directed the State Resources Agency and the California Coastal Commission to identify all legal and administrative actions available to the state to protect California's coastline from new drilling. Governor Davis, the California Coastal Commission, the State Attorney General, and numerous conservation groups sue the US Department of Interior to prevent drilling on these undeveloped offshore leases.

2001: In June, a Federal judge in California ruled that state officials have the right to review the potential environmental impacts any new offshore oil and gas drilling leases along the California coast, effectively barring new exploration. In August, the Bush Administration appealed the judge’s ruling.

2002: California congressional letter to the President – 32 Members of the California US House of Representatives Delegation on June 6, 2002, wrote a bipartisan letter to President Bush asking for cancellation of the remaining 36 undeveloped offshore leases on the California coast near Pt. Conception. A separate letter from Senator Barbara Boxer made a similar request.

Senator Boxer and Senator Mary Laudrieu (D-LA) introduced legislation to allow energy companies that hold the 36 leases to obtain credits fore their investment that they could apply to oil and gas exploration in the Central and Western Gulf of Mexico. Congresswoman Lois Capps (D-Santa Barbara) introduced similar legislation in the House.

2002: Governor Davis reiterates his request for cancellation of Pt. Conception leases – On June 7, 2002, Governor Gray Davis reiterates his request that the administration cancel the remaining undeveloped federal leases on the Central California coastline.

President Bush rejected Governor Gray Davis’ pleas to extend the same protection against oil and gas drilling to California that he granted to Florida.

2002: On December 2, a Federal appeals court upheld a lower court ruling that the government illegally extended 36 undeveloped oil leases off the central California coast. The panel agreed with the State of California and environmental groups who had sued the Federal government because of the environmental risks posed by oil drilling.

2003: On March 31, the Bush Administration announced that it would not ask the US Supreme Count to overturn two lower court rulings upholding the state’s authority to review and decide on the future drilling along its coast.

benefits in general oppose drilling in their whale-hunting grounds. On the Kenai Peninsula south of Anchorage, attitudes are generally mixed about oil and gas leasing in the federal waters of Cook Inlet. In the northern Cook Inlet basin, where oil has been produced since the 1950s, the idea of OCS development is generally embraced, while farther south, support is much less established.[41]

Moreover, the preoccupation of most environmental groups on leasing of the Arctic National Wildlife Refuge (ANWR) has tended to divert their attention from Alaska OCS leasing.

(5) <u>Offshore Resource Inventory</u>

One part of the energy policy debate that occurred in the 2003 Legislative Session concerned a provision that would require the Secretary of the Interior to develop an inventory of potential oil and gas resources off the U.S. OCS. Opponents to the inventory argue that it will undermine the decades-old moratorium on offshore drilling, and fear it is the first step toward lifting the 20-year ban on leasing and exploration. Supporters of the inventory claim it is needed to learn how much oil and gas the country has, using the most modern technology, and does not signal any attempt to open currently off-limit waters to energy development. They say it makes sense for the federal government to identify available energy resources and contend that critics are misguided in their belief it is a precursor to lifting the ban on offshore drilling.

An amendment proposed by Democratic Senator Dianne Feinstein of California and Senator Bob Graham of Florida to strip from comprehensive energy legislation this inventory provision lost on a 54-44 vote. A dozen Democrats joined 42 Republicans to defeat the amendment. In June 2003, the House voted to reject the inventory provision, and voted again in October 2003, by a vote of 229-182 to oppose the OCS inventory.[42]

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[41] National Research Council, *Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope*, Committee on the Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope, 2003

[42] Anonymous, “U.S. House votes to oppose OCS inventory,” *Oil and Gas Journal Online*, October 16, 2003

(6) U.S. Commission on Ocean Policy

The Oceans Act of 2000 directed the President to form the U.S. Commission on Ocean Policy, with the charge to establish findings and develop recommendations for a new comprehensive national ocean policy. Beginning in September 2001, the Commission convened a series of public meetings. In April 2004, the Commission released its Preliminary Report.[43] One of the recommendations made by the Commission (Recommendation 24-4) explicitly addresses methane hydrates, in particular, the need for R&D and resource access by private industry. This recommendation stated:

> "The National Ocean Council (NOC), working with the U.S. Department of Energy and other appropriate entities, should review the status of methane hydrates research and development and seek to determine whether methane hydrates can contribute significantly to meeting the nation's long-term energy needs. If such contribution looks promising, the NOC should determine how much the current investment in methane hydrates research and development efforts should be increased, and whether a comprehensive management regime for private industry access to methane hydrates deposits is needed."

The public comment period on this Preliminary Report ended on June 4, 2004. The Commission will review and consider comments received from the Governors and interested stakeholders, and then submit a Final Report to the President and Congress. After receiving the Commission's Final Report, the President is directed by the Act to consult with state and local governments, and other non-federal interests, prior to submitting to Congress his statement of proposals to implement or respond to the Commission's recommendations. The President's statement is due within 90 days after he receives the report[44].

[43] U.S. Commission on Ocean Policy, *Preliminary Report of the U.S. Commission on Ocean Policy*, Governors' Draft, April 2004

[44] http://www.oceancommission.gov/

Access to methane hydrates resources on the North Slope of Alaska

In the Alaska onshore, methane hydrates are believed to exist on federal and state lands, as well as on North Slope lands under the jurisdiction of Native Alaskan corporations. Of Alaska's 375 million acres, 60% (222 million acres) is under the jurisdiction of the federal government (over half of this is managed by the National Park Service or the Fish and Wildlife Service for purposes of resource protection and fish and wildlife conservation), 28% (105 million acres) is State land, 12% (44 million acres) is owned by regional and village Alaskan Native corporations, and only 1% (about 4 million acres) is privately owned, most around or within Alaska's communities.[45]

In characterizing issues associated with access to oil and gas resources on the Alaska North slope, including gas hydrates resources, several categories of resources should be considered, and are described below.

(1) <u>Leased Resources on State Lands</u>

Nearly 4 million acres are already subject to oil and gas leases in the North Slope, North Slope Foothills, and Beaufort Sea lease sale areas, issued under leases by the Alaska Division of Oil and Gas. About 87% of this acreage is onshore, with the rest in offshore state waters.[46] Alaska's competitive oil and gas leasing program has been in place since 1959, with area-wide lease sales conducted annually since 1998. Since hydrates can potentially exist in the same geographic location as conventional oil and gas resources, the hydrates resources coexistent with conventional oil and gas resources on leased state lands are already leased under state leases, so its development would be considered an extension of the development and production of these producing fields. [47]

[45] Alaska Dept. of Natural Resources, Division of Mining, Land, and Water, *Fact Sheet: Land Ownership In Alaska*, March 2000

[46] Alaska Dept. of Natural Resources, Division of Oil and Gas, *Active Oil and Gas Lease Inventory*, March 6, 2004

[47] Patrick Galvin, Petroleum Land Manager, Division of Oil and Gas, Alaska Department of Natural Resources, Personal Communication, April 22, 2004

(2) Unleased Resources on State Lands

The Alaska Division of Oil and Gas periodically issues leases for the exploration and development of oil and natural gas resources on state lands through a competitive sale process. Gas hydrates are also included in these lease offerings.[48] The state's current Five-Year Oil and Gas Leasing Program provides a stable and predictable schedule of proposed lease sales. Typically, during a lease sale, the bidder having the highest bonus bid is awarded a lease, no larger than 5,760 acres, for a term of 5 to 10 years depending upon the specific sale. In general, minimum acceptable bids of $5 to $10 per acre are established for these sales. This is generally not a function of the perceived value of the lease.

Two types of leasing mechanisms are currently offered by the state that could be used for prospective gas hydrates development for areas not already under lease:[49]

- Annual area-wide lease sales are offered in four major geographic regions – the North Slope, the Beaufort Sea, the North Slope Foothills, and Cook Inlet.
- Exploration licensing is offered for remote areas of the state not included in the main area-wide lease sale areas. Rather than up-front bonus payments, applicants for an exploration license present a bid for what they propose to spend on exploration expenditures, with the winner being the bidder offering to spend the most. The licensing process is initiated either by proposals submitted by applicants or by a Commissioner of Natural Resources' request for proposals for a designated area.

(3) Shallow Gas Leases on State Lands

In 2002, the Shallow Natural Gas Leasing Program was started in Alaska, permitting the Alaska's Division of Oil and Gas to issue non-competitive "shallow gas leases" for the exploration and development of natural gas resources located within 3,000 feet of the surface. Targeted at coalbed methane resources, the intent of this program was to locate local sources of gas that could be delivered to consumers in

[48] ibid
[49] Alaska Department of Natural Resources, Division of Oil and Gas, *Five-Year Oil and Gas Leasing Program*, March 2004

remote areas less expensively than alternative sources. To encourage participation, these leases required no bonus payment, and only an application fee of $500. Also, annual rental payments were set at only $0.50 per acre, less than half of that of a conventional gas lease, and the royalty rate was set at 6.25%, again half the rate for conventional gas leasing. Lands already subject to Exploration License or already leased under the State's Oil and Gas Leasing Program would not be eligible. [50] For purposes of potential gas hydrates development, most of the current producing areas of the North Slope would be excluded from the shallow gas-leasing program.

In February 2004, however, proposed legislation was introduced in the Alaska state Senate that would terminate the shallow gas leasing program in its current form, [51] primarily as a result of opposition from residents in the Matanuska-Susitna and Homer Boroughs (north and south of Anchorage, respectively). Residents in these boroughs claimed that inadequate public notice was issued pertaining to leases issued for the development of coalbed methane resources. These residents were concerned about the ease with which companies were able to lease subsurface rights beneath their private surface holdings. While most of the citizen's concerns were based on inaccurate characterizations of coalbed methane production processes, they were able to prevail upon state legislators to implement changes.

On June 21, 2004, HB 521 was signed into law. The legislation, among other things, would bring all future non-conventional gas leasing under the state's competitive bidding program, and would clarify its intent by changing the "shallow gas" designation to all sources of "non-conventional" gas, including coalbed methane, shale gas, and *gas hydrates*. However, resources designated under this category would still receive some of the preferential leasing terms provided under the shallow gas program currently in place, including lower minimum bonus bids, application fees, rental payments, and royalty rates.

[50] http://www.dog.dnr.state.ak.us/oil/programs/shallowgas/shallowgas.htm
[51] Persily, Larry, "Proposed bill would change leasing rules," *Petroleum News*, Vol. 9, No. 7, February 15, 2004

In addition, this legislation imposed more specific requirements on unconventional gas operations, primarily targeted at coalbed methane development. These requirements include prohibitions on surface discharge, requirements for regulating hydraulic fracturing and for the management and disposal of water produced and other wastes, and/or for drilling in unconventional gas formations determined to also be potential sources of water for human consumption or agricultural purposes. The legislation also establishes requirements for testing water wells in the vicinity of coalbed methane wells, and for imposing “reasonable and appropriate measures” to mitigate noise from exploration and production operations. The new legislation also gives the State Oil and Gas Director additional authority to deny the extension of shallow gas leases that have already been issued, if justifiable. Shale gas and gas hydrates are not subject to all of the same requirements as coalbed methane.[52]

(4) Leased Resources on Federal Lands

BLM is responsible for leasing oil, natural gas, and geothermal resources on all Federally owned lands and Indian lands, including those lands managed by other Federal agencies, and including all Federal lands in Alaska. BLM is also responsible for review and approval of permits and licenses to explore, develop, and produce oil and gas and geothermal resources, to ensure that lessees and operators comply with lease requirements and regulations.

One of the major undeveloped areas of federal lands on the North Slope of Alaska exists in the National Petroleum Reserve in Alaska (NPR-A). Federal lands in the NPR-A cover 23.5 million acres on Alaska's North Slope. Hydrates prospects could potentially exist within much of the NPR-A. Although established in 1923, the NPR-A saw its first major leasing activity in 1999. After conducting oil and gas lease sales in the 4.6 million acres Northeast Planning Area (see Figure 11) in 1999 and 2002, BLM authorized several oil and gas exploration projects in the area. An Environmental Impact Statement (EIS) evaluating oilfield development in the Northeast NPR-A in response

[52] Bradner, Jim, “New Law Targets Suspended Gas Program,” *Alaska Journal of Commerce,* June 7, 2004

one proposed project, the Alpine project, a proposal from ConocoPhillips, has been prepared, and several others are being prepared.[53]

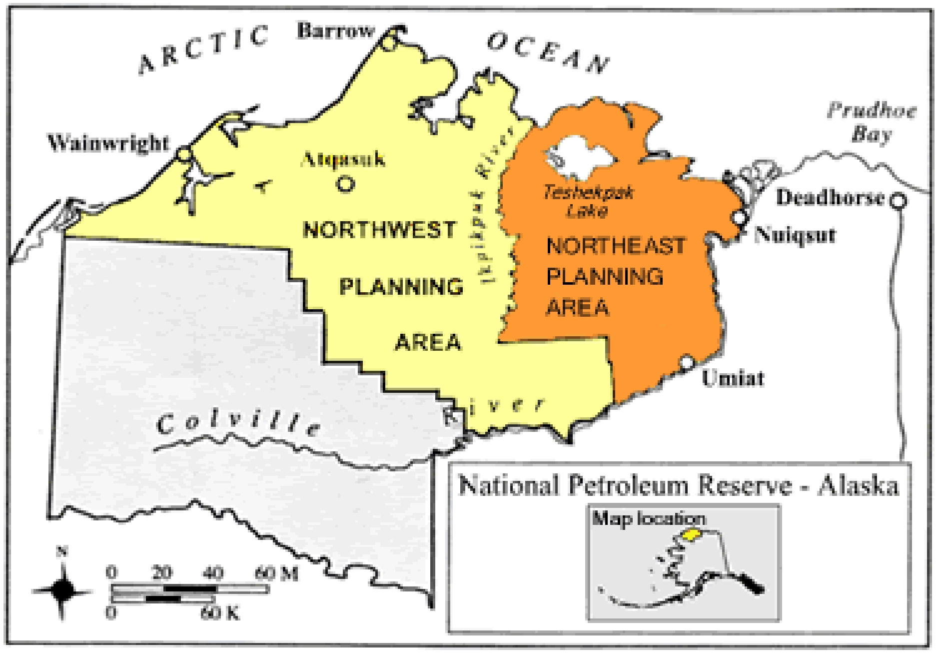

Figure 11:
Lease Planning Areas for the National Petroleum Reserve - Alaska

In April 2003, BLM announced plans to amend the 1998 Integrated Activity Plan (IAP) for the Northeast Planning Area of NPR-A and prepare an accompanying EIS. The purpose of this amendment is to:

- To evaluate exploration and development opportunities that could provide access to significant new oil discoveries
- To consider changing the current stipulations so they more closely resemble the performance-based stipulations now under development for the Northwest Planning Area of NPR-A (see discussion below).[54]

The original plan considered six alternatives, including the Preferred Alternative. Some alternatives propose designation of some lands in recognition of their outstanding

[53] http://aurora.ak.blm.gov/npra/nenpra2/default.html
[54] Bureau of Land Management, Alaska State Office, “BLM to hold public scoping meetings for revised plan for Northeast National Petroleum Reserve-Alaska,” press release, September 5, 2003

surface values. The Preferred Alternative protects habitats important to molting geese and the Teshekpuk Lake caribou herd by making these habitats unavailable for leasing, or by strict restrictions on oil and gas surface occupancy. In addition, surface use restrictions and other stipulations are applied to other habitats identified as having high surface resource values or that protect species of particular concern. While protecting these resources, the alternative makes 87% of the planning area available for leasing. Through the use of stipulations, leasing would be conducted in a manner that is consistent with the protection of the surface resources, including requiring a thorough consultation with affected communities, establishment of a subsistence advisory panel, and creation of an Interagency Research and Monitoring Team. This team would coordinate research and monitoring efforts related to the effectiveness of stipulations and surface resource impacts. No roads connecting outside the planning area (other than temporary ice roads) will be allowed.[55]

Public scoping meetings were held in October and November 2003. BLM's current schedule is to have a Final Plan and EIS published by October 31, 2004, with a Record of Decision (ROD) signed by November 30, 2004.[56] Additional leasing in the Northeast Planning Area will likely be initiated after the ROD is signed.

(5) <u>Un-leased Resources on Federal Lands</u>

In addition to the Northeast Planning Area, BLM is in the process of planning the first lease sale for the Northwest Planning Area of NPR-A. The final Northwest NPR-A Integrated Activity Plan (IAP) and Environmental Impact Statement (EIS) have been completed and a Record of Decision (ROD) signed January 22, 2004. The IAP describes four possible management alternatives, along with a "No Action" alternative, for 8.8 million acres of public lands in the Northwest Planning NPRA. The ROD emphasizes restrictions and designations to protect water quality, vegetation, wetlands, fish and wildlife habitat, subsistence uses, and scenic/recreational values. At the same

[55] U.S. Department of the Interior, Bureau of Land Management, *Northeast National Petroleum Reserve – Alaska: Final Integrated Activity Plan/Environmental Impact Statement*, August 1998

[56] http://aurora.ak.blm.gov/npra/nenpra2/schedule.html

time, it makes all available lands within the area available for oil and gas leasing, but defers leasing for 10 years on 1.6 million acres, or about 17% of the total area, pending completion of a Combined South NPR-A IAP/Coleville River Management Plan.[57]

Another major area of un-leased onshore federal lands in the North Slope of Alaska is contained within the Arctic National Wildlife Refuge (ANWR). While perhaps containing the largest accumulations of hydrocarbons remaining to be found in the U.S., ANWR remains off-limits to leasing and development, and continues to be a focal point of debate for national energy policy. However, since methane hydrates are believed to exist in other areas of the Alaska North Slope that have already been or are in the process of being leased, decisions concerning the ultimate fate of ANWR will unlikely have any major impact on the first commercial production of gas hydrates on the Alaska North Slope.

Issues Associated with the Legal Ownership of Gas Hydrates

A legal problem experienced by other categories of natural resources concerns determining ownership of these resources when there is no explicit provision granting ownership to a particular entity. As occurs quite frequently, the same piece of property can have separate owners for separate purposes. For example, one entity may own the oil and gas estate, another entity may own the coal estate, and yet another entity may own surface rights.

(1) Background

One relatively recent court case illustrates why the legal ownership of natural gas from hydrates may be a subject of concern. In June 1999, the U.S. Supreme Court overturned a lower court decision, declaring that coalbed methane belongs to the owner of the natural gas rights In many western states, the federal government reserved the coal rights to itself but not the rights to the gas and oil. In the case before the Supreme Court, the Southern Ute Indian Tribe had the coal rights, while Amoco Production Company, among others, owned the oil and natural gas rights, on some of the tribe's

[57] U.S. Department of Interior, Bureau of Land Management, *Northwest National Petroleum Reserve-Alaska, Integrated Activity Plan/Environmental Impact Statement: Record of Decision*, January 2004

reservation land. The 10th Circuit Court ruled that gas in coal seams belongs to the coal estate, which reversed 90 years of practice.

In December 1998, the State of Wyoming filed a brief asking the Supreme Court to review the Circuit Court decision on ownership rights. In June 1999, the Supreme Court overturned the lower court decision, ruling that coalbed methane is not a part of a coal lease. The basis for the Supreme Court decision revolved around the Congressional intent in creating the Coal Lands Acts of 1909 and 1910, which reserved to the United States coal interests in land that was later returned to the Southern Utes. In its decision, the Supreme Court held that Congress did not consider coalbed methane gas part of coal; and therefore, only the coal was reserved to the United States (later returned to the Southern Utes), not the coalbed methane.[58]

To hopefully not have this same type of issue impede the development of tar sands resources in the U.S., Section 319 of the proposed Energy Policy Act of 2003 (which was never passed into law) contained provisions amending Section 17(b)(2) of the Mineral Leasing Act that authorizes the Secretary of Interior to issue separate leases for the exploration and development of oil and gas from leases for the exploration for and extraction of tar sands, in areas where both tar sand and oil and gas may be present.

This severance of property rights can lead to legal battles if explicit ownership is not established. In the case of gas hydrates, *this question of ownership will primarily apply to public lands*, since commercial hydrate production is unlikely to occur on private lands any time in the foreseeable future.

The U.S. Code of Federal Regulations (CFR) pertaining to production accounting regulations for the MMS (30 CFR 216.6) defines gas as:

[58] *Amoco Production Co. v. Southern Ute Tribe*, No. 98-830, June 7, 1999

"any fluid, either combustible or noncombustible, which is extracted from a reservoir and which as neither independent shape no volume, but tends to expand indefinitely; a substance that exists in a gaseous or rarified state under standard temperature and pressure conditions."

Under this definition, gas produced from hydrates would clearly fall within the definition of gas under the terms of federal oil and gas leases managed by the U.S. Department of Interior (DOI). This would therefore apply to both offshore lands managed by the MMS and onshore lands managed by the BLM. It would also apply to any tax and/or royalty obligations associated with gas produced from hydrates.

(2) <u>MMS Determination</u>

This interpretation was further confirmed in a letter dated June 2, 1998, from Carolita Kallaur, then Associate Director for the MMS Offshore Minerals Management to J.G. Larre, of Chevron U.S.A. Production Company, in response to an earlier inquiry requesting MMS clarification on whether gas hydrates are covered under OCS oil and gas leases. In her response, Ms. Kallaur states:

"The OCS Lands Act authorizes MMS to manage OCS mineral resources. Therefore, MMS is authorized to manage any future development of gas hydrates. A company has the right to produce gas from hydrates and any free gas that is below the solid gas hydrate phase on its oil and gas leases."

This letter was approved by the DOI's Solicitor's Office, and BLM concurred.

The fundamental concern is whether this provides enough of a legal foundation for federal offshore resources, and/or whether this determination can extend to other categories of hydrates resources (onshore federal lands, state lands, private lands, etc.). If not, perhaps more definitive legislation may be necessary to clarify ownership of gas produced from hydrates. Unless changed, however, most believe this to be the current definitive determination of the status of methane hydrates at the current point in time.[59] Moreover, the federal government, the State of Alaska, or Alaska Native corporations have rights to all resources underlying federal lands with hydrates resource potential, so the split estate ownership issue would not be an issue for hydrates under federal lands.

(3) State Land Considerations

Under the State of Alaska's leasing program, the state issues oil and gas leases under which all types of oil and gas resources are included, including gas from gas hydrates. Similar to federal lands, split estate concerns are minimal in Alaska, because the State of Alaska reserves the rights of all subsurface mineral and hydrocarbon resources, even if they convey surface rights. On the North Slope, the state has never conveyed surface rights (or any subsurface rights for that matter) to private entities. However, as described above, a new law now defines gas hydrates as a "non-conventional gas resource" for state oil and gas leasing purposes.

(4) Native Corporation Lands

The passage of the Alaska Native Claims Settlement Act (ANCSA) in 1971 granted Alaska Natives title to 44 million acres of land. The act also established 13 Native regional corporations and more than 200 village corporations, capitalizing them with $962.5 million. Traditional concepts of land and resource utilization were expanded under ANCSA to include the concepts of corporate land ownership by Native Corporations by creating for-profit corporations, entitled to select a discreet amount of land in the region and to develop that land in order to bring economic benefits to Native Alaskans. ANCSA defined entitlement in terms of acreage only. The burden of translating that entitlement into a meaningful economic asset was the immediate challenge to these corporations, and remains so to this day

The Arctic Slope Regional Corporation (ASRC) is one of these Native Corporations, and owns approximately 5 million acres on the North Slope. Companies have leased, and are leasing, tracts of ASRC land throughout the region. While several exploratory wells have been drilled on ASRC lands, no development activity occurred

[59] Ray, Pulak, personal communication, July 7, 2004.

until the recent discovery of the Alpine Oil Field located in the Colville River Delta. (Approximately 50% of the Alpine Oil Field is on ASRC leases.) The development of hydrates, as of yet, is not a priority on ASRC lands. However, in principle, these lands could also be subject to leasing and development of hydrates, upon agreement between ASRC and the lessees.

Tax and Royalty Considerations

Royalty and tax considerations could plan an important role in establishing the commercial viability of gas hydrates production. Moreover, financial incentives could be provided to encourage development of hydrates, though in the assessments of commercial viability presented in this report, no financial incentives for gas hydrates development are assumed. This section discusses the current tax and royalty situation for gas development and production in regions of the U.S. that could contain hydrates.

(1) <u>State Land Considerations</u>

In 2003, the State of Alaska collected $1.6 billion in unrestricted revenues from oil and gas industry operations, the vast majority (87%) from royalties and severance taxes. These revenues represent 84% of the total amount of unrestricted revenues collected for the State General Fund. In addition, the state received on the order of $460 million in 2003 in restricted revenues. These correspond to royalties paid to the state Permanent Fund and School Fund; royalties, rents, and bonus received by the state from the leases on the NPR-A, and settlements to the Constitutional Budget Reserve Fund (CBRF) associated with tax and royalty disputes.

The primary sources of revenue from oil and gas operations, in order of contribution, are as follows:[60]

- **Royalties**. Most currently producing leases receive a fixed 12.5% royalty. Some is also subject to a net profit share, and some royalty rates are as high as 20%. There is no general differentiation between onshore and offshore, and between resource categories other than the provisions, described above, for unconventional gas resources (which include gas hydrates).

[60] http://www.tax.state.ak.us/programs/oil/production/petroleumtax.asp

- **Severance Taxes**. The severance tax rate for natural gas is 10%, with a minimum tax of $0.064/Mcf. For oil, the severance tax rate is 12.25% for the first 5 years of production, and 15% thereafter, with a minimum tax of $0.80/Bbl, if coming on production after June, 1981. For fields producing before that, the rate is a flat 15%.
- **Petroleum Industry Corporate Income Taxes**. Income taxes are derived from the corporation's worldwide net income, apportioned to Alaska, under a three-factor formula comprised of: (1) percentage of corporate sales and tariffs from Alaskan operations, (2) percentage of production from Alaska, and (3) percentage of property represented by Alaska holdings. The maximum marginal rate is 9.4%.
- **Petroleum Property Taxes**. Ad valorum taxes are assessed at a rate of 2% on the appraised value of all oil and gas production, and transportation hardware (tangible property). For planning purposes, Alaska state agencies assume a rate of 1.4% to 3.0% of net income.
- **Bonuses and Rents**. These are revenues gained from bonuses and rents from state leases.

(All State taxes and royalties are deductible for federal income tax purposes with the federal corporate income tax assessed at a maximum marginal rate of 35%).
Under the terms of the legislation recently signed into law, as described above, any gas produced from hydrates would be subject to the state tax and royalty obligations for "unconventional gas."

In Alaska, state revenues from oil and gas production are declining because of declining oil production (offset somewhat by higher prices). Consequently, some are concerned that state government may need to resort to raising taxes to offset these declining revenues. However, higher taxes could affect the economic viability of future projects, further reducing the potential tax base.

In April 2003, partially in response to these concerns, the Alaska State Legislature passed, and Governor Murkowski signed, the Alaska Stranded Gas Development Act (AS 43.82.).[61] The purpose of this legislation is to authorize the establishment of fiscal terms to encourage new investment in the state's stranded gas resources without significantly altering the tax and royalties methodologies and rates on existing infrastructure and production. The legislation allows the State to negotiate a contract of regular payments from the operators of qualified projects, in lieu of state and municipal taxes. The intent is to provide investors with greater fiscal certainty associated with the costs of transporting to market the stranded gas resources on the Alaska North Slope. With access to market more certain, the prospects for the economic development of any gas hydrates resources on the Alaskan North Slope can be significantly improved.

(2) Federal Land Considerations

In general, Federal lessees generally pay 12.5% (one-eight) the value of production in royalties from onshore leases, and 16.7% (one-sixth) of the value in royalties on offshore lands. A number of incentives are currently being offered for resources under federal lands (marginal wells, heavy oil, deep formations offshore), but none apply to gas hydrates.

One federal incentive exists that could apply to gas hydrates in the deepwater offshore Gulf of Mexico. In 1995, the U.S. Congress passed the Deepwater Royalty Relief Act (DWRRA) that provided economic incentives for leases issued between November 28, 1995 and November 28, 2000. These incentives provided automatic suspension of royalties for OCS fields, as follows:

- 200 – 400 meter water depth: relief on the first 17.5 MMBOE produced
- 400 – 800 meter water depth: relief on the first 52.5 MMBOE produced
- Greater than 800-meter water depth: relief on the first 87.5 MMBOE produced.

The introduction of deepwater royalty relief had a major impact on the industry. Prior to 1995, most of the acreage leased was in the shallow water areas. Upon

[61] http://old-www.legis.state.ak.us/cgi-bin/folioisa.dll/stattx01/query=[group+chapter4382]/doc/{@1}/hits_only?

passage of deepwater royalty relief in 1996, combined with considerable advancements in technology, industry's leasing attention shifted to the deep water. Since 2000, with the expiration of deepwater royalty relief (plus the growing participation of independent producers), once again more shallow water than deep-water leases are being acquired.

While the provisions of DWRRA expired on November 28, 2000, new provisions became effective in 2001. These new provisions will be specified for each Lease Sale, based on prevailing economic conditions. They will be granted to individual leases, not fields as under the DWRRA, and will be designated at the time of the final notice of sale. The extent to which this may apply to hydrates, if and/or when they are commercially developed, is unknown at this time.

Valuation of Leases Potentially Containing Gas Hydrates

Before leasing federal lands, government agencies generally make a determination of the minimal acceptable bid they would be willing to entertain for a particular parcel of land, based on the perceived value of hydrocarbon resources that underlie it. For example, the MMS conducts economic analyses to support policies for lease terms, conditions and bidding systems for individual lease sales, and for its 5-Year Leasing Program. The purpose of these analyses is to ensure that the MMS receives fair market value for its leases. It has developed and continues to maintain a suite of economic models and databases to support sale design, resource evaluation, and post-sale and operational activities.

To date, MMS has not considered the potential value of gas resources from hydrates in determining the fair market value for the lease bids. This is because they have not been able to establish either the costs or potential producibility associated with this resource.[62] Once the value of hydrates resources are considered, minimum acceptable bids for leases could increase, potentially raising the costs associated with pursuing these resources.

[62] Roy, Pulak, personal communication, July 7, 2004.

The minimum acceptable bids for Alaska State leases are established by statute; consequently any perceived value associated with the hydrates would not affect the state's minimum acceptable bid.

Perspectives on the Impact of Leasing Policy on Hydrates Development

Given the current status of U.S. offshore leasing policy in the OCS, and the likelihood that this status will not change much in the foreseeable future, it is unlikely that commercial <u>offshore</u> methane hydrates production can occur anywhere except the Central and Western Gulf of Mexico, or perhaps, certain areas of the Alaska OCS. Because of current policy, only an estimated 40% of the total U.S. offshore gas hydrates resource in place is currently accessible for development.

Moreover, given the vast amount of hydrates believed to exist in association with the developed areas of the onshore North Slope of Alaska, hydrates development on ANWR will not take place until development and production from the more established, already leased or currently leasable areas on the North Slope takes place. At this time, the proportion of the gas hydrates resource to which this applies is unknown. Consequently, leasing issues are not likely to play a major role in the first commercial development of methane hydrates on the Alaska North Slope.

Recent actions by the state of Alaska, and determinations made by senior officials at the U.S Department of Interior have helped to clarify the status of gas produced from hydrates under current leasing policy. Moreover, these actions established the ownership and taxation specifications associated with gas produced from hydrates. However, especially at the federal level, it is not clear whether these actions are enough, or whether federal legislation, similar to that recently enacted by the state of Alaska, may be required.

For the most part, currently existing financial incentives for oil and gas development will likely have limited, if any, impact on the future commercial viability of methane hydrates.

OPERATIONAL ISSUES

As discussed in Chapter I, the precise location and characteristics of the domestic gas hydrates resources are as of yet not well established. The applicability of various development and production approaches is likely to be setting specific, as would the associated environmental considerations, so the location and geologic setting of hydrates will be key in determining which production technologies are most suitable, and therefore will influence the timing of the first commercial production of gas hydrates. Substantial development and demonstration of hydrates development and production technologies will be required before the first commercial production is established, but initial progress is underway.

This chapter discusses the operational issues and uncertainties that will need to be addressed before commercial production of gas hydrates can be established. It also sets the stage for characterizing the environmental and operational considerations that may pose potential barriers to the commercial viability of hydrates development, which will be discussed in subsequent chapters.

Geologic Settings for Gas Hydrates

One of the major motivations for producing methane from gas hydrates is the high concentration of methane contained within the clathrate structure. A cubic foot of hydrate in a reservoir rock can hold many times more gas than other natural gas resources, as shown below:

Natural Gas Source	**Energy Content (cu.ft. of gas per cu. ft. of reservoir rock)**
Methane hydrates	50
Coalbed methane	8-16
Tight Sands	5-10
Devonian Shale	2-5
Conventional Gas	10-20

Note: Assuming a reservoir with 30% porosity and depth less than 5,000 feet

Interestingly, that same cubic feet of hydrates contains only about 0.8 cubic feet of water. (This is discussed in more detail below.)

The potential producibilty of natural gas hydrates will likely depend on the conditions associated with its accumulation and entrapment. Research on methane hydrates, much of which is supported by NETL, continues to focus on detection and characterization of hydrates deposits, and considerable progress is being made on characterizing the reservoir settings within which the hydrates exist. Hydrates are known or are believed to exist in seafloor mounds, as fill in faults and/or fractures, and as dispersed in shales or seafloor sediments, as shown in Figure 12. Most occurrences of hydrates known to exist in the marine environment occur in fine-grained, clay-rich sediments with little or no permeability. In many cases, the concentrations of hydrates in these settings are low, making the commercial production of gas from hydrates in these settings challenging.

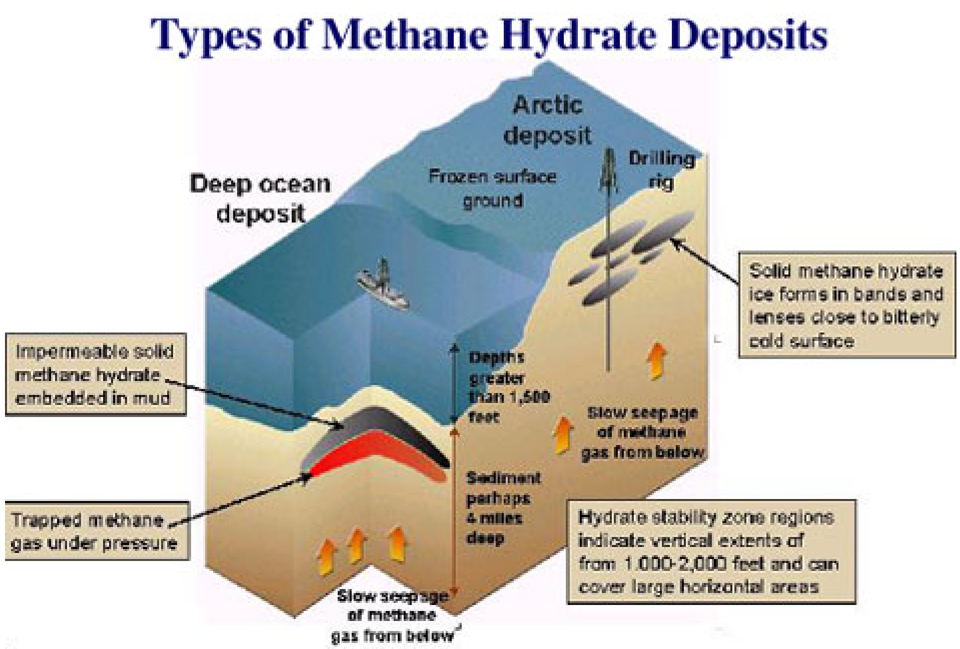

Figure 12
Types of Methane Hydrate Deposits

On the other hand, hydrates have also been shown to exist in more traditional types of reservoirs, characterized by structural or stratigraphic traps, at higher concentrations. The only difference between these settings and conventional gas reservoirs is that the gas and water in the reservoir is “frozen” in the hydrate. In some cases, the hydrate formation exists above a free gas reservoir, where the hydrate zone serves as the trapping mechanism for the free gas. Alternatively, the hydrate may exist in a distinct but more continuous reservoir zone, similar to “basin-center” unconventional gas resources.

The type of geologic setting for the hydrate will dictate the approach for its development and production that would likely be most appropriate, and the corresponding operational, safety and environmental implications associated with that approach. Critical to defining the geologic setting is an understanding of the petroleum system defining the accumulation, including the hydrocarbon source, trapping mechanism, and reservoir characteristics (porosity, permeability, saturation, temperature, pressure, and hydrate concentration). Approaches to systematically characterizing hydrates resource settings are only in their very early stages of development.

Improved geophysical tools are required to help better define and characterize gas hydrates resources and increase confidence in the presence and quantity of hydrates at a particular location. Tools are also necessary to better define reservoir characteristics of those hydrates, and the mechanical properties of the sediment, particularly for safety and facility design purposes.

Approaches for the Development and Production of Gas Hydrates

From an exploration and drilling perspective, the engineering required to access hydrates is well established. In the offshore, the base of the hydrate stability zone is at about 400 to 500 meters below the seafloor, in water depths of around 400 meters. This is the same general range as current deepwater activities. On the North Slope, the hydrate stability zone is shallower than the target formations for conventional oil and gas resources.

Appropriate methods for the production of methane hydrates, on the other hand, are less well established, though progress is being made. First of all, as described above, geological models for hydrate deposits are just beginning to be developed. Like any large but dispersed resource (like unconventional gas), favorable recovery economics will coincide with areas of greatest resource concentration – i.e., the "sweet spots."

Developing safe and cost-effective methods for dissociating hydrates is another critical technical and economic challenge to achieving commercial development and production. Conceptually, hydrates production involves the introduction of heat or the lowering of pressure to allow for the gas in the hydrate to liberate, or "dissociate." Injecting an inhibitor such as methanol or glycol into a reservoir can also serve to decrease hydrate stability and initiate dissociation. The development and demonstration of extraction methods that could potentially be commercially viable and environmentally acceptable is currently in its early stages.

The production mechanisms currently considered are described below, and are illustrated schematically in Figure 13. Also presented is a brief overview of the operational and environmental considerations associated with each potential approach. More detailed characterizations of potential environmental, regulatory, and public perception issues are provided in subsequent chapters.

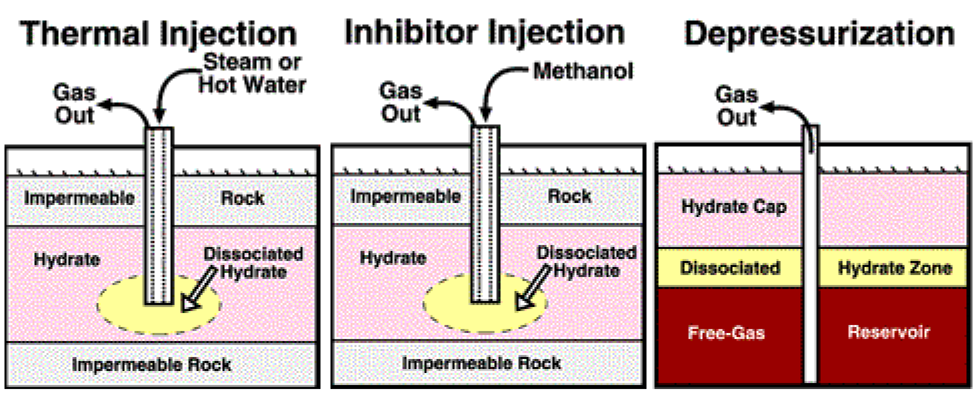

Figure 13:
Schematic Diagram of Gas Hydrate Production Methods

(1) Depressurization

The depressurization process for producing gas hydrates involves the lowering of the pressure of the hydrate reservoir. This is roughly equivalent to traditional reservoir depletion processes for gas production with the difference being that some water may also need to be pumped out. The process is probably most feasible in situations where the hydrates form the cap or seal for an underlying, conventional free gas zone immediately below the hydrate stability zone (HSZ). The process would involve drilling into the free gas zone, where the bottom of the HSZ would begin to decompose as the pressure from the free gas zone is reduced. The gas produced up the wellbore would consist of both free gas and the gas from the decomposed hydrate.

A critical aspect of depressurization is that the process is endothermic, implying that the hydrate absorbs energy as it dissociates, which will tend to reduce reservoir temperature. When this occurs, the hydrates can immediately reform, essentially reversing the dissociation/production process. A successful process may require the introduction of some heat into the reservoir (see discussion below for thermal injection). Successfully managing the transfer of heat to and from the hydrate reservoir will probably be the key to commercial success.

Of the various processes currently under consideration for producing gas hydrates, depressurization would probably have the least environmental impact, and would be the least likely to generate new and/or unique regulatory or public concerns, because it is process that is the most similar to conventional production operations. The application of this process will generally involve issues and considerations familiar to regulators in areas with a history of oil and gas development and production (like the North Slope of Alaska and the offshore Gulf of Mexico). For the most part, the environmental considerations associated with the process of producing gas from hydrates via the depressurization process include drilling and completing wells in the HSZ and managing the water produced with the hydrates. All other considerations correspond to those common to any, or at least most, oil and gas operations.

(2) Thermal injection

Thermal injection involves introducing heat into the hydrate reservoir, most likely in the form of injected steam or hot water, to raise its temperature to allow the hydrate to decompose. Computer simulations for thermal injection using hot water and steam suggest that enough gas could be released to be technically recoverable.

Conceptually, several ways are under consideration to accomplish this. One approach involves the injection of steam or hot water into the hydrate in a frontal sweep similar to a steam flood in a heavy oil reservoir. Another process involves the injection of steam or hot water into a well for a specified period of time, where the well is then shut-in while the heat gets distributed into the hydrate reservoir for a period of time, and the hydrate begins to decompose. The decomposed hydrate gas is then produced up the wellbore, and then the cycle begins again. A third approach involves injecting steam through a vertical fracture between an injection well and a production well.

In addition to process steam or hot water generated at the production facility, other possible variations on the thermal process include circulating hot water or warm oil from deeper formations, or the use of microwave energy input. These approaches, however, could be quite costly.

The thermal injection process requires sufficient porosity, on the order of 15%, along with reasonable permeability for the heat flows to be effective and for production to be sustained. In some cases, fracturing may be necessary to help provide the necessary porosity to facilitate the effective flow of heat to the reservoir. This could generate concerns about the impact of introducing fracture fluids into relatively shallow formations that could be near potential sources of fresh water. These concerns are similar to those that have been raised in association with fracturing of coal seams in Alabama.[63]

[63] See LEAF v. EPA, 118 F.3d 1467, and U.S. Environmental Protection Agency, *DRAFT Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs,* EPA 816-D-02-006, August 2002

The process of introducing heat into the hydrate formation could entail potentially large heat losses into adjacent, non-hydrate bearing strata as well. In the case of the Arctic, this could include the permafrost. This could create potential concerns about subsidence, and its impact on surface facilities, surface water resources, and local ecosystems. Operations would have to be designed and implemented with the intention of minimizing heat losses outside of the hydrate formation.

Moreover, substantial energy would have to be produced to generate the steam or hot water used as the mechanism to introduce heat into the hydrate formation. Generating this steam or hot water will generally involve the combustion of fossil fuels, such as diesel fuel or produced gas, which would result in associated emissions. Air permits would undoubtedly be required for these production facilities, and may have some impact of the approved size of the operations.

(3) Chemical inhibitors

Certain alcohols and other chemicals can act as inhibitors when injected into a gas hydrate layer, and cause the hydrate material to change, shifting the pressure-temperature conditions needed for hydrate stability. The use of chemical inhibitors to stimulate production is similar in concept to the present method of using these chemicals to inhibit the formation of hydrates in wellbores, pipelines, and production equipment. The process considered would instead involve injecting the inhibitors into a reservoir to change the equilibrium conditions in the HSZ to enhance dissociation, rather than inhibit hydration formation.

The two most common inhibitors – methanol and ethylene glycol – are widely used industrial solvents. If discharged to the marine environment, they will disperse through the water column quickly, and ultimately be removed by biological degradation. Very high concentrations are required to produce measurable aquatic toxicity. Current regulatory requirements on the use of chemical inhibitors are described in more detail in Chapter VI.

Like the thermal injection process, the use of chemical inhibitors will require facilitation of good contact between the inhibitors and the hydrate surface. This would necessitate hydrate formation porosities of 15% or more, along with good permeability. Consequently, not all formations are likely to be amenable. Moreover, both fracturing to enhance permeability and porosity, as well as the fact the process involves injecting chemicals into the relatively shallow subsurface, which may be difficult to retrieve, will likely generate the same concerns as those associated introducing fracture fluids into relatively shallow formations that could be near potential sources of fresh water.

In addition, the commercial viability of this process will be difficult to achieve given the current costs of today's most common inhibitors, as well as the large volumes likely to be required for large scale hydrate disassociation. Moreover, inhibitor costs are driven by the price of oil. In mid-2003, methanol costs were on the order of $0.80-$0.85 per gallon, while ethylene glycol costs were on the order of $0.25-$0.35 per pound. For each inhibitor, costs were on the rise.

Gas Hydrates Production Today?

The Messoyakha gas field in northern Russia is often cited as an example of a hydrocarbon accumulation from which gas has historically been produced from hydrates – via the process of reservoir depressurization. The Messoyakha Gas Field is located on the eastern margin of the West Siberian Sedimentary Basin. Part of the gas reservoir in the field is believed to be in the HSZ. Some claim that the production history of the Messoyakha field demonstrates that gas hydrates are contributing to the production from the field. As production began from the lower, free gas zone in the late 1960s, the measured reservoir pressure followed the predicted decline. However, by 1971, reservoir pressures began to deviate from predicted values. The explanation at the time was that part of the produced gas of the field was coming from the hydrate layer, which served as a partial cap for the reservoir. The decrease in reservoir pressure in the free gas zone was believed to be contributing to the dissociation of the hydrate. Under this interpretation, as much as 36% of the gas produced was believed to be associated with the hydrate.[64]

If the original interpretation was correct, then the Messoyakha Gas Field could have been considered the world's first commercial operation producing gas from hydrate. However, more recent work reexamining the evidence indicates that gas hydrates may not have had the role previously hypothesized, and that all of the gas produced is most likely free gas.[65]

Recent Experimental Projects and Field Tests

A number of experiments and field tests have been conducted or are currently planned which could shed some light on the potential producibility of gas from hydrates. The information resulting from these projects will be essential for making a more reliable "first judgment" as to potential areas for early methane hydrate production. It would be much too speculative to attempt to provide this "first judgment" on the potential area for early methane hydrate production without further review of this pending information.

Highlights of these experiments and field projects, in terms of efforts to demonstrate the producibility of gas from hydrates, are described briefly below.

(1) <u>Mallik 2002 Gas Hydrate Production Research Well Program</u>

Recent production tests for the Mallik research well (in Canada) have recently provided some verification of the viability of production from gas hydrates. The Mallik research project is a $25-million (Canadian dollars) international research project led by Natural Resources Canada (NRCan), where a well was drilled through the permafrost of the Mackenzie Delta in Northern Canada to evaluate the potential and economic viability of gas hydrate production and to study the role of gas hydrates in climate change. The Mallik well was drilled into one of the most concentrated and extensive gas

[64] http://www.aist.go.jp/GSJ/dMG/dMGold/hydrate/Messoyakha.html

[65] Collett, T.S., and Ginsburg, G.D., "Gas hydrates in the Messoyakha gas field of the West Siberian Basin -- a re-examination of the geologic evidence": Seventh International Offshore and Polar Engineering Conference, May 25-30, 1997, Honolulu, USA, Proceedings, v. 1, p. 96-103, 1997.

hydrates reservoirs discovered to date, with a gross thickness of over 200 meters and pore space hydrate concentrations in excess of 90%.

The Mallik researchers conducted a variety of scientific experiments to gain a better understanding of gas hydrates and test new drilling techniques and production methods. Well-controlled production tests were conducted to monitor the physical behavior of the gas hydrate deposits in response to depressurization and thermal stimulation experiments. Due to logistics and cost constraints, rather than carry out long term production testing, a decision was made by the project partners to conduct short, carefully controlled production experiments. The plan was to evaluate the response of gas hydrates to heating and depressurization, with careful attention to accurately measuring both input conditions and reservoir responses, to allow for calibration and refinement of reservoir simulation models capable of predicting long-term production response.

Preliminary results of this research were released publicly for the first time at an international symposium at Chiba, Japan in early December 2003.[66] Detailed comprehensive results of these tests will not be published until later in 2004. Nonetheless, project sponsors report that these tests demonstrate for the first time that gas production from hydrates is technically feasible. Reports on three short-duration gas hydrate tests indicate that gas can be produced from gas hydrates with different concentrations and characteristics, exclusively through depressurization. The data supports the interpretation that the gas hydrates are much more permeable and conducive to flow from depressurization than previously thought. In one test, the gas production rates were reportedly enhanced by artificially fracturing the reservoir.

According to the project sponsors, experiments designed to destabilize gas hydrates by thermal stimulation resulted in gas that was continuously produced at varying rates, with a maximum flow rate reaching 1,500 cubic meters per day (53 Mcf per day). A decrease in the production rate occurred at 52 hours into the test, which is

[66] http://gashydrate.nrcan.gc.ca/mallik2002/news_dec_10_2003_b.asp

interpreted as a formation event, which may be indicative of sudden loss of produced gas. Several lines of evidence suggest that natural and enhanced fractures may have been conduits for gas transmission with reservoir storage away from the well.

The Mallik data for the first time allowed for the assessment of the production response of a gas hydrate accumulation if the various tests had extended far into the future. These assessments are based on detailed reservoir simulators, using the Mallik well results to calibrate and improve the simulations. These studies show that among the possible techniques for production of natural gas from in-situ gas hydrates, depressurization appears to produce more gas than just heating the formation. However, the combination of heating and depressurizing the gas hydrate at the same time appears, based on these initial results, to produce the greatest amount of gas.

(2) <u>DOE “Hot Ice” Project</u>

DOE recently helped sponsor a research project to potentially tap methane hydrates on the North Slope of Alaska.[67] This project involves drilling a well using a new type of onshore drilling platform, developed by Anadarko in partnership with DOE that dramatically reduces impacts on fragile ecosystems. This "Arctic Platform," is a lightweight, 100-by-100-foot aluminum drilling platform elevated a dozen feet above the frozen tundra on specially designed steel legs. Based on platforms similar to those used offshore, the Arctic Platform is compact and modular, allowing it to be safely transported by air or with ultra-low-impact vehicles called rolligons.

On March 31, 2003, drilling began on the “Hot Ice No. 1” well using a slim hole rig provided by Dynatec. Researchers analyzed core samples of the hydrates in a specialized mobile laboratory on the platform. By April 21, after 22 days of drilling, the decision was made to suspend drilling until winter. Melting of the tundra was occurring sooner than predicted; requiring that the platform be mothballed until drilling could be

[67] U.S. Department of Energy**, “**Drilling of U.S.'s First Hydrate Well Underway on North Slope Using Anadarko's Innovative 'Arctic Platform', “ *Fossil Energy Techline, April 11, 2003* *(*http://www.fe.doe.gov/news/techlines/03/tl_arcticplatform.html)

restarted in early 2004.[68] At this point, the well had been drilled to a depth of 1,403 ft (427 m), and was logged, cased, cemented, and submitted to a BOP test.

In early January 2004, drilling operations began again. On February 7, 2004, the well reached its planned total depth of 2,300 feet, about 300 feet below the hydrate stability zone where temperature and pressure conditions would theoretically permit gas hydrates to exist. Although significant gas shows were encountered, no methane hydrate was found. The target sands were there as anticipated, but they contained free gas and water, rather than hydrates. A thorough post-mortem analysis of the core, log, and seismic data from the well is underway. Researchers are confident that the state-of-knowledge will be advanced significantly through analyses of these data.[69]

Nonetheless, the Hot Ice #1 well successfully demonstrated for the first time a number of innovative technologies, including the Arctic Drilling Platform, a mobile hydrate core analysis laboratory, and a new application of a continuous coring rig.

(3) <u>Other North Slope Production Tests</u>

In September 2001, DOE awarded a contract to BP Exploration (Alaska) Inc. (BPX), in collaboration with the University of Alaska in Fairbanks, the University of Arizona in Tucson, and the U.S. Geological Survey, to characterize, quantify, and determine the commercial viability of in-situ recoverable gas hydrates and associated free-gas resources in three areas of the Alaska North Slope. The project will provide practical data input into reservoir and economic models. It will also help determine the feasibility of gas at these locations.[70]

To date, results of the multi-task project highlight: (1) the importance of a complete characterization of reservoir and fluid compartmentalization prior to selecting the best sites for potential delineation and/or production testing, (2) the initial

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[68] Bradbury, John, "Drilling in the freezer, *Hart's E&P*, August 2003
[69] U.S. Department of Energy**, "**Alaska Well Targets Gas Hydrate, Produces Wealth of Information, " *Fossil Energy Techline, March 1, 2004* (http://www.fe.doe.gov/news/techlines/04/tl_anadarko3.html)
[70] Hunter, Robert, "Characterization of Alaska North Slope Gas Hydrate Resource Potential", *Fire in the Ice Newsletter*, National Energy Technology Laboratory, Spring 2004.

identification of apparent gas hydrate/free gas plays within the study area, (3) reservoir modeling evidence that depressurization of free gas zones can allow adjacent gas hydrates to dissociate at significant rates, and (4) a new laboratory method for measuring relative permeability in hydrate/sediment mixtures.

(4) Proposed Japanese Production Tests

In early January 2004, the Ministry of Economy, Trade, and Industry of Japan announced its intent to begin drilling for methane hydrates at 16 locations off the coast of central Japan, beginning in late January. A consortium of Japan Petroleum Exploration Co., Japan National Oil Corp. and Teikoku Oil Company are pursuing this undertaking, drilling in water depths ranging from 700 to 2,000 meters, with the objective of testing the commercial potential of methane hydrates production off Japan's coast.[71] None of the results from this effort have yet been made public.

Predicting Future Production from Gas Hydrates

Commercial production of gas hydrates will not occur until adequate well and reservoir production rates from hydrates are established. Critical will be the establishment of potentially economic production rates from hydrates for both an individual well and for a multi-well field. The sustainability of production over an extended life for both a well and the field will need to be assured. Since no extended production of hydrates has yet taken place, the potential producibility of gas hydrates is today predicted on the basis of numerical simulators.

First-order models have been developed to simulate the process of liberating and producing natural gas hydrates. The TOUGH2 simulator, with its EOSHYDR2 module, a general purpose simulator for multi-component, multiphase fluid and heat flow in the subsurface, can simulate the non-isothermal gas release, phase behavior, and flow of fluids and heat under conditions believed to be typical of common natural hydrates deposits in complex formations. EORSHYDR2 includes both equilibrium and kinetic models of hydrate formation. These models have shown that, at least in theory, gas

[71] Anonymous, "Japan to Begin Drilling for Methane Hydrate by End-January," *Jiji Press English News Service*, January 8, 2004

can be produced from hydrates at sufficient rates to be recoverable, but major difficulties exist in establishing and maintaining reservoir flow paths. These models will need to be further enhanced and calibrated based on the results of the hydrates well production tests at Mallik , as well as the other demonstration project efforts described above.

Nonetheless, preliminary simulation results have shown that methane production from hydrates could be technically feasible and has significant potential. According to these simulations, based on reservoir data from Mallik, production can be enhanced by multi-well, injection-production systems (five spot patterns with four production wells surrounding one hot water injection well). The best production rates were achieved in these multi-well settings using depressurization coupled with thermal stimulation (produced water heated and injected for thermal stimulation). Under certain types of reservoir settings, production rates of 20 MMcf per day per well are achievable from these systems[72].

These simulations are performed without much data on the fundamental properties of hydrate reservoirs and on the field thermodynamic behavior. There are few reliable measurements of permeability, porosity, and saturation at this early stage, and understanding of the kinetic behavior of hydrates is not yet well established.

Perspectives on the Impact of Operational Considerations on Methane Hydrates Development

One of the key factors influencing potential commercial hydrates development will be the nature and distribution of hydrates accumulation. Despite the high concentration of methane in a clathrate, much still needs to be learned about the nature of these accumulations, and whether they have the characteristics sufficient to support commercial production. For the most part, the more these accumulations look like

[72] Moridis, George J, and Timothy S. Collett, “Strategies for Gas Production from Hydrate Accumulations under Various Geological and Reservoir Conditions” TOUGH Symposium 2003, Berkeley, California, May 12-14, 2003.

conventional hydrocarbon reservoirs (except that they are frozen), the greater the potential for commercial viability.

A second important factor will be the approaches determined to be most effective at producing the hydrates resource. Processes like depressurization and thermal stimulation are characteristically similar to current oil field processes. However, each process has its own operational and environmental issues with which to contend.

While efforts to shed more light on characterizing hydrates deposits and the production mechanisms most suited for their development are underway, many results are just now being published.. Preliminary results show some promise, but much more needs to be done to confirm whether hydrates can be produced at sustained rates which could lead to commercial viability.

ENVIRONMENTAL AND SAFETY ISSUES

The environmental and safety issues and concerns likely to be associated with the commercial development of gas hydrates will depend on the location of its development, the nature of the geologic systems from which it is produced, the production mechanism employed, and the required infrastructure for producing the gas from the hydrates and delivering it to market. The process for developing the hydrates, for the most part, will be similar to conventional natural gas development and production. Consequently, most of the environmental and safety issues to be addressed will be essentially the same as those associated with traditional oil and gas exploration and production activity.

Ideally, the first commercial production of gas from hydrates will most likely occur at a location with a history of oil and gas activity. Because of this, existing regulatory frameworks will most likely be employed by state and federal regulatory agencies, overseen by knowledgeable, experienced regulatory officials attuned to the real issues and concerns associated with oil and gas operations.

On the other hand, gas hydrates represent a commodity that is currently unknown to most Americans. As discussed in more detail later in this report, this lack of knowledge and understanding, if not effectively addressed, could hinder the eventual development and commercial production of gas hydrates, because of opposition by a potentially misinformed public, or from those opposed to continuing our dependence on fossil fuels, even resources that may exist with essentially unlimited abundance.

In the discussion that follows, the environmental and safety issues associated with traditional oil and natural gas development and production, and that likely will be also associated with gas hydrates development and production, are described, highlighting any special features that relate to gas hydrates. Following that, those issues unique to gas hydrates are discussed.

Considerations Common to Both Hydrates and Traditional Oil and Gas Operations

(1) Offshore Operations – Overview of Environmental Issues

Offshore exploration and production operations are being pursued in many areas around the world. In most areas, a well-established regime of regulatory oversight has been established to ensure that these operations take place with proper regard for the safety of workers, the marine environment, and our atmosphere. The environmental issues associated with these activities have been the focus of public and scientific attention since the industry's beginning. Hundreds of studies of the impact of oil and gas operations on the Gulf of Mexico and other offshore areas have been conducted. For the most part, these studies have concluded that offshore oil and gas industry operations, when properly pursued, have little adverse impact on marine life, on endangered species, or on the quality of the water and air. The studies also report that wherever petroleum industry operations had been found to be of concern, the industry, in conjunction with government, have taken timely corrective actions.

The principal environmental concerns associated with offshore oil and gas operations include impacts on the offshore ecosystems and marine biological resources (including seafood stocks), on wetlands loss, on offshore air quality, and, increasingly, on the global atmosphere. In terms of water quality impacts, the primary concern is associated with major accidental spills, from offshore oil and gas operations, with the primary concern being oil, drilling wastes, and to a lesser extent, process chemicals. Contamination from oil spills is essentially not a concern with the development of gas hydrates. Potential spills of process chemicals and discharges of drilling waste and produced water may pose a risk (more discussion below), but these would probably be no different than those associated with traditional oil and gas operations.

The primary water quality concern has been the potential impacts associated with the exposure of marine organisms to low-level operational waste discharges, including drilling wastes (spent drilling mud and well cuttings), and produced water recovered from the hydrocarbon-bearing strata (which is the highest volume waste generated during production). Drilling wastes and produced water may contain elevated concentrations of metals, nutrients, radionuclides, hydrocarbons, and trace amounts of chemical agents.

Drilling waste concerns associated with the development of gas hydrates will be essentially the same as those corresponding to conventional oil and gas development. However, gas hydrates deposits will tend to be much shallower than conventional oil and gas prospects. Consequently, the volumes of drilling wastes generated by drilling with gas hydrates as a target will be considerably less than those associated with drilling for conventional oil and gas prospects.

Environmental concerns associated with produced water disposal impacts will generally be much less for producing gas from hydrates. Brines produced from conventional oil and gas production are highly saline, are produced in large volumes, and can contain many of the contaminants listed above. In contrast, water produced along with the gas from pure hydrates will be essentially pure, causing much less potential environmental harm. In fact, salinity is one of the principal measures used as an indicator of hydrate occurrence. When hydrates form, dissolved salts (specifically sodium and chloride ions) are excluded from the hydrate lattice. Consequently, geochemical analyses that identify zones of pore water fresher than anticipated are interpreted to suggest the presence of hydrates. Also, with conventional oil and gas production from 5 to 10 (or more) volume units of water are produced per each unit of hydrocarbons. In general, water produced in association with gas from hydrates will be much less than conventional oil or water-drive gas reservoirs. The one exception of this may be where a hydrate –bearing interval overlays a mobile water zone (i.e., an aquifer) with no free gas. Hydrates accumulations of this type would probably not be commercially attractive candidates for gas production from hydrates.

Finally, at the end of the life of offshore facilities, the ultimate disposition of the offshore structures can also be an issue.

In addition, offshore oil and gas activities may occasionally conflict, depending on their location, with subsea pipelines, military or naval activities (such as for training personnel and equipment testing), vessel and helicopter traffic, commercial fishing activities, and tourism activities. On occasion, issues may be raised concerning potentially valuable historical and/or archeological resources, such as that associated with shipwrecks.

Today, there are over 70 international conventions and agreements focused on protecting the marine environment, with many affecting oil and gas operations directly. Regional agreements have also been established in many areas of the world. Currently, these generally do not explicitly address issues uniquely associated with the development and production of gas hydrates, though a few recognize safety issues associated with hydrates formation and dissociation. In the United States, the MMS, the U.S. Coast Guard (USCG), and EPA all have oversight and regulatory responsibilities over offshore oil and gas operations. Industry associations like the American Petroleum Institute (domestically),[73] and the International Association of Oil and Gas Producers (internationally),[74] establish industry standards for the environmental performance of offshore oil and gas operations. Both industry guidelines and regulatory standards generally establish limits for pollutants in offshore effluents and emissions. These take into account the best available technology and acceptable dilution rates for discharged wastes and emissions.[75] Where hydrates are addressed at all, concerns focus on the safety issues associated with drilling through strata containing hydrates, and from the risks associated with hydrate formation in flow lines, pipes, and production equipment.

(2) Offshore Operations – Overview of Regulatory Processes

Once an offshore tract is leased, the lessee is entitled to explore, develop and produce the oil and gas contained within the leased area, conditioned upon due diligence requirements and the approval of a development and production plan. The first time that gas hydrates may be currently addressed in the MMS permitting process

[73] http://api-ep.api.org/index.cfm
[74] http://www.ogp.org.uk/index.html
[75] Patin, Stanislav, *Environmental Impact of the Offshore Oil and Gas Industry*, EcoMonitor Publishing, New York, 1999 (Translated from Russian by Elena Cascio)

occurs when a company submits a Plan of Exploration (POE) to the Office of Field Operations. Here, the company generally identifies potential hydrate outcrops and describes its plan to avoid them. Under current regulatory requirements, the prospect of producing gas from hydrates is not considered. After the surface location is approved, the company submits an Application for Permit to Drill (APD). Since companies have traditionally avoided hydrate-prone areas, to-date there has been no hydrate-related incidents reported in U.S. waters. MMS has recently modified its regulations to require companies to submit more geologic and geophysical information during the site selection process to aid in the identification of gas hydrates and other shallow “hazards”.

In the current Code of Federal Regulations pertaining to offshore oil and gas operations (30 CFR-Part 250 – Oil and Gas and Sulphur Operations in the Outer Continental Shelf), gas hydrates is addressed only twice in almost 200 pages of regulations. One reference (Section 250.456) addresses safe practices that a drilling program must follow, where drilling fluid temperatures must be controlled when drilling in area where permafrost and/or hydrates zones are or may be present.

The second reference (Section 250.801) pertains to the design, installation, and operation of subsurface safety devices that shut-off the flow from the well in the event of any emergency. In this reference, the regulations require the installation of these devices where, among other things, conditions are such that hydrates are present or could form.

Nowhere in 30 CFR 250 do the regulations address issues associated with the development or production of gas hydrates.

Again, once hydrates become a specific target for resource development activities, modifications to current permitting processes will probably be warranted. However, MMS considers it to be premature at this stage to speculate about future additional requirements, until better understanding is gained about the geologic characteristics, development constraints, production performance, and potential impacts of developing and producing hydrates. Such understanding, it is believed, can only be gained through additional research, and the eventual pilot testing of approaches and technologies for gas hydrates development and production.[76]

MMS pipeline regulations do not currently have explicit requirements that address pipeline blockage problems associated with hydrate formation, since it views that as a performance and operational issue, and is of the position that it is in a company's best interest to have a hydrate avoidance and mitigation plan. FERC essentially takes the same position on hydrates in pipelines.

The discharge of any wastes produced in association with oil and gas or hydrates production in the OCS is regulated under the authority of EPA, who has current jurisdiction under a general permit program for discharges from oil and gas facilities (under 40 CFR Part 435). EPA regulates discharges associated with offshore oil and gas exploration, development, and production on the OCS under the National Pollutant Discharge Elimination Program (NPDES) under the Clean Water Act (CWA). EPA Regional Offices issue NPDES permits to offshore facilities discharging into ocean waters beyond the three-mile limit of the territorial seas and may also issue permits to facilities in the territorial sea if the adjoining State does not have an approved NPDES program. Section 403 of the CWA requires that NPDES permits for discharges into the territorial seas, contiguous zone, and the oceans be issued in compliance with EPA's guidelines for determining the degradation of marine waters.

As described above, under the current NPDES general permit, the management and disposal of drilling wastes generated while drilling to develop gas hydrates would essentially be the same as that associated with conventional oil and gas development, except that the volumes to be managed would be considerably lower, since the hydrates would exist in formations significantly shallower than conventional and oil and gas prospects. Drilling wastes and drill cuttings discharged to the ocean must meet

[76] Ray, Pulak, Minerals Management Service, personal communication, July 7, 2004.

standards for free oil, diesel oil, mercury, cadmium, and overall toxicity. These are generally met by the choice of drilling muds and additives used during drilling operations.

The management of produced water discharges, on the other hand, would be of less concern under the NPDES general permit, because of the relative purity of the produced water, along with the lower volume likely to be involved. Nonetheless, water produced in association with gas hydrates would have to meet the same standards as conventional oil and gas production, which involve limits on the concentrations of oil and grease in the produced water (42 mg/l daily maximum, 29 mg/l daily average for 30 consecutive days). These same standards apply to well treatment, completion, and workover fluids.

(3) Arctic operations – Overview of Environmental Issues

Today, the Alaska North Slope supplies about 20% of U.S. oil production. On federal lands, the MMS, EPA, and the U.S. Fish and Wildlife Service all have oversight and regulatory responsibilities over oil and gas operations. On state and private lands, a wide variety of state government agencies have responsibility for specific areas of concern related to oil and gas exploration and production activities, including the Alaska Oil and Gas Conservation Commission, the Alaska Department of Natural Resources, the Alaska Division of Oil and Gas, the Alaska Department of Environmental Conservation, and the Alaska Department of Fish and Game. In some cases, regulatory and oversight responsibilities among these various agencies can overlap.

The principal environmental concerns associated with oil and gas operations in the sensitive Arctic environment include those associated with wildlife (fish, birds, terrestrial animals, marine animals, and threatened and endangered species), vegetation and wetlands, and climate and air quality. A large concern relates to effects on migrating animals like caribou and polar bears, and for the protected habitats of other species. Also of particular concern are subsistence considerations (hunting, fishing, and gathering) for native Alaskans (Inupiats) and for those Alaskans living in remote areas far from the state's road network. Finally, in some areas, issues may arise concerning the protection of valuable cultural and/or paleontological resources. All of these are significant considerations, particularly in frontier areas where little oil and gas exploration and production has yet to take place, such NPR-A. Gas hydrates and conventional oil and gas development will need to be address essentially the same concerns.

Operationally, one of the largest areas of environmental concern on the North Slope is associated with water requirements for drilling and supporting operations and for the construction of ice roads and ice pads, and the potential for an oil spill or natural gas leak (especially for gas containing H_2S) from exploration and production operations. As discussed above for the offshore, oil spills will not be a concern associated with gas hydrates production, while issues associated with H_2S will only be an issue if H_2S is contained within the clathrate structure of the hydrates to be developed. H_2S-rich hydrates have been found in a few locations.

Increased understanding of the North Slope resource and environmental issues since the initial discovery at the Prudhoe Bay, combined with substantial technological technical progress, has greatly lessened the impact of oil and gas operations on the Arctic environment. For example:[77]

- Temporary ice roads largely eliminate the need for permanent gravel roads adjacent to pipelines or to transport equipment to remote sites to support exploratory drilling. Ice roads and pads melt in the spring with minimal impact to the tundra.
- Since it is generally not feasible to build ice roads for conducting initial seismic surveys, the industry has developed large all-terrain vehicles with huge, low-pressure, balloon-like tires that can carry substantial loads across the tundra, leaving virtually no tracks.

[77] Congressional Research Service, *Arctic Petroleum Development: Implications of Advances in Technology*, Report No. RL31022, January 19, 2001

- To further protect the tundra, such operations are conducted only in the winter, when the ground is frozen solid and wildlife is generally absent. However, the time window for tundra travel has tended to decrease over time, from about 200 days in the early 1980s to 100 to 120 days today. A joint industry-government-academic study is underway to scientifically determine the conditions where tundra travel in the Arctic can occur without ecosystem damage.[78]
- Directional drilling reduces the footprint of the drill pad, allowing many wells to be drilled from a single pad. Today, a single five-acre North Slope drilling pad can support 35 horizontal wells.
- Advances in 3-D seismic technology have significantly improved the drilling success rates on the North Slope, reducing the number of wells drilled to achieve the same level of production. Thus, surface disturbance is diminished and waste volumes are decreased.
- The advent of technology that proved that processed drill cuttings could be ground and used in road construction or could be reinjected into the subsurface as a slurry allows drilling operations in Arctic environments to operate without drill pits and to achieve "zero discharge" of drilling wastes. This technology results in decreased waste volumes, less mining of surface gravel, and less surface disturbance.

In addition, many of these advances have also led to major declines in exploration and development costs.

Despite this improvement, a recent study by the National Academies of Science (NAS) identifies a number of accumulated environmental, social and economic effects associated with oil and gas leasing, exploration, and production on the North Slope.[79] The roads, infrastructure and other activities of oil and gas production and their impact on the terrain, plants, animals and peoples of the North Slope offset, to some extent, the

[78] U.S. Department of Energy, Office of Fossil Energy, "DOE Joins Alaska in Replacing 30-Year Old 'Ad-Hoc' Rule with Science-Based Model for Protecting Tundra, *Techlin*e, June 11, 2003

[79] National Research Council, *Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope*, Committee on the Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope, 2003

economic benefits to the region from oil and gas production. While attempts by industry and regulatory agencies to continually reduce these environmental effects continue to be made, these impacts have not nonetheless been eliminated, according to the study. The study makes recommendations for further environmental research related to environmental effects to better assess these impacts and potential mechanisms to mitigate them.

The most significant cumulative environmental impacts on the Arctic environment due to oil and gas operations cited in the NAS study included:

- *Roads*. The report says that roads have had effects as far-reaching and complex as any physical component of the North Slope oil fields. Roads alter animal habitat and behavior, but also increase communication between North Slope residents and those outside the area.
- *Damage to tundra*. Tundra has been damaged by the geophysical survey techniques that are critical to oil exploration efforts.
- *Animal populations*. Because human food is available in oil fields despite efforts to control foodstuffs, more predators (brown bears, arctic foxes, ravens, etc.) have been observed. As a result, some bird and mammal species have been negatively impacted.

Gas hydrates development and production could be expected to contribute to these cumulative environmental impacts in a manner comparable to that associated with conventional oil and gas operations.

Other issues important to Arctic environments are the extent or footprint of oil and gas gathering, processing, and transportation facilities, and the extent to which these operations affect the local environment in terms of emissions and noise. Again, the impacts associated with conventional oil and gas operations and those associated with gas hydrates development are very similar in this regard.

(4) Arctic Operations – Overview of Regulatory Processes

The State of Alaska will be responsible for oversight and regulations associated with methane hydrates development and production on state-owned lands on the North Slope. A wide variety of state government agencies have responsibility for specific areas of concern related to oil and gas exploration and production agencies. Moreover, a wide variety of leases, permits, authorizations, and consultations are required from these agencies for conventional oil and gas exploration, development, and/or production activities, and *hydrates development and production operations will likely not be much different*. Examples of some of the permits, authorizations, and consultations required, along with the state agencies with primary responsibility, are listed below.

- Fish Habitat Permit (Alaska Department of Fish and Game)
- Air Construction Permit (Alaska Department of Environmental Conservation)
- Authorization for Temporary Storage of Drilling Wastes (Alaska Department of Environmental Conservation)
- Certificate of Financial Responsibility (Alaska Department of Environmental Conservation)
- Oil Discharge Prevention and Contingency Plan Approval (Alaska Department of Environmental Conservation)
- Land Use Permit for Arctic Travel (Alaska Department of Natural Resources, Division of Mining, Land, and Water)
- Temporary Water Use Permit (Alaska Department of Natural Resources, Division of Mining, Land, and Water)
- Lease Plan of Operations (Alaska Department of Natural Resources, Division of Oil and Gas)
- Alaska Coastal Management Program, Coastal Zone Determination (Alaska Division of Governmental Coordination)
- Cultural Resource Clearance (Alaska State Historic Preservation Office)
- Drilling Permit (Alaska Oil and Gas Conservation Commission)

Even for production on state lands, several federal permits and authorizations may be also required. For example, the U.S. Fish and Wildlife Service may require a Polar Bear/Personnel Encounter Plan and a Letter of Authorization for Incidental Take of Polar Bears in order to comply with the Endangered Species Act. In addition, EPA may require a Notice of Intent for coverage under the NPDES program, requiring the operator to prepare and file a Best Management Practices Plan.

Finally, local government agencies may also be involved, requiring local development permits and administrative approvals.

On federal lands, similar permits, authorizations and consultations are also required, with BLM, the U.S. Fish and Wildlife Service, and EPA having primary oversight and regulatory responsibilities over oil and gas operations.

These existing regulatory processes would apply to the oversight of a gas hydrates development and production operation, if such a project was initialized on the Alaska North Slope today. However, as of yet, very little consideration has been given by any of these agencies to the unique characteristics associated with the development of gas hydrates. One project seeking to target gas hydrates – Anadarko's Hot Ice Research Project described above – sought and received all the necessary permits and approvals required of operations on existing leases, with no requirements or stipulations included that were specific to the prospect of producing gas hydrates.[80]

As part of the Hot Ice project permitting process, one issue that was discussed briefly related to hydrates was concerns about possible subsidence if the hydrates were dissociated and the reservoir material was unconsolidated. The geologic evidence associated with the target formation indicated that this risk was minimal. However, since hydrates were not found, confirmation of this could not be achieved.

One unique issue that may impact gas production from gas hydrates relates to the disposal of any water that may be produced. Under the current NPDES General Permit for oil and gas operations on the North Slope of Alaska, water produced in association with oil and gas cannot be discharged to the surface, and must be reinjected. This requirement may pose economic constraints on hydrates development that may not be justified given the anticipated purity and/or volumes of water associated with gas hydrates production. Finding good disposal zones for re-injecting the produced

[80] Schmitz, Steve, National Resource Specialist III, Alaska Department of Natural Resources, Division of Oil and Gas, July 7, 2004

water would likely require drilling expensive disposal wells considerably deeper than the zone where hydrates would likely exist.

Considerations Uniquely Associated with Drilling into Gas Hydrates

Operational concerns associated with drilling to or through a gas hydrate focus on both operational safety and sea floor stability where hydrates may be present. As the oil and gas industry has ventured into deeper water, it has become increasingly likely that their operations will encounter hydrates. Current operations in both the deepwater offshore and the North Slope of Alaska treat gas hydrates as a hazard that must be addressed, and preferably avoided, as part of drilling and production operations, not as a resource to be exploited. A substantial amount of research has been performed and is ongoing to address the geo-hazards associated with drilling though hydrates in both marine and permafrost environments. For example, DOE is sponsoring work with the Ocean Drilling Program (ODP) of the Joint Oceanographic Institutions (JOI) to develop technology to assist characterization of deep water, naturally occurring hydrates in the Gulf of Mexico; understand how natural gas hydrates affect sea floor stability; gather data to aid the development of safe and efficient drilling and coring protocols in naturally occurring gas hydrates; and determine how project results can be used to assess if and how gas hydrates act as trapping mechanisms for shallow oil or gas.[81] These concerns remain even if the hydrates are developed as a resource.

(1) Risks of Hydrate Formation

In deepwater and Arctic settings, hydrates can reform in wells, pipelines, and production facilities, severely impacting drilling and production operations. Hydrate formation can plug up pipes and well bores, hindering or stopping flow, and create pressure build-ups that could rupture pipes. Drilling equipment can become frozen, creating a safety hazard.

Operators in deepwater and Arctic settings where hydrates may be present or could form currently employ a number of procedures to hinder the formation of hydrates in their facilities. Traditionally, companies have attempted to avoid drilling in locations

[81] http://www.netl.doe.gov/scng/hydrate/index.html

where hydrates are known to be present. MMS maintains maps of locations where hydrates are believed to exist to help operators minimize drilling risks associated with hydrates.

In addition, various chemicals, like methanol and ethylene glycol, are used as a hydrate inhibitors in gas production lines, and work well as long as there is no brine contamination in the gas stream. New products being developed for removing hydrate plugs are kinetic inhibitors and anti-agglomerates. Kinetic inhibitors are water-soluble polymers that can slow the rate of hydrate formation – from hours to days. Anti-agglomerates are surfactants that cause hydrates to form in small, dispersed crystalline clumps – instead of a solid plug. Heated lines can be an option in some applications to help avoid hydrate formation.

According to the International Association of Drilling Contractors (IADC) Offshore Operators Committee (OOC) Deepwater Well Control Guidelines,[82] deepwater drilling operations should have hydrate control and relief plans in place before any project begins. Moreover, as described above, 30 CFR Part 250 addresses how impacts associated with gas hydrates can be minimized or avoided, to ensure general safety and environmental protection. Finally, considerable research continues to better understand the nature and extent of gas hydrates, and to help minimize and/or mitigate problems associated with drilling into and through hydrates.

(2) Risks of Hydrate Dissociation

Gas hydrates can also dissociate as a result of oil and gas operations, causing additional potential concerns. The friction of drilling and the drilling muds used could provide sources of heat that could cause hydrates to dissociate near the wellbore. Hydrate decomposition can potentially result in hole washouts, sloughing, and collapse of wellbore casings. When drilling through hydrates cannot be avoided, the well is generally drilled using special muds and is cased as soon as possible to minimize the risk of well failure caused by hydrates. Proper use of wellbore control equipment, the

[82] http://www.gomr.mms.gov/homepg/regulate/regs/ntls/ntl99-g01.html

use of non-thermally conducting drilling muds, and proper techniques for well casing and cementing can help minimize potential problems associated with drilling through hydrates.

Where drilling through hydrates is the intention, or cannot otherwise be avoided, a number of remedies exist to reduce and/or mitigate the environmental and safety problems posed by gas hydrates:

- Reducing the temperature of drilling fluids
- Using small downhole drilling motors to reduce mud temperatures
- Using cements with low heat of hydration
- Running casing after penetrating the gas hydrate zone
- Using mud additives to stabilize gas hydrates.

These same remedies would generally apply to drilling operations targeting the production of gas from hydrates.

Drilling and production problems associated with gas hydrates also include uncontrolled gas releases during drilling when hydrates zones have been encountered. Free gas under a hydrate zone cap could be over-pressured, causing concerns about well control and blowouts, and gas leakage from hydrate zones along the outside of the wellbore.

The safety considerations associated with gas hydrate formation and dissociation exist for both conventional oil and gas development and production in deepwater and Arctic settings, as well as eventual commercial development and production of gas hydrates. Moreover, the knowledge base concerning drilling into and through hydrates is relatively new and not well developed. Better understanding is required of the mechanical and thermal properties of hydrates to aid in better facility design, well bore integrity, and reservoir flow characterization.

The bottom line is that for both the offshore Gulf of Mexico and the Alaska North Slope, existing regulatory requirements focus solely on the safety and environmental risks associated with drilling through hydrates zones; and do not even contemplate, at this time, issues associated with the production of natural gas from hydrates.

(3) <u>Wastes from Gas Hydrates Drilling</u>

In the Gulf of Mexico offshore, typical oil and gas well depths range from 5,000 to 15,000 feet; while on the Alaska North Slope, well depths range from 5,000 to 18,000 feet. In contrast, as described in Chapter 1, the hydrates tend to exist between 2,500 and 5,400 feet (750 to 1,650 meters) in the North Slope, and from 1,300 to 5,400 feet (400 to 1600 m) in the offshore, depending on water depth. Consequently, because of the shallow drill depths, drilling for hydrates will generate much less volume of drilling waste requiring management and disposal, in both Arctic and offshore settings.

Considerations Uniquely Associated with Producing Gas Hydrates

(1) <u>Management of Produced Water</u>

One concern sometimes raised in conjunction with the potential future production of gas from hydrates is associated with the management and disposal of the water produced with the hydrates. Produced water from hydrates is expected to be relatively pure. Moreover, produced water volumes associated with gas hydrates, however, especially when compared to that associated with conventional oil production and some high water-cut gas production, are expected to be relatively low compared to the amount of gas produced. Since the methane molecules in the hydrate lattice are compressed closely together, about 1 cubic meter of pure hydrate (assuming 100% porosity) yields 160 cubic meters of methane and only 0.87 cubic meters of water. This is substantially less than that produced in association with oil and gas on the North Slope and the Gulf of Mexico.

The one possible exception to this (as described above) is where the gas hydrate zone overlays an aquifer. In this case, considerable amounts of water could be produced with the gas from the hydrates. However, this type of hydrate reservoir setting would probably not be an attractive candidate for commercial development.

Consequently, appropriately designed development and production operations should be able to be address the water management issue without much difficulty, In fact, production schemes have been proposed that could conceivably result in zero net water production. For example, production from dipping reservoirs could allow drainage of the produced water down dip, minimizing its potential impact on dissociation, and reducing the amount brought to the surface, therefore minimizing its potential impacts on the environment. In addition, because of its relative purity that is anticipated, the produced water can also be heated and reinjected back into the hydrates reservoir, if necessary, to assist in any additional thermal simulation required.

(2) <u>Possible associated constituents with methane from hydrates</u>

Another issue of possible concern with the potential future production of gas from hydrates is associated with the potential composition of the gas produced from the hydrates. Processing gas produced from hydrates will probably not be that different than processing conventionally produced natural gas. The predominant hydrate-forming gas is methane, with lesser amounts of CO_2, hydrogen sulfide (H_2S), nitrogen (N_2), and a wide variety of heavier hydrocarbons (though primarily ethane and propane).[83] In general, the gas in the hydrates will have been produced by the same mechanisms producing natural gas – the *in situ* microbial breakdown of sedimentary organic matter. In hydrocarbon-rich provinces, there may also be more deep-seated thermogenic gas components, like ethane and propane. In fact, the primary impact of gas composition is that it can cause a shift the hydrate stability zone changing the temperature/pressure conditions that trigger dissociation, since the hydrate phase boundary is a function of gas composition.

(3) <u>Addition of heat or chemicals to stimulate dissociation</u>

Additional issues may be associated with producing methane hydrates, based primarily on the production method utilized. For example, in the case of thermal

[83] Wiersberg, Thomas, et al., "Gas Geochemistry Studies at the Gas Hydrates Occurrence in the Permafrost Environment of Mallik (NWT, Canada), *Geophysical Research Abstracts*, Volume 5, 02722, 2003 (European Geophysical Society)

stimulation, substantial energy may have to be produced to generate the steam or hot water injected to stimulate dissociation. A portion of the gas produced would likely be used for steam generation. This could result in additional emissions, which would likely require that a hydrates project obtain an air quality permit. This permit would be the same as those routinely issued for gas-fired power generators on the North Slope or in the OCS.

Environmental concerns could also be raised about the injection of the large volumes of chemicals that may be required if chemical hydrate inhibitors are used to stimulate production. This will primarily be of concern in marine environments. Recovering these chemicals may be difficult (and costly) in order to ensure that they cause minimal environmental impacts. Permits associated with their use and disposal may be required. Regulatory requirements associated with the use of oil field chemicals depend upon whether the chemicals are classified as hazardous or non-hazardous. On the OCS, USCG is the principal federal agency responsible for worker health and safety, the Occupational Safety and Health Administration (OSHA) regulates the methods and containers for storing chemicals, and the Department of Transportation regulates containers used for storing chemicals. However, the two currently most common hydrate's inhibitors are methanol and ethylene glycol, which are both widely used industrial solvents, and are commonly used (in relatively small quantities) in oil field operations. They are both soluble in water, and if discharged to the marine environment, they will disperse through the water column quickly, and ultimately be removed by biological degradation.

If either steam or chemical inhibitors are used as an injectant to stimulate hydrate dissociation, they would likely be regulated under the federal Underground Injection Control (UIC) Program. In the case of steam, inspection requirements would fall under the same jurisdiction as wells used for water or steam injection for enhanced oil recovery (EOR) operations. In this case, they would be regulated as Class II wells, the same as all water injection wells used in oil and gas operations.

In the case of chemical inhibitors, regulation as Class II wells may be less certain. Most of the historical enhanced oil recovery projects that used injection were initiated prior to the current federal UIC program and thus were regulated at the time under state programs.

One concern may relate to the fact that the hydrate zone, because of the anticipated purity of the water, may qualify if as a potential Underground Source of Drinking Water (USDW). However, since some methane gas will be entrained in an water produced from the hydrates, it would likely quality for an exception as a USDW under the federal Safe Drinking Water Act statutes.

Other Environmental And Safety Issues Unique To Gas Hydrates

Some environmental and safety concerns are also uniquely associated with gas hydrates, though these are mostly associated with the characteristics of hydrates in general, and not specifically to the process of commercially producing the gas from the hydrates. These concerns range from their possible impact on initiating subsidence or landslides to their role in influencing global climate change. Moreover, recent research has identified a number of unique organisms that thrive in areas where gas hydrates exist or where hydrocarbons are vented into the sea. Concerns about the protection of these organisms have added a new environmental dimension associated with gas hydrates.

These issues are discussed in more detail below.

(1) <u>Potential Subsidence and Landslides</u>

In Clive Cussler's fictional novel *Fire Ice*, published in 2002, a mining tycoon, claiming Romanov ancestry, declares himself the next tsar of Russia, with intentions of taking over the country.[84] As one ploy to distract the Russian government from discovering his plot, he devises a scheme for detonating large areas of methane hydrates off the eastern seaboard of the U.S., creating landslides that cause large

[84] Cussler, Clive, with Paul Kemprecos, *Fire Ice*, Berkley Books, New York, 2002

tsunami waves to devastate east coast cities. Fortunately, Kurt Austin, the novel's hero, foils this plot.

While fantastic and not likely to be achievable, public fears based on this type of imaginative concept cannot be overlooked or ignored. The potential impact of gas hydrates development and production on sea floor stability is not yet known. Hydrates, however, can pose a hazard to the stability of wells, platform anchors, tethers, and possibly even the entire platform. Existing regulatory requirements and operational guidelines designed to avoid drilling in hydrate-prone areas, or to minimize potential risks if these areas are unavoidable, address these hazards. These requirements would apply regardless of whether drilling through a hydrates zone to the target formation, or to hydrates as the hydrocarbon target.

The presence of hydrates can strengthen sediments through both pore filling and cementation, thus retarding the potential for compaction. However, gas hydrates are considered "quasi-stable," and their dissociation can be either slow or quite rapid, depending on the composition of the hydrates, and the rate of change in temperature and pressure conditions. Since the gas can exist in hydrates at very high concentrations, a hydrate can release 160 times its volume in gas. This can convert an otherwise rigid hydrate-bearing sediment into a liquid-like slurry. Drilling operations, if not properly managed, could cause rapid pressure and temperature changes if drilling occurs through a hydrates zone or into the hydrates as the target formation.

Circumstantial evidence does exist that indicates that gas hydrates dissociation may have played a role in triggering seafloor landslides. The USGS has used high-resolution seismic data to relate sea-floor stability with the presence of gas hydrates, and has postulated that the formation and dissociation of hydrates at the seafloor is causally linked to many subsurface and sea floor failures in the Gulf of Mexico.[85] Similar evidence of the potential linkage between gas hydrates and sea floor landslides

[85] Cooper, Alan, Patrick Hart, and David Twichell, "Gulf of Mexico gas hydrates – a potential link to shallow flows and continental-slope stability," paper presented at the 2000 Annual Meeting of the American Association of Petroleum Geologists, New Orleans, Louisiana

along the Atlantic margin of the U.S. has also been presented. In general, areas where the conditions leading to this type of occurrence exist would be areas that offshore operations would probably want to avoid. Higher quality hydrates zones in consolidated formations, with adequate porosity and permeability (much like conventional oil and gas resources) would be much better prospects for hydrates development.

On the Alaska North Slope, current evidence seems to suggest that hydrates tend to exist in depositional environments similar to conventional oil and gas reservoirs. Given this geologic and depositional characteristics, subsidence of the hydrates will be less of an issue. Some concerns exist about instances where hydrates exist in the permafrost. In these instances, appropriate precautions would be warranted.

With an understanding of the effects of gas hydrates in sediments, proper planning and engineering has provided, and can continue to provide, the necessary level of safety required for oil and gas exploration, production, and transportation operations. However, improvements in current characterization and modeling technologies are critical to overcome potential barriers to understanding and predicting sea floor stability and developing methods to insure the safety of oil and gas operations and facilities.

(2) Large Scale Methane Releases Contributing to Global Warming

Arguably one of the more important issues that the future commercial development of gas hydrates will face is concern about the potential of large scale, uncontrolled releases of methane from hydrates, primarily those existing in sediments in the OCS. Some researchers hypothesize that changes in global temperature (resulting in changes in sea levels and/or seawater temperatures) have in the past resulted (and could again in the future result) from significant natural releases of methane from hydrates (if global average temperatures increase). For example, Dickens, et al., have hypothesized that abrupt releases of methane from hydrates may have caused the mass extinction of half to two-thirds of all benthic marine fauna which occurred about 55 million years ago.[86] A report released in December 2003 describes potentially new evidence, based on stable isotope data, of a substantial methane release from hydrates that occurred about 600 million years ago, providing one of the primary drivers contributing to the rapid warming of the earth at the end of this particular ice age.[87]

The historical role of methane hydrates in influencing global climate is currently the subject of considerable debate within the scientific community. Kennett and others suggest that methane outgassing from methane hydrates, the result of declining sea levels (reducing pressure) or increasing ocean water temperatures, played a key role in "jump-starting" the erratic climate behavior characteristic of the late Quaternary period, and that a wide range of paleoclimatic and marine geologic data supports this hypothesis. They call this the *Clathrate Gun Hypothesis*.[88] They link this phenomenon with both evidence of upper continental slope instability and the periods of rapid global warming that are characteristic of this period. They offer recommendations on numerous potential areas of research that could serve to test this hypothesis. These include additional research on establishing the historical atmospheric methane record from ice cores, characterizing sources of atmospheric methane, establishing the mechanisms of wetland initiation and evolution, characterizing marine methane hydrate stability, conducting additional paleoceanographic and paleo climatological research, and expanding and enhancing models of methane atmospheric chemistry.

Others do not support this theory, providing evidence that the climate behavior of the time is more likely attributable to changes in the extent of tropical and temperate wetlands and peat bogs.[89,90]

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[86] Dickens, G.R., M.M. Castillo, and J.G. Walker, "A blast of gas in the latest Paleocene: Simulating first-order effects of massive dissociation of oceanic methane hydrate," *Geology*, Vol. 25, No. 3, 1997
[87] Anonymous, "Stable Isotope Data Provide Evidence for Huge Global Methane Release about 600 Million Years Ago," National Science Foundation press release, December 17, 2003
[88] Kennett, James P, Kevin G. Cannariato, Ingrid L. Hendy, and Richard J. Behl, *Methane Hydrates in Quaternary Climate Change: The Clathrate Gun Hypothesis*, American Geophysical Union, Washington, D.C., 2003
[89] Maslin, M and E. Thomas, "The Clathrate Gun is Firing Blanks: Evidence from Balancing the Deglacial Global Carbon Budget, *Geophysical Research Abstracts*, Vol. 5, 12015, 2003
[90] Anonymous, "Methane and climate change: Swamp thing or monster of the deep?" *The Economist*, April 17, 2003

Speculations on the potential impact of this as of yet unconfirmed theory have already raised the specter of this risk as a major future environmental concern. These warnings, offered on the heals of the recently released motion picture *The Day After Tomorrow*, are being presented as further evidence of the potential dangers of global warming and the pace that society may be taking to address it.[91]

On the other hand, some researchers have begun to speculate on the potential application of hydrate formation as a means of helping to reduce global atmospheric concentrations of greenhouse gases. Just like methane and other hydrocarbon gases, CO_2, the primary global greenhouse gas, can also be locked into a hydrate under the appropriate temperature and pressure conditions. The sequestration of CO_2 into hydrates in the ocean is being proposed as another possible approach for reducing atmospheric concentrations of CO_2. Injecting CO_2 into the ocean at depths of 400 meters or greater, in theory, can facilitate the formation of CO_2 hydrate. The application of this approach relates only peripherally with the potential commercial production of natural gas from hydrates.

(3) Chemosynthetic Communities/Marine Ecosystems

Methane and other gases associated with gas hydrates appear to be the energy source for some, very specialized, seafloor organisms. Such deepwater chemosynthetic communities were first discovered in 1984 in the Central Gulf of Mexico. The nature of these organisms and the processes by which they thrive are just beginning to be understood. These communities can include some or all of the following organisms: clams, mussels, bacterial mats, tubeworms, centipede-like, hydrate-dwelling ice worms, and other organisms. These life forms are unique in that they use a carbon (food) source independent of photosynthesis and the food chain associated with photosynthesis.[92]

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[91] Muslin, Mark, *Gas Hydrates: A Hazard for the 21st Century* Issues in Risk Science 03, Benfield Hazard Research Centre, University College London, May 2004

[92] MacDonald, I.R., ed., *Stability and Change in Gulf of Mexico Chemosynthetic Communities - Volume I: Executive Summary*, prepared by the Texas A&M University Geomechanical and Environmental Research Group for the U.S. Department of Interior, Minerals Management Service, OCS Study MMS 2002-035, July 2002

While generally represented in isolated locations and in relatively low density on the sea floor, locations of communities of relatively high density are known to exist. Generally, these higher density communities appear to be linked to hydrocarbon-charged sediments associated with surface faulting, exposed mounds of gas hydrates, and gas vents or oil seeps. Very little data exist on the location, extent, structure, and relationships of these communities and the local, physical environment. Concerns relate to the potential damage of these communities resulting from seafloor disturbance associated with oil and gas operations such as drilling, anchoring, placing seafloor templates, discharging muds and cuttings, and installing pipelines.

The MMS has established procedures that are intended to provide a consistent and comprehensive approach to protecting high-density chemosynthetic communities from damage caused by oil and gas activities. This includes regulatory authority to require avoidance or protection of chemosynthetic communities and avoidance of shallow hazards, such as gaseous sediments. In general, this authority ensures that if an operation could disturb seafloor areas in water depths 400 meters or greater, then these operations must maintain the following separation distances from features or areas that could support high-density chemosynthetic communities:

- At least 1,500 feet from each proposed muds and cuttings discharge location;
- At least 250 feet from the location of all other proposed seafloor disturbances (including those caused by anchors, anchor chains, wire ropes, seafloor template installation, and pipeline construction).

A substantial amount of research is currently underway to correlate the locations of chemosynthetic communities and data from 3-D seismic surveys.

At this point in time, the potential relationship between these chemosynthetic communities of marine organisms and potentially commercial accumulations of hydrates is not well established. Approaches for protecting chemosynthetic communities on the sea floor would be the same whether drilling for conventional oil and gas prospects or for commercial accumulations of gas hydrates; these should not materially affect the economics of developing hydrates. If, however, some link is established between the target gas hydrate accumulation and the mechanism for sustaining these chemosynthetic communities, then possible constraints on gas hydrates development and production could arise.

Perspectives On The Impact Of Environmental And Safety Issues on Gas Hydrates Development

For the most part, the process of developing and producing gas hydrates on a well or field specific-basis will be quite similar to conventional gas exploration and production operations, with only slight variations from these operations due to the unique characteristics of the gas hydrates. This assumes that the first commercial production of gas from hydrates will take place in either a marine or permafrost environment, in an area with existing infrastructure, and a history of oil and gas industry operations.

Future hydrates development and production will have to take greater strides to address environmental concerns in Arctic and deepwater settings, particularly those associated with some of the unique behavioral characteristics of hydrates. The principal concerns focus on both operational safety and sea floor stability where hydrates may be present. However, to address most concerns, industry and regulatory guidelines are already in place, and new research is continually adding to the knowledge base on the extent and characteristics of hydrates in both marine and Arctic environments.

However, natural gas hydrates represent a commodity that is currently unknown to most Americans. Some “fears” associated with hydrates, if not properly understood, managed, and communicated, could hinder the eventual development and commercial production of gas hydrates. Uncertainty associated with this “exotic” resource, which exists in areas that many in society feel need to be preserved at all costs (the oceans and the Arctic tundra) will certainly cause some concern among environmentalist advocates. Moreover, those that oppose fossil energy development and production could oppose the development of hydrates, since they will see hydrates development as a means to continue society's dependence on fossil energy for a very long time. Experience has shown that fantastic, unsubstantiated claims may be made to incite public fears about such an unknown, exotic source of energy.

These issues are discussed in greater depth in the following chapters.

REGULATORY AND POLICY ISSUES, PROCESSES, AND POTENTIAL BARRIERS

Regulatory Processes and Requirements for OCS Operations

For both environmental and safety, MMS will be the primary agency responsible for regulating methane hydrates development and production in the OCS. To ensure that the environment is adequately protected, MMS regulates exploration, development, and production activities on about 8,000 active leases and 4,000 production facilities in the OCS, primarily in the Gulf of Mexico, including ensuring that activities are conducted safely and in an environmentally sound manner. In addition, as described above, EPA, the U.S. Coast Guard, and other agencies also have some jurisdiction.

Prior to commencing any operations, and during all exploration, development, production, and facility abandonment activities, companies are required to comply with MMS requirements. This includes addressing environmental, archeological, and safety considerations, pertaining to impacts to both air and water, and ensuring the co-existence of oil and gas operations with all other activity in these waters. MMS must implement numerous environmental laws, regulations, and executive orders to carry out its mission. These include, but are not limited to:

- National Environmental Policy Act (NEPA)
- Endangered Species Act (ESA)
- Marine Mammal Protection Act (MMPA)
- Coastal Zone Management Act (CZMA)
- Clean Air Act (CAA)
- Clean Water Act (CWA)
- National Historic Preservation Act (NHPA)
- Government Performance and Results Act (GPRA)
- Fishery Conservation and Management Act (FCMA)
- Executive Order 12114: Environmental Effects Abroad
- Executive Order 12898: Environmental Justice
- Executive Order 13007: Indian Sacred Sites
- Executive Order 13089: Coral Reef Protection.

While none of these statutes address or even recognize issues associated with the development and production of gas hydrates, gas hydrates development projects would nonetheless need to comply with their requirements. As stated throughout this report, for the most part, these would be essentially no different than those for conventional oil and gas development projects.

Prior to leasing offshore lands for exploration and development, MMS is required to collect and make publicly available information needed to analyze, discuss and guide future decisions on exploration, development, and production and lease sales proposed for its 5-year leasing program. Detailed Environmental Impact Statements (EISs) are prepared for offshore lease sales in order to assess the potential environmental, social and economic effects of industry activities on exploration and development of OCS resources, and to support MMS and other agencies on environmental rulemakings affecting OCS activities. This process is required under the National Environmental Policy Act (NEPA) of 1969. The NEPA process is intended to help public officials make decisions based on an understanding of environmental consequences and take actions that protect, restore, and enhance the environment. This EIS process involves:[93]

- Scoping analyses to determine the appropriate contents of the EIS. This includes identifying all relevant issues, alternatives, mitigation measures and analytical tools. Public participation is integral to this scoping process.
- The development of alternative scenarios corresponding to different options the government could pursue related to leasing of offshore activities, and the characterization of the activity ultimately associated with each scenario.
- Performing detailed impact analyses for all the scenarios, characterizing the nature, severity and duration of impacts; and comparing the impacts among the various alternatives considered.
- Preparing a draft EIS and submitting it for public review and comment.
- Preparing a final EIS that addresses the public comments in a responsive and responsible manner.

As part of developing its leasing plan, MMS may place various stipulations on leasing. These stipulations are protective measures designed to reduce adverse

[93] Detailed descriptions of this process is provided by MMS at http://www.mms.gov/eppd/compliance/nepa/index.htm

environmental impacts. These stipulations apply to all tracts leased in a particular sale, throughout their life. These stipulations precede more detailed environmental review and mitigation of exploration and development impacts on individual leases.

In the most current EIS for OCS Lease Sales in the Gulf of Mexico,[94] applying to sales to be conducted over the 2003-2007 time period, gas hydrates are mentioned briefly; but again, only as they pertain to safety and environmental considerations, not as a target for development. For example, the EIS references the role of primarily shallow hydrates at chemosynthetic communities (p.3.26-3.28); potential operational problems associated with hydrates formation in flowlines and processing equipment (p.4.25-4.26); and the role hydrates may play in affecting wellbore stability and/or sea floor stability (p.9.1.6-9.1.8).

Nowhere in the OCS EIS is the issue of commercially developing and/or producing gas from hydrates discussed or mentioned.

Since the development of gas from hydrates as a commercial resource has not been the focus of existing EIS documents supporting the MMS Five-Year Leasing Plan to date, new or amended EIS procedures would probably be required under NEPA when the prospect of commercial hydrates production comes closer to being realized.

Regulatory Processes and Requirements for Alaska North Slope Operations

For operations on the Alaska North Slope, Table 16 lists the permits and other requirements that must be met before oil and gas exploration or development activities may occur. Projects focused on the commercial development of gas hydrates have to adhere to these same requirements.

[94] U.S. Department of Interior, Minerals Management Service, *Gulf of Mexico OCS Oil and Gas Lease Sales: 2003-2007 Final Environmental Impact Statement,* OCS EIS/EA, MMS-2002-052, 2002.

Table 16:
Federal, State, and Local Permits and/or Approvals
For Oil and Gas Exploration, Development, and Production Activities

Regulation Agency	Permit/Approval Actions/Requirements
FEDERAL	
U.S. Army Corps of Engineers (USACE)	• Issues a Section 404 permit under the Federal Water Pollution Control Act of 1972, as amended (Clean Water Act; 33 USC § 1344) for discharge of dredged and fill material into U.S. waters, including wetlands. • Issues a Section 10 permit under the Rivers and Harbors Act of 1899 (33 USC § 403) for structures or work in, of affecting, navigable waters of the U.S. • Issues a Section 103 Ocean Dumping permit under Section 103 of the Marine Protection Research and Sanctuaries Act of 1972 (33 USC § 27) for transport of dredged material for ocean disposal.
U.S. Environmental Protection Agency (USEPA)	• Issues a National Pollutant Discharge and Elimination System (NPDES) Permit under Section 402, Federal Water Pollution Control Act of 1972, as amended (Clean Water Act; 33 USC § 1251) for discharges into waters of the U.S. • Issues an Underground Injection Control Class 1 Industrial Well permit under the Safe Drinking Water Act (40 CFR § 124 A; 40 CFR § 144; 40 CFR § 146) for underground injection of Class I (industrial) waste materials. • Issues a Spill Prevention Containment and Countermeasure (SPCC) Plan under Section 311, Federal Water Pollution Control Act of 1972, as amended (Clean Water Act) (40 CFR § 112) for storage of over 660 gallons of fuel in a single container or over 1,320 gallons in aggregate in tanks above ground. • Conducts a review and evaluation of the Draft and Final EIS for compliance with CEQ guidelines (40 CFR § 1500-1508) and Section 309 of the Clean Air Act. • Authority delegated to ADEC to issue air quality permits for facilities operating within state jurisdiction, including a Title V operating permit and a Prevention of Significant Deterioration (PSD) permit under the Clean Air Act, as amended (42 USC § 7401), to address air pollutant emissions.
National Oceanic and Atmospheric Administration (NOAA) Fisheries Service (formerly National Marine Fisheries Service [NMFS])	• Provides consultation under the Endangered Species Act of 1973, Section 7(a)(2) regarding effects to threatened or endangered species. • Provides consultation under the Magnuson-Stevens Fishery Management and Conservation Act for effects on Essential Fish Habitat. • Provides consultation under the Fish and Wildlife Coordination Act regarding effects on fish and wildlife resources. • Provides consultation under the Marine Mammal Protection Act regarding effects on marine mammals. • Issues Incidental Harassment Authorization under the Marine Mammal Protection Act for incidental takes of protected marine mammals (bowhead whales and ringed seals).
U.S. Department of the Interior, Bureau of Land Management (USDOI BLM)	• Reviews and approves Applications for Permit to Drill (including drilling plans and surface-use plans of operations) and Subsequent Well Operations as prescribed in 43 CFR § 3160, under authority of the Naval Petroleum Reserves Production Act (43 USC § 6501-6508) and other federal laws, for development and production of federal leases.

Table 16: (continued)
Federal, State, and Local Permits and/or Approvals
For Oil and Gas Exploration, Development, and Production Activities

Regulation Agency	Permit/Approval Actions/Requirements
	• Approves lease administration requirements including Unit Agreements and Plans of Development, Communitization Agreements, and Participating Area Determinations, as described in 43 CFR § 3130 and 3180, under the Mineral Leasing Act of 1920 (30 USC § Sec. 181 et seq.), Federal Oil and Gas Royalty Management Act of 1982 (42 USC § 4321 et seq.), Naval Petroleum Reserve Production Act of 1976 (42 USC § 6504), Department of the Interior Appropriations Act, Fiscal Year 1981 (42 USC § 6508), and other federal laws, for exploration and development of oil and gas leases. • Issues geophysical permits to conduct seismic activities as described in 43 CFR § 3150, under authority of the Mineral Leasing Act of 1920 (30 USC § 181 et seq.), Alaska National Interest Lands Conservation Act (16 USC § 1301 et seq.), Federal Land Policy and Management Act of 1976 (43 USC § 1701 et seq.), Naval Petroleum Reserves Production Act of 1976 (42 USC § 6504), and Department of the Interior Appropriations Act, Fiscal Year 1981 (42 USC § 6508). • Issues rights-of-way grants and temporary use permits for the construction, operation, and maintenance of pipeline, production, and related facilities under the Naval Petroleum Reserve Production Act (42 USC § 6501-6508). • Delegates authority to ADEC for review and approval of Oil Discharge Prevention and Contingency Plans and Certification of Financial Responsibility for accidental oil discharge into navigable waters under Section 4202(b)(4) of the Oil Pollution Act of 1990 (OPA90), and Section 3110)(5) of the Federal Water Pollution Control Act (30 CFR § 254).
U.S. Fish and Wildlife Service (USFWS)	• Provides consultation under the Endangered Species Act of 1973, Section 7(a)(2) regarding effects to threatened or endangered species. • Provides consultation under the Fish and Wildlife Coordination Act regarding effects to fish and wildlife resources. • Issues a Letter of Authorization under the Marine Mammal Protection Act for incidental takes of marine mammals.
STATE	
Alaska Department of Environmental Conservation (ADEC)	• Issues a Certificate of Reasonable Assurance for discharge of dredged and fill material into U.S. waters under Section 401, Federal Water Pollution Control Act of 1972, as amended in 1977 (Clean Water Act) (33 USC § 1341); AS 46.03.020; 18 AAC § 15; 18 AAC § 70; 18 AAC § 72. • Issues a Certificate of Reasonable Assurance/NPDES and Mixing Zone Approval for wastewater disposal into all state waters under Section 402, Federal Water Pollution Control Act of 1972, as amended (Clean Water Act) (33 USC § 1341 et seq.); AS 46.03.020, .100, .110, .120, & .710; 18 AAC § 15, 70, 010 & 72.500. • Issues a Class I well wastewater disposal permit for underground injection of non-domestic wastewater under AS 46.03.020,050, and 100. • Reviews and approves all public water systems including plan review, monitoring program, and operator certification under AS 46.03.020, 050, 070, and 720, 18 AAC § 80.005. • Approves domestic wastewater collection, treatment, and disposal plans for domestic wastewaters (18 AAC § 72). • Approves financial responsibility for cleanup of oil spills (18 AAC § 75).
Alaska Department of Environmental Conservation (ADEC) (Continued)	• Reviews and approves the Oil Discharge Prevention and Contingency Plan and the Certificate of Financial Responsibility for storage or transport of oil under AS 46.04.030, 18 AAC § 75 et seq. The State review applies to oil exploration and production facilities, crude oil pipelines, oil terminals, tank vessels and barges, and certain non-tank vessels.

Table 16: (continued)
Federal, State, and Local Permits and/or Approvals
For Oil and Gas Exploration, Development, and Production Activities

Regulation Agency	Permit/Approval Actions/Requirements
	• Issues a Title V Operating Permit and a Prevention of Significant Deterioration (PSD) permit under Clean Air Act Amendments (Title V) for air pollutant emissions from construction and operation activities (18 AAC § 50). • Issues solid waste disposal permit for state lands under AS 46.03.010, 020, 100, and 110; AS 46.06.080; 18 AAC § 60.005; and 200. • Reviews and approves solid waste processing and temporary storage facilities plan for handling and temporary storage of solid waste on federal and state lands under AS 46.03.005, 010, and 020; and 18 AAC § 60.430. • Approval of siting of hazardous waste management facilities.
Alaska Oil and Gas Conservation Commission (AOGCC)	• Issues a Permit to Drill under 20 AAC § 25.05. • Issues approval for annular disposal of drilling waste (20 AAC § 25.080). • Authorizes Plugging, Abandonment, and Location Clearance (20 AAC § 25.105 through 25.172). • Authorizes Production Practices (20 AAC § 25.200 through 25.245). • Authorizes Class II Waste Disposal and Storage (20 § AAC 25.252). • Approves Workover Operations (20 § AAC 25.280). • Reports (20 AAC § 25.300 through 25.320). Authorizes Enhanced Recovery Under 20 AAC 25.402 through 25.460.
Alaska Department of Fish and Game ADFG	• Issues a Fish Habitat Permits under AS 16.05.840
Alaska Department of Natural Resources (ADNR)	• Conducts a Coastal Zone Consistency review and issues determination of consistency of proposed development within the coastal zone under Coastal Zone Management Act of 1972, as amended in 1976 (16 USC § 1451 et seq.); AS 46.40 Alaska Coastal Management Program Act of 1977; and 6 AAC § 50. • Issues a Material Sales Contract for mining and purchase of gravel from state lands under AS 38.05.850; and 11 AAC § 71.070 through .075. • Issues a Material Sales Contract for mining and purchase of gravel from state lands under AS 38.05.850; and 11 AAC § 71.070 through .075. • Issues Rights-of-Way (ROW) and Land Use permits for use of state land, ice road construction on state land, and state freshwater bodies under AS 38.05.850. • Issues a Temporary Water Use and Water Rights permit under AS 46.15 for water use necessary for construction and operations. • Issues pipeline ROW leases for pipeline construction and operation across state lands under AS 38.35.020. • Issues a Cultural Resources Concurrence for developments that may affect historic or archaeological sites under the National Historic Preservation Act of 1966, as amended (16 USC § 470 et seq.); AS 41.35.010 to .240, Alaska Historic Preservation Act.
BOROUGH	
North Slope Borough (NSB)	• Issues a Coastal Zone Consistency Determination to address project planning or development within the coastal zone under the Coastal Zone Management Act of 1972, as amended in 1976 (16 USC § 1451); AS 46.40 Alaska Coastal Management Program, 1977; Borough Ordinance 90-39. • Issues Development Permits for oil and gas projects under NSB Code of Ordinance Title 19.

As with all other existing permit and regulatory requirements, none of these specifically consider the unique issues that may exist with the commercial development of gas hydrates. For example, the recent draft EIS for the Northeast NPR-A[95] refers to hydrates only as they pertain to issues associated with geographical hazard areas; primarily requiring that appropriate measures be taken to avoid damage to the permafrost, minimize property damage, and ensuring worker safety.

The only well drilled to date on the Alaska North Slope, Anadarko's "Hot Ice" will discussed earlier in this report, did not experience any uniquely imposed permit requirements specifically pertaining to the fact that hydrates was the drilling target[96]. In fact, the only special considerations pertaining to the permits for this well had to do with the unique "Arctic Platform" used for drilling this well.

Coastal Zone Management Act Considerations

One particularly important federal statute affecting offshore operations, and one that is particularly useful to those opposing offshore oil and gas activities in the federal OCS, is the Coastal Zone Management Act. The CZMA recognizes the national interest in coastal zone resources, and in the balancing of competing uses of those resources. It provides for:

> *"priority consideration being given to coastal-dependent uses and orderly processes for siting major facilities related to national defense, energy, . . . and the location, to the maximum extent practicable, of new commercial and industrial developments in or adjacent to areas where such development already exists," and, "the coordination and simplification of procedures in order to ensure expedited governmental decision making for the management of coastal resources."*

The CZMA also provides for a voluntary state program, where each participating State must develop and implement a coastal management program (CMP). Currently,

[95] U.S. Department of Interior, Minerals Management Service, Northeast National petroleum Reserve – Alaska DRAFT Amended Integrated Activity Plan/Environmental Impact Statement, June 2004.
[96] Galvin, Patrick, Petroleum Land Manager, Alaska Division of Oil and Gas, personal communication, April 22, 2004.

34 of 35 eligible states have a CMP. Once a state CMP is approved, the federal Consistency provision applies. This is a limited waiver of federal supremacy and authority, requiring that federal agency activities that have coastal effects must be consistent to the "maximum extent practicable" with the federally approved enforceable policies of state CMPs. Additionally, activities of non-federal applicants for federal authorizations must be "fully consistent" with state CMPs.

State and federal agencies have mostly cooperated to safely permit OCS oil and gas activities in the OCS, while coping with competing coastal use interests and providing effective environmental protection. However, over the past two decades, these regulations have significantly affected sitting and permitting of OCS oil and natural gas leasing, exploration, and development activities. In some cases, federal and state agency partnerships created by CZMA have become strained, causing unreasonable delays, or cancellation of major projects. For example, consistency appeals in the Millennium Pipeline Project were affirmed by the Secretary of Commerce and prevented the project from going forward. In the case of the Islander East Pipeline Project, consistency appeals by the state of Connecticut substantially delayed the project, but in this case, a decision by the Secretary of Commerce eventually overrode the state's objection.

In the case of gas hydrates, the CZMA can be an effective tool to prevent their development in the offshore. However, state opposition to development is necessary to trigger its requirements; and such opposition is unlikely if the first hydrates development occurs in the Gulf OCS or the Alaska North Slope.

Lessons Learned from Comparable Experiences

(1) Leasing in Moratoria Areas

The experiences described in Chapter V concerning the evolution and continuation of leasing moratoria off much of the nation's coastline demonstrate the effectiveness of well-financed and committed opposition. It also demonstrates the difficulty associated with promoting development where the local populations perceives itself as the bearer of all of the risks and the recipient of little or none of the benefits. In areas under current moratoria, it is highly unlikely that this local opposition will be tempered in any way with the development of hydrates in these moratoria areas.

(2) Native Alaskan Considerations

Oil and gas development on the North Slope of Alaska has brought considerable economic benefits to the Native Alaskan communities living in the region, providing schools, health care, housing, and other community services that would not have occurred had this development not taken place. However, substantial (though often difficult to substantiate) evidence exists that this development, among perhaps other factors, is contributing to irreversible changes of a less positive character, such as increased rates of alcoholism, diabetes, and circulatory disease. This development has impacted Native Alaskan culture, particularly in terms of its dependence, from both a subsistence and spiritual level, on the bowhead whale and on caribou.

As revenues from North Slope production continues to decline, and the benefits from oil and gas development become more difficult to sustain, Native opposition to continued and expanded oil and gas development in this region could grow.[97] On the other hand, the increased (or continued) revenues associated with the additional development of oil and gas resources on the North Slope, including the potential development and commercial production of methane from hydrates could be welcomed by Native Alaskans. The key (as always) is the share the Native Alaskans receive of the economic rewards associated with commercial hydrates development.

(3) Proposed Ocean CO2 Sequestration Projects in Hawaii and Norway

A research experiment was proposed by the Pacific International Center for High Technology Research (PICHTR) in Hawaii that was designed to evaluate the viability of pumping liquid CO_2 into deep ocean waters as one way to reduce CO_2 in the atmosphere. Originally planned for the waters within the Natural Energy Laboratory of Hawaii (NELH) research corridor off Keahole Point in Kona, the proposed experiment

[97] For a much more detailed examination of Native Alaskan issues related to North Slope oil and gas development, see National Research Council, *Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope*, Committee on the Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope, 2003

generated intense public opposition and met with some serious roadblocks. An organization was formed for the purpose of raising community awareness about (and ultimately oppose) this research project. In February 2002, the NELH Board of Directors rescinded their previous approval of the project.

An alternative project in the Norwegian Sea, led by the Norwegian Institute for Water Research (Niva), was proposed Similar public opposition to this project was organized, and as a result, in August 2002, a last minute veto from Norway's Environment Minister, Borge Brende terminated consideration of this project.

In both cases, unsubstantiated claims, vague speculation and hypothesized environmental impacts were used as the justification for stopping these research projects, which were in fact specifically designed with the intent to provide a better scientific foundation for understanding these issues. Some claim that in fact environmental groups fundamentally opposed to the continued use of fossil energy played on the innate public fears of the local population of a new technology, when that technology is not explained to the local population. On the other hand, those proposing the research failed to effectively explain to the public the objectives of the research, and to proactively engage the public in the decision-making process from the beginning.

Projects targeting the commercial development of gas hydrates, given the unfamiliar nature of this resource, could suffer the same fate if developers are not wary of these issues, and the tactics of potential opponents to such projects.

Perspectives on the Impact of Regulatory/Policy Process Issues on Hydrates Development

Environmentalist opposition to fossil energy development and production is likely to outweigh environmental benefits that can result from the development and production from gas from hydrates. A detailed analysis of the Hawaii experience[98] resulted in

[98] de Figueiredo, Mark Anthony, *The Hawaii Carbon Dioxide Ocean Sequestration Field Experiment: A Case Study in Public Perceptions and Institutional Effectiveness,* Masters Thesis, Massachusetts Institute of Technology, Laboratory for Energy and the Environment, Publication No. LFEE 2003-001 TH, June 2003

conclusions that could also apply to future hydrates research projects, as well as the commercial production of gas from hydrates. The project, despite general agreement that it would be environmentally benign, became a lightning rod for purposes beyond the immediate issues with the project. The local population perceived that it would receive no benefits from the project, and project proponents did little, until it was too late, to dispel this perception. The project sponsors did not devote sufficient resources to address public concerns, and were forced to pick and choose their battles, often in reactive mode. The public became fearful of a new technology that was not explained, and was skeptical because of its perceived exclusion from the decision-making process.

In this example, but certainly not unique to it, by the time the project proponents had their first public meeting, the citizens had been “educated” by the opposition, where the terms of the debate has already been defined. Residents were of the mindset that if the experiment was not dangerous, why did the scientists not tell them about it earlier. Scientists and technologists have the tendency of developing their plans in their offices and laboratories, submitting them to peer review, and only then presenting them to the public. In the Hawaii project example, like in many others, the public felt it was a stakeholder in the project, and should be consulted; when it was not, it clearly displayed its displeasure.

In the case of the development of gas hydrates, opponents to hydrates development could begin to incite public opposition by the use of terminology and phrases intended to immediately raise concerns and or perpetuate fears. Opponents could conceivably begin their opposition through normal public consultation processes. These same processes are also one forum for public education and outreach; though this should be initiated well before the time of public hearings. For activities on federal lands or involving federal funding, projects will be subject to the National Environmental Policy Act (NEPA), where Environmental Assessments (EAs) and Environmental Impact Statements (EISs) will be requirements. These projects will also be subject to the CZMA consistency review process, and facility permitting processes. Opponents could stall projects through litigation, or by requesting that further studies be conducted to better understand the impacts of gas hydrates activities on marine ecosystems, creating "paralysis by analysis." Finally, opponents could use local political pressure put on supportive politicians, attempting to threaten them to conform to the interests of their "constituents" or face possible removal from office.

Other interest groups besides environmentalists could also line up to oppose hydrates developments. Small independent U.S. producers without a stake in hydrates prospects could oppose hydrates development because it may create dependence on difficult-to-access resources when much more accessible resources – if access to these more common resources is allowed by government policy - exist within the continental U.S. International interests, in particular those with large volumes of "stranded gas" looking for markets, could also oppose development, citing market considerations, in particular, the higher prices likely to be required for hydrates commerciality, and claiming options for imported gas would be much more cost-effective for U.S. consumers. These issues are discussed in more detail in the next chapter.

COMPARISON OF HYDRATES ISSUES TO THOSE ASSOCIATED WITH TO ALTERNATIVE SOURCES OF FUTURE NATURAL GAS SUPPLIES

In order to respond to the recent perceived crisis in natural gas supply, many have voiced significant support for government policy to rapidly encourage the development of new sources of domestic natural gas supplies, including supplies from imported LNG, from the development of supplies underlying federal lands, and from the North Slope of Alaska and Northern Canada, transported to U.S. markets via long distance natural gas pipelines.[99] However, substantial barriers exist for the development of these sources of supply, and these should be compared to those that could confront the commercial development of gas hydrates. These barriers are discussed below.

Liquefied Natural Gas (LNG) imports

Liquefied natural gas (LNG) has been transported and used safely in the U.S. for nearly 40 years, and the LNG industry has an excellent safety record, with well-established mechanisms for ensure process safety and the protection of workers and nearby communities.[100] Many energy experts believe LNG is one of the most important sources of future supply to help resolve the natural gas demand and supply imbalance that confronts this nation today. As described in Chapter II, EIA forecasts that net imports of natural gas will increase from 0.43 Tcf per year in 2001 to 4.8 Tcf annually in 2025, an 11-fold increase. Over two dozen project proposals for LNG facilities in North America have been announced.[101]

However, in the post–9/11 world, the prospect of terrorist attack is an ever-present concern, and LNG facilities could pose an attractive terrorist target, as do

[99] See, for example: National Energy Policy Development Group, *National Energy Policy*, May 2001; National Petroleum Council, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, September 25, 2003; and National Commission on Energy Policy, *Increasing U.S. Natural Gas Supplies: A Discussion Paper and Recommendations form the National Commission on Energy Policy*, October 2003

[100] Institute for Energy, Law, & Enterprise, University of Houston Law Center, *LNG Safety and Security*, October 2003

[101] Lorenzetti, Maureen, "DOE, industry ask regulators to coordinate LNG's role," *Oil and Gas Journal Online*, January 5, 2004

multiple other facilities, especially if located near a large population. Moreover, some believe that large LNG facilities off our nation's coastlines could also cause significant environmental impacts. In response to both of these concerns, the opposition to LNG facilities along the nation's coastlines is vocal and well organized: For example:

- Boston Mayor Thomas Menino has proposed a ban on LNG tankers in Boston Harbor, saying that federal and industry officials are playing "Russian roulette" with the city's safety.[102] He came to this conclusion despite realization of the fact that there has never been an uncontrolled release of natural gas from an LNG tanker, or a catastrophic failure or penetration of a tanker's containment system.
- In early 2003, the Vallejo City, California Council ruled out Mare Island as the possible site for a LNG facility. Despite early support from Mayor Anthony J. Intintoli Jr., the proposal set off a chain reaction of protests uniting community, homeowner and environmental groups. As the opposition grew and threatened Mayor Intintoli's prospects for a fourth term, he switched sides.[103]
- Two proposals to build LNG terminals of the Coast of Ventura County, California face stiff local opposition, with opponents citing fears of fire, leaks, earthquakes, and intentional breaches,[104] even though these facilities would be located a considerable distance from shore. One proposal would involve the conversion of an existing offshore platform, 11 miles off shore, while the other would involve the installation of a permanently moored floating storage and regasification unit 21 miles offshore.

In California, such facilities will require authorization and/or permits from the U.S. Coast Guard, Federal Energy Regulatory Commission, DOE, the State Lands Commission, and the California Coastal Commission.

The sitting of LNG facilities will inevitably encounter NIMBY ("Not In My Back Yard") considerations that cannot be underestimated. Moreover, the significant capital

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[102] Fitzgerald, Jay, "Mayor: Ban LNG ships in Hub," *BostonHerald.com*, November 8, 2003
[103] Doyle, Alan, "Vallejo City Council Bans LNG Plant," *East Bay Business Times*, February 5, 2003
[104] Hankins, John, "Fierce opposition seen for Offshore California LNG terminals, *Oil and Gas Journal Online*, November 4, 2003

investments associated with LNG facilities make them already a risky financial venture, and major delays caused by public opposition could impact corporate decisions to proceed ahead with LNG projects, even if they believe that they would eventually prevail.

Federal Lands/ Moratoria Areas

Most of the new potential sources of U.S. natural gas supplies exist under lands controlled by the federal government. However, access to domestic resources underlying federal lands remains constrained. Federal lands currently provide over 25% of the nation's oil supplies, and nearly 40% of its natural gas supplies. Over half of the natural gas that remains to be discovered in the U.S. underlies lands under the stewardship of the Federal government.

In OCS, as described in Chapter III, because of moratoria on leasing, only 15% of the OCS acreage in the U.S. is available for leasing, and the current MMS Five-Year Leasing Plan for 2002-2007 offers no "new" areas for offshore leasing. Onshore, the federal government owns over 30% of the Nation's land. In the Rockies, over 75% of the resource potential underlies federal land, and much of this potential is inaccessible to leasing and development, in order to preserve wildlife habitat or wilderness, or provide for other uses for this land, such as grazing, recreation, timber production, and mineral extraction.

Even on land where leasing and development can take place, operators are often subject to substantial restrictions that can add costs, delay development, and create considerable project uncertainty, all affecting industry's willingness to invest in the development of these resources. Land and water management concerns have and will likely continue to create significant barriers to wide scale development. Finally, production from federal lands, particularly in the Rocky Mountain west, has often also been limited due to constrained transportation capacity.[105]

[105] U.S. Department of Energy, Office of Fossil Energy, *Rocky Mountain States Natural Gas: Resource Potential and Prerequisites to Expanded Production*, DOE/FE-0460, September 2003, (http://www.fe.doe.gov/programs/oilgas/publications/)

Natural Gas Pipelines from Alaska and/or Arctic Canada

In Arctic Alaska and Canada, the issues and concerns associated with a natural gas pipelines and those associated with gas hydrates development are inseparable, since the gas produced from the hydrates would need gas transportation infrastructure to access gas markets. Consequently, any policies that tend to enhance the prospects for construction of a natural gas pipeline also enhance the prospects for developing gas hydrates, and conversely, policies that hinder pipeline construction will also hinder gas hydrates development in the Arctic regions of Alaska or Canada.

Recently, several events have occurred that indicate that the outlook for the Alaska Natural Gas Pipeline and for net Alaska wellhead prices could be more favorable than set forth above. The Energy Policy Act of 2003, which did not pass Congress in 2003, contained a number of provisions designed to help promote construction of a natural gas pipeline from the North Slope of Alaska. While provisions to directly provide price supports for gas produced from Alaska did not survive the committee review process, the proposed bill did contain provisions that could, in aggregate, serve to encourage the development of Alaska gas supplies in general, which could also pertain to gas hydrates later. Specific provisions include those that:

- Encourage expedited FERC consideration of the certificate of public convenience and necessity, and the environmental impact statement for the pipeline
- Establish a federal coordinator responsible for coordinating the expeditious discharge of all activities for all federal agencies with respect to the project
- Encourage the so-called "southern route" of the pipeline that maximizes the length of the line through the state of Alaska
- Provide loan guarantees for the construction of the pipeline.

Perspectives on Supply Alternatives

In summary, this very brief characterization of issues associated with potential alternative sources of domestic natural gas supplies shows that all have "non-technical" as well as technical barriers to overcome; in may ways no less formidable than those confronting gas hydrates. Organized opposition exists to the development of all of these resource options; each faces economic barriers, primarily related to its current limited accessibility to gas markets, and each faces barriers imposed by both the existing regulatory oversight process and by an uninformed or misinformed public. Overcoming these barriers will be a challenge to all of these potential alternative supply sources.

CONCLUSIONS

This effort to identify describe, analyze, and report on non-technical issues pertaining to methane hydrates, which could serve to impact the commercial production of this resource, shows that issues or barriers do exist that may constrain or delay bringing this “exotic” source of natural gas to market. Important considerations impacting the commercial development and production from gas hydrates fall in several general categories:

- *Market Considerations.* These relate to the ability of gas production from hydrates to compete with other potential futures sources of natural gas supplies serving North American markets. These considerations will impact both the level and ultimate timing of commercial gas hydrates development and production, and include the ultimate evolution of the North American natural gas market, the costs associated with potentially competitive supplies, the infrastructure available to transport various sources of supplies to market, and potential barriers to the development of alternative supplies.
- *Resource Considerations.* These relate to the geographic location and geologic settings associated with gas hydrates accumulations. The size, hydrate concentration, and depositional environment of these accumulations will determine both their commercial viability and the environmental and safety concerns associated with their development. Improved characterization of gas hydrates prospects is essential to better specification of these concerns, and to provide the scientific foundation for better defining regulatory requirements associated with their development.
- *Operational Considerations.* These relate to safety and environmental considerations, both those generally applicable to all oil and gas development and production, including gas hydrates, and those pertaining to some of the unique characteristics associated with drilling into and producing gas hydrates. Appropriate approaches for developing and producing methane from hydrates have been proposed, but remain to be proven in field tests. Again, precise specification of environmental and safety concerns, and the potential regulatory

requirements necessary to address these concerns, must await further demonstrations of these approaches to development and production. Nonetheless, in general, the more gas hydrates development and production is perceived as comparable to traditional oil and gas development and production, the greater the ease with which regulators, and the public they represent, will accept gas hydrates development as an acceptable approach to helping meet our nation's energy requirements.

- *Governmental/Process Considerations.* These correspond to the leasing, regulatory, permitting and other processes by which public comment and potential opposition could be organized to oppose or support hydrates development. These processes could serve to both help address some of the market and environmental considerations listed above, but could also make potential hydrates development a "lightning rod" for other public concerns. To date, the prospect of developing natural gas from hydrates is essentially unknown to all but a few government, academic, and private sector researchers. Very little thought and planning has been pursued to date to attempt to regulate hydrates development. For the most part, this is because it is believed that further demonstration of its production potential, and the methods used to develop and produce the resource, is necessary before regulatory considerations can be specified. One exception has been in the area of leasing, where both the Minerals Management Service (at the federal level) and the Alaska State legislature (at the state level) have taken action to define gas produced from hydrates as part of the oil and gas estate for purposes of oil and gas leasing. A major information transfer effort will be required to educate regulatory officials on the issues and concerns associated with gas hydrates development and production, and the potential mechanisms to address them.
- *Environmental Considerations.* Two general categories of environmental consideration will be associated with gas hydrates development and production: (1) those common to conventional oil and gas exploration and production operations, that would also apply to gas hydrates; and (2) those that are essentially unique to natural gas hydrates. For those considerations that

hydrates has in common with conventional oil and gas operations, regulatory mechanisms are in place and are established. For those concerns unique to hydrates, additional research will be required to better understand them and develop approaches and technologies to address them.

In addressing potential barriers to hydrates development and production, it is useful to consider ways to categorize and prioritize them, both in terms of how they may ultimately impact the commercial development of gas hydrates, and how efforts can be organized and pursued to attempt to overcome them. Among other approaches, four criteria for prioritization seem to exist by which the potential issues and barriers to commercial hydrates production could be considered. While there is likely to be considerable overlap and interrelatedness among these criteria, they at least represent one way of beginning to evaluate and prioritize the issues and barriers discussed throughout this report, to help better define the appropriate approaches or mechanisms for addressing these barriers. These four criteria, and the highest priority issues for each criterion, are described in the following.

Risks based on science and/or project engineering considerations

These would generally relate to issues associated with scientific concerns or uncertainties, or issues associated with the potential approaches for gas hydrates development and production, that remain unresolved or that may be difficult to resolve. For this criterion, the highest priority issues relate to the “big ticket” environmental considerations that may arise from potential future hydrates development. This includes concerns about triggering relatively large scale hydrates dissociation, possibly causing large releases of methane (increasing atmospheric concentrations of greenhouse gases) and potential subsea landslides leading to marine and coastal disturbances. It also concerns impacts potentially associated with disturbing rare species that could be impacted by large-scale hydrates development. Of somewhat lower priority are more operational issues, like those associated with drilling into or through hydrates, and managing the water associated with gas produced from hydrates. Clearly, new research and scientific work will be necessary to help understand these impacts, and if significant, for developing approaches to minimize or mitigate them.

Public perception considerations

These generally relate to issues or concerns of the general public, either real or perceived, that, if not affectively addressed, could impact the pace and/or ultimate commercial development of gas hydrates. For this criterion, the highest priority issues will relate to effectively addressing the "big ticket" environmental considerations described above, as well as not allowing hydrates to become a "lightening rod" for other issues. In addition, it is unlikely that hydrates development will take place in areas with a long tradition of resistance to oil and gas development, like the Atlantic and Pacific coasts, or the Eastern Gulf of Mexico. Here, the federal government, particularly DOE, has a critically important role in disseminating objective, factual information on the nature of potential concerns and the research that is underway to address these concerns.

Political and/or economic considerations

These could manifest themselves in a number of ways, and can be driven by a number of factors. For example, hydrates development could become a platform used to raise public awareness on other issues only peripherally related to hydrates, such as our dependence on fossil fuels, the fate of the world's oceans, or the conditions of the indigenous people in Alaska. They may also be used as a platform for promoting alternative potential future sources of gas supply for North America. Other than uncertainties associated with the evolution of the North American natural gas market, the uncertainties associated with the big ticket environmental considerations and the costs associated with developing and producing gas hydrates are the highest priority considerations that will need to be addressed from an economic and political perspective. Informed decision-making, by both government officials and private industry, can be facilitated by proactive federal research and the factual, unbiased publication of this information in a manner useful to these decision makers.

Timing considerations

These represent issues and concerns that could affect the ultimate timing of hydrates development. These could be related to market forces, political and regulatory processes, or the development of technology. The ultimate timing of commercial hydrates development and production will depend on the cost and availability of gas supply alternatives and the cost of hydrates development, assuming the other issues are resolved. Critical to hydrates development will be the availability of transportation infrastructure capable of delivering gas produced from hydrates to market and the development of cost-effective technologies for gas hydrates development and production. Public policy can play a key role in impacting the timing of these market developments, in a way that can either help or hinder the ultimate commercial development of methane hydrates.

Based on this review, the highest priority issues that will need to be addressed will involve efforts to improve understanding and developed approaches for mitigating or avoiding potential impacts associated with large-scale releases of methane and harm to chemosynthetic communities dependent upon subsea gas hydrates.

Of second priority will be addressing operational and regulatory issues associated with developing hydrates, in particular, those issues associated with operational safety and sea floor stability where hydrates may be present, the management and disposal of the water produced with the hydrates, the potential composition of the gas produced from the hydrates, and the injection of heat or chemicals to help stimulate the dissociation and production of gas from hydrates.

To be effective, DOE, other federal agencies, the academic community, and industry need to be proactive in characterizing these issues, demonstrating the nature of the real risks posed, and establishing effective mechanisms for addressing any risks that exist. A reactive response to these issues, in contrast, allows others to define the terms of the debate and the nature of the proper response to address real and/or perceived concerns.

Figures and table data are credited to:

- Bureau of Land Management/Department of Interior
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