Energy from Gas Hydrates: Assessing the Opportunities & Challenges for Canada

The Expert Panel on Gas Hydrates

Council of Canadian Academies
Conseil des académies canadiennes

Science Advice in the Public Interest

ENERGY FROM GAS HYDRATES – ASSESSING THE OPPORTUNITIES AND CHALLENGES FOR CANADA

Report of the Expert Panel on Gas Hydrates

THE COUNCIL OF CANADIAN ACADEMIES
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Report Review

This report was reviewed in draft form by the individuals listed below — a group of reviewers selected by the Council of Canadian Academies for their diverse perspectives, areas of expertise and broad representation of academic, industrial, policy and non-governmental organizations.

The reviewers assessed the objectivity and quality of the report. Their submissions — which will remain confidential — were considered fully by the panel, and most of their suggestions were incorporated into the report. They were not asked to endorse the conclusions nor did they see the final draft of the report before its release. Responsibility for the final content of this report rests entirely with the authoring panel and the Council.

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The report review procedure was monitored on behalf of the Council's Board and Scientific Advisory Committee (SAC) by **Norbert Morgenstern**. Dr. Morgenstern (FRSC, FCAE) is University Professor (Emeritus) of Civil and Environmental Engineering at the University of Alberta. The role of the report review monitor is to ensure that the panel gives full and fair consideration to the submissions of the report reviewers. The Board of the Council authorizes public release of an expert panel report only after the report review monitor confirms that the Council's report review requirements have been satisfied. The Council thanks Dr. Morgenstern for his diligent contribution as review monitor.

Peter J. Nicholson
President, Council of Canadian Academies

Acronyms

The following is a list of acronyms that appear in the report.

2D and 3D	two-dimensional and three-dimensional
AAPG	American Association of Petroleum Geologists
AOSTRA	Alberta Oil Sands Technology and Research Authority
BHP	bottom-hole flowing pressure
BOP	blow-out preventer
BSR	bottom-simulating reflector
Btoe	billions of tonnes of oil equivalent
CBM	coalbed methane
CCA	Council of Canadian Academies
CCOD	Canadian Consortium for Ocean Drilling
CGHR	Guangzhou Center for Gas Hydrates Research (China)
ClO_2	chlorine dioxide
CO_2	carbon dioxide
COGOA	Canada Oil and Gas Operations Act
CPRA	Canadian Petroleum Resources Act
CSEM	controlled-source electromagnetics
DGH	Directorate General of Hydrocarbons (India)
DINA	Department of Indian Affairs
DOE	Department of Energy (U.S.)
DSDP	Deep Sea Drilling Program
DTS	distributed temperature sensors
EIA	Energy Information Administration
EM	electromagnetic
EMR	Energy, Mines & Resources
ESP	electric submersible pump

GGO	German Gas Hydrate Organisation
GH	gas hydrate
GHG	greenhouse gas
GHSZ	gas hydrate stability zone
GJ	gigajoule
GMGS	Guangzhou Marine Geological Survey
GSC	Geological Survey of Canada
GWP	global warming potential
ICDP	International Continental Drilling Program
ICGH	International Conference on Gas Hydrates
IEA	International Energy Agency
INAC	Indian and Northern Affairs Canada
IODP	Integrated Ocean Drilling Program
IPCC	Intergovernmental Panel on Climate Change
JAPEX	Japan Petroleum Exploration Co., Ltd.
JNOC	Japan National Oil Corporation
JOGMEC	Japan Oil, Gas and Metals National Corporation
LNG	liquefied natural gas
LWD	logging-while-drilling
MBSF	metres below sea floor
Mcf	thousand cubic feet
MDT	Modular Dynamic Formation Tester
METI	Ministry of Economy, Trade and Industry (Japan)
MITI	Ministry of International Trade and Industry (Japan)
MMcf	million cubic feet
MMS	Mineral Management Services
MOCIE	Ministry of Commerce, Industry and Energy (Korea)
MT	magnetotellurics

NEB	National Energy Board
NEPTUNE	North-East Pacific Time-series Undersea Network Experiments
NGHP	National Gas Hydrate Program (India)
NMR	nuclear magnetic resonance
NRC	National Research Council Canada
NRCan	Natural Resources Canada
NSERC	Natural Sciences and Engineering Research Council of Canada
NWT	Northwest Territories
O&G	oil and gas
OBC	ocean-bottom cable
OBS	ocean-bottom seismometer
ODP	Ocean Drilling Program
PSA	petroleum system analysis
R&D	research and development
RAB	resistivity-at-bit
ROPOS	remotely operated platform for ocean science
RSC	Royal Society of Canada
SAGD	Steam-Assisted Gravity Drainage
Tcf	trillion cubic feet
Toe	tonne of oil equivalent
UAlberta	University of Alberta
UBC	University of British Columbia
UCalgary	University of Calgary
U of T	University of Toronto
U.S. DOE	U.S. Department of Energy
USGS	U.S. Geological Survey
UTF	Underground Test Facility
UVic	University of Victoria

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SUMMARY

Gas hydrates[1] form when water and natural gas combine at low temperatures and high pressures — for example, in regions of permafrost and in marine subseafloor sediments. They exist in abundance worldwide and some estimates suggest that the total amount of natural gas bound in hydrate form may exceed all conventional gas resources, or even the amount of all hydrocarbon energy — coal, oil and natural gas combined. Gas from gas hydrate could therefore provide a potentially vast new source of energy to offset declining supplies of conventional natural gas in North America and to provide greater energy security for countries such as Japan and India that have limited domestic sources.

Complex issues would need to be addressed if gas hydrate were to become a significant part of the energy future of Canada and of the world. These issues arise from unknowns about the resource itself. How much is there? Where is it located, at what concentrations, and in what kinds of geological environments? How could the gas best be produced? The interplay of these physical and engineering issues with future economic considerations, environmental policies and community impact concerns will determine whether, and where, natural gas from gas hydrate might be produced.

To better understand these issues, so as to have a more informed basis on which to develop policy for gas hydrate as one possible future energy option for Canada, Natural Resources Canada asked the Council of Canadian Academies to assemble a panel of experts to address the question: *What are the challenges for an acceptable operational extraction of gas hydrates in Canada?* The panel was asked not to make explicit policy recommendations, but rather to assess the current state of knowledge on matters relevant to possible policy choices.

1 In this report the panel generally refers to gas hydrate in the singular, but occasionally uses the plural (hydrates) if emphasis is intended on the multiple types of gas hydrate or multiple areas of its occurrence.

KEY MESSAGES AND ISSUES

- Natural gas hydrate is a potentially vast, but yet untapped, global energy source.
- Because Canada appears to have some of the world's most favourable conditions for the occurrence of gas hydrate, and has played a leadership role in geophysical, and laboratory hydrate assessments, as well as field testing and modelling, Canada is well-positioned to be a global leader in exploration, R&D, and exploitation of gas hydrate. At the very least, research is required to fulfill a responsibility to gain a more comprehensive understanding of Canada's physical resources.
- Gas hydrate yields natural gas. Most of the environmental, safety, regulatory and social considerations related to its exploitation appear to be similar to those associated with conventional gas production in frontier areas, whether in the North or offshore.
- No insuperable technical problems are foreseen in producing gas from gas hydrate, though this would be more costly than producing gas from conventional reservoirs in similar environments.
- The most promising method of production appears to be to dissociate gas hydrate via pressure drawdown within a reservoir. The most favourable conditions are when gas hydrate occurs in marine and subpermafrost sand formations.
- Although combustion of gas from gas hydrate would generate less CO_2 per unit energy than either coal or oil, the proportion of gas hydrate, and other hydrocarbons, in the future energy mix will depend on decisions on how best to mitigate the anthropogenic drivers of climate change.
- The volume and location of gas hydrate that might ultimately be profitably produced in Canada cannot be adequately quantified at this time. Ongoing exploration and research will be required to delimit the resource, and to determine the technical and economic factors that would govern gas production.
- Commercial production of gas from gas hydrate in Canada would likely begin in association with (frontier) natural gas fields, developed to exploit conventional resources. Gas hydrate production could share established infrastructure, particularly for gas transport.
- In view of the need for further exploration and appraisal of the gas hydrate resource, the construction of new transport infrastructure, and government approvals for various permits, large-scale, stand-alone commercial production of gas from gas hydrate is not likely to take place in Canada within at least the next two decades.
- The economic, environmental and certain technical uncertainties that affect the commercial prospects of gas hydrate, when considered in the context of current alternative opportunities for energy companies, imply that the private sector on its own is unlikely to undertake development of gas hydrate in Canada at this time. Industry must be effectively engaged if significant progress is to be made. Government-industry partnerships could create the option to include gas hydrate in a diversified energy portfolio for the future.

OVERVIEW OF GAS HYDRATES – A PRIMER ON THE CONTEXT

The gas held in naturally occurring gas hydrate is generated by microbial or thermal alteration of organic matter under the seafloor or permafrost, producing methane and other gaseous byproducts. (Methane is by far the dominant gas found in gas hydrates, which is why they are often referred to as methane hydrates.) Although chemists have known about gas hydrates for almost 200 years, the oil and gas industry began to take an interest only in the 1930s when gas hydrate formation in pipelines was found to cause troublesome blockages. Russian scientists in the late 1960s were the first to propose that gas hydrate might occur naturally in marine and onshore locations under conditions of pressure and temperature that permit gas hydrate to form and remain stable.

Global Occurrence and Quantity — Vast portions of the world's continental margins and permafrost regions appear to be underlain by gas hydrates. In recent years, a growing number of deepsea drilling expeditions have been dedicated to assessing marine gas hydrate accumulations, and understanding the geologic controls on their occurrence. Gas hydrate associated with permafrost has been documented in Canada, Alaska and northern Russia. One of the most studied permafrost gas hydrate accumulations is the Mallik site in Canada's Mackenzie Delta.

Recent estimates suggest that the worldwide volume of gas trapped in hydrate accumulations is in the range of 1 to 120 x 10^{15} m^3 (35,000 to 4,200,000 trillion cubic feet, Tcf). With very few drilling and coring data sets available, a reliable estimate of global volume of natural gas hydrate appears to be elusive. Moreover, the various global assessments do not reveal how much gas could be produced from the world's gas hydrate accumulations. Much more work is needed to refine estimates of the total volume of gas hydrate and to quantify producible volumes. For simple comparison purposes (and to give the reader an idea of the magnitudes of other resources) conventional natural gas accumulations, including reserves and technically recoverable global resources, are estimated to be approximately 4.4 x 10^{14} m^3 (15,500 Tcf).

Potential Role in the Energy Future — The commercial viability of gas hydrate as a future source of energy will depend on supply and demand, and therefore price, in the markets for energy, and particularly for natural gas, in the medium to long term. Estimates by the U.S. Department of Energy and the International Energy Agency suggest that global energy demand will grow by between 40 per cent and 70 per cent by 2030. More than 80 per cent of this growth is projected to be met by oil, natural gas and coal. The expectation is that natural gas, given its significantly lower carbon footprint, will displace some growth in the use of both oil and coal.

For Canada, natural gas production is projected to begin to decline after 2010 while domestic consumption continues to grow. This projection implies decreasing Canadian gas exports to the United States, where the prospects are for increasing reliance on imports of liquefied natural gas (LNG) as a substitute for conventional U.S. or Canadian supplies. It is in this context, and in view of growing concerns over security of supply, that the possibility of significant production of gas from gas hydrate becomes particularly important. Canada's potentially large gas hydrate resource could make a key contribution to meeting North American energy demands during this century. Given the potential size of the global gas hydrate resource and its relatively wide distribution, many countries, such as the United States, Japan, India, and South Korea, are showing substantial interest in exploiting this resource over the long term.

Global Environmental Considerations — The natural gas that would be produced from gas hydrate would generate carbon dioxide (CO_2) upon combustion, though in lesser amounts, per unit of useful energy generated, than either coal or oil. It is beyond the scope of this report to address the overarching issue of the future role of hydrocarbon fuels in the world's energy supply mix. It should be noted that growing concern over climate change is stimulating a great deal of research and development (R&D) worldwide to develop effective ways to curb and/or sequester CO_2 emissions. The extent to which this effort bears fruit will have a significant impact on the demand for natural gas in the medium to long term. If, as expected, hydrocarbon fuels do continue to be a major component of the global energy supply for at least several more decades, the lower carbon intensity of natural gas (and thus of gas hydrate) will likely make it increasingly attractive relative to coal and oil.

The possibility that global warming may induce widespread gas hydrate dissociation ("melting") causing the release of large amounts of methane (itself a potent greenhouse gas) — and thus accelerating warming due to feedback — is the subject of research explaining historical climate change events and projecting the climatic impact of gas hydrate into the future. Simulation modelling suggests that there is potential for gas hydrate-related release of methane that could far surpass human-caused climate warming on time scales of 1,000 to 100,000 years. It should also be noted that the exploitation of gas hydrate could not remove sufficient quantities from the earth's crust to prevent the possible long-term dissociation of gas hydrate due to climate change. Given existing technology, the emissions of natural gas into the atmosphere as a result of gas production from gas hydrate should be similar to those from conventional natural gas production.

From investigations of continental margins and extensive surveys by offshore energy companies, it is evident that widespread continental margin instability due to dissociation of gas hydrates is not occurring today, nor has it occurred during the past 5,000 years or so. It would appear that seafloor instability will have little impact on the development of gas hydrate as a resource.

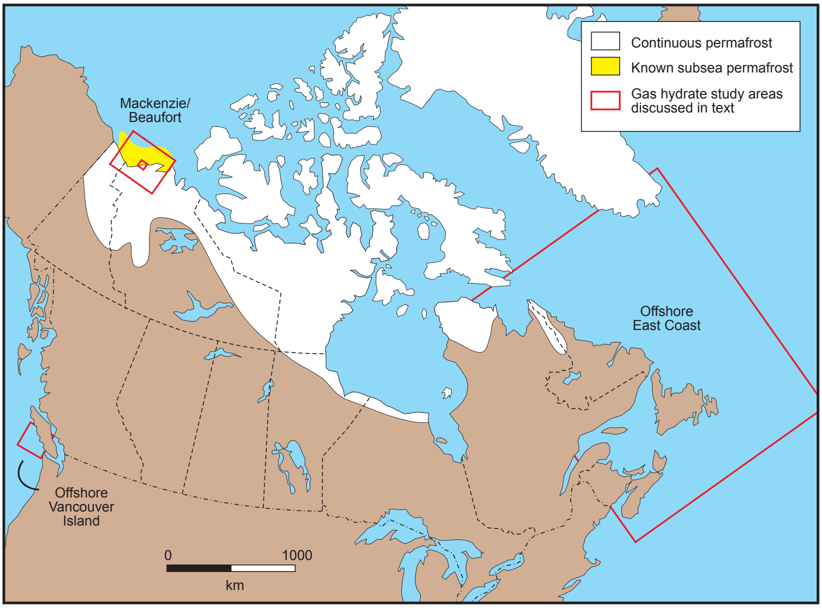
Canada's Contribution in a Global Context — Despite having no official national gas hydrate program, Canada has made significant contributions to gas hydrate research. Canadian scientists and engineers have been leaders in elucidating the chemical structure and physical properties of gas hydrates, and Canada is home to two of the world's most intensively studied natural permafrost and marine occurrences: those at Mallik in the Mackenzie Delta and the northern Cascadia margin off the west coast. Canada's main strength has been due to highly qualified people contributing globally and training researchers from countries where gas hydrates are emerging as a topic of importance. So far at least, unlike in the United States, there has been very little industrial investment in gas hydrate as a potential energy resource in Canada.

THE QUANTITY AND LOCATION OF GAS HYDRATE IN CANADA

Canadian Quantity Estimates — Little research exists to assess the regional occurrence, distribution and total volume of gas hydrate in Canada. The total volume of methane locked in hydrate deposits in Canada was estimated in 2001 to be between 10^{12} and 10^{14} m^3 (between 35 and 3,500 Tcf).[2] The reliability of this estimate is limited by the fact that the analysis excludes consideration of local geological and tectonic conditions, and basin characteristics. A later and more refined assessment (2005) for the Mackenzie Delta/Beaufort Sea region alone estimated the volume of gas in gas hydrate in that region to be between 8.8 and 10.2×10^{12} m^3 (between 310 and 360 Tcf). There is no equivalent detailed summary estimate for the northern Cascadia margin off Vancouver Island, the Atlantic coast or the Arctic Archipelago.

2 For comparison, the NEB estimated in 2004 that Canada's ultimate potential of conventional natural gas is about 14.2×10^{12} m^3 or 500 Tcf.

Location of Gas Hydrates — Despite extensive research in individual locations, and the high quality of Canadian work in this field, Canada's coastal margins and permafrost areas have not been extensively studied for gas hydrates (see Figure 1). Other mineral resources are commonly estimated without mapping their total occurrence, and attempting to map all Canadian gas hydrate deposits on a basin-by-basin scale is impractical because of the length of Canada's coastline.



(Majorowicz and Osadetz, 2001)

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Figure 1

Regional assessments of gas hydrate in Canada

Note that while this map shows the three regions on which assessments have been focused to date, gas hydrate may occur on other parts of the margin.

Naturally occurring gas hydrates have been studied off Vancouver Island for more than two decades. The Cascadia margin is one of the best-studied gas hydrate environments in continental margin settings worldwide. Studies have included two dedicated deep-drilling expeditions by the Ocean Drilling Program (ODP, Leg 146 in 1992) and the Integrated Ocean Drilling Program (IODP, Expedition 311 in 2005). The most significant findings of the recently completed IODP Expedition 311 in Cascadia are as follows:

- Gas hydrate is formed mainly within the sand-rich formations and is virtually absent from the fine-grained sediments. Thus the presence of gas hydrate is mainly driven by lithology (i.e., the type of sediment formation and its physical character in terms of grain size).
- The bottom-simulating reflector (BSR — a seismic signature that can indicate the presence of gas hydrate) is unrelated to the concentration of gas hydrate within the pressure-temperature stability zone, and provides only a first-order indicator of the potential occurrence of gas hydrate.
- All sites showed a high degree of heterogeneity in gas hydrate occurrence (on the 10-metre near-borehole scale to the margin scale on several kilometres). Thus there are potential pitfalls in extrapolating small-scale borehole observations to the regional scale.

Gas hydrate research on the east coast of Canada has been very limited. New seismic data analyses have shown few indications of BSRs off Canada's east coast. However, this does not automatically imply that gas hydrates are absent. The existing geophysical data are inconclusive as to the potential gas hydrate resource in this region and further research, especially direct sampling through deep drilling and coring, is required.

Several attempts have been made to characterize the total gas hydrate potential of the Canadian Arctic, including the Beaufort Sea shelf, the Mackenzie Delta and the Arctic Archipelago. Some of the main findings in permafrost environments are as follows:

- In the Mackenzie Delta/Beaufort Sea (based on more than 200 wells drilled) gas hydrate occurrence was higher offshore, where 45 per cent of wells were interpreted to contain gas hydrate, compared with only 14 per cent onshore.
- In the Arctic Archipelago, gas hydrate was probable in more than half of 168 wells drilled in the Sverdrup Basin.
- Gas hydrate was found to be more likely to occur in sand layers or coarser-grained sediments.

Although gas hydrate has been reported in many wells across the Arctic, some of the evidence is of doubtful value, and data are inconclusive because of poor knowledge of the vertical extent of the gas hydrate stability zone.

To achieve a more reliable estimate of Canadian gas hydrate accumulations and volumes, intensive field studies, combined with spot coring and drilling, are required, especially in yet under-represented areas such as the east coast and Arctic islands. Because many of the regions of interest have been charted in the past by industry in the course of exploration for conventional hydrocarbons, it may be possible to involve the private sector more closely in the search for gas hydrate deposits in Canada's frontier areas.

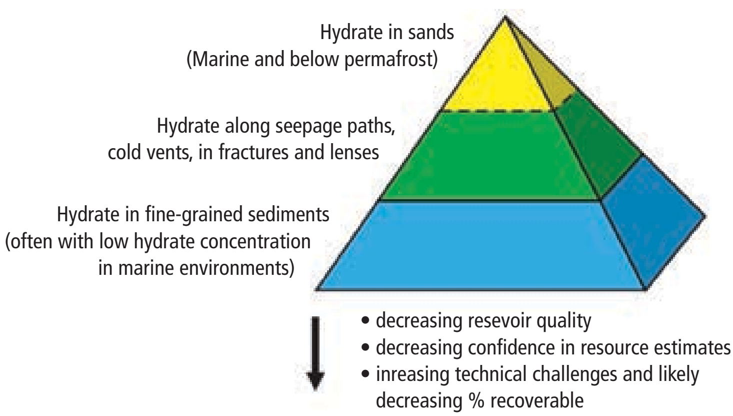
THE PRODUCTION OF NATURAL GAS FROM GAS HYDRATE

The current state of knowledge about the producibility of gas hydrate is analogous to the understanding of coalbed methane (CBM) or oil sands about three decades ago. While both CBM and oil sands took several decades to become commercially viable, it is too early to judge whether the development horizon of the gas hydrate resource will be longer or shorter. While it can be expected — by analogy with oil sands and CBM — that gas production from gas hydrate will be facilitated, perhaps significantly, by innovative and "out-of-the-box" ideas, the report limits its attention to technologies currently available for production of hydrocarbons.

Producing Natural Gas from Gas Hydrate — Experience with test wells at Mallik and elsewhere suggests that most problems in drilling and completion of gas hydrate wells can be foreseen and successfully dealt with at the design stage. Long-term experience is nevertheless required to better understand the severity of problems that may be associated with the production of gas from gas hydrate, including problems with sand flow. While problems may affect the economy of the operations, they are not expected to be technically insurmountable. Once gas has been dissociated from the hydrate phase and collected from a well, it is like conventional natural gas, the handling and marketing of which are familiar.

Based on current knowledge, the technical assessment of producibility is most readily carried out if the gas hydrate is contained within sand formations at temperatures above the freezing-point of water, whether below permafrost or in marine sands. Fine-grained sediments can also contain low concentrations of gas hydrate. While flow may be established in such systems on a local basis, the continuity of the permeable media, which is needed to allow production of a significant amount of gas from the gas hydrate, is not demonstrated and has little analogy with other conventional hydrocarbon production. Massive gas hydrates concentrated in and around seafloor vents are excluded from this report's analysis of producibility in view of the very significant technical, environmental and safety uncertainties related to their potential exploitation.

The hierarchy of feasibility of producing natural gas from gas hydrate can be illustrated schematically as a pyramid (see Figure 2). The vertical distance below the apex indicates, qualitatively, the relative ease of producibility. At the top of the pyramid — which would be the initial focus of experiment and exploration — are gas hydrates in marine and subpermafrost sand formations.



(Boswell and Collett, 2006)
Modified and reproduced with permission from Ray Boswell and Timothy Collett.

Figure 2
A schematic representation of technical producibility of the gas hydrate resource, with the easiest on top

Recovery begins by dissociating a gas hydrate reservoir into its constituents of natural gas and water, followed by production of the gas via a well. Because gas hydrate is stable only under certain pressure/temperature conditions, the three most commonly proposed techniques are (i) thermal stimulation, in which the gas hydrate is heated beyond its zone of stability; (ii) depressurization, in which pressure in the reservoir is drawn down below the point of hydrate equilibrium at a prevailing temperature; and (iii) "inhibitor" injection to shift the gas hydrate stability conditions. Depressurization is considered the most promising method of production when account is taken of cost and environmental impact.

The availability and type of fluid below the gas hydrate is of significant importance because the volume of hydrate that can be accessed by a production technique such as depressurization — and the rate of heat transfer required for hydrate dissociation — are strongly affected by the presence of an underlying fluid. The most promising type of gas hydrate appears to be that underlain by free gas.

(a) Underlying Free Gas: Under these conditions, production of gas from gas hydrate can proceed in a manner similar to a conventional hydrocarbon reservoir by producing from the underlying free gas. This would initiate pressure reduction and decomposition across the hydrate/free gas interface. Modelling indicates that a significant portion of the gas hydrate would decompose naturally at promising rates. It is possible that production from such "sweet spots" could be accomplished technically within the next 10 years. Nevertheless, the reliability of the models used to predict gas hydrate reservoir performance remains uncertain as they have not been tested against long-term field data.

(b) Underlying Free Water: When the underlying fluid is water, depressurization can be achieved by removing the water. Studies suggest that gas hydrate underlain by free water is technically recoverable, though, as modelling has indicated, less economically attractive than with underlying gas.

(c) No Underlying Fluids: The rate of gas production from gas hydrate reservoirs without underlying free fluids — i.e., bounded by impermeable sediments at top and bottom — remains uncertain. Some studies suggest that in the absence of underlying fluids, a number of other factors (including pressure, temperature and hydrate saturation) need to be favourable for economically attractive flow rates from such gas hydrate accumulations to be possible.

Production Testing at Mallik — The focus of gas production testing from gas hydrate in Canada has been at the Mallik site, the only reservoir in Canada that has been studied in enough detail to permit analysis of production rate and volume. The main findings and implications of the three Mallik international scientific programs (1998, 2002 and 2006-08) can be summarized as follows:[3]

- Gas hydrate occurs primarily as pore-filling material within the sands (50 per cent to 90 per cent pore-space saturation). No pore filling is observed in the silt-dominated intervals, suggesting a strong lithologic control on gas hydrate occurrence.
- The presence of gas hydrate appears to contribute substantively to the "strength" of the sediment matrix, with the hydrate providing reinforcement.
- The 2007 production test was deliberately undertaken without sand control measures in order to assess whether the reduction in sediment "strength" caused by gas hydrate dissociation would result in sediment inflow into the well. A substantial inflow of sand did occur, constraining the duration of the test to approximately 24 hours.
- A six-day production test in March 2008 was extremely successful, with excellent equipment performance. (Sand screens were installed to hold back the coarse-grained sediments.) While the raw test data and detailed interpretation of results are confidential at this time, sustained gas flows ranging from 2,000 to 4,000 m^3/day (70,000 to 140,000 ft^3/day) were maintained throughout the course of the test, and physical operations proceeded very smoothly during the progression to three target drawdown pressures.
- The 2006-08 Mallik Production Research Program successfully demonstrated proof-of-concept for gas production from gas hydrate by depressurization. The Mallik tests indicate that sustained gas flow can be achieved from a sand-dominated gas hydrate reservoir, through reduction of bottom-hole pressures using conventional oilfield technologies adapted for an arctic gas hydrate system.

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3 The panel acknowledges the helpful input — on which the listed findings are based — from S.R. Dallimore and J.F. Wright of the Geological Survey of Canada and K. Yamamoto of Japan Oil, Gas, Metals National Corporation.

Economics of Gas Hydrate Production — Studies of the economics of gas production from onshore and offshore gas hydrate are limited. Those that do exist suggest that a number of factors interact to make production from a gas hydrate accumulation more costly than from comparable conventional gas reservoirs because a gas hydrate reservoir is predicted to:

- produce at a lower rate;
- require compression from the beginning; and
- require more expensive well-completion due to:
  - (i) the production of more water, therefore requiring lift and disposal of the produced water;
  - (ii) the need for chemical injection equipment and/or local heating to avoid gas hydrate (re)formation and plugging; and
  - (iii) the application of suitable techniques to avoid production of sand.

Price Scenarios for Natural Gas — A critical determinant of the prospects for commercial gas hydrate exploitation will be the cost of delivered production relative to the likely range of market prices for gas. In 2007, Canada's National Energy Board (NEB) projected natural gas prices associated with several supply and demand scenarios through 2030. The projected prices cover a range from about US$5.70 per gigajoule (GJ) to about US$11.40/GJ based on delivery at Henry Hub, Louisiana (the reference point for North American gas prices). Taking into account (a) the average cost of pipeline transportation from Henry Hub to the Calgary hub (AECO-C), plus (b) an estimate of US$2.85/GJ (or possibly higher) to connect via a potential Mackenzie Valley pipeline, implies that the current NEB gas price forecast range would translate to prices between US$1.90/GJ and US$7.60/GJ at potential supply areas in the Mackenzie Delta. (If one assumes an exchange rate of US$0.90 to C$1.00 over the long run, the foregoing price range would be C$2.15/GJ to C$8.50/GJ.)[4]

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4 To the extent that there is some substitutability between oil and gas over longer time periods, some rough correlation between higher (lower) oil prices and higher (lower) gas prices might be expected over the long term. Because the recent world price of oil has substantially exceeded the longer-range prices assumed in the NEB scenarios, it might be thought that the NEB's projected (real) gas prices for 2030 are much too low. While the existence of very substantial forecast uncertainties is acknowledged, it should be noted that (a) supply and demand conditions in domestic gas markets and global oil markets can be very different, and thus the gas-oil price correlation could be very different in the future than in the past; and (b) the current spike in oil prices may or may not reflect the future. In the event that gas prices in the medium to longer term do exceed the NEB scenarios, the viability of gas from gas hydrate would improve, other factors being equal.

For the Mallik field, preliminary estimates suggest that total capital and operating costs for production could be in the range of about C$4.75/GJ to C$5.70/GJ for gas hydrate over free gas and about C$6.20/GJ to C$9.00/GJ for gas hydrate over free water. When royalties, taxes and returns to capital are included, it would appear that the cost of this gas could be competitive if gas prices were sustained above or near the upper end of the range in the NEB scenarios. Estimates of the production cost of natural gas from gas hydrate must nevertheless be viewed with considerable caution, given the large technical uncertainties.

Gas Transport Infrastructure — The prospect of gas hydrate extraction in Canada, even in the medium term of 20 to 30 years, depends on policy decisions of government and commercial decisions of energy companies affecting whether or not infrastructure is put in place in areas where favourable gas hydrate deposits exist in close proximity to conventional gas reservoirs. (The *Unconventional Gas Technology Roadmap* (2006) argues that the lack of transportation systems to bring natural gas from gas hydrate to market is the critical issue facing gas hydrate development in Canada.)[5] Further development of Mallik, or other gas hydrate accumulations in the Canadian Arctic, is therefore unlikely unless and until the Mackenzie Valley or other similar pipeline access is in place.

The cost of developing *offshore* hydrocarbon resources is so large that only a few major energy companies are involved in offshore development, even of conventional hydrocarbons. Development prospects off Canada's Pacific coast are further exacerbated by a general moratorium on all offshore energy exploration and development. On the Atlantic coast, existing production platforms are so few and far between that lack of adjacent infrastructure would likely have a significant effect on the economics of production of gas from gas hydrate.

Security of Supply and Economic Development — While there will be a growing market for Canadian gas exports to the United States, these will have to compete with imported LNG. Once major investments are made to accommodate imported LNG, its competitive advantage could become insurmountable. This suggests that a "security premium," or other such incentive for the development of domestic gas supplies, may be required to bring northern and perhaps other unconventional gas onstream. It is therefore likely that

5 Petroleum Technology Alliance Canada. 2006. *Filling the gap: Unconventional gas technology roadmap*. Available at: www.ptac.org/cbm/dl/PTAC.UGTR.pdf. [Accessed June 26, 2008].

there would have to be government incentives, at least in the early phases, to stimulate development of gas hydrate.

Safety Considerations for Drilling and Exploitation of Gas Hydrate — Current gas hydrate-related safety concerns arise primarily when gas hydrate is encountered in the course of *conventional* hydrocarbon exploration and production (offshore and in the Arctic). These concerns come up in the context of targeting deeper hydrocarbons, when trying to *avoid* gas hydrate. Current knowledge of safety issues in offshore and Arctic settings is mostly anecdotal, with only a few published studies that focus on documented drilling problems. Much of the information on gas hydrate-related safety is currently proprietary, residing outside Canada with national energy programs or the commercial energy industry. While taking into account the lack of publicly available documentation, the safety issues associated with producing gas from a gas hydrate reservoir appear to be similar to those encountered in producing from a conventional natural gas field.

ENVIRONMENTAL, JURISDICTIONAL AND COMMUNITY CONSIDERATIONS

Environmental Considerations — Extracting natural gas from gas hydrate involves mostly issues common to the recovery of other hydrocarbon resources, especially conventional natural gas. Past experience with resource development in the Far North or in offshore marine settings should serve as models.

The leakage of methane gas from a gas hydrate-bearing formation as a result of production-related activities is not likely to be a problem because, by discontinuing depressurization, any significant wellbore leakage could be controlled. After completing methane production from gas hydrate-bearing strata, these formations would be expected to return to their original state. Inadvertent loss of methane would be detrimental for economic, environmental, and safety reasons. Well operators would be motivated to minimize leakage.

Although significant amounts of water would be produced as gas hydrate is dissociated, the situation is similar to that for other hydrocarbon production processes. As gas hydrates are destabilized, they produce water purified through the freshening effect.

It has been suggested that CO_2 emitted from the burning of fossil fuels could be sequestered in gas hydrate reservoirs by displacing methane hydrate, allowing CO_2 hydrate to form in its place. Although coupling methane extraction with CO_2 sequestration is conceptually attractive, a practical procedure is likely to be decades away. Nevertheless, research into the details and impacts of the idea warrants further support.

Jurisdictional Considerations — The future development of gas hydrate would be affected by a number of jurisdictional issues particular to Canada. The situations differ on the East, West and Arctic coasts. Only the East Coast has a detailed federal-provincial framework for resource development — the Atlantic Accords. These accords may provide a framework for working out a comparable agreement on the West Coast. Gas hydrate development could not take place there until the federal and provincial moratoria on oil and gas exploration off the coast of British Columbia are lifted and a new regulatory regime is put in place. Although the scientific studies and reports conducted by both British Columbia and Canada since 2001 have concluded that there is no scientific evidence to support maintaining the moratoria, the challenges of lifting them are considerable in light of public scepticism and the inevitable complexity of the required regulatory regime. For example, one study estimated that 60 federal statutes and 38 provincial statutes apply to offshore activity.

Arrangements in the Arctic are likely to be influenced by the agreements associated with developing the proposed Mackenzie Valley pipeline, and the debate on devolution of legislative authority to the territorial governments. The federal government is currently placing greater priority on Canada's Arctic regions because they contain much of the country's energy potential. Moreover, Canada could use development and regulation of offshore resources, including gas hydrate, to reinforce its claim over its Arctic territory.

Community Impact Considerations — The social, cultural and economic development considerations related to the exploitation of gas hydrate in northern and offshore areas are similar to those associated with conventional gas production in frontier areas. While the specific circumstances of every proposed project will need to be addressed, the production of natural gas from gas hydrate does not appear to present social and cultural issues unique to *gas hydrate*, as distinct from conventional gas reservoirs of comparable extent. The many lessons that have been learned about resource development in environmentally and culturally fragile areas, and the protocols that have been devised to ensure that local consultation and due process are respected, must apply to any future gas hydrate development in Arctic and offshore areas.

Considerable time is needed to build community collaboration and consensus. For a significant gas hydrate development project, it could take at least 10 years to complete an acceptable and open process of establishing the science and technology, creating the necessary infrastructure, consulting in meaningful ways with local communities, and building local knowledge and consensus. The organizations responsible for planning major gas hydrate projects must be prepared to take these long timelines into consideration.

PROSPECTS FOR GAS HYDRATE DEVELOPMENT IN CANADA

Canada could be well-positioned to be among the world leaders in gas hydrate exploitation if it were to invest sufficiently in exploration, research, development and production. A long-term government commitment would be needed because commercial production of gas from gas hydrate is unlikely in Canada within at least the next two decades.

Three Broad Approaches for the Future — To address the knowledge gaps associated with the gas hydrate opportunity, Canada must choose, explicitly or implicitly, a level of involvement and investment. The support of governments — federal, provincial and territorial — might be based on one of the following three broad approaches:

- **Research Only:** Canada could continue to perform scientific research on gas hydrate while leaving, for the foreseeable future at least, gas hydrate development as a resource to other countries with more pressing needs for alternative sources of energy.
- **Research and Limited Development:** Canada could devote considerably more funding and effort than at present to research and development of gas hydrate in "sweet spots" to better understand the resource and to develop the expertise needed for extraction and processing, while leaving the major development efforts to other countries. This approach would acknowledge that gas hydrate represents only one of the many possible future energy sources in Canada that require R&D funding until their relative merits are more clearly delineated.
- **Major Targeted Research and Development:** Canada could make a determined effort to be an international leader in gas hydrate development with hydrate exploitation as a national priority. This effort would require a combination of massive investment, focused strategic R&D, infrastructure facilitation and development of training programs. Such an approach would view gas hydrate as one of the best options for bridging to a future where carbon emissions are greatly reduced and North American energy security is more assured.

The *Research Only* approach would fulfil the need for Canada to better understand its physical territory and resources. This approach would, however, mean that Canada could lose the opportunity to be in the vanguard of what might become a major global development. There is some financial risk associated with the *Research and Limited Development* approach, and more significant financial risk with the *Major Targeted Research and Development* approach. The latter option could be undertaken as a contingent extension of the second because a great deal of preparatory work would be needed before committing to commercial development. If Canada ignores gas hydrates altogether, more damaging ways of meeting energy needs could be adopted, and Canada could lose out competitively to other countries, perhaps even to the point of having others exploit Canadian resources. On the other hand, as climate change escalates, carbon-based energy sources may become unacceptable to Canadians.

Actions Canada Could Take — In view of the great uncertainty and risk associated with the commercial potential of gas hydrate, the federal government would need to provide significant funding and/or assume some risk with respect to many of the following activities, which are offered as examples of what might be done and listed roughly in order from research to commercial development:

- Undertake geological, geophysical and geochemical studies to better delineate the extent, location, quality and potential recoverability of Canada's gas hydrate resources.
- Participate more fully in opportunities for international collaboration in gas hydrate research.
- Undertake a wide range of basic and applied research to gain a better understanding of the environmental issues related to exploitation of gas hydrate.
- Support R&D in all aspects of gas hydrate extraction technology.
- Encourage the private sector to collect and report data about the occurrence and location of gas hydrate in the course of commercial drilling through gas hydrate formations.
- Identify opportunities for developing new technologies for gas hydrate related to instrumentation, drilling and onshore processing, thereby creating technology export opportunities.
- Support educational and training initiatives for developing personnel with skills and expertise relevant to gas hydrate.
- Include gas hydrate on the agenda for ongoing discussions of community development in coastal and northern communities, and with Aboriginal Peoples.

- Undertake one or two major demonstration production/testing projects to extend the engineering and scientific expertise already in place. For example, after reviewing the results of the Mallik 2006-08 project, Canada could proceed, preferably again in collaboration with international partners and industry, with a new Mallik program featuring new objectives to extend the lessons learned in the earlier programs.
- Collaborate with provinces and territories to establish taxation and other measures to ensure that (a) clear rules govern the exploitation of gas hydrate resources, and (b) affected areas receive a return of benefits that assist local communities and help develop renewable energy technology and greenhouse gas sequestration.
- Evaluate the incremental costs, risks and benefits of including gas hydrate extraction, before deciding whether or not to proceed with conventional natural gas extraction projects in the Far North and off the east and west coasts.

SUMMARY RESPONSE TO THE CHARGE TO THE PANEL

The panel's response to the overarching question may be summarized in terms of the three subquestions, which were part of the charge to the panel:

What share of the total Canadian reserves [of gas hydrate] can be profitably extracted?

It is impossible at this time to provide an accurate assessment of the extent of Canada's exploitable gas hydrate resource. The most that can be stated is that the resource is potentially large, possibly even larger by an order of magnitude or more than conventional hydrocarbon resources. Indications are that gas hydrate underlies coastal areas off the west, north and east coasts of Canada, and that there are also significant amounts beneath the permafrost in the Arctic. The most attractive gas hydrate deposits are those associated with sand below permafrost. It is not known what proportion of the total gas hydrate resource these more favourable deposits comprise.

The exploitation of gas hydrate is most likely to take place when conventional gas extraction is ongoing, or exhausted, in northern drilled sites (e.g., in the Mackenzie Delta) or offshore, by completing wells where gas hydrate was found when drilling initially. The profitability of gas hydrate extraction will depend on further development of efficient means of production, as well as on many of the same unpredictable factors that will govern the future profitability of conventional natural gas. Under some circumstances, and with substantial investment, gas hydrate could be a significant source of energy for Canada in the future. However, it is also possible that other alternatives will become more economically and environmentally attractive, to a point where gas hydrate could not compete in the foreseeable future.

What are the science and technology needs for the safe use of energy from gas hydrates?

Subject to confirmation from long-term production experience, there do not appear to be significant safety issues, unique to the production of gas from gas hydrate, that are not already encountered and addressed in the course of more conventional natural gas production, both onshore and offshore.

What are the environmental considerations related to the use, and the non-use, of this resource?

From an environmental perspective, gas, once produced from gas hydrate, is essentially identical to conventional natural gas. Hence, gas hydrate would lead to emission of carbon dioxide (a greenhouse gas) when the gas is used as a fuel. In the medium term, it could displace some oil and coal (fossil fuels with greater greenhouse gas emissions per unit of energy), but there is growing consensus that in the long term, carbon-bearing fuels will need to be curtailed and/or subjected to substantial carbon capture and sequestration.

It is possible that gas hydrates in the earth may warm as a result of climate change to the point where they are unstable and eventually dissociate causing a release of methane that would further accelerate climate change. Although the methane in marine gas hydrate is not expected to dissociate under the influence of global warming in this century, it is possible that gas hydrate under permafrost may be affected by warming in some specific locations. If so, the methane release is expected to be chronic rather than abrupt. The potential exploitation of gas hydrate could not meaningfully mitigate this possibility because it would extract and convert such a tiny fraction of the resource that it would have negligible impact on the overall quantity of gas hydrate and on the possible eventual release of methane from natural destabilization.

1. INTRODUCTION AND CHARGE TO THE PANEL

Natural gas hydrate[6] is a potentially vast source of hydrocarbon energy that is currently unexploited. Gas hydrates are cage-like structures of water molecules, surrounding molecules of gas, primarily methane. Methane is the principal component of natural gas — a major source of industrial and residential power and heat, as well as a chemical feedstock. Natural gas currently constitutes about 30 per cent of Canada's primary energy supply.

Gas hydrates exist in abundance worldwide. They form when water and natural gas combine at sufficiently low temperatures and high pressures — for example, in regions of permafrost and in subseafloor sediments. Some estimates suggest that the total amount of natural gas bound in hydrate form may exceed all conventional gas resources, or even the amount of all hydrocarbon energy — coal, oil and natural gas combined. In Canada, gas hydrate is known to be present off the west, north and east coasts, as well as in onshore permafrost regions. Gas from gas hydrate could therefore provide a potentially vast new source of energy to offset declining supplies of conventional natural gas in North America and to provide greater energy security for countries such as Japan and India that have limited domestic sources.

Complex issues would need to be considered if gas hydrate were to become a significant part of the energy future of Canada and of the world.[7] These issues arise from unknowns about the resource itself. How much is there? Where is it located, at what concentrations and in what kinds of geological environments? How could the gas best be produced? The interplay of these physical and engineering issues with future economic considerations, environmental policies and community impact concerns will determine whether, and where, natural gas from gas hydrate might be produced.

To better understand these issues, so as to have a more informed basis on which to develop policy for gas hydrate as one possible future energy option for Canada, Natural Resources Canada (NRCan) asked the Council of Canadian Academies

6 In this report the panel generally refers to gas hydrate in the singular, but occasionally uses the plural (hydrates) if emphasis is intended on the multiple types of gas hydrate or multiple areas of its occurrence.

7 The panel has been asked to make no recommendations. Therefore we provide information that is expected to be helpful to the Government of Canada in answering its questions, but we do not address the question of whether or not Canada should include gas hydrate as a significant component of its energy future.

(the Council) to assemble a panel of experts (the panel) to address the question: *What are the challenges for an acceptable operational extraction of gas hydrates in Canada?*

In response to the charge, this report is intended to provide information and analysis to help the government assign appropriate priority to research, and to the development of policy related to gas hydrate. The panel was asked not to make explicit policy recommendations, but rather to assess the current state of knowledge and informed opinion on matters relevant to possible policy choices.

The report is structured as follows. Chapter 2 presents an overview of relevant contextual background — some basic science; the medium-term outlook for supply and demand in markets for natural gas; broad environmental issues related to gas hydrate in its natural state and as a fuel; and an overview of Canada's contribution to knowledge about gas hydrate in the context of ongoing international research activity.

In addition to the principal question noted above, three subsidiary questions were also addressed to the panel, the first of which was: *What share of the total Canadian reserves [of gas hydrate] can be profitably extracted?* In response, Chapters 3 and 4 describe what is currently known and what would be required to delineate and better quantify the resource, as well as describing currently envisioned techniques for extracting gas from gas hydrate. The present state of knowledge does not permit estimation of "reserves" of gas hydrate in the technical sense because this term, as used in the energy industry, applies only to a resource accumulation that is either in production, under development or planned for imminent development.

The charge to the panel included two further subquestions: *What are the science and technology needs for the safe use of energy from gas hydrates?* and *What are the environmental considerations related to the use, and the non-use, of this resource?* These and related questions are addressed in Chapters 4 and 5 where there is discussion of: possible safety issues related to gas hydrate dissociation during drilling operations or release into the atmosphere; the environmental issues associated with potential leakage of methane into the atmosphere and with the large volumes of water produced during gas hydrate dissociation; and jurisdictional and local community issues that would need to be resolved for the commercial exploitation of gas hydrate to proceed.

Chapter 6 contains a summary discussion of Canada's comparative strengths and weaknesses in the field and whether or not Canada is positioned to take advantage of the development potential of gas hydrate. Observations are included on steps that Canada could take to fill the most pressing knowledge gaps and thus to reduce the considerable uncertainties currently associated with gas hydrate as a potentially significant future source of energy.

The report concludes in Chapter 7 with the principal messages and with a summary outline of the panel's responses to the questions posed in the charge.

The panel of 13 experts assembled to prepare this report includes nine members with specific expertise related to gas hydrates and four with more general backgrounds that were helpful in broadening the overall perspective. Nine panel members are from Canada and four from the United States. All served in a voluntary capacity and subject to Council procedures designed to ensure that panel members had no conflicts of interest that might compromise the objectivity of their work.

The panel met as a whole on four occasions, and there were also separate meetings of the principal authors of each chapter and frequent conference calls and other communications among subgroups of the panel. In its first meeting, the panel met with representatives of key ministries of the Government of Canada to clarify the mandate and to extend its concerns to environmental, judicial and social matters.

2. OVERVIEW OF GAS HYDRATES – A PRIMER ON THE CONTEXT

The viability of gas hydrate as a future source of energy depends first on whether the concentration of the resource and the geological conditions of its occurrence will permit commercially significant quantities of gas to be produced at sufficiently low cost. Proving the technical and economic viability of the gas hydrate resource will require further exploration, delineation and long-term production testing, combined with engineering research and development (R&D), to better understand and improve the process of extracting the natural gas from its hydrate matrix. If these challenges can be met, commercial investment in gas hydrate production would only be forthcoming if transport infrastructure were available to deliver the gas to market and if the outlook for gas prices, relative to the cost of production and delivery of the gas, made a gas hydrate option competitive with alternative investments available to energy companies, possibly aided by government incentives. Finally, if production were commercially justified in principle, development should proceed only if environmental and other regulatory and fiscal conditions could be met, and if the interests of stakeholders — including, in particular, affected communities — could be accommodated.

These issues are addressed, to the extent that current knowledge permits, in subsequent chapters of this report. The purpose of this overview chapter is to set the context in terms of: (a) some basic scientific concepts regarding the nature and occurrence of gas hydrate; (b) the long-term outlook for energy supply and demand with particular emphasis on the prospects for natural gas, the price of which will strongly influence the development potential of gas hydrate prospects; (c) the broad-scale environmental implications of exploiting gas hydrate as an energy source in the context of climate change; and (d) a brief account of Canadian contributions to knowledge about gas hydrate, together with a summary of many of the principal activities underway worldwide.

2.1 GAS HYDRATE BASICS – INTRODUCTION TO THE SCIENCE AND OCCURRENCE OF GAS HYDRATES

Natural gas hydrate occurs under conditions of high pressure and low temperature, when water combines with natural gases to form an ice-like solid substance. Gas hydrates are crystalline compounds that result from the three-dimensional (3D) stacking of space-filling cages (see Box 1 for a description of the three types of gas hydrate structure). The compact nature of the hydrate structure makes for highly effective packing of gas. A volume of gas hydrate expands 150- to 170-fold when released in gaseous form at standard pressure and temperature (101.3 kPa and 20°C). Thus one cubic metre of solid gas hydrate would yield in the range of 150 to 170 m^3 (5,300 to 6,000 ft^3) of natural gas when the hydrate "melts". On a macroscopic level, the mechanical properties of gas hydrate are similar to those of ice because gas hydrate contains about 85 per cent water by mass. While gas hydrate may look like ice, it does not behave like ice — for example, it burns when lit with a match (that is, it supports combustion, with the evolving methane burning).

The gas held in naturally occurring gas hydrate is generated by microbial or thermal alteration of organic matter under the seafloor or permafrost, producing methane and other gaseous byproducts including carbon dioxide, hydrogen sulphide, ethane and propane. Evidence exists that in a limited number of settings, the gas in gas hydrates may also come from thermogenic sources within more deeply buried sediments. While all these gases can be incorporated as guest molecules in hydrate cages, methane is by far the dominant gas found in gas hydrates, which is why they are often referred to as methane hydrates.

Chemists have known about gas hydrates for almost 200 years, but treated them as mere laboratory curiosities for the first 130 years. The oil and gas industry began to take an interest in the 1930s when gas hydrate formation in pipelines was found to cause troublesome blockages. Russian scientists in the late 1960s were the first to propose that gas hydrate might occur naturally in marine and onshore locations (Makogon and Medovskiy, 1969; Makogon *et al.*, 1971; Trofimuk *et al.*, 1973). In the early 1970s, scientists in the West inferred that gas hydrate existed below the permafrost and in marine sediments (Stoll *et al.*, 1971; Bily and Dick, 1974). In addition, scientists on deepsea drilling expeditions confirmed that gas hydrate occurred naturally in deepwater sediments along outer continental margins (Paull *et al.*, 1996; Tréhu *et al.*, 2003; Riedel *et al.*, *Proceedings of the ODP,* 2006).

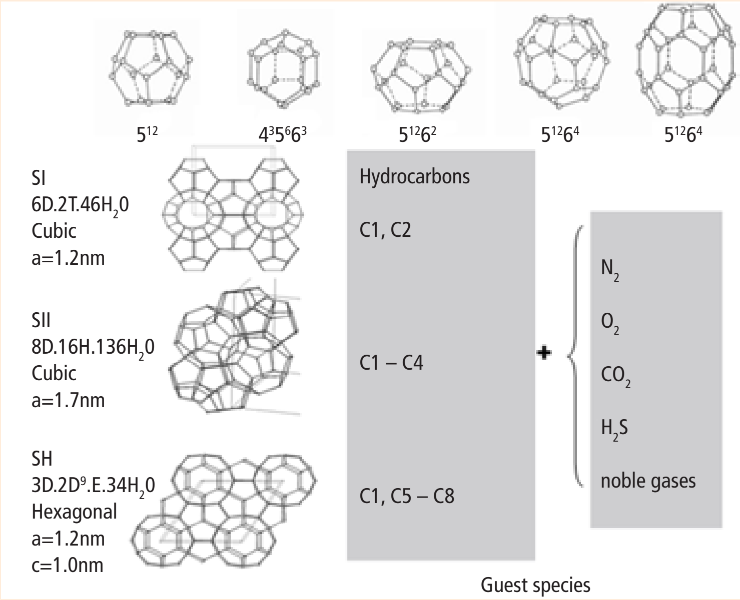
The Zone of Hydrate Stability

Laboratory experiments have shown that the stability of the gas hydrate depends mostly on pressure and temperature, with some dependence on chemistry. The earliest encounters with naturally occurring oceanic gas hydrates corroborated these stability conditions. Deepsea research programs drilled and retrieved gas hydrate-bearing sediment samples for shipboard and laboratory study (Davidson *et al.*, 1986; Tulk, Radcliffe, *et al.*, 1999; Tulk, Wright, *et al.*, 1999; Lu, Dutrisac, *et al.*, 2005; Lu, Moudrakovski, *et al.*, 2005; Ripmeester *et al.*, 2005; Lu *et al.*, 2007; Udachin *et al.*, 2007). When the first cores were brought onboard however, they depressurized and self-destructed.

Box 1 — The Three Structural Types of Gas Hydrate

Gas hydrates are clathrate structures (from the Greek and Latin words for "cage-work") where "guest" molecules are encaged in a host framework. Each cage contains hydrogen-bonded water molecules and usually holds a single gas molecule (see figure). The encapsulated gas molecules are needed to stabilize the clathrate crystal, even at temperatures above the freezing point of water, because the empty cagework is unstable.

Gas hydrates can form in the presence of gas molecules that cover a size range of 0.48 to 0.90 nanometres (1 nm = 10^{-9} m). There are three distinct structural types — Structure I, II and H, or sI, sII and sH — and in general the structure that is formed depends on the size of the largest gas molecules present. There are considerable complexities in the structure-size relationship — for example, methane and ethane individually form sI hydrate, but in certain combinations also form sII hydrate. The structures encountered in nature will reflect the natural gas composition, with the abundance of each structural type depending on the relative amount of each structure-determining hydrocarbon molecule. In sediments that produce only biogenic methane, sI hydrate predominates, and this is indeed by far the major marine gas hydrate resource. Materials produced by thermal



(Ripmeester, 2007)

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"cracking" of more deeply buried organic carbon and transported to zones of gas hydrate stability can contain a wider range of hydrocarbons, in addition to methane. Significant amounts of propane and butane result in sII hydrate being formed, whereas small amounts of larger hydrocarbon molecules result in sH hydrate. The latter is structurally related to sII, and the two gas hydrates are found in close association, although they may be difficult to differentiate.

Natural Gas Hydrate Mineral System

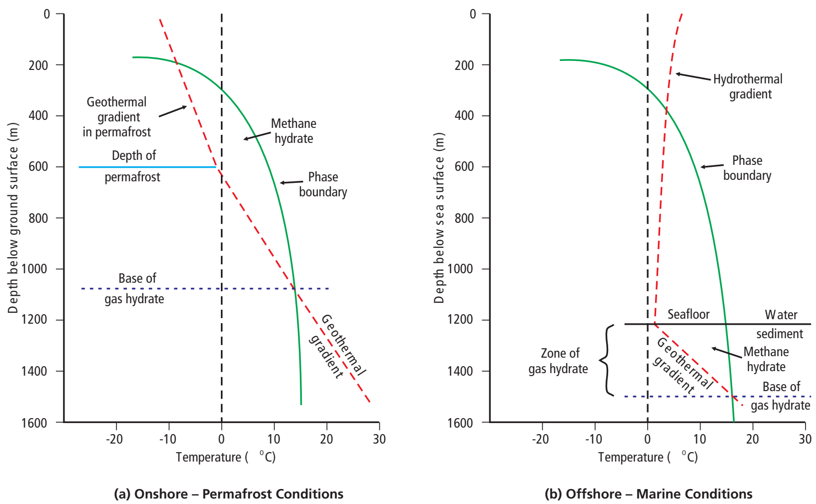
Top row – the cages that occur in the natural gas hydrate structures. Below that, the three structural types that have been observed for natural gas hydrates; Structures I, II and H, and their three-dimensional structures are shown. The hydrocarbon guest types associated with the different structures are shown, as well as other natural gases that can be found as guests in gas hydrates, usually as minor components (Ripmeester, 2007).

The pressure and temperature conditions under which gas hydrate is stable exist in permafrost regions and under (and on) the seafloor on continental slopes around the world. Potential gas hydrate reservoirs are shallow gas reservoirs, generally much less than 1,000 m, in contrast to deep hydrocarbon reservoirs, which are generally greater than 1,000 m. The zones of gas hydrate stability in both arctic and marine environments are illustrated in Figure 2.1. The solid (green) curve describes the combinations of temperature and pressure under which a gas hydrate is stable.[8] For all combinations of temperature and pressure to the left of this phase boundary — i.e., colder temperatures and/or higher pressures — the gas hydrate is stable. The precise boundary depends on the type of gas hydrate — sI, sII or sH.[9] Temperature increases with depth below the earth's surface and seafloor. This geothermal gradient is plotted as the dashed lines in Figure 2.1. As one goes deeper, the increasing temperature profile eventually intersects the boundary of the gas hydrate stability zone and thus defines the lower depth at which gas hydrate can form naturally — the base of the gas hydrate stability zone. Conversely, as one moves to shallower

8 Pressure is proxied in Figure 2.1 by depth — underground or under the sea — and increases in the downward direction in the diagram.

9 The pressure and temperature stability zone for sII and sH is much greater than for sI hydrate. For all gas hydrate structures, the pressure and temperature stability conditions also depend on the incorporation of other small gas molecules such as nitrogen, hydrogen sulphide and carbon dioxide. In much of the literature, a reference to the "zone of hydrate stability" refers to sI methane hydrate only.

depths — below the surface of the ground or under the seafloor — the pressure diminishes. Eventually, the pressure decreases to the point where the gas hydrate cannot remain stable at the prevailing temperature. The intersection of the geothermal gradient and the phase stability curve determines the top of the gas hydrate layer. This can occur in marine environments within the water column itself, as in the instance illustrated in Figure 2.1(b). Gas hydrate is buoyant, so should it occur in the water column, it is likely to float to a depth where it is no longer stable and it will dissociate ("melt"). The effective top of the gas hydrate zone in these cases is the seafloor itself. The depth and thickness of the zone of gas hydrate stability can be calculated with information on subsurface temperature and pressure conditions, together with knowledge of the composition of the gas included within the gas hydrate.



(Collett, 2002)
Modified and reproduced with permission from Timothy Collett.

Figure 2.1
Methane hydrate stability zones

Permafrost regions

In the example shown in Figure 2.1(a), the zone of potential methane hydrate stability is about 890 m thick. Assuming a hydrostatic pore-pressure gradient, the stability zone can be calculated in principle as follows: The below-ground temperature profile is projected to an assumed permafrost base of around 600 m in this example. The temperature profile intersects the 100 per cent methane hydrate stability curve at about 200 m, marking the upper boundary of the stability zone. The geothermal gradient is projected from the base of permafrost at around 600 m and intersects the 100 per cent methane hydrate stability curve at about 1,090 m in this example, thus marking the lower boundary of the stability zone. The stability zone thus lies between 200 m and 1,090 m, which makes it about 890 m thick in this example.

Deep marine environments

As shown in the example in Figure 2.1(b), methane hydrate would be stable below about 400 m, but as the water depth is 1,200 m, the gas hydrate would be found at or below the seafloor at 1,200 m. The stability zone would extend to a depth of about 1,500 m, or 300 m below the seafloor, where the geothermal gradient intersects the methane hydrate stability curve.

In practice, determination of the gas hydrate stability zone is more complex than the foregoing schematic descriptions suggest. The actual phase boundary (the solid curved lines in Figure 2.1) depends also on the salinity of pore water and the gas composition (Sloan and Koh, 2007). Salts are excluded from the crystal structure, but shift the equilibrium gas hydrate formation pressure to higher values at a given temperature (inhibition of gas hydrate formation). As a result, the phase boundary in Figure 2.1 would shift to the left. The degree of inhibition depends on the type of salts present and their concentration. Depending on the amount of higher hydrocarbons, actual conditions could favour sII or sH hydrates, which are stable at higher temperatures and could therefore extend deeper than sI methane hydrate.

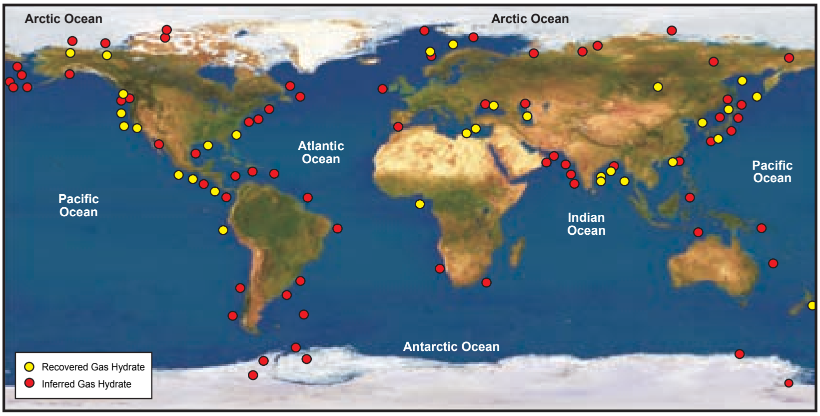
The geological environment is also an important factor. For example, high-porosity sand increases the likelihood of finding concentrated gas hydrate occurrences. Low-permeability clays, on the other hand, diminish the potential for concentrated gas hydrate. Fracture systems can also host significant amounts of gas hydrate, as seen in cold vents (Integrated Ocean Drilling Program — IODP — Expedition 311) and fractured controlled reservoirs (Indian National Gas Hydrate Program — NGHP — Expedition 01). Furthermore, it is becoming more widely accepted that a gas hydrate accumulation requires the presence of all components of a petroleum system (source, migration, reservoir, charge, trap and seal) in addition to the necessary presence of a gas hydrate stability zone with available gas and water. Some researchers also speculate that gas hydrate can form part of the seal of this natural petroleum system.

Box 2 — Bottom-Simulating Reflectors

The base of the gas hydrate stability zone marks the boundary between the gas hydrate-bearing sediments above and the free-gas-bearing sediments below. Where present, this transition creates a strong acoustic impedance contrast, which causes seismic waves to reflect upward. This "reflector" usually follows the base of the stability zone at a certain depth below the seafloor, cuts across bedding planes and mimics the seafloor topography. It is therefore referred to as a "bottom-simulating reflector" or BSR. These anomalous seismic patterns have been used to infer the presence of gas hydrate in offshore continental margins (as reviewed by Kvenvolden, 1993; Collett, 2002). BSRs have been mapped from seafloor depths to as great as 1,100 m below the seafloor. However, the current consensus of the scientific community is that the BSR should be regarded only as a positive indicator of the presence of gas hydrate in an area, but not as a means of quantifying its extent.

Occurrence of Gas Hydrates

Many research programs have shown that gas hydrate occurs naturally in permafrost regions and beneath the seafloor in sediments of the outer continental margins (Figure 2.2). These are sensitive remote areas, adding to the difficulties of exploration, exploitation and delivery of product to market.



(Kvenvolden and Rogers, 2005)
Reproduced with permission from Keith Kvenvolden and Bruce Rogers.

Figure 2.2
Location of known and inferred gas hydrate occurrences in deep marine and arctic permafrost environments

Deep marine gas hydrate

Even though vast portions of the world's continental margins appear to be underlain by gas hydrate, its concentration within most marine accumulations — which typically are clay-rich sedimentary sections that exhibit little or no permeability — appears to be low (Collett, 2002). Conditions under which gas hydrate concentrations are higher are:

- deposits associated with cold vents and large thermogenic seeps as seen on the Cascadia margin offshore Oregon (Tréhu *et al.*, 2003) and Vancouver Island (Schwalenberg *et al.*, 2005; Riedel *et al.*, *Proceedings of the IODP*, 2006), the Gulf of Mexico (MacDonald *et al.*, 1994; Sassen and MacDonald, 1994), or in the East Sea / Japan Sea (Lee *et al.*, 2005), and
- sedimentary basins with significant input of coarse-grained sandy sediments (as demonstrated during the Indian NGHP Expedition 01; Collett *et al.*, 2008) because gas hydrate can be found at high concentrations in more conventional sand-dominated reservoirs, a situation more analogous to gas hydrate occurrences in onshore permafrost environments (Collett, 2002; Dallimore and Collett, 2005).

Gas hydrates have been recovered from shallow sediment cores within 10 to 30 m of the seafloor in many places around the world, including the Gulf of Mexico, the Cascadia continental margin of North America, the Black Sea and Caspian Sea, the Sea of Okhotsk, and the Sea of Japan. Gas hydrates have also been recovered at greater sub-bottom depths along the southeastern coast of the United States on the Blake Ridge; in the Gulf of Mexico; along the Cascadia margin; along the Middle America Trench; offshore Peru and India; and on the eastern and western margins off Japan.

In recent years, a growing number of deepsea drilling expeditions have been dedicated to assessing marine gas hydrate accumulations, and understanding the geologic controls on their occurrence. The most notable projects are:

- the Ocean Drilling Program (ODP) including:
  i) ODP Leg 164 (Paull *et al.*, 1996), and
  ii) ODP Leg 204 (Tréhu *et al.*, 2003).
- the IODP including IODP Expedition 311 (Riedel *et al.*, *Proceedings of the IODP*, 2006)

- industry-focused gas hydrate drilling projects including the U.S. Department of Energy (U.S. DOE)-sponsored Joint Industry Project in the Gulf of Mexico (e.g., Ruppel *et al.*, 2008) and the Indian NGHP Expedition 01 (Collett *et al.*, 2006), and
- ongoing and scheduled drilling projects offshore China (Zhang *et al.*, 2007) and South Korea (Park *et al.*, 2008).

Onshore arctic gas hydrate

Studies show that gas hydrate in permafrost regions may exist at subsurface depths from about 130 to 2,000 m. Onshore, gas hydrates have been found in arctic regions of permafrost and in deep lakes like Lake Baikal in Russia (reviewed by Kvenvolden, 1993; Collett, 2002). Gas hydrates associated with permafrost have been documented in Canada, Alaska and northern Russia. Onshore gas hydrates are known to exist in the West Siberian Basin and are believed to occur in other permafrost areas of northern Russia. Direct evidence for gas hydrate on the North Slope of Alaska comes from two core tests (Northwest Eileen State-2 well drilled in 1972 and the Mount Elbert 1 well drilled in 2007). Indirect evidence from drilling and openhole industry well logs suggests that many gas hydrate layers exist in the area of the Prudhoe Bay, Kuparuk River and Milne Point oilfields in Alaska (Collett, 1993). The well-log responses of about one-fifth of the wells drilled in the Mackenzie Delta have indicated the presence of gas hydrate, and more than half of the wells on the Canadian Arctic islands are inferred to contain gas hydrate (Judge *et al.*, 1994; Osadetz and Chen, 2005).

Two of the most studied permafrost gas hydrate accumulations are:

- *the Mallik site in the Mackenzie Delta of Canada* – The Mallik 2002 Gas Hydrate Production Research Well Program, described further in Chapter 3, yielded the first modern, fully integrated field study and wireline reservoir assessment of a natural gas hydrate accumulation. Japan has collaborated with the Government of Canada on a further Mallik testing program. In total, there have been three Mallik programs: 1998, 2002 and 2006-08.
- *the Mount Elbert test site, Eileen trend, the North Slope of Alaska* – This program, supporting the U.S. DOE and BP-sponsored Mount Elbert gas hydrate test well project, generated critical gas hydrate engineering and production test data, together with some of the most comprehensive data on an arctic gas hydrate accumulation.

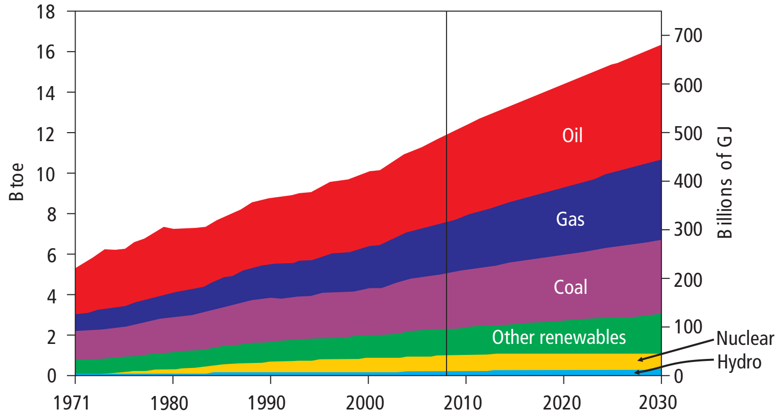
2.2 POTENTIAL ROLE OF GAS HYDRATE IN THE ENERGY FUTURE

The commercial viability of gas hydrate as a future source of energy will depend on supply and demand, and therefore price, in the markets for energy — and particularly for natural gas — in the medium to long term. Increasing wealth, population and competitive pressures are driving a growing global demand for energy. Meeting this rising demand will be challenging in the face of pressure on conventional oil and gas reserves, ever-tighter environmental constraints, and increasing concerns about security and affordability. Indeed, energy and the environment will likely be two of the defining issues of this century.

There is little doubt that global energy demand will continue to expand, even with substantial improvements in energy efficiency, higher real costs of energy and growing concerns over the climate change impact of energy production and consumption. Estimates by the U.S. DOE Energy Information Administration (EIA) and the International Energy Agency (IEA) suggest that total energy demand will grow by between 40 and 70 per cent by 2030 (U.S. DOE, 2007; IEA, 2006). Roughly 70 per cent of the projected increase in demand is expected to come from developing countries. If there were to be aggressive measures to curb CO_2 emissions, and to enhance energy security, the total increase would be reduced, but would still likely represent growth of more than one-third over today's global energy consumption (IEA, 2006: 2-6).

These analyses also suggest that more than 80 per cent of the growth in total energy demand through 2030 will be met by oil, natural gas and coal (Figure 2.3). Hydrocarbon-based fuels are expected to retain their dominant position, despite the substantial growth in renewable and alternative forms of energy — for example, wind, solar and biomass.[10] Forecasts generally project faster growth in the use of natural gas than other fuels.

10 Energy production, whether conventional or alternative, is capital intensive. There is enormous installed infrastructure committed to the use of hydrocarbon fuels — e.g., coal-fired electricity generation, natural gas heating, internal combustion engines. These factors imply that the world's total energy supply mix can only change relatively slowly.



(The Energy Mix of a Sustainable Future © OECD/IEA, 2006 "World Primary Energy Demand" p. 2)
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Figure 2.3
World primary energy demand (billions of tonnes of oil equivalent)[11]

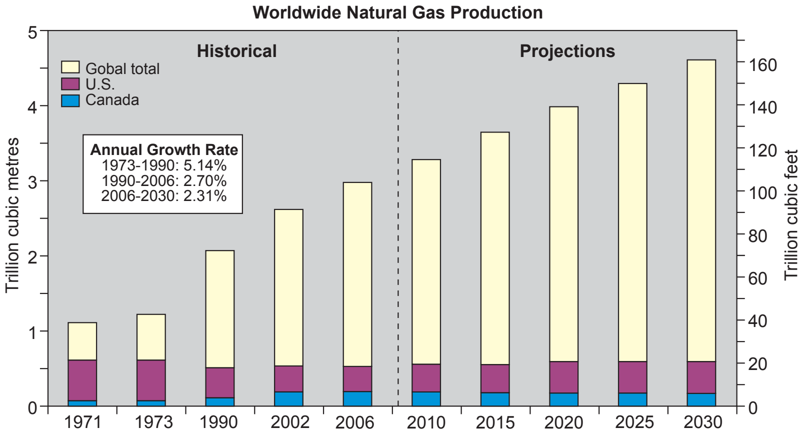
IEA forecasts that global gas production will grow by about 2.3 per cent annually over the period to 2030 (Figure 2.4). The expectation implicit in these forecasts is that natural gas, given its significantly lower carbon footprint relative to oil and coal, will displace some growth in both oil and coal use (U.S. DOE, 2007: 5, 39).

There are large and increasing reserves of natural gas worldwide.[12] Based on estimates from January 2007, total reserves were 6,183 trillion cubic feet (Tcf; 175×10^{12} m^3). But there is a growing disparity between where the gas is produced and where it is consumed. Three-quarters of total reserves are located in the Middle East (42 per cent) and Eurasia (33 per cent), far from the areas of most rapid growth of demand for natural gas (U.S. DOE, 2007: 40). It is projected that this disparity between supply and demand locations will be dealt with

11 A tonne of oil equivalent (toe) is a unit of energy equivalent to the amount of energy in one tonne of crude oil, or approximately 42 GJ. A billion tonnes of oil equivalent is equivalent to the energy in a billion tonnes of crude oil.

12 A hydrocarbon energy "reserve" is an economic concept that refers to the amount of resource that has been proven to exist by exploration and is producible given prices and costs prevailing at the time the reserve amount is estimated. Thus, for example, natural gas reserves could increase in a given time interval, despite production drawdowns, provided that exploration or technology advances confirm greater volumes of commercially producible gas than the amounts consumed during that interval.

increasingly through the liquefaction of natural gas and then its transport by ship to markets, at which point it would be re-vaporized and injected into existing transmission and distribution systems.

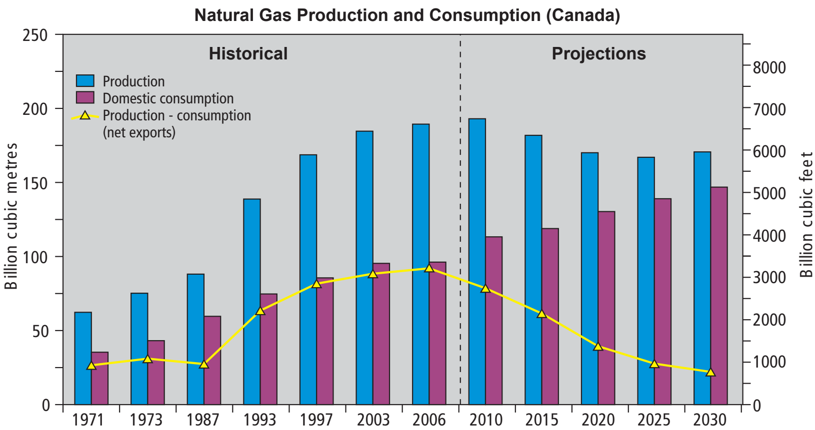


Source of data: 1971-2006: Derived from IEA, Natural Gas Information 2007, website: www.iea.org. Projections: EIA, System for the Analysis of Global Energy Markets (2007).

(Council of Canadian Academies)

Figure 2.4
Global natural gas production, historical and projected, with Canadian and U.S. production highlighted

For Canada, natural gas production is expected to begin to decline after 2010 while domestic consumption continues to grow (see Figure 2.5). This projection implies decreasing Canadian gas exports to the United States. Given the magnitude of the volume and value of these flows, falling exports would have a significantly negative impact on Canada's balance of trade and on overall levels of economic activity in the major gas-producing regions. For the United States, the prospects are for growing reliance on imports of liquefied natural gas (LNG) as a substitute for conventional U.S. or Canadian gas supplies (see Box 3 for a discussion of the North American natural gas outlook). It is in this context that the possibility of significant production of gas from gas hydrate becomes particularly important. Canada's potentially large gas hydrate resource could make a key contribution to meeting North American and global energy demands during this century.



Source of data: 1971-2006: Derived from IEA, Natural Gas Information 2007, website: www.iea.org. Projections: EIA, System for the Analysis of Global Energy Markets (2007).

(Council of Canadian Academies)

Figure 2.5
Historical and projected natural gas production, consumption and net exports for Canada, 1971-2030

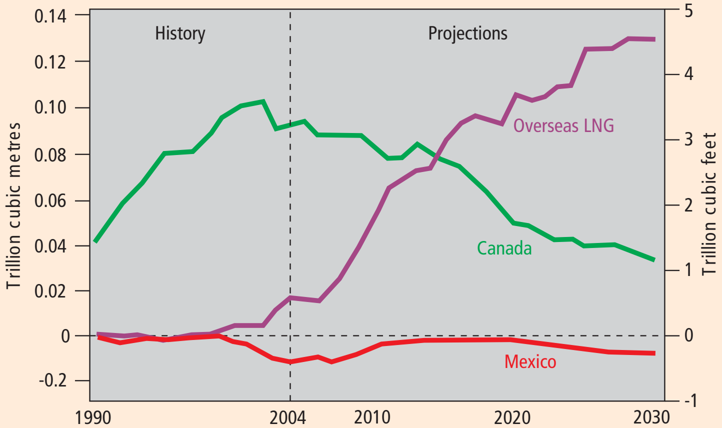
In view of the considerable uncertainty about the viability and potential contribution of gas hydrate, the official projections of global gas supply assume that gas from gas hydrate will not be significant before 2030.[13] Nevertheless, given the size of the potential global gas hydrate resource, its relatively wide distribution and growing concerns about energy security, it is likely that many countries, including Canada, will continue to show substantial interest in exploiting this resource over the long term.

The looming North American supply deficit (see Box 3) should provide strong incentives for determining the development potential of gas hydrate. To the extent there are concerns about increasing reliance on imported supplies of LNG, and if this were to translate into a significant premium for secure gas-supplies, there would be growing interest in tapping gas hydrate within the North American region.

13 For example, Canada's National Energy Board (NEB) states: "The likelihood of achieving commercial methane production from gas hydrates by 2030 is very low and so has not been included in the unconventional resource estimate" (NEB, Nov. 2007, p. 28). As well, the projections to 2030 in the latest U.S. DOE *Energy Outlook* do not include any production from gas hydrate (U.S. DOE, 2008).

Box 3 — The Natural Gas Outlook in North America

Over the period 2004-30, gas demand in North America is projected to increase from 27.6 Tcf (0.8×10^{12} m^3) to 36.8 Tcf (1.0×10^{12} m^3), with 73 per cent of the 2030 demand in the United States, 14 per cent in Canada and about 13 per cent in Mexico.[14] Even with access to northern natural gas supplies, this leaves a rapidly growing North American supply deficit that is amplified by an expected decline in Canadian gas exports to the United States. It is assumed that this deficit will be filled by LNG imported from outside North America (the figure below is based on Reference Case in U.S. DOE, 2007: 39-46, 89).



(Energy Information Administration)
Source of graph: Energy Information Administration. 2007. International Energy Outlook 2007. p. 42

14 These projections depend on assumptions about future growth rates and energy prices. For example, under a high economic growth rate scenario, the U.S. DOE estimates that total North American gas demand would be about five per cent above that for the Reference Case, and about 10 per cent below that for the Reference Case under a low growth scenario (U.S. DOE 2007).

U.S. Net Imports of Natural Gas by Source, 1990-2030

While projections far into the future are subject to considerable error, it nevertheless appears likely that imported LNG will represent a growing gas supply source for North America and, if so, gas prices will eventually come to reflect global *supply* and demand conditions, much as oil prices do. Many LNG terminals are planned, with a total annual import capacity of 18.5 Tcf (0.5×10^{12} m^3). Most of these are along the eastern coastal regions and on the Gulf Coast, with a few planned for the West Coast including one at Kitimat, British Columbia. There are, however, numerous challenges in the construction of the facilities, including siting issues and rapid increases in the capital cost. It is therefore not clear that the projected North American gas supply deficit will be completely met with imported LNG.

2.3 GLOBAL ENVIRONMENTAL CONSIDERATIONS

The panel has been asked to assess *the challenges for an acceptable operational extraction of gas hydrates in Canada*, and not whether hydrocarbon fuels should be exploited at all in the future. The exploitation of any energy resource has environmental impacts that need to be considered carefully in relation to benefits. In the case of gas hydrate, these impacts could be both local — related to drilling, extraction and transportation — as well as global, related to possible escape of methane itself, a powerful greenhouse gas, or the subsequent production of carbon dioxide (CO_2), a less potent greenhouse gas, when the methane product is used in combustion or other processes. In the context of its charge, the panel addresses both the foreseeable global and local environmental impacts of the potential commercial extraction of gas hydrate. We discuss these matters in some detail in Chapter 5.

Because of the key importance of questions related to climate change caused by greenhouse gases, we provide a brief primer on methane and greenhouse gas emissions in Box 4 below. It is beyond the scope of this report to address the overarching issue of the future role of hydrocarbon fuels in the world's energy supply mix, other than to note the official projections, cited in the last section, of continued growth in the demand for these fuels through at least 2030. Growing concern over the climate change implications of increasing CO_2 concentration in the atmosphere is stimulating a great deal of R&D worldwide to develop cheaper and more effective ways to curb emissions and/or sequester CO_2. The extent to which this effort bears fruit will have a significant impact on the demand for natural gas in the medium to long term. If, as expected, hydrocarbon fuels do continue to be a major component of the global energy supply for at least several more decades, the lower carbon intensity of natural gas (and thus natural gas derived from gas hydrate) will likely make it increasingly attractive relative to coal and oil. This, combined with security of supply considerations, could significantly stimulate the potential future development of gas hydrate. On the other hand, rapid development and deployment of alternative carbon-free energy technologies could greatly diminish the world's voracious appetite for carbon-based energy, thereby reducing interest in the development of gas hydrate.

Box 4 — Methane and Greenhouse Gas Emissions

The methane derived from gas hydrate can affect greenhouse gas emissions: (a) directly, via release of gaseous methane into the atmosphere during production, processing or transportation; (b) indirectly, via the CO_2 produced when methane is burned as a fuel; and (c) indirectly, as a result of the "parasitic" energy required to extract and process the methane.

Direct release of methane

There are obstacles to methane (released from gas hydrates) reaching the atmosphere because methane oxidizes to CO_2 in the ocean and the atmosphere (Kvenvolden, 1999; Archer, 2007; Reeburgh, 2007). Inevitably, there would be some "fugitive emissions" associated with leakage in the course of production and transportation, although no more is likely than for conventional natural gas wells. For existing natural gas systems, this typically ranges from 0.5 to 1.5 per cent from well to end-user (Schultz *et al.*, 2003). Assessing the global warming effects of different gases is complex because of a number of factors, including the absorption of infrared radiation, the average residence time in the atmosphere, products when the gases eventually leave the atmosphere and feedback mechanisms. To compare the relative effects of different greenhouse gases, the concept of the *global warming potential* (GWP) is widely used. With CO_2 as the reference material, methane has a GWP of 21-23 over a 100-year interval, meaning that per unit of mass emitted, methane is 21 to 23 times more potent than CO_2 as a greenhouse gas over a period of one century. Over a shorter period, the relative effect of methane would be even larger because methane has a much shorter half-life in the atmosphere than CO_2. Conversely, averaged over longer periods of time, the GWP of methane declines relative to the CO_2 reference. It is clear that methane emissions have much more potent climate change impacts than similar amounts of CO_2. However, much more attention has been paid to constraining and reducing CO_2 emissions than methane emissions because the total emissions of CO_2 are far in excess of those of methane.

CO_2 generated by methane utilization (e.g., by combustion and reforming)

The major concern in the context of climate change is the CO_2 generated when methane is used, i.e., burned to produce energy. Methane (the primary constituent of natural gas) has the highest hydrogen-to-carbon ratio of any hydrocarbon fuel. As a result, less CO_2 is generated per unit of energy released for methane than for other carbon-based fuels such as oil and coal. Gough *et al.* (2002) reported that the amount of carbon emitted per unit energy for coal, oil and natural gas is as follows: 27 kgC/GJ for coal, 21 kgC/GJ for oil and 15 kgC/GJ for natural gas.

Furthermore, the relative emissions for the different fuels depend on such factors as the rank of the coal (e.g., bituminous or lignite), the exact composition of the oil and natural gas, as well as the efficiency of the technology used to produce the energy. For purposes of illustration, the life-cycle analysis data reported by Denholm and Kulcinski (2004) give average CO_2 emissions per unit of electrical energy produced (relative to coal at 100) as 75 for oil and 50 for natural gas. Thus, for equivalent energy, natural gas generates only half as much CO_2 as coal and two-thirds as much as oil. In the absence of carbon mitigation, the use of natural gas as a fuel therefore results in considerably lower emissions of CO_2 than burning either coal or oil.

Greenhouse gas emissions associated with producing and processing methane from gas hydrate

Other life-cycle greenhouse gas emissions are associated with the consumption of energy to produce methane from gas hydrate, process the gas and compress it for transportation. These emissions differ according to the source, even for the same fossil fuel, e.g., for LNG vs. conventional natural gas (Jaramillo *et al.*, 2007). Because of the additional challenges associated with methane production from gas hydrate, these parasitic emissions could be greater than for conventional natural gas production. However, the actual emissions will depend on the specifics of each operation and need to be estimated on a case-by-case basis.

2.4 CANADA'S CONTRIBUTION IN A GLOBAL CONTEXT

Despite having no official national gas hydrate program covering both laboratory and field work, Canada has made significant contributions to gas hydrate research. Government scientists — particularly at the National Research Council (NRC) in the area of molecular science, and NRCan for earth science — have collaborated formally and informally with each other and with university and industry researchers. Canadian scientists and engineers have been leaders in elucidating the chemical structure and physical properties of gas hydrates, and Canada is home to two of the most intensively studied natural permafrost and marine occurrences at Mallik and offshore Cascadia (off the west coast). This has been a story of individuals and small groups who, through long-term personal commitment, have carried out world-class gas hydrate research. Highlights from the history of gas hydrate research and development, and Canada's significant contributions to the development of this knowledge, are summarized in Box 5. See also Appendix A for a history of gas hydrate activities in Canada.

Box 5 — CHRONOLOGY OF CANADIAN GAS HYDRATE ACTIVITIES

	Laboratory Research
	Field Work
1906	First Canadian to work on gas hydrate: Crowell-Bray recognizes that reaction of ClO_2 with water forms hydrate (also recognized by Millon, 1843). First example that hydrate formation can stabilize reactive material.
1923	Maass and Boomer (McGill) report the phase diagram of water soluble ethylene oxide hydrate.
1950s	Robinson (UAlberta) begins work on hydrate for the gas processing industry in Alberta.
1950s	Glew (Dow Chemicals) uses hydrate technology to concentrate aqueous solutions and reports on fundamental thermodynamic work on hydrate.
1960s	Drilling through gas hydrates by O&G companies takes place without much awareness. Panarctic Oils documents hydrates in northern exploration when hydrate decomposition is noted in drill cuttings.
1960s	Pinder (UBC) studies fundamental kinetics of hydrates relevant to desalination of seawater.
1960s	McDowell (UBC) pioneers nuclear magnetic resonance (NMR) techniques to study gas hydrates and Bertie (UAlberta) begins developing low-temperature infrared spectroscopic techniques.
1963–70	Davidson (NRC) uses dielectric relaxation to identify and characterize gas hydrates of polar molecules in hydrate cages.

Box 5 continued

1970	Davidson and co-workers (Garg, Gough, Ripmeester) carry out dielectric and NMR studies on the dynamics of clathrate hydrates. Davidson publishes "Clathrate hydrates" in *Water: A comprehensive treatise*, *Vol 2*. (1972).
1970s	GSC helps industry to address exploratory drilling problems in the Mackenzie Delta, southern Beaufort Sea and Canada's Arctic islands; Judge's group (Energy, Mines & Resources) extensively maps wells in Canadian Arctic with evidence of gas hydrate zones.
1972	Bily and Dick (Imperial Oil) report gas in drilling mud while penetrating gas-bearing reservoirs associated with test well Imp IOE Mallik L38 and later Imp Ivik J-26. First reports published on the presence of natural gas hydrates in Canadian Arctic.
1973	EMR, NRC and DINA collaborate on hydrate safety issues in the North.
1974	Hitchon (Alberta Research Council) provides assessment of gas hydrates in land-based sedimentary basins in Canada and the world.
1976	Robinson's group develops the celebrated Peng-Robinson equation to calculate equilibrium properties of fluid mixtures, transforming routine design calculations from tables and nomographs to process-simulation packages.
1976	Bishnoi (UCalgary) investigates impact of hydrate formation on oil spread in arctic water during well blow-out, and shows high-pressure gas bubbles can form hydrate.
1979–80	Drilling manuals of oil companies operating in the North document procedures for dealing with hydrates (Dome Petroleum and Canadian Marine Drilling Ltd).
1980	Davidson initiates multitechnique laboratory research (NMR, dielectrics, powder X-ray diffraction, calorimetry, and computational modelling) on gas hydrates at NRC with expanded NRC gas hydrate group (Tse, Handa, and Ratcliffe).
1980s	NRC group finds that structures are not generally predictable just from knowing the guests that are present, and that the structures that prevail must be determined experimentally; collaborates with U.S. DOE to characterize hydrate samples from the Gulf of Mexico and Blake Ridge, showing that sI and sII hydrate exist in nature; provides first direct measurement of hydrate cage occupancies; pioneers instrumental methods for the determination of hydrate compositions; synthesizes and characterizes a new hydrate structure (sH) and predicts that it will be found in nature (confirmed in 2007); develops novel NMR approaches to hydrate characterization; carries out experimental and modelling work on hydrate thermal conductivity.
1980s	Marine electomagnetic geophysical imaging techniques pioneered in Canada by UofT (Edwards group). Later collaboration with GSC.
1980s	GSC includes gas hydrates in regional geophysical assessment of the Beaufort Sea. Work continues with geothermal modelling, geological, geochemical and geophysical local studies.
1980–90s	GSC-sponsored research of hydrate occurrence off Canada's east coast based on geophysical well logs and seismic data.

Box 5 continued

1980–90s	Bishnoi's group monitors hydrate crystallization under high pressure conditions, contributes equilibrium hydrate data on the effect of thermodynamic inhibitors, and on models and methods for calculating thermodynamic properties and hydrate equilibria. Studies kinetics of hydrate formation & decomposition. Develops Kim-Bishnoi hydrate decomposition model for reservoir simulation non-equilibrium models to evaluate gas production from gas hydrate.
1983	Franklin (Panarctic Oils) patents novel approach to drilling through hydrate zones.
	Canadian scientists (Hyndman, Spense, Chapman, Riedel) play a major role in exploring and defining marine hydrates.
1985–89	Naturally occurring gas hydrates off Vancouver Island are inferred from seismic data. GSC researchers find BSRs in multi-channel seismic surveys.
Early 1990s	GSC researchers first to employ EM methods in attempt to map gas hydrate.
1990s	Englezos (UBC) presents first numerical heat transfer model taking into account composite media and permafrost phase change to compute time required for hydrates below permafrost or the ocean floor to begin feeling the effect of global warming.
1990s	Buffet (UBC) shows gas hydrate can exist in a metastable state below the usual base of the stability zone.
1990s	GSC scientists develop gas hydrate testing cells that were used to clarify key variables on gas hydrate in natural reservoirs. Cells were then used to develop a dielectric tool to quantify gas hydrate amounts in lab specimens and in the field, impacting development of numerical models of gas production from hydrate.
1990s	NRC group expanded (Enright, Moudrakovski, Udachin) with new experimental capabilities, begins work on hydrate structural determination by single crystal diffraction; NMR spectroscopy with hyperpolarized xenon; NMR microscopy; and imaging to study hydrate processes.
1990s	GSC conducts quantitative assessment of regional gas hydrates in the southern Beaufort Sea, Mackenzie Delta, southern Mackenzie Valley and Arctic islands (offshore and onshore).
Late 1990s	New CSEM towed array developed at UofT (Edwards group) for gas hydrate mapping. First report of successful resistivity mapping and resource assessment of marine gas hydrates, followed by identification and assessment of massive gas hydrate deposits.
1990–	NRC group (Tse, Klug and Handa) carry out work on gas hydrates at ultrahigh pressures.
1992/ 2005	ODP/IODP expeditions based on GSC-led proposals are dedicated to sampling and measuring gas hydrate off Vancouver Island.
1992–	GSC leads multidisciplinary programs including geologic, geophysical, lab & modelling; estimation of gas in gas hydrate form.
1998	Mallik research well program with Japan National Oil and Gas Corporation (JNOC): GSC develops and tests techniques for drilling, coring and logging gas hydrate occurrences, and collects the first subpermafrost core samples.

Box 5 continued

1998–08	GSC scientists (Dallimore, Wright, and Nixon) play a leading role in all three international Mallik programs (1998, 2002, 2006-08), which allowed for testing advanced well-logging tools for quantifying *in situ* amounts of gas hydrate, deploying downhole monitoring devices, and testing gas hydrate production by thermal stimulation and depressurization.
2000	Fishing vessel drags up 1.5T of gas hydrate from Barkley Canyon, revealing pingos and massive outcrops of structures II and H hydrates.
2000–	Pooladi-Darvish's group (UCalgary) develops numerical and analytical models for studying gas production from gas hydrate accumulations. These models have been used subsequently for production tests at Mallik and Mt. Elbert.
2002	Mallik Gas Hydrate Production Research Program with 7 international partners from 5 countries: Tests new coring methods and a state-of-the-art open-cased - and cross hole logging program; installs DTS outside-of-casing cables to define thermal fields; first small-scale pressure drawdown testing, and extended thermal stimulation testing.
2003–07	Three GSC expeditions are dedicated to gas hydrate on the east coast margin. Samples have yet to be recovered, though they have been by industry.
2003–	Recovered gas hydrate samples are routinely sent to NRC for characterization including offshore Cascadia, IODP 311, offshore India, Sea of Japan, and onshore from Mallik and Mt Elbert, Alaska. NRC group adds geochemical expertise (Lu); trains scientists from a number of countries with emerging hydrate programs, and develops laboratory protocol for natural gas hydrate analysis.
2003–	Walker (Queen's), Englezos (UBC) and NRC collaborators explore the use of antifreeze proteins and other biomaterials to control the growth of hydrate crystals for possible use in plug prevention in pipelines.
2003–	McGill University establishes a Tier 2 Canada Research Chair in Gas Hydrates (Servio).
2004	Identification of BSR off Nova Scotia and Newfoundland is published using industry seismic data.
2004–	Englezos (UBC) and NRC group work on the development of hydrate technology for gas separation and storage.
2006–07	sH hydrate is found in a sample recovered from Cascadia margin.
2006–08	Mallik Gas Hydrate Production Research Program with JOGMEC: Conducts production testing by depressurization. In 2007, two previously drilled research wells are re-entered to establish a production test and water injection wells. Activities include installation and testing of a novel suite of *in situ* monitoring devices and extensive open- and cased hole logging. In 2008, gas production is maintained for a period of six days.

(Council of Canadian Academies)

Canadian work has built upon important international contributions to the field, as listed below in Box 6.

Box 6 — EARLY INTERNATIONAL CONTRIBUTIONS (1810-1970s) LEADING TO AN UNDERSTANDING OF GAS HYDRATE FUNDAMENTALS

1810	Davy (U.K.) reports chlorine in water freezes more easily than water itself, thus identifying the first clathrate hydrate.
1823	Faraday (U.K.) reports chlorine hydrate has 10 water molecules for every Cl_2 molecule.
1828	Lowig (Germany) reports bromine hydrate.
1829	De la Rive (Switzerland) discovers SO_2 hydrate.
1856	Berthelot (France) synthesizes first organic hydrates of methyl, bromide & chloride.
1882	Wroblewski (Poland) discovers CO_2 hydrate.
	Hydrate research emerges as a distinct discipline; Bakhuis Roozeboom, de Forcrand, Villard devote most of their research careers to hydrates.
1884	Le Chatelier (France) applies Clausius-Clapeyron equation to hydrate formation, allowing heat of formation to be derived.
1888–89	Villard (France) reports CH_4, C_2H_6 and C_3H_8 hydrates.
1890s	De Forcrand (France) reports existence of double hydrates.
	Liquid hydrates are now recognized as a separate species from gas hydrates.
1932	Von Stackelberg (Germany) initiates 25 years of research on composition and structure of hydrates.
1936–40	Nikitin (Russia) shows rare gases, Xe, Kr and Ar, can be separated by partitioning between solid hydrate and the liquid phase in contact with it.
1934	Hammerschmidt (U.S.) suggests that gas hydrate, rather than ice, forms gas pipeline blockages; leads to phase equilibrium studies and procedures to predict solid hydrate formation and recipes for prevention (1940–60; Deaton and Frost, Katz, Kobayashi (U.S.).
1951–52	Claussen (U.S.), von Stackelberg (Germany), and Pauling and Marsh (U.S.) use X-ray diffraction to show that hydrate structures are clathrates.
1957	van der Waals and Platteeuw (Netherlands) formulate the statistical theory of clathrates, the foundation of all hydrate prediction procedures.
1960s	U.S. Office of Saline Water initiates projects on desalination of sea water with hydrates; a new cycle of hydrate structural determinations by diffraction methods (Jeffrey, U.S.).
1960–70s	Discovery of gas hydrates in nature. Scientists in the USSR and North America present evidence for hydrate under permafrost and in offshore marine sediment.
	Experimental and computational approaches to the science and engineering of gas hydrates are now in place, allowing rapid progress in knowledge generation on hydrates.

(Council of Canadian Academies)

The panel surveyed, aided by personal contacts, several authorities involved in gas hydrate research programs in a number of countries. A questionnaire was designed to gain an understanding of the contributions — historical and ongoing — of various gas hydrate research programs throughout the world. The responses from 27 prominent international gas hydrate research organizations and groups are summarized schematically in Table 2.1, followed by a list of national gas hydrate program highlights. In countries where gas hydrate has recently emerged as an area of interest, significant funding has been made available, entire gas hydrate research institutes have sprung up, and growing communities of scientists are building on expertise originally developed in Canada.

Canada's main strength in the area of gas hydrate research rests with highly qualified people contributing globally and also taking a strong position in training researchers from countries where gas hydrates are emerging as a topic of importance. So far at least, unlike in the United States,[15] there has been very little industrial investment in gas hydrate as a potential energy resource in Canada. Canada is also not participating fully in opportunities for international collaboration — e.g., it is not a full member of either the IODP or the International Continental Drilling Program (ICDP). Canada's place in the global gas hydrate research community could therefore become marginal.

15 In the United States, two industry partnerships are the Chevron-led partnership in the Gulf of Mexico, and the BP-led partnership in the North Slope of Alaska.

Table 2.1

Responses from Survey on International Gas Hydrate Research (Survey is reproduced in Appendix B)

Country Responding	**China**	**Germany**	**India**	**Japan**	**Korea**	**Norway**	**Russia**	**Taiwan**	**UK**	**USA**
National Research Program?	yes	yes	yes	yes	yes	yes	no	no	no	yes
Motivation for Program/Research										
Security of Energy Supply	X		X	X	X		X	X		X
Environmental/Climate Change		X			X	X				X
Co-operation with other Programs		X	X				X	X		X
Focus of Research										
Energy Assessment	X		X	X		X	X	X	X	X
Production Modelling & Testing	X		X	X			X		X	X
Hazard Assessment		X				X	X	X	X	X
Climate Change Implications		X			X	X	X		X	X
Natural Gas Storage & Tranport	X		X	X	X	X	X		X	X
CO_2 Capture & Sequestration	X			X	X	X	X		X	X
Key Actors										
Government Agencies	X	X	X	X	X	X	X	X	X	X
Private Sector Firms			X	X		X	X			X
Universities	X	X	X	X	X	X	X	X	X	X

(Council of Canadian Academies)

Results are based on responses received from the following countries: China (1), Germany (2), India (3), Japan (3), Korea (1), Norway (2), Russia (3), Taiwan (2), United Kingdom (4), United States (6).

Highlights of National Gas Hydrate Programs

Note: These highlights are based largely on international survey results. The panel recognizes that this is not an exhaustive list, and that important contributions may not have been included in this section.

Chile

- Foundation for Scientific Development and Technology in Chile funds a national gas hydrate program, *Underwater gas hydrate: a new source of energy for the 21st century*, in 2001.
- Pontifical Catholic University of Valparaíso, in collaboration with researchers from the United States, Europe, Japan and Canada, conducts marine gas hydrate field surveys offshore Chile (Grevermeyer *et al.*, 2003; Schwalenberg *et al.*, 2004).

China

- Government establishes Guangzhou Center for Gas Hydrate Research (CGHR) in 2004.
- GMGS-1, the first gas hydrate drilling program, was completed in South China Sea in 2007 for the Guangzhou Marine Geological Survey, China Geological Survey and the Ministry of Land and Resources of P.R. China.
- GMGS-1 reveals thick sediment layers rich in gas hydrate just above the base of the gas hydrate stability zone at three of the eight sites drilled.

France

- Gas hydrate hazards are studied at Institut Français du Pétrole and work on hydrate engineering concerns are carried out at École Nationale Supérieure des Mines de St-Etienne.

Germany

- Government launches national program, *Gas Hydrates in the Geosystem*, in 2000.
- Germany participates in international expeditions to Hydrate Ridge, Gulf of Mexico, Black Sea, Congo Delta and the Chilean Margin.
- The German Gas Hydrate Organisation (GGO) is initiated in 2007 by government and research organizations, and includes several private-sector companies as members.

India

- Directorate General of Hydrocarbons (DGH) co-ordinates the Indian NGHP, which is monitored by a Steering Committee chaired by the Secretary of Petroleum & Natural Gas.
- NGHP Expedition 01, April-August 2006, with the collaboration of the DGH, the U.S. Geological Survey and the Consortium for Scientific Methane Hydrate Investigations:
    - cores and drills 39 holes at 21 sites and penetrates more than 9,250 m of section
    - finds gas hydrates in Krishna-Godavari, Mahanadi and Andaman basins, and
    - recovers 2,850 m of core samples for analysis by international experts.
- A second NGHP drilling expedition is proposed for 2009-10 to drill and log the most promising sand-dominated gas hydrate prospects.

Japan

- Ministry of Economy, Trade and Industry (METI) (then Ministry of International Trade and Industry – MITI) establishes the Japan National Gas Hydrate Program in 1995, the first large-scale national gas hydrate program in the world.
- Japan Oil Gas & Metals National Corp. (JOGMEC) develops a highly integrated gas hydrate R&D program of basic research and field studies.
- Seismic surveys confirm extensive BSRs in the Nankai Trough.
- The first five years of the Japan National Gas Hydrate Program culminated in 1999/2000 with the drilling of closely spaced core and geophysical logging holes in the Nankai Trough.
- METI launches the *Japan Methane Hydrate Exploitation Program* in 2001 to evaluate the resource potential of deepwater methane hydrates in the Nankai Trough area. The program:
    - carries out multiwell drilling program for 16 sites in 2004
    - cores and analyzes gas hydrate-bearing sands, and
    - plans field testing for 2009 and development of commercial production technologies by 2016.
- JOGMEC plays a leadership role in all three phases of the Mallik research program in Canada's Mackenzie Delta.

Korea

- Ministry of Commerce, Industry and Energy (MOCIE) supports a strong national gas hydrate program, which includes government research organizations and industry partners.
- Program aims to commercially produce gas from gas hydrate by 2015 and provide a 30-year supply of natural gas.
- Korean Gas Hydrate Research and Development project begins in 2000 in the East Sea and Ulleung Basin; two phases are now complete with two more planned up to 2014.
- Project carries out first deep-drilling expedition in the Ulleung Basin in 2007.
- New drilling is anticipated by 2010-12.

New Zealand

- New Zealand (NZ) Gas Hydrates Steering Group is currently developing a strategy for the commercial development of NZ's gas hydrate resources, and aims to make the business and science case in 2009-11 for an offshore gas hydrate technology demonstration site at a sweet spot off the eastern coast of the North Island.

Norway

- Gas hydrate hazard assessment, climate change implications, and CO_2 capture and sequestration are the key drivers for hydrate research led by industry, government agencies, and academia at the Universities of Bergen and Trømso.

Russia

- 5×10^9 m^3 (0.18 Tcf) of gas claimed to have been produced from gas hydrate in the Messoyakha gas field since 1969.
- Laboratory for Gas Hydrate Geology at VNIIOkeangeologiya in 1980 publishes worldwide gas hydrate estimates, consistent with other widely-cited estimates.
- VNIIOkeangeologiya publishes field studies in the North Atlantic, Black Sea, Caspian Sea and Okhotsk Sea off Sahkalin Island.

Taiwan

- Central Geological Survey leads ongoing gas hydrate research efforts and is working on the development of a national program.
- Government launches a four-year program in 2007 to study offshore gas hydrate occurrences.

United Kingdom

- Gas hydrates in nature are studied at the National Oceanographic Centre in Southampton and the University of Birmingham. Flow assurances problems are studied at Heriot-Watt University and the University of Coventry.
- The European Union-managed HYDRATECH project is established to develop techniques for the quantification of methane hydrate in European continental margins, with a focus on developing seismic techniques that can be used to identify and quantify methane hydrates along the Norwegian margin.

United States

- Government enacts *Methane Hydrate Research and Development Act* in 2000 and reauthorizes it through 2010 as Sec. 968 of the 2005 *Energy Policy Act*.
- DOE leads gas hydrate R&D with six other federal agencies involved.
- DOE funds a wide range of laboratory investigations to determine physical and chemical properties of gas hydrates.
- DOE-funded research efforts make significant advancements in gas hydrate production simulators.
- The U.S. Geological Survey (USGS) has also maintained active gas hydrate research programs since the early 1980s with a focus on understanding the geologic and geochemical controls on the occurrence of gas hydrates in both marine and arctic permafrost environments.
- In 1995 the USGS conducts the first assessment of the volume of gas stored within gas hydrate in the offshore and onshore regions of the United States.
- In 2008 the U.S. Minerals Management Service publishes a geologic risk-based assessment of the volume of gas stored as gas hydrate in the Gulf of Mexico (http://www.mms.gov/revaldiv/GasHydrateAssessment.htm).
- Main field studies include:
  - DOE/Mauer/Anadarko *Hot Ice* project on the Alaskan North Slope completed in 2004
  - DOE/Chevron-managed Gulf of Mexico Joint Industry Project (2002 through current)
  - DOE/BP Alaskan North Slope project, and
  - the MMS/NOAA/DOE/USGS Gulf of Mexico Sea Floor Monitoring Station.
- United States collaborates on international field programs including:
  - Mallik 2002
  - IODP Leg 204 and Expedition 311 along Cascadia margin
  - 2006 India Directorate General for Hydrocarbons drilling and coring expedition in Indian Ocean, and
  - geophysical and geochemical surveys along the Chilean Margin.

3. THE ESTIMATED QUANTITY AND LOCATION OF GAS HYDRATE IN CANADA

3.1 ESTIMATING GAS HYDRATE QUANTITY

Global Estimates

The amount of natural gas contained in the world's gas hydrate accumulations is enormous. Estimates are speculative and range over three orders of magnitude, from about 2.8 x 10^{15} m^3 to 8 x 10^{18} m^3 (100,000 to 280,000,000 Tcf) (see Table 3.1). Recent reports (Milkov *et al.*, 2003) suggest that the worldwide volume of gas trapped in gas hydrate accumulations is in the range of 3 to 5 x 10^{15} m^3 (110,000 to 180,000 Tcf), about one-seventh to one-quarter of some of the more widely cited estimates (reviewed by Kvenvolden, 1993). In comparison, conventional natural gas accumulations, including reserves and technically recoverable undiscovered global resources, are estimated to be approximately 4.4 x 10^{14} m^3 (16,000 Tcf; Ahlbrandt, 2002), or about one-tenth the Milkov estimate of the amount of gas contained in gas hydrates. Thus even the lowest estimates indicate that gas hydrate could be a much greater potential source of natural gas than conventional accumulations.

Several studies have focused on assessing the total amount of gas hydrate within marine margins. The earliest assessment was by Trofimuk *et al.* (1973). Milkov *et al.* (2003) summarized all assessments up to 2003 and revised the value of methane trapped worldwide in natural gas hydrate deposits from 21 x 10^{15} m^3 (740,000 Tcf) of methane gas (at standard temperature and pressure) and proposed a revised lower range of 1 to 5 x10^{15} m^3 (35,000 to 180,000 Tcf) of gas.[16] Regardless of how careful the estimates of gas composition, average gas hydrate saturation, sediment porosity, and extent of the lateral and vertical gas hydrate stability zone, large uncertainty remains. As new drilling results are obtained, these in-place estimates need to be revised. With very few drilling and coring data sets available,[17] a reliable estimate of global volume of natural gas hydrate is elusive. It is also difficult to assess the quantity of gas hydrate present on a given margin because of the heterogeneous sedimentological environments along each margin. IODP Expedition 311 showed that gas hydrate

16 When methane is released from a given volume of solid gas hydrate, it expands 150- to 170-fold at STP (Kvenvolden, 1999). Thus 10^{15} m^3 (35,000 Tcf) of methane gas is equivalent to a solid volume of ~6 x 10^{12} m^3 (~220 Tcf) of gas hydrate.

17 Data come mainly from drilling expeditions co-ordinated through the ODP (Legs 146, 164, 204) and IODP (Expedition 311), and recently by the Indian NGHP Expedition 01.

deposits varied significantly, even within tens of metres (Riedel *et al.*, *Proceedings of the IODP*, 2006). Extrapolation from the local scale can be unreliable without additional knowledge of the scale of heterogeneity.

Table 3.1

World estimates of the amount of in-place gas in gas hydrates in continental (onshore) and oceanic settings (at standard temperature and pressure; 101.3 kPa and 20°C)

Continental Gas Hydrates

(x 10^{12} m^3)	(Tcf)	Reference
14	490	Meyer (1981)
31	1,000	McIver (1981)
57	2,000	Trofimuk *et al.* (1977)
740	26,000	MacDonald (1990)
34,000	1,200,000	Dobrynin *et al.* (1981)

Oceanic Gas Hydrates

(x 10^{15} m^3)	(Tcf)	Reference
1 to 5	35,000 to 180,000	Milkov *et al.* (2003)
3.1	110,000	McIver (1981)
5 to 25	180,000 to 880,000	Trofimuk *et al.* (1977)
20	706,000	Kvenvolden (1988a)
21	740,000	MacDonald (1990)
40	1,400,000	Kvenvolden and Claypool (1988)
120	4,200,000	Klauda and Sandler (2005)
7,600	270,000,000	Dobrynin *et al.* (1981)

The foregoing global assessments are of total in-place gas in hydrate form, and *not* of the amounts of gas that could actually be produced from the world's gas hydrate accumulations. Much more work is needed to refine estimates of the total volume of gas hydrate and to quantify producible volumes. (See Chapter 4 for a discussion of factors that influence the producibility of gas from gas hydrate.) Despite the large uncertainties, it is instructive to make order-of-magnitude comparisons with estimates of *recoverable* conventional natural gas resources (Table 3.2). The data in Tables 3.1 and 3.2 are not strictly comparable — because we do not know what fraction of gas from gas hydrate might prove to be recoverable — but the significance of the gas hydrate potential is evident.

Table 3.2
Estimates of Recoverable Conventional Natural Gas

	(x 10^{12} m^3)	(Tcf)	Reference
Remaining Recoverable Conventional Natural Gas (World)	440	16,000	Ahlbrandt (2002)
Total Initial Reserves Conventional Natural Gas (Canada)	5.9	210	NEB (2007)
Remaining Established Reserves Conventional Natural Gas (Canada)	1.6	57	NEB (2007)

Canadian Estimates

Canada benefits from two of the most intensive field studies of natural gas hydrate worldwide with the northern Cascadia marine gas hydrate (off Vancouver Island) and the permafrost gas hydrate deposit at the Mallik research wells of the Mackenzie Delta, Northwest Territories (NWT). However, these studies are only local in scale. Little research exists to assess the regional occurrence, distribution and total volume of gas hydrate in Canada. All such assessments are based on extrapolation from local studies and knowledge about where gas hydrates *could* occur. In order to estimate the total gas hydrate present in any geographical region, assumptions need to be made involving the nature of gas hydrate occurrence, the regional geologic setting and the petroleum system (see the technical Annex at the end of this chapter for further information on the petroleum system). Although gas hydrate occurrences are highly heterogeneous, as recent studies on the west coast have shown (Riedel *et al.*, *Proceedings of the IODP*, 2006), estimates have typically ignored variations in gas hydrate concentration, porosity of the reservoir strata, temperature and pressure regimes, gas composition, and pore-water salinity. Given the natural variability in all these factors, gas hydrate volume estimates range over several orders of magnitude.

Majorowicz and Osadetz (2001) estimated the total volume of methane locked in gas hydrate deposits in Canada to be between 10^{12} and 10^{14} m^3 (between 35 and 3,500 Tcf). The reliability of this estimate is limited by the fact that the analysis excludes consideration of local geological and tectonic conditions, and basin characteristics. These limitations notwithstanding, the estimates are useful in a general sense as they indicate a potentially large hydrocarbon pool that, according to the authors, may be equivalent in magnitude to the conventional natural gas resources in Canada. These were estimated by the same authors to be about 27×10^{12} m^3 (about 950 Tcf). The NEB estimates that Canada's ultimate potential of conventional natural gas is 14.2×10^{12} m^3 (about 500 Tcf) (*Canada's Conventional Natural Gas Resources – A Status Report*, April 2004).

In order to overcome some limitations of the 2001 study, Osadetz and Chen (2005) refined the assessment for the Mackenzie Delta/Beaufort Sea region by introducing additional constraints. They took into account a tectonic intensity index for various subregions — e.g., to describe faulting that could provide migration pathways for methane gas. The Osadetz and Chen (2005) study provided estimates within the same bounds as given by Majorowicz and Osadetz (2001), from 10^{12} to 10^{13} m^3 (35 to 350 Tcf) of gas in place for the Mackenzie Delta/Beaufort Sea region. There is no equivalent detailed summary for the northern Cascadia margin off Vancouver Island, despite numerous and detailed studies of that margin (discussed below). The results from these two studies by Majorowicz and Osadetz (2001), and Osadetz and Chen (2005), are summarized in Table 3.3. Additional studies were performed for the offshore east coast region (Majorowicz and Osadetz, 2003), as discussed below.

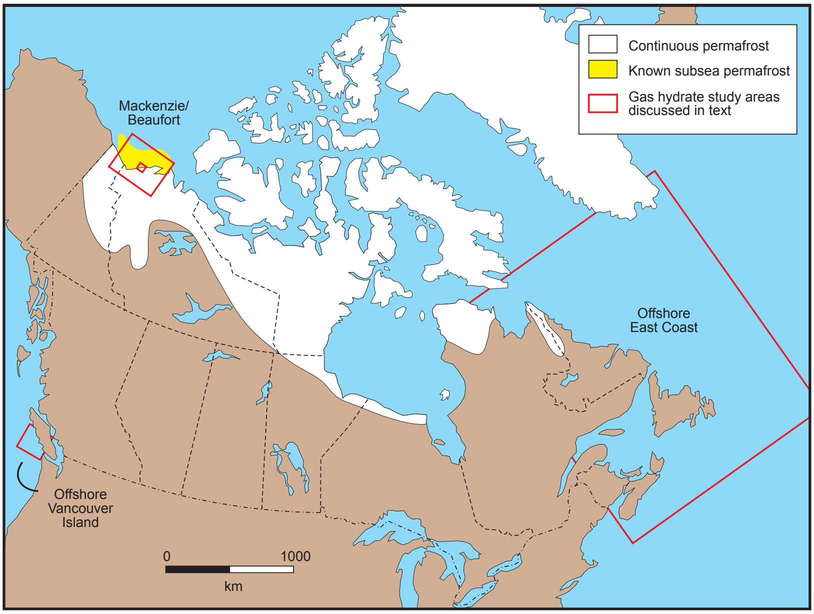
Table 3.3

Total estimates of volume of gas in all Canadian gas hydrate regions

		Mackenzie Delta/ Beaufort Sea	**Arctic Archipelago**	**East Coast**	**West Coast**
Majorowicz and Osadetz (2001)	(x 10^{12} m^3)	2.4-87	19-620	19-78	3.2-24
	(Tcf)	85-3,000	670-22,000	670-2,800	110-850
Osadetz and Chen (2005)	(x 10^{12} m^3)	8.8-10.2	No estimate	No estimate	No estimate
	(Tcf)	310-360			
Techniques and tools used to provide estimates		**2001:** Well-log data, thermal modelling of stability zone; range was obtained by using possible extent in values for porosity, concentration and occupancy ratios for porosity, concentration and occupancy ratios **2005:** Additional geological complexity factor and probabilistic approach in determining estimates	Well-log data, thermal modelling of stability zone; range was obtained by using possible extent in values for porosity, concentration and occupancy ratios for porosity, concentration and occupancy ratios	Well-log data, thermal modelling of stability zone; range was obtained by using possible extent in values for porosity, concentration and occupancy ratios porosity, concentration and occupancy ratios	Well-log data, thermal modelling of stability zone, concentration estimates from ODP drilling, BSR distribution

3.2 LOCATION OF GAS HYDRATES

In Canada, gas hydrates have been studied in both continental margins and permafrost regions (see Figure 3.1). There is more information about the west coast and the North, mainly due to the location of Canada's two natural labs — Cascadia (west coast) and Mallik (Arctic). However, there are certain to be more locations in Canada with gas hydrates than have been studied and/or identified on the map.



(Majorowicz and Osadetz, 2001)

Figure 3.1

Regional assessments of gas hydrate in Canada

Note that while this map shows the three regions on which assessments have been focused to date, gas hydrate may occur on other parts of the margin.

There is a clear need for expanded mapping and research into gas hydrate on all margins. Despite extensive research in individual locations and the high quality of Canadian work in this field, Canada's coastal margins and permafrost areas have not been extensively studied and charted for gas hydrates. Note however, that other mineral resources are commonly estimated without mapping their total occurrence, and attempting to map all Canadian gas hydrate deposits on a basin-by-basin scale is impractical because of the length of Canada's coastline. However, two examples exist in South Korea and Taiwan, where, through strong national programs, the entire margins offshore were systematically imaged with 2D and 3D seismic data on a grid-by-grid base over several years (e.g., Liu *et al.*, 2006; Park *et al.*, 2008). Also, the U.S. Minerals Management Service has recently released a study that evaluates the potential for gas hydrate occurrences in the entire Gulf of Mexico (Minerals Management Service, 2008).

Surveying the gas hydrate distribution can best be achieved through both seismic and electromagnetic methods, although estimates from these methods are only confirmed when calibrated against well logs or core samples. In the marine environment, detection of gas hydrate by remote geophysical sensing techniques is quite challenging, but has been achieved. Because of the geological complexity of onshore environments, the seismic analysis is much more difficult.

An overview of the various geoscientific tools used in mapping and characterizing gas hydrate deposits are summarized in a technical Annex at the end of this chapter.

Canada's Marine Areas

Gas hydrate is known to occur along all marine margins of Canada — off Vancouver Island at the northern Cascadia margin, off Nova Scotia, Newfoundland and Labrador, as well as in the Beaufort Sea. Samples of gas hydrate have so far been recovered only on the west coast.[18] Studies on the Arctic and Atlantic coasts have been much less extensive.

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18 Samples were recovered as part of IODP Expedition 311 (Riedel et al., *Proceedings of the IODP*, 2006), dedicated piston-coring across a high-flux region, known as Bullseye vent (Riedel *et al.*, *Gas hydrates transect*, 2006), as well as at Barkley Canyon, where massive gas hydrate mounds were discovered by remote bottom video surveys (Chapman *et al.*, 2004) after a fishing trawler accidentally dredged an estimated 1.5 tons of gas hydrate off the seafloor (Spence *et al.*, 2001).

Traditionally, the BSR was used in marine environments to infer the presence and concentration of gas hydrate. More recent studies on the west coast have shown that gas hydrate can exist without a BSR (e.g., Yuan and Edwards, 2000), and that there may be a BSR without much gas hydrate being present above this seismic reflection (Riedel *et al.*, *Proceedings of the IODP*, 2006; *Gas hydrates transect*, 2006). However, the current consensus of the scientific community is that the BSR should be regarded only as a qualifying indicator of the potential of gas hydrate being present in an area, and not as a means of quantifying the extent of the resource. The reflection seen on seismic profiles is believed to be mainly an indicator of free gas below the gas hydrate stability field.

Despite its shortcomings in making reliable concentration estimates, the BSR is still the initial indicator of the presence of gas hydrate. New analyses from offshore India, the Gulf of Mexico, and the North Slope of Alaska show that mapping and detection of reservoir sands — i.e., a traditional petroleum-system approach (as described in the Annex) to a basin of interest — are necessary to detect the reservoir strata (mainly sand) that could contain gas hydrate. This mapping can only be achieved through high-quality, 3D seismic data.

As described in the Annex to this chapter, the most significant effects of gas hydrate within the stability zone itself are the increases in elastic properties (as a solid replaces a fluid), and in the electrical resistivity (as an electrical insulator replaces a conductor). Thus surveying gas hydrate distribution over an extended area can be achieved by seismic methods[19] and controlled-source electromagnetic (CSEM) methods sensitive to electrical resistivity (e.g., Yuan and Edwards, 2000; Schwalenberg *et al.*, 2005). In addition, detailed site analysis — including heat transfer measurements, magnetic surveying and seafloor compliance — help to further characterize a particular deposit and describe the physical properties of the sediments (e.g., Willoughby *et al.*, 2005; Novosel *et al.*, 2005; Riedel *et al.*, *Gas hydrates transect*, 2006; Enkin *et al.*, 2007).

Despite extensive research carried out in individual locations and the high quality of Canadian work and leadership in this field, Canada's margins have not been well studied and charted for the regional occurrence of gas hydrate. On the east coast, there has been little gas hydrate research. However, large seismic data sets exist and — contrary to the study by Majorowicz and Osadetz

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19 Seismic methods survey compressional-wave velocity (or impedance through inversion) or shear-wave velocity from multi-component surveys (e.g. Yuan *et al.*, 1996; Dai *et al.*, 2004; Lu and McMechan, 2004; Hobro *et al.*, 2005).

in 2001 — the low lateral density of BSRs may suggest that the distribution of free gas beneath the zone of gas hydrates varies. Although gas hydrate could still exist despite the lack of a BSR, other geophysical means of detection would be required to define the extent of the gas hydrate (see the Annex at the end of this chapter). To date, these geophysical mapping techniques have only sparingly been used on the east coast (Shimeld *et al.*, 2004; Mosher *et al.*, 2005). Off the west coast there have been intensive local studies but sparse geophysical mapping on the margin, and much of the seismic data are either old (1989 or earlier) or of relatively poor quality.

As discussed above, there is a need for expanded mapping and research into gas hydrates on all margins. Field studies could benefit from a common, well-maintained pool of geophysical survey equipment and associated heavy machinery. Furthermore, there are strong limitations in surveying opportunities because of (a) lack of research vessels; (b) lack of technical expertise previously provided by NRCan through the Geological Survey of Canada (GSC); (c) high costs of surveys; and (d) environmental restrictions — e.g., on the size of seismic sources — including the west coast moratoria issues (as described in Chapter 5) on offshore exploration activity.[20]

Although concentrations of gas hydrate within most marine accumulations appear to be low (e.g., Collett, 2002), there is growing evidence for enriched marine gas hydrate deposits associated with cold vents (areas of excessive gas migration; see Box 8) and large thermogenic seeps as seen on the Cascadia margin off Oregon (Tréhu *et al.*, 2003) and Vancouver Island (Schwalenberg *et al.*, 2005; Riedel *et al.*, *Proceedings of the IODP*, 2006), the Gulf of Mexico (MacDonald *et al.*, 1994; Sassen and MacDonald, 1994), or in the East Sea/ Japan Sea (Lee *et al.*, 2005). The Cascadia field study described below is a good example.

East Coast

Gas hydrate research on the east coast of Canada has been very limited. In the past, it was thought that there was more gas hydrate on the east coast than on the west, based on the regional assessment of Majorowicz and Osadetz (2003). They compiled known wells in the entire region and defined those with probable occurrence of gas hydrate. Only 18 out of more than 100 wells considered

20 The west coast moratoria do not apply to academic research.

actually exhibit conditions for probable gas hydrate formation.[21] Over 90 per cent of the available wells are located in waters no deeper than 300 m and are thus outside the gas hydrate stability zone. The interpretation of gas hydrate from industrial wells is further limited in the upper few hundred metres below the seafloor where geophysical logs are usually unavailable. A re-evaluation of the methane hydrate stability zone led Majorowicz and Osadetz (2003) to conclude that some of the methane hydrate zones identified earlier by Judge *et al.* (1990) and Smith *et al.* (2001) were in fact outside the normal boundaries for methane hydrate stability. Majorowicz and Osadetz speculated that these deeper zones corresponded to sII gas hydrates containing heavier hydrocarbons of thermogenic origin.

Efforts have focused lately on detecting and mapping BSRs in seismic data (Mosher *et al.*, 2006; Shimeld *et al.*, 2006). There are few indications of seismic BSRs off Canada's east coast. Thurber Consultants (1986) reported BSRs in the Gjoa area (Davis Strait), Bjarni area (Labrador shelf), Gander Block and Sackville Spur. Detailed analyses of seismic data along the Scotian shelf showed only two main areas of BSR occurrence — at the Haddock Channel and Mohican Channel (Shimeld *et al.*, 2004; Mosher *et al.*, 2005; see Figure 3.3).

The studies on BSR occurrences were complemented by special analyses with ocean-bottom seismometers (OBS; LeBlanc *et al.*, 2007). The data from an OBS can be used to delineate the fine-scale velocity structure around the OBS deployment site. Analyses around the Mohican Channel indicate that the observed velocity increase above the BSR may indicate gas hydrate concentrations between two and six per cent of the pore space, with a free gas concentration of less than one per cent below the BSR. Note that this is the only detailed single study of the velocity structure on the east coast, so that regional estimates based on this study would likely be meaningless.

Recent analyses of an industry-provided 3D seismic data set in the area around the Mohican Channel show vent-like structures with strong evidence for localized enhanced methane flux and the potential for high gas hydrate accumulations similar to what has been observed on the Cascadia margin (Mosher *et al.*, 2005).

The existing data and investigations are inconclusive as to the potential gas hydrate resource in this region and further research, especially direct sampling

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21 Four wells on the Labrador Shelf, nine in the Grand Banks area, and five on the Scotian shelf.

through deep drilling and coring, is required. Existing data sets could be re-interpreted to search for reservoir sands following the more recent petroleum system approach (as described in the Annex).

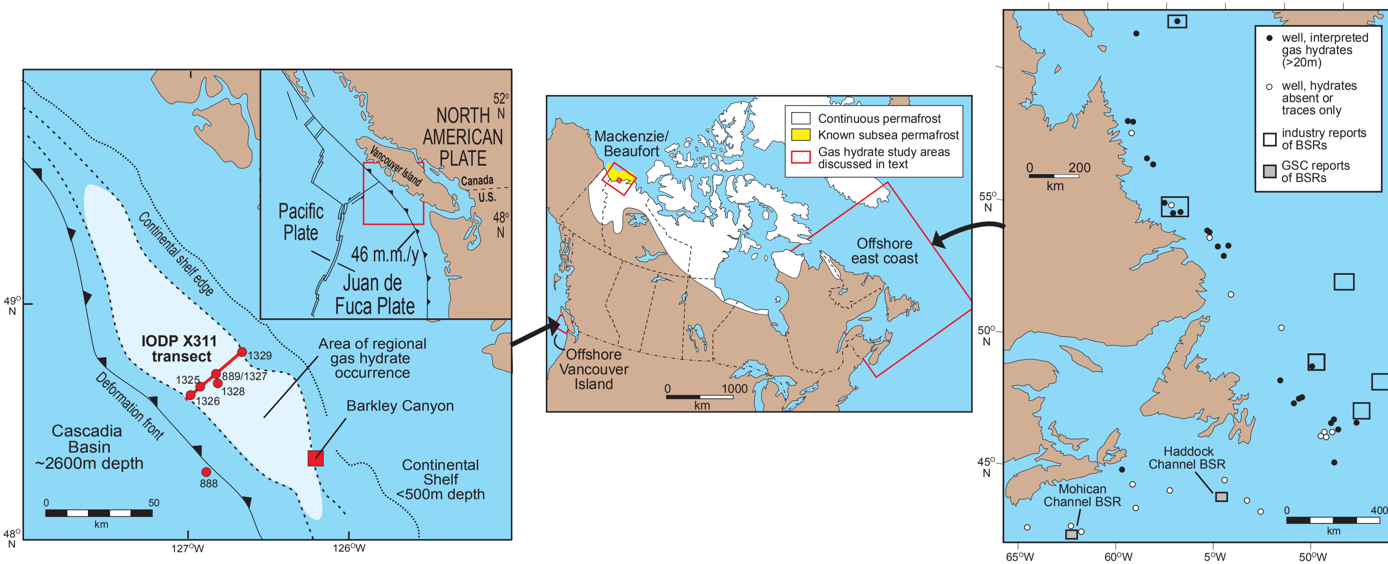
West Coast

Naturally occurring gas hydrates have been studied off Vancouver Island for more than two decades. Unlike the east coast, well-log data from two ODP/IODP research drilling expeditions exist (Westbrook *et al.*, 1994; Riedel *et al.*, *Proceedings of the IODP*, 2006) to help define probable occurrence of gas hydrate. The presence of gas hydrate was first inferred from seismic data collected in 1985 and 1989 (e.g., Hyndman and Spence, 1992). Subsequently, ODP Leg 146 (Westbrook *et al.*, 1994) and IODP Expedition 311 (Riedel *et al.*, *Proceedings of the IODP*, 2006) provided a wealth of quantitative data, with direct sampling of gas hydrate-bearing core and indirect evidence of gas hydrate from increased seismic velocities and electrical resistivities in well logs, intensive pore-water freshening, and reduced temperatures from infrared imaging in the recovered core.

While there are geophysical mapping data sets, these are sparsely distributed over the margin. Most seismic data are decades old, of variable quality and not thoroughly archived. The CSEM imaging data are quite sparse. The distribution has been mapped primarily based on a BSR, and, as on the east coast, better assessment of the amount of gas hydrate trapped in these deposits may be achieved by supplementing reflection seismic data with other geophysical methods.

The accretionary prism — the wedge of sediments scraped off the Pacific plate as it subducts beneath the Juan de Fuca plate (Figure 3.2) — off Vancouver Island has been the focus of many marine geological and geophysical studies over the past two decades. A high abundance of gas hydrate in the accretionary sedimentary prism is explained by methane-rich pore fluids in the sedimentary section on the Juan de Fuca plate being tectonically expelled upward into the gas hydrate stability zone (Hyndman and Davis, 1992).

A number of geophysical, geotechnical and geological methods have been used to detect and characterize gas hydrate, including scientific drilling, single and multichannel, 2D and 3D seismic imaging, seafloor compliance studies, CSEM surveys, OBS, heat flow determinations, piston coring with measurements of sediment physical properties and pore-fluid geochemistry, seafloor video observation, and sampling with an unmanned submersible ROPOS (a remotely operated platform for ocean science). Summaries have been provided in Spence *et al.* (2000) and by Hyndman *et al.* (2001). These studies include wide-spread surveys over an extended region in the vicinity of ODP Site 889 and focused small-scale surveys over vent structures initially identified in seismic data (Riedel *et al.*, 2002; Riedel, 2007). The area is well-suited for comparing the strengths of various methodologies, and provides an opportunity to calibrate data to gas hydrate content measured during the recently completed IODP Expedition 311. The Cascadia margin is one of the best-studied natural gas hydrate environments in continental margin settings anywhere in the world.



(Hyndman, R. D. 1995)

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Figure 3.2 (above)

The intensively studied gas hydrate region, on the northern Cascadia margin in offshore Vancouver Island, is indicated by the grey shaded region; its area was inferred from BSRs observed in vintage seismic data. The IODP Expedition 311 and ODP Site 889 scientific drillholes for gas hydrate and the reference "no hydrate" hole ODP Site 888 are highlighted in red. Massive gas hydrate outcrops were observed at the Barkley Canyon Site (red square).

(Shimeld *et al.* 2004)

Reproduced with permission from John Shimeld.

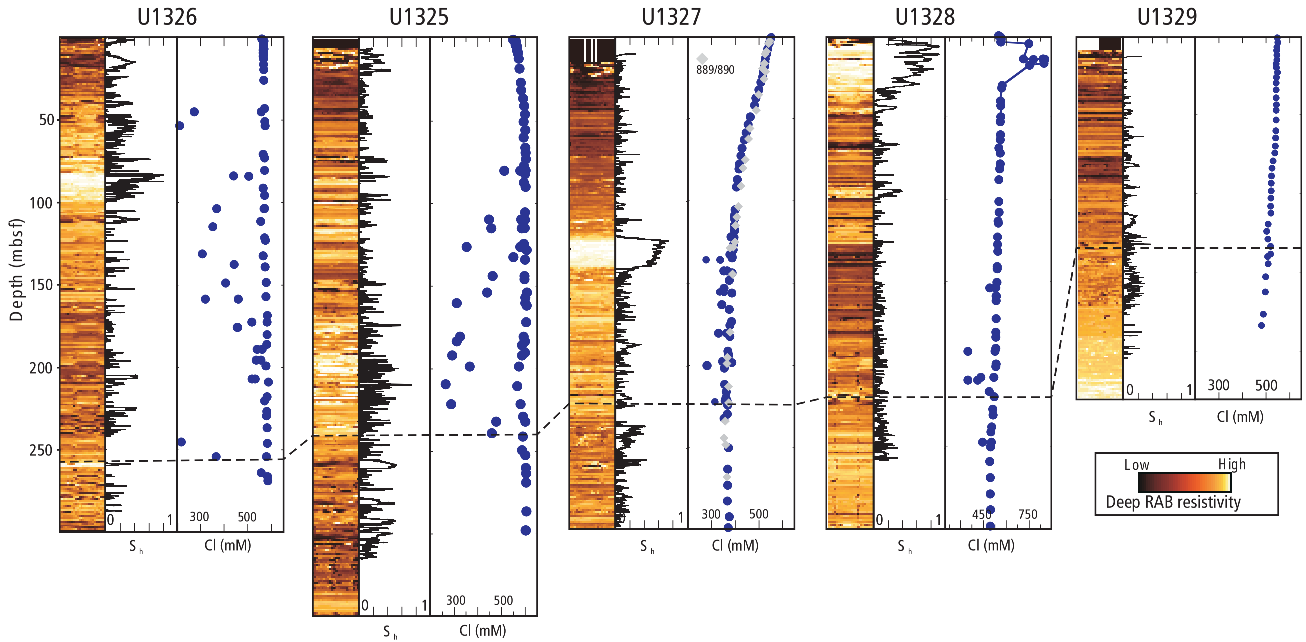
Figure 3.3 (above)

This map shows locations of reported BSRs on Canada's east coast from industry studies (open boxes) and from detailed analyses carried out by the GSC (grey boxes). Also shown on this map are the location of industry wells interpreted to contain gas hydrates (solid circles) and without gas hydrates (white circles); modified from Shimeld *et al.*, 2004). For details see main text.

The most significant findings of IODP Expedition 311 are as follows:

- There is considerably more sand than was appreciated before, thus providing the required reservoir strata with high porosity and permeability for large amounts of gas hydrate.
- Gas hydrate is formed mainly within the sand-rich formations and is virtually absent from the fine-grained sediments (within resolution limits of the tools and techniques used to quantify concentrations). Thus the presence of gas hydrate is mainly driven by lithology (i.e., the type of sediment formation and its physical character in terms of grain size).
- The BSR is unrelated to the concentration of gas hydrate within the pressure-temperature stability zone, and provides only a first-order indicator of the potential occurrence of gas hydrate.
- All sites showed a high degree of heterogeneity in gas hydrate occurrence. Individual gas hydrate-bearing layers cannot be traced between adjacent wells over distances larger than a few tens of metres, if at all. Thus there are potential pitfalls in extrapolating small-scale borehole observations to the regional scale.

The gas hydrate occurrence on the Cascadia margin is far more complicated than previously appreciated (Figure 3.4).



(Riedel *et al.*, 2006)

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Figure 3.4

Results of IODP Expedition 311 coring and logging transect across northern Cascadia margin (from Riedel *et al.*, 2006). Shown for all drilling sites along transect (U1326, U1325, U1327, and U1329) as well as the cold vent site (U1328) are the resensitivity-at-bit (RAB) results from logging-while-drilling and derived gas hydrate concentrations (Sh, black lines) and pore-water chlorinity profiles (blue dots).

High electricity resensitivity (shown in the RAB image as whitish colors) is a proxy for high gas hydrate content. The base of the gas hydrate stability field is shown as dashed lines, coinciding with the BSR. The RAB images, derived concentrations and pore-water chlorinity profiles highlight the extreme heterogeneous character of the gas hydrate deposits off Canada's west coast from drill site to drill site. No uniform gas hydrate-bearing layer above the BSR (as previously proposed) has been observed. Each drill site exhibits a unique geochemical profile and gas hydrate distribution.

Strong geologic control — either through lithology or fault/fracture systems — is apparent, and there is also a high degree of lateral variability and complexity. Although the results of IODP Expedition 311 have given new and promising results that marine gas hydrate deposits in sand may be present off Vancouver Island, problems remain in assessing the total potential gas hydrate on the west coast. For example, the highly variable pore-fluid salinity along the drilling transect makes it difficult to define reference resistivity-depth profiles away from the immediate vicinity of the borehole, which provides a challenge for the interpretation of CSEM survey data (see Figure 3.4). Some gas hydrate also appears in fractures, not as a pore-filling material.

The observation of fracture-filling gas hydrate shows that care must be taken in applying empirical relations (such as 'Archie's law' to resistivity data, or many seismic relations for velocity data) that implicitly assume gas hydrate is pore filling. Seismic methods rely on the knowledge of a background no-gas hydrate velocity trend to infer concentrations, which is difficult to assess in areas with a highly variable lithology, and concentration estimates (as with the resistivity methods) assume a pore-filling nature of gas hydrate.

Box 7 — Integrated Ocean Drilling Program (IODP)

The IODP is a co-operative marine geological drilling program launched in 2004 to conduct research into earth processes. It is aimed at solving problems of Earth science by recovering sediment and rock samples from below the ocean floor and using the resulting holes to perform downhole measurements and experiments. Gas hydrate is just one of the many focuses of the IODP research.

The IODP builds on work previously carried out under the Deep Sea Drilling Project (DSDP, started in 1968) and the ODP, started in 1985. The ODP was funded by the U.S. National Science Foundation with 22 international partners, and was directed by the Joint Oceanographic Institutions for Deep Earth Sampling.[22] The ODP used a drilling vessel to sample sediments lying as deep as 2,000 m below the seafloor.

The IODP features a major research and drilling vessel (the Japanese *Chikyu*), the largest scientific research vessel ever built, and includes new special-mission-specific-platform expeditions to access complex areas unreachable with a large drilling vessel (e.g., reefs and arctic areas with permanent ice cover

22 See http://www.odplegacy.org/science_results.

requiring the help of icebreakers). The *Chikyu* uses riser drilling techniques, more effective in deep water. Riser drilling includes the ability to "seal off" the drill hole if dangerous conditions are encountered. Riser drilling capability opens up a variety of new target areas previously considered unsafe to drill because of the possibility of unstable subseafloor conditions — e.g., hydrocarbons or other fluids/gases under high pressure. Over the years, the collaborative research of DSDP, ODP and IODP has led to the exploration of over 800 sites (Hayes, 2008).

Canada was an active member in ODP in the past, and many Canadian scientists were able to directly participate in the drilling vessel expedition. However, recent changes in the funding situation and political climate have reduced the Canadian involvement in IODP, and decreased the membership capacities significantly to only one Canadian scientist per year allowed onboard drilling vessels. The shortage in funding also led to the closure of the Canadian ODP office in 2003. A university-based community, the Canadian Consortium for Ocean Drilling (CCOD), was formed to keep the Canadian researchers involved in ocean drilling activities. CCOD now has 14 members — NRCan and 13 universities countrywide.

IODP offers an exceptional platform for international collaboration and the ability to share knowledge and train future scientists in marine geoscience. Not being a member of IODP limits Canada's ability to remain at the forefront of R&D, especially in important fields such as climate studies, which have a global impact on society.

Majorowicz and Osadetz (2001) estimated the mean gas hydrate present on Canada's west coast to be 3.2×10^{12} to 24×10^{12} m^3 (110 to 850 Tcf) based on regional calculation of the gas hydrate stability zone thickness, average porosities and gas hydrate concentrations. Yuan and Edwards (2000) made an attempt to constrain the concentration and regional amount of gas hydrate around the ODP Site 889. Seafloor CSEM surveys were used to determine the lateral distribution of the observed resistivities associated with gas hydrate. Yuan and Edwards (2000) found that the electrical resistivities over a wide area were comparable to those found in the ODP 889 wireline logs. They modelled the subsurface gas hydrate content based on the assumed resistivity background trend of Hyndman *et al.* (1999), and interpreted the increased resistivities to correspond to 17 to 26 per cent gas hydrate (in the pore space). However, the more recent IODP Expedition 311 found that gas hydrate concentrations at this site are more likely to be very low (zero to five per cent) and defined a new baseline trend for the resistivity (Riedel *et al.*, *Proceedings of the IODP*, 2006), although greater heterogeneity was observed from one drillhole to the next at Site U1327 (near Hole 889). Despite these new drillhole results and some heterogeneity on the 10-meter scale, the CSEM data clearly indicate that on a scale of hundreds of metres laterally, resistivities, and hence by inference, gas hydrate concentrations, are quite uniform. The interpretation of gas hydrate content from CSEM data should be revisited in light of the new Expedition 311 drilling data.

Box 8 — Seismic Blank Zones and Cold Vents

Of particular interest over the last 10 years are several so-called seismic blank zones (where coherent seismic images cannot be obtained). A series of blank zones offshore Vancouver Island, with diameters between 80 and 400 m, were initially observed on a high-resolution 3-D multichannel seismic section. Gas hydrate was found with a piston corer during IODP Expedition 311 at different locations within the largest of the blank zones. There are competing models, such as a gas chimney with little gas hydrate (Wood *et al.*, 2002), hydraulic fracturing with free gas bubbles within fractures (Zühlsdorff and Spiess, 2004), and gas hydrate-rich lenses, fractures and conduits (Riedel *et al.*, 2002; *Gas hydrates transect*, 2006), to explain the blanking, which demonstrates the need to complement seismic studies with other imaging and sampling techniques.

Because seismic imaging is masked in cold vents (areas of excessive gas migration), additional geophysical techniques have been deployed across those vents to further determine their physical characteristics. Schwalenberg *et al.* (2005) reported large anomalies in electrical resistivities over the cold vents, which were explained by the presence of electrically-insulating gas hydrate displacing electrically conductive saltwater. Willoughby *et al.* (2005) reported that the shear modulus — higher where solid gas hydrate replaces pore fluids — is also anomalously high over vent sites. These results and interpretations were confirmed by IODP Expedition 311, which showed that the uppermost 40 m of the largest cold vent was mostly gas hydrate.

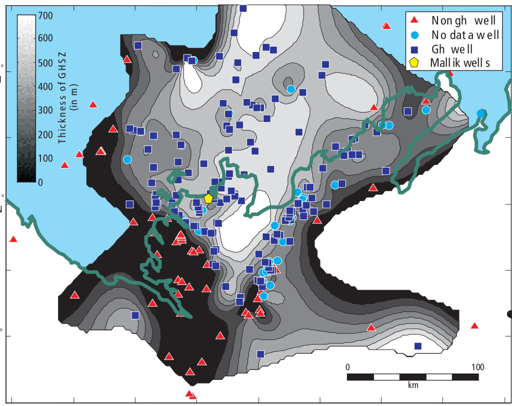
Research on continental margins worldwide has now confirmed these early Canadian results — cold vents, identified by seismic blank zones in the gas hydrate stability field, are common features of interest (e.g., Gorman *et al.*, 2002; Lee *et al.*, 2005; Haacke *et al.*, 2007; Liu and Flemings, 2007; Park *et al.*, 2008; Westbrook, 2008). With the addition of other geophysical imaging techniques, such as those pioneered in Canada, these local massive deposits and the total amount of gas hydrate they contain can be assessed with greater precision.

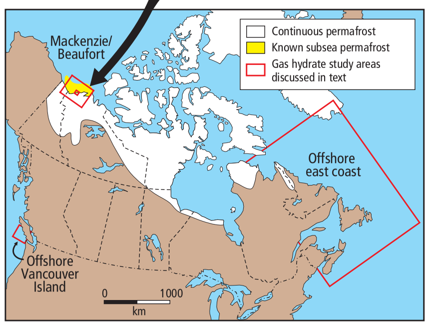
Canada's Permafrost Environment

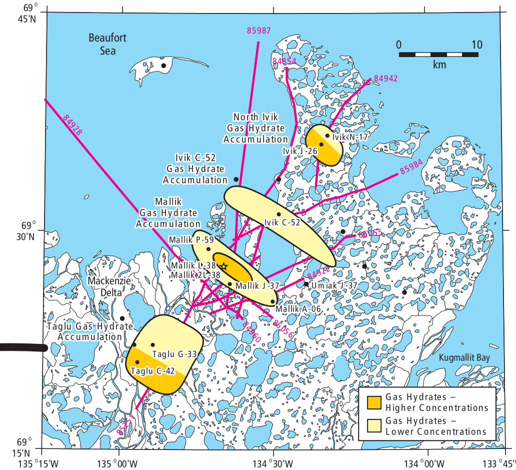
Several attempts have been made to characterize the total gas hydrate potential of the Canadian Arctic, including the Beaufort Sea shelf, the Mackenzie Delta and the Arctic Archipelago, using thermal modelling of the gas hydrate stability field in combination with observations in onshore/offshore geophysical well logs (e.g., Majorowicz and Osadetz, 2001; Osadetz and Chen, 2005). Occurrences of gas hydrate have been interpreted from geophysical well logs in the Mackenzie Delta/Beaufort Sea, and the Arctic islands (Bily and Dick, 1974; D&S Petrophysical Consultants, 1983; Hardy and Associates (1978) Ltd., 1984; Thurber Consultants, 1986, 1988; Judge *et al.*, 1994; Dallimore *et al.*, 1999; Dallimore and Collett, 2005).

Some of the main findings in permafrost environments are as follows:

- In the Mackenzie Delta/Beaufort Sea region, gas hydrate was detected or inferred in 29 per cent of wells using geophysical logs from over 200 wells drilled (D&S Petrophysical Consultants, 1983; Thurber Consultants, 1986, 1988; Smith and Judge, 1993, 1995).
- In the Mackenzie Delta/Beaufort Sea region (based on more than 200 wells drilled), gas hydrate occurrence was higher offshore, where 45 per cent of wells were interpreted to contain gas hydrate, compared with only 14 per cent onshore (Judge *et al.*, 1994). (See Figure 3.5.)
- In the Arctic Archipelago, gas hydrate was probable in 52 per cent of 168 wells drilled in the Sverdrup Basin (Hardy Associates Ltd., 1984; Majorowicz and Osadetz, 2001).
- Gas hydrate in the Arctic is also more likely to occur in sand layers or coarser-grained sediments (e.g., Collett *et al.*, 1999; Dallimore and Collett, 1998, 2005; Medioli *et al.*, 2005).
- Although gas hydrate has been reported in many wells across the Arctic, some of the evidence is of doubtful value, and data are inconclusive — e.g., as to whether the observation is from a gas hydrate or free gas occurrence — because of poor knowledge of the vertical extent of the gas hydrate stability zone (Majorowicz and Osadetz, 2001).
- Studies carried out in the 1980s and early 1990s onshore and offshore in the Mackenzie Delta/Beaufort Sea region showed gas hydrate below thick permafrost (300 to 700 m).







(Osadetz and Chen, 2005)

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Figure 3.5 (above)
Map of calculated thickness of sI gas hydrate stability zone (in metres) compared to evidence of gas hydrate occurrence in wells of the Mackenzie Delta-Beaufort Sea region (from Osadetz and Chen, 2005). Coastline is outlined in green.

(Collett *et al.*, 1999)

Reproduced with permission from Timothy Collett.

Figure 3.6 (above)
This map shows the Taglu, Mallik, and Ivik gas hydrate accumulations on Richards Island analyzed by Collett *et al.*, 1999. The various accumulations were originally divided into two zones with assumed higher, >80% (dark yellow) and lower, 50-60% (light yellow) gas hydrate concentrations. For details on volume estimates and comparison to more recent assessments focusing on the Mallik L-38 area, see text.

Despite the strength and importance of these studies, the reported estimates in Table 3.3 remain speculative. There is a lack of extensive geophysical mapping for gas hydrate in the Canadian Arctic that could help validate the estimates reported by Majorowicz and Osadetz (2001) and Osadetz and Chen (2005). This is in part because seismic methods remain limited in their ability to detect gas hydrate in this environment, or at least require extensive interpretation. The region's surface terrain also makes field data acquisition difficult. BSRs are not clearly observed in arctic onshore environments. Electromagnetic techniques that have been successful over marine gas hydrate accumulations have not been used in the Arctic to detect and quantify gas hydrate, partly because of the complexity of electrical imaging beneath thick permafrost. However, these techniques are frequently used to detect permafrost thickness and/or permafrost degradation and internal structures (e.g., Palacky and Stephens, 1992; Todd and Dallimore, 1998; Craven *et al.*, 2003).

Mallik Project

Mallik is one of the best-studied gas hydrate occurrences worldwide in a permafrost environment (Dallimore and Collett, 1998, 2005). Gas hydrate was first identified at Mallik in 1971-72 through well-log interpretation and drill-stem tests by Imperial Oil Ltd. at the Mallik L-38 well (Bily and Dick, 1974). Further studies on arctic, subpermafrost gas hydrate were carried out in the 1980s and early 1990s onshore and offshore in the Mackenzie Delta/Beaufort Sea region (Weaver and Stewart, 1982; Judge, 1986; Judge and Majorowicz, 1992). All these studies showed that gas hydrate occurs below thick permafrost (300 to 700 m).

A site-specific evaluation of the gas hydrate volume associated with the Mallik area was first conducted by Collett *et al.* (1999) using large-scale seismic data across Richards Island, Mackenzie Delta (Figure 3.6), followed by two detailed seismic impedance inversion projects using 3-D seismic data (Bellefleur *et al.*, 2006, 2008). The results of these assessments are summarized in Table 3.4. The early assessment by Collett *et al.* (1999) defined approximate gas hydrate volumes for the Mallik, Taglu, and Ivik accumulations (Figure 3.6) based on results from well logs acquired in 11 wells in the area. Lateral extrapolation of uniform layer thicknesses, porosity and concentrations away from the well sites were based on 13 regional seismic reflection profiles provided by Imperial Oil Ltd.

A more detailed assessment for the Mallik accumulation based on acoustic impedance inversion (see the Annex for more information on acoustic impedance inversion) of surface 3-D seismic data (Bellefleur *et al.*, 2006) showed that the Mallik accumulation is likely much smaller in area, and large faults compartmentalize the area around the Mallik wells, which makes the lateral extrapolation of well logs extremely challenging (Brent *et al.*, 2005). The original acoustic impedance inversion was recently refined through better ties with well logs and structural elements, and a new gas hydrate volume was defined (Bellefleur *et al.*, 2008). This new inversion also showed that within the area of the 3D seismic data, two additional promising accumulations may exist near the Mallik P-59 and A-06 wells. However, these potential new accumulations are also restricted in size and coverage, and are not connected laterally.

The difference in the gas hydrate volume estimate in the assessments by Bellefleur *et al.* (2006 and 2008) compared with the assessment by Collett *et al.* (1999) mainly results from a reduction in the lateral extent of where gas hydrate is believed to exist in the Mallik area. Assumptions on gas hydrate concentration, porosity and thickness are similar in all cases. The accumulations near Mallik P-59 and A-06 wells defined by Bellefleur *et al.* (2008) appear to be roughly comparable in size to those around the Mallik 5L-38 well. Including these two additional locations would triple the total volume estimate of gas hydrate reported in Table 3.4 for the Bellefleur *et al.* (2008) assessment, but would still be only about five per cent of the Collett *et al.* (1999) assessment.

Table 3.4

Summary of Gas Hydrate Volume Estimates Associated with Accumulations on Richards Island, Mackenzie Delta

Assessment		Gas hydrate accumulation (solid volume)		
		Mallik	Taglu	Ivik
Collett *et al.* (1999)	(x 10^6 m^3)	670	70	400
	(MMcf)	24,000	2,500	14,000
Bellefleur *et al.* (2006)	(x 10^6 m^3)	1*	N/A	N/A
	(MMcf)	35		
Bellefleur *et al.* (2008)	(x 10^6 m^3)	10*	N/A	N/A
	(MMcf)	350		

*Mallik L-, 2L-, 3L-, 4L-, 5L-38 area only; without accumulations near Mallik A-06 and P-59.

The first major scientific research program at Mallik was conducted in 1998 with Canadian, Japanese and U.S. collaboration. The JAPEX/JNOC/GSC Mallik 2L-38 drill site was established (Dallimore *et al.*, 1999). During the 1998 project, the first subpermafrost gas hydrate core samples were recovered, and a wealth of downhole geophysical, geochemical and geological data were gathered. In 2001-02, the Mallik 2002 Gas Hydrate Production Research Well Program drilled three more boreholes: a main coring hole (in which production tests were conducted) and two observation wells for monitoring a thermal production test (Dallimore and Collett, 2005). This 2002 project also included a set of small-scale pressure drawdown tests (Satoh *et al.*, 2005; Hancock, Dallimore, *et al.*, 2005; Hancock, Okazawa, *et al.*, 2005; Anderson *et al.*, 2005) and related numerical modelling (Kurihara, Funatsu, *et al.*, 2005; Kurihara, Ouchi, *et al.*, 2005; Hong and Pooladi-Darvish, 2005; Moridis *et al.*, 2005). These studies provide unprecedented, detailed information on the distribution of gas hydrate and all other materials within the wells, together with their physical and chemical properties.

The three Mallik programs (1998, 2002, and 2006-08) have provided an opportunity for testing a wide variety of technologies, including advanced well-logging tools for quantifying *in situ* gas hydrate amounts, deployment of downhole monitoring devices to measure reservoir responses to drilling and production testing, and the first scientifically documented gas hydrate production tests by thermal stimulation and depressurization techniques. Although these programs were designed for production testing, they were not designed as conventional industry-style production tests to evaluate commercial recovery. Instead, short-term controlled experiments were conducted to test the response of gas hydrate to changes in pressure and temperature, and to provide critical engineering data to develop, constrain and calibrate gas hydrate production simulators, which would then be used to project long-term response beyond the duration and conditions of the actual tests.

The main findings and implications of the three Mallik programs can be summarized as follows:

- Gas hydrates at Mallik are constrained to certain lithological units in sands and gravel, and lateral and vertical distribution is governed by the occurrence of these lithologies.
- Regional formation at this site is driven by the structural setting of the anticline and heavy faulting, which form pathways for gas migration and a trapping mechanism.

- The results from Mallik and seismic studies show that gas hydrate is not found homogeneously throughout the area, despite favourable thermal conditions.
- Extrapolation is severely hindered by the tectonic setting and is likely valid only for a few hundred metres around the well sites (Bellefleur *et al.*, 2006).
- Small-scale production by thermal stimulation carried out during the 2002 field test showed formation responses of the gas hydrate zones but also demonstrated the limitation in heat transfer away from the wellbore.
- Small-scale production by pressure drawdown carried out during the 2002 field test showed favourable formation responses of the gas hydrate zones for potential sustainable production.
- The 2008 pressure drawdown test achieved a sustained flow of methane over a limited time.

Seasonal infrastructure access limitations currently prevent long-term production testing at Mallik.

3.3 NEED FOR FURTHER EXPLORATION

This chapter has highlighted the lack of geophysical mapping projects to further delineate Canadian gas hydrate accumulations on all coasts and in the Arctic. Various geophysical mapping tools exist and have already been successfully used to delineate known gas hydrate deposits on Canada's west coast along the IODP Expedition 311 drilling transect (seismic methods, CSEM and compliance) and around the Mallik 5L-38 drill sites (seismic methods). Other international applications of the same tools exist — e.g., in the Gulf of Mexico (Dai *et al.*, 2004), and the Alaskan North Slope (Hunter *et al.*, 2007; Inks *et al.*, 2008). Despite these successes, most (if not all) geophysical remote sensing techniques depend on "ground truth" information from drilling and coring to give reliable estimates.

To achieve a more reliable estimate of Canadian gas hydrate accumulations and volumes, intensive field studies, combined with spot coring and drilling, are required, especially in yet under-represented areas such as the east coast and Arctic islands. Acquisition of new geophysical data is complicated in many of these regions because of natural climatic restrictions on access to the area, or limitations on the use of these tools to protect the environment — e.g., the west coast moratoria, discussed in Chapter 5. It is important to develop and maintain state-of-the-art geophysical surveying equipment. Because many of the regions of interest have been charted in the past by industry in the search for conventional hydrocarbon resources, it may be possible to involve the private sector more closely in exploration for gas hydrate deposits in Canada's frontier areas.

Given the restrictions on financial resources and number of qualified personnel in Canada — compared, for example, with the United States or Japan where there are much larger and more aggressive gas hydrate programs — Canada could consider becoming more involved in international collaborations, such as the IODP and the ICDP. Through stronger collaboration with countries that have national gas hydrate programs and plans to carry out new research drilling and geophysical mapping in the near future, Canadian scientists could benefit by gaining knowledge applicable to Canadian projects.

Reliable estimation of the magnitude of an energy resource is important because it has such a large bearing on justifying the investment required for its development. Identifying the magnitude of conventional hydrocarbon reservoirs relies on a combination of geological, geophysical, petrophysical and reservoir-engineering techniques. The evaluation is performed in a sequence of stages, where results from each stage determine whether or not the next stage is justified. In the first phase, geological and geophysical techniques are used to identify potential reservoirs.[23] Next, drilling of exploration and delineation wells confirms the presence of the hydrocarbon reservoir and enables determination of the type and size of the hydrocarbon accumulation.[24] While extensive effort has been invested in improving the identification and quantification reliability of these techniques, more R&D is needed to increase the reliability of estimates of the magnitude of gas hydrate resources. Nevertheless, there are success stories that suggest that the geological and geophysical techniques are being developed to a point where they enable the gas hydrate resource to

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23 This study typically includes identification of the source rock, migration paths, associated reservoir rocks, trapping mechanism and the appropriate timing of events for possible formation of a hydrocarbon reservoir. For gas hydrates, the pressure and temperature of the prospective resource need also to be taken into consideration, such that depending on the gas chemistry and salinity of the water, gas hydrates could be found at a predictable depth (see Figure 2.1, and Collett, 2002). If this indicates enough potential, low- and then-high accuracy seismic measurement and interpretation are used to determine the individual traps and assess the magnitude of the resource.

24 Drilling of exploration wells allows determination of the fluid type, quantification of the reservoir rock and determination of its porosity and fluid saturation through logging and coring techniques, as well as estimation of productivity of the wells through coring and flow-testing. The delineation wells would then determine the fluid contacts and the areal extent of the reservoir, characterize heterogeneity, and enable better characterization of the magnitude and producibility of the resource. The knowledge gained is useful in geological models, characterizing flow units and reservoir connectivity for reservoir and flow modelling.

be determined with enough certainty to justify drilling exploration and delineation wells. For example, Dai *et al.* (2008) reported the success of geophysical techniques in identifying and estimating the gas hydrate concentration in a particular location in the Gulf of Mexico, prior to drilling wells; measurements subsequent to the drilling agreed closely with the pre-drilling assessment. In other cases however, the availability of well data has been essential. The difficulty in assessing the magnitude of the hydrocarbon resource based on geophysical information alone (without well data) is not specific to gas hydrates. For example, the use of so-called "direct hydrocarbon indicators" as a means of evaluating the magnitude of the conventional hydrocarbon resource remains controversial.

Since the early 1980s, it has been acknowledged that the evaluation of the volume of in-place hydrocarbon is inherently uncertain and therefore relies on a probabilistic approach. In the absence of well information, the uncertainty in estimating gas hydrate volumes remains large. The degree of success of geological and geophysical methods in assessing the magnitude of the gas hydrate resource (in place and/or technically recoverable) remains contentious and depends on many complicating factors that must be assessed on a case-by-case basis. Although this area is progressing quickly, assessing the magnitude of the gas hydrate resource in Canada is primarily limited by the lack of geological studies and geophysical measurements targeted at potential gas hydrate accumulations, as well as by unresolved technical and scientific issues specific to gas hydrate accumulations, such as the effect of permafrost on data quality.

CHAPTER ANNEX – STATE-OF-THE-ART TECHNIQUES AND METHODS FOR GAS HYDRATE EXPLORATION

1. Geological Tools and Methods

While exploration for gas hydrates is in many ways similar to exploration for other hydrocarbons, the unique properties of hydrates may well lead to use of new or modified techniques. The definition of a gas hydrate petroleum system is still relatively young (e.g., Boswell and Collett, 2006; Boswell *et al.*, 2007) but is gaining acceptance rapidly.

Petroleum system analysis (PSA) in general is an integrative approach that uses geochemical, geologic and hydrologic data in a basin to conceptually model and simulate basin development from early basin formation, subsidence, structural and tectonic events, hydrocarbon generation, migration pathways, and emplacement through geologic time.

PSA and basin modelling tools constrain the explorationist to a few working models of where hydrocarbon may be present in the basin. PSA and basin-modelling answer the question of hydrocarbon being available in a basin before, at, or after trap formation. PSA helps to minimize exploration risk by assessing exploration areas in a basin with maximum and least potential to find reservoir hydrocarbons.

Gas hydrate-specific aspects of a PSA include defining the gas hydrate stability zone by mapping the pressure and temperature regime, mapping the regional distribution and thickness of suitable reservoir strata (e.g., amount of sand), defining structural elements, providing possible fluid migration (faults and fractures), and defining seals (e.g., impermeable clay beds) and traps.

2. Coring techniques and core analyses for gas hydrate reservoirs

Several coring techniques have been developed over the past two decades for specialized gas hydrate applications. Most of the techniques that involve deep coring (> 100 m coring depth) have been developed solely by the ODP and IODP.

Gas hydrate-bearing cores are first imaged with infrared cameras to detect cold spots from dissociating gas hydrates (e.g., Long *et al.*, 2004). Special sampling routines for gas hydrate-bearing sediments were developed in association with dedicated ODP and IODP gas hydrate research expeditions. Those special routines involved sampling for pore-water geochemistry (mainly chlorinity) and gas geochemistry (head-space and void gas), as well as for microbiology.

Several special pressure coring techniques and non-destructive testing and imaging routines were developed through the ODP and IODP (e.g., Schultheiss *et al.*, 2004; Holland and Schultheiss, 2008). Core sections, up to 1 m in length, can be retrieved with these special tools under *in situ* pressure conditions. Through careful temperature monitoring, the sediment samples are kept within gas hydrate stability conditions.

3. Geophysical Tools and Methods

Historically, the most commonly used geophysical technique for detecting natural gas hydrate has been the reflection seismic method. This method has proven effective for surveying large areas efficiently, although we now know that gas hydrate concentration cannot be inferred from the intensity of reflections from a BSR, nor can the lack of a BSR be interpreted as evidence that gas hydrate is not present. CSEM studies are becoming more common and are an excellent complement to reflection seismic data. They should be used together where possible because they sense different physical properties of the subsurface, thus providing an independent assessment of gas hydrate concentration over the same area.

Seismic reflection profiling is sensitive to changes in the acoustic properties of the subsurface, notably velocity, and allows one to infer the geological structures and depositional environment. Depending on the seismic acquisition parameters — notably frequency and depth of the seismic source and receiver — the lateral and vertical resolution of the seismic data can range from submetre to several tens of metres. In the marine environment, seismic reflection profiling is often used to determine the presence of a BSR, which in most cases identifies the base of the gas hydrate stability zone. It is impossible, however, to infer gas hydrate concentrations from the BSR reflection strength. Instead, a BSR identifies the presence (not the concentration) of free gas below the gas hydrate stability zone and the potential that gas hydrate may be present above the interface. It should be noted that a BSR appears to be absent in most (if not all) onshore gas hydrate provinces. The use of seismic data is challenged in the presence of free gas or in complex geologic structures that alter the seismic response, such as in cold vents (areas of excessive gas migration; see Box 8).

Through special processing steps like impedance inversion (see below), seismic data can be used to quantify gas hydrate concentrations, but reliable results require the calibration of the seismic data with well-log information (velocity and density). Success in these inversions was reported for a few areas including the Gulf of Mexico (Dai *et al.*, 2004), Mackenzie Delta (Bellefleur *et al.*, 2006) and the Alaskan North Slope (Inks *et al.*, 2008). The Japanese have been successful in inferring the presence of gas hydrates in the Nankai Trough by both amplitude and interval velocity data (Tsuji *et al.*, 2004; Fujii *et al.*, 2005).

Multicomponent seismic recordings. Through deployments of seismic receivers on the ocean floor called ocean-bottom seismometers (OBS) or ocean-bottom cables (OBC), it is possible to infer the acoustic and shear-wave velocity structure subsurface in more detail than with surface-deployed techniques. These seafloor-based techniques use a stationary receiver and a moving source (e.g., an airgun) towed and fired from a vessel above it. Much larger offsets can be achieved with this technique than with towed streamers, thus allowing for more accurate velocity analyses. The direct contact of the receiver(s) to the ocean floor makes it possible to detect shear-wave energy directly. There have been many applications of the OBS technique in the academic sciences across several gas hydrate provinces including those in Canada (e.g., Hobro *et al.*, 2005, at the northern Cascadia margin; LeBlanc *et al.*, 2007, at the east coast). However, the OBC technology is still restricted due to the enormous equipment and deployment costs. Applications of the OBC technology have been reported from the Gulf of Mexico (e.g., Hardage *et al.*, 2002), and from the Norwegian margin (Andreassen *et al.*, 2003; Bünz *et al.*, 2005).

Seismic (or acoustic) impedance is the mathematical product of sound velocity and density of the transmitting medium. Acoustic impedance inversion is applied to seismic reflection data. Information on acoustic velocity and density obtained through logging is used for calibrating seismic data at the local well site and then extrapolating this information to a regional scale. It allows interpretation of physical properties sensitive to the quantification of gas hydrate concentration (e.g., acoustic velocity) on a more regional scale for reservoir estimation.

CSEM imaging methods map the electrical resistivity of the subsurface. A time-varying electromagnetic field is generated near the seafloor and induces “eddy” currents in the seawater and the seafloor sediments. Below the seafloor, the currents are transmitted by ions through the conductive salt water in the sedimentary pore space. The progress of these currents with time is a measure of the electrical conductivity of the subsection. Measurements of electric or magnetic fields associated with these currents are made at a remote location. The sedimentary resistivity structure can be deduced from these data. Because gas hydrates are electrically insulating and replace conductive pore water, they can significantly increase the electrical resistivity, and hydrate concentration can thus be inferred.

CSEM experiments provide data that are completely independent of seismic data. Unlike seismic reflection studies, CSEM data are not hampered by the presence of free gas. However, CSEM data alone cannot distinguish among different possible causes of increased resistivity (including free gas, freshened pore water or reduced porosity). Although CSEM data are sensitive to the combination of the resistivity and the thickness of the target, they are particularly useful for evaluating the concentration and distribution of gas hydrate. The geological complexity of the arctic environment hampers the straightforward application of the CSEM technique. Imaging gas hydrate below the electrically resistive permafrost layer is challenging. A well-designed electromagnetic imaging study in the arctic environment should nonetheless be able to map the subpermafrost gas hydrate resistive zone; such a survey has yet to be conducted.

Magnetotelluric (MT) surveys use variations in electric and magnetic fields to probe the earth's deep electrical impedance structure, which can be profoundly affected by the presence of resistive gas hydrate. These variations are often naturally occurring, although artificial sources can be used. In general, MT surveys have lower spatial resolution but much deeper sounding ability than controlled-source methods. An MT survey was recently performed at Mallik, but results are not available as of the release date of this report.

Seafloor compliance uses the relationship between pressure induced on the seafloor by naturally occurring surface waves and the associated movement of the seafloor. These data are gathered by measuring pressure displacement of the seafloor over time. Compliance data are most sensitive to the shear modulus as a function of depth of the underlying sediments. When the ice-like solid gas hydrate displaces fluid pore water, the shear modulus (and hence, shear velocity) of sediments is increased. Compliance data can thus delineate local gas hydrate concentration and distribution by assessing the shear-wave velocity implied by measurement of long-term displacement or acceleration and pressure time series (Willoughby and Edwards, 1997, 2000; Willoughby *et al.*, 2005).

4. Well-logging techniques

Well logging refers to a technique in borehole geophysics, where special tools are lowered into a borehole to measure the physical properties of the subsurface.

In gas hydrate studies, there are several physical properties of special interest used for estimating concentration. These include acoustic and shear velocity, electrical resistivity, and porosity.

Other logging parameters (such as gamma-ray) can be used to help define the lithologic environment (e.g., shale vs. sand, indicating grain size), which is also an important first-order discrimination factor for estimating the occurrence of gas hydrate. The presence of gas hydrate profoundly changes the physical properties of the host sediments. Acoustic and shear velocity, as well as electrical resistivity, are strongly increased in comparison with a gas hydrate-free scenario. In the case of electrical resistivity, this increase can be several orders of magnitude. In combination with porosity, the resource can be evaluated to define the total amount of gas hydrate present in the sediments of interest.

5. Laboratory tools

Various geochemical and physicochemical laboratory tools are used to characterize gas hydrate. Several autoclave systems measure physical properties of gas hydrate-bearing sediments under simulated *in situ* conditions. These provide calibration data for well-log and seismic analyses, and gas hydrate concentration estimates. Results from measurements on gas hydrate-bearing sediments with these various systems are provided by Winters *et al.* (1999), Kulenkampff and Spangenberg (2005), Priest *et al.* (2005), and Uchida *et al.* (2005). Gas hydrate recovered from natural sites can be stored in liquid nitrogen or pressure vessels, and characterized in the laboratory as follows: Visual observation – hydrate morphology; Temperature programmed decomposition in a pressure vessel – Pressure – Temperature zone of stability; Gas analysis (amount and composition) – Gas chromatography/Mass spectrometry; gas isotope analysis (high resolution mass spectrometry) – gas origin (thermogenic/biogenic); Water/sediment ratio and pore size analysis – water saturation; X-ray diffraction – structure and unit cell parameters of gas hydrate; 13C nuclear magnetic resonance (NMR) spectroscopy – gas hydrate structure, composition and guest distribution (hydration number); Raman spectroscopy – gas hydrate structure and sample homogeneity; Calorimetry – gas hydrate decomposition characteristics.

From the water saturation level and gas hydrate composition, one can obtain the conversion of water to gas hydrate. For samples that have experienced dissociation of gas hydrate during core recovery, analysis of pore-water chemistry — especially determination of Cl and SO4 concentrations — is widely used for estimating the conversion of water to gas hydrate in sediments. In such a case, a pore-water squeezer and ion chromatography are needed.

4. THE PRODUCTION OF NATURAL GAS FROM GAS HYDRATE

4.1 UNCONVENTIONAL HYDROCARBON DEVELOPMENT IN CANADA

Chapter 3 described the current state of knowledge as to the estimated amount and locations of gas hydrate in Canada. The next consideration is of factors that bear on the potential for commercial extraction of natural gas from gas hydrate. Because of the lack of experience with commercial production at a field scale, the producibility of gas from gas hydrate can be assessed by analogy with the technology used in commercializing other unconventional resources — e.g., coalbed methane (CBM) and oil sands.[25] It is emphasized that once gas has been dissociated from the hydrate phase and collected from a well, it is like conventional natural gas, the handling and marketing of which are familiar.

The current state of knowledge about the producibility of gas hydrate is analogous to the understanding of CBM or oil sands about three decades ago. The analogy goes beyond their similar classification as an unconventional, and potentially very large, resource. For both CBM and gas hydrate, for example, the natural gas is trapped (or adsorbed) within a solid structure and needs to be released before it can be produced. In both cases, release of natural gas can be initiated by reduction in pressure, which may be facilitated by production of the associated fluids (water or gas).

A common motivating factor in the development of gas hydrate and other unconventional hydrocarbons considered here is their significant resource size in Canada, which, in the case of gas hydrates, as reviewed in Chapter 3, could be one or more orders of magnitude larger than conventional hydrocarbon resources.

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25 As reviewed in Chapter 3, there is only one known example of long-term gas production from a naturally occurring gas hydrate resource in the world, where about one-third of the total gas produced from the Messoyakha field is estimated to be from the gas hydrates (Makogon, 1981). Several studies have suggested, however, that gas hydrate may not have significantly contributed to gas production in the Messoyakha field (see Collett and Ginsburg, 1998). Except for Messoyakha and short-term production tests at Mallik and Mt. Elbert from the Eileen accumulation in Alaska, no other production from gas hydrate reservoirs is known.

While both CBM and oil sands took several decades to become commercially viable (Bolger and Isaacs, 2003; *Unconventional Gas Technology Roadmap*, 2006), it is too early to judge whether the development horizon of the gas hydrate resource will be longer or shorter. The development of CBM and oil sands required new technologies. In Alberta for example — and with the exception of the small fraction of the oil sands that are shallow enough to be mined — attaining commercial production required development of horizontal well technology and the concept of Steam-Assisted Gravity Drainage (SAGD; see Box 9 for more information on SAGD). While it can be expected that gas production from gas hydrate will also be facilitated, perhaps significantly, by innovative and "out-of-the-box" ideas (Sloan, 2003; *Unconventional Gas Technology Roadmap*, 2006), this chapter limits its attention to technologies *currently available* for production of hydrocarbons.[26] While gas hydrate recovery techniques using non-well-based methods have been suggested (e.g., using mining techniques), as explained in section 4.2, the panel considers here only the well-based techniques more commonly used for hydrocarbon production.

Box 9 **— Oil Sands Development**

The following brief review of the development of the oil sands summarizes some of the factors that led to the development of successful technology for oil sands production from underground reservoirs.

Fundamental, laboratory and modelling research (pioneered by the late Dr. Roger Butler, University of Calgary, 1994) developed the concept of SAGD for oil sands production. The provincial government's Alberta Oil Sands Technology and Research Authority (AOSTRA) facilitated the pilot testing of this technology at an Underground Test Facility (UTF). This pilot test proved the applicability of SAGD as a viable technology for commercial production of the oil sands, while identifying a number of other technology developments that needed to take place.

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26 This discussion does not include some recently developed advanced oil and gas production methods because gas hydrate production schemes have not considered and evaluated them to date. Gas hydrates that are in close proximity to existing conventional oil and gas production sites may provide opportunities for testing methods such as downhole heating methods (including *in situ* combustion, electromagnetic heating, and downhole electrical heating), and advanced drilling techniques and complex downhole completions (including horizontal wells and multiple lateral wells).

The UTF site, with a continuous high-permeability sand of high bitumen content, exhibited characteristics of a sweet spot for SAGD. According to S. Asgarpour, president of the Petroleum Technology Alliance Canada (personal communication, June 2007), direct government investment and ownership of the Syncrude project and the Husky upgraders encouraged investment in upgrading and mining. Government investment took place when oil prices were depressed. A new oil sands royalty regime was also of great help in that, prior to pay-out, the government royalty was limited to one per cent of gross revenue. In other words, the government shared the upfront investment risk with developers and reduced their investment risk. The royalty regime has been responsible for encouraging huge investment in oil sands and upgrading. It is estimated that the Government of Alberta spent over $600 million to develop mining and *in situ* technologies, of which more than $80 million was to develop SAGD technology. (For a detailed account of the Government of Alberta's role in oil sands development, see Bolger and Isaacs, 2003, and publications of the Alberta Energy Research Institute.)

Experience with test wells at Mallik and elsewhere suggests that most problems in drilling and completion[27] of gas hydrate wells can be foreseen and successfully dealt with at the design stage, including using:

- chilled drilling fluids with appropriate chemistry to limit gas hydrate decomposition during drilling (see section 4.4 below for details)
- appropriate sand control methods to restrict the flow of sand into the wellbore
- ports for injecting chemicals and provisions for near-wellbore heating to remedy any plugging that may occur due to freezing or gas hydrate re-formation, and
- monitoring devices for measuring pressure and temperature.

Hancock, Okazawa, *et al.* (2005) anticipated that production of gas from gas hydrate would require pumps to remove the water that is produced when the hydrate dissociates ("melts") or that may co-exist with the hydrate, and

27 Completing a well (completion) may be defined as a series of mechanical operations conducted to obtain and maintain effective transfer of fluid(s) between the reservoir and the wellbore.

compressors for transportation of the produced gas.[28] Campaigns in Japan and India have been successful in drilling tens of gas hydrate wells in a span of a few months (Matsuzawa *et al.*, 2006). Long-term experience is required to better understand the severity of problems that may be associated with gas production from gas hydrate, including problems with sand flow. Nevertheless, it appears that the technology exists, or will be developed, to overcome such problems. While problems may affect the economy of the operations, they are not expected to be technically insurmountable (Bement *et al.*, 1998).

4.2 PRODUCING NATURAL GAS FROM GAS HYDRATE

Gas hydrate in Canada occurs in different settings and with different characteristics that have major implications for their producibility. Based on current knowledge, the technical assessment of producibility is most readily carried out if the gas hydrate is contained within sand formations at temperatures above the freezing point of water, whether below permafrost or in marine sands. The establishment of pathways for flow of gas (and its production) is possible in unfrozen coarse sediments (sands).

Gas hydrate can also occur in fine-grained sediments — e.g., clays and silts, which often contain low concentrations of gas hydrate — as well as in fractures, veins and small lenses. While flow may be established in such systems on a local basis, the continuity of the permeable media, which is needed to allow production of a significant amount of gas from the gas hydrate, is not demonstrated and has little analogy with other conventional hydrocarbon production. Finally, massive gas hydrates concentrated in and around vents seeping methane at the ocean floor are excluded from analysis of producibility in this section. The lack of knowledge about the extent of the technical, environmental and safety uncertainties surrounding these categories means that producibility cannot be assessed at this time.[29]

The hierarchy for the feasibility of producing natural gas from gas hydrate can be illustrated schematically as a pyramid (see Figure 4.1). Gas hydrates occurring in different sediments (or of different conditions) are colour-coded.

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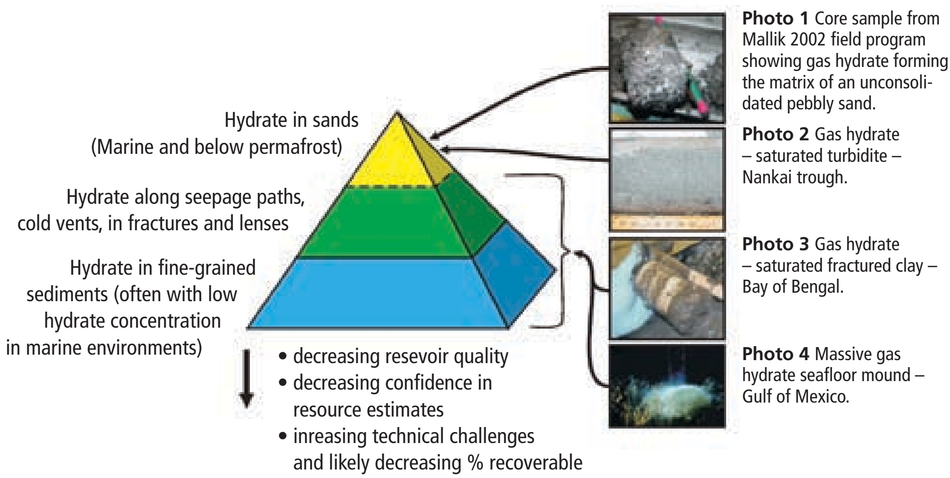
28 The water may be a product of gas hydrate dissociation, or the water that already co-exists with the hydrate. Hancock *et al.* (2005) foresaw that gas from gas hydrate would be produced at the lowest possible pressure (to achieve maximum rate of decomposition of the hydrate), requiring compression for the transportation of the gas.

29 It is believed, nevertheless, that long-term research and development will explore out-of-the box ideas for development of gas hydrates in all settings.

The vertical distance below the apex of the pyramid indicates, qualitatively, the relative ease of producibility. At the top of the pyramid are gas hydrates in sands that are warmer than the freezing temperature of water (under permafrost or marine). Below are gas hydrates along seepage paths, and in fractures and lenses. At the base of the pyramid are gas hydrates in fine-grain sediments that exhibit little permeability.

The initial focus of experiment and exploration would naturally be the pyramid apex.[30] These sands can be expected to have the fewest technical complications, and hence their producibility can be assessed with reasonable reliability. Consistent with this, a recent study of the gas hydrate resource in the Gulf of Mexico by the U.S. Department of Interior included an evaluation of the gas hydrate volumes of all types shown in Figure 4.1. However, further examination of the technical and economic factors in the Gulf of Mexico will consider gas hydrates in sands only.



(Boswell and Collett, 2006)

Modified and reproduced with permission from Ray Boswell and Timothy Collett.

(Photo 1: courtesy of Mallik 2002 R&D program; Photo 2: courtesy of MH21 Research Consortium, Japan; Photo 3: courtesy of the India NGHP Expedition 01; Photo 4: courtesy of Ian R. MacDonald, Texas A&M University – Corpus Christi)

Figure 4.1

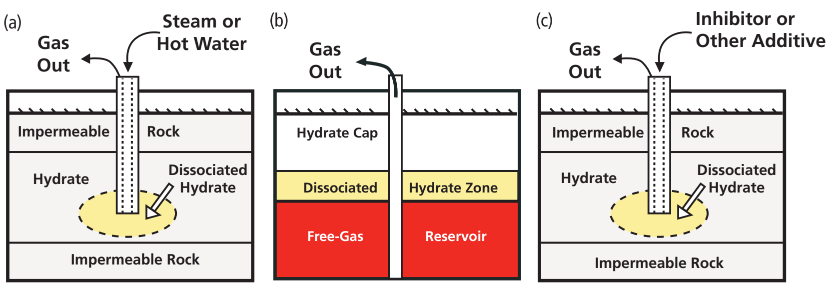
A schematic representation of technical producibility of the gas hydrate resource, with the easiest on top

30 The information that is currently available does not allow identification of the portions of the Canadian gas hydrate resource that would fall into each of the three categories shown in Figure 4.1.

Potential Production Methods

The production of natural gas from gas hydrate is challenging, in part because of its solid form. Proposed recovery methods usually begin by dissociating, or "melting", a gas hydrate reservoir into the constituents of natural gas and water in the reservoir, followed by production of the gas via a well. This is analogous to production of gas from coal wherein the gas is released from the coal in the reservoir, and then extracted.

Because gas hydrate is stable only under certain pressure/temperature conditions, the two most commonly proposed techniques for producing gas from gas hydrate rely on changing the pressure and temperature environments (Makogon, 1981; Sloan, 1998). Thermal stimulation heats the gas hydrate beyond its zone of stability, while depressurization decreases the pressure below the point of gas hydrate equilibrium at a prevailing temperature. A third technique relies on shifting the gas hydrate stability conditions by injecting an inhibitor such as methanol or glycol or other additive (Makogon, 1981).



(Collett, 2002)
Modified and reproduced with permission from Timothy Collett.

Figure 4.2
Schematic of proposed gas hydrate production methods: (a) thermal injection (b) depressurization, and (c) inhibitor or other additive

Initial economic evaluations show that gas recovery by injecting an inhibitor is probably the most expensive method (Collett and Kuuskraa, 1998), and there would be high environmental costs associated with using large volumes of chemicals like methanol. For an equal volume of gas produced, thermal stimulation is significantly more expensive than depressurization (Collett and Kuuskraa, 1998). While early studies based on energy balance calculations (Holder *et al.*, 1982) suggested that the amount of energy that can be produced from typical gas hydrate-bearing reservoirs is many times more than the heat required to decompose the hydrate, a number of subsequent modelling studies have shown that the effectiveness of transferring heat from the wellbore to the dissociating gas hydrate deep inside the reservoir is so low that success of thermal stimulation techniques would require innovative solutions (Collett, 2002)[31] and/or combinations with other methods. Studies such as that of Collett and Kuuskraa (1998), combined with modelling results indicating reasonably high gas production rates — exceeding 0.1×10^6 m^3/day from some reservoirs (Moridis, 2003; Hong and Pooladi-Darvish, 2005) — have focused attention on depressurization. This is commonly considered the most economically promising method of producing gas from gas hydrate. In decomposition by depressurization, wellbore production leads to fluid flow and consequently to pressure reduction within the reservoir. This reduced pressure, when transferred to the fluid surrounding gas hydrate particles in pores, destabilizes the gas hydrate. The generated gas flows towards the wellbore and to the surface.

Decomposition of gas hydrate into gas and water is endothermic — i.e., it absorbs heat and thus causes cooling of the surrounding medium. Continued decomposition of gas hydrate therefore may also require a source of heat. When no artificial heat is introduced into the reservoir, the heat of decomposition must be supplied from the gas hydrate-bearing reservoir and its surrounding formation. Studies have indicated that heat transfer could be the rate-controlling step in the overall decomposition process (Selim and Sloan, 1990; Hong and Pooladi-Darvish, 2005). Therefore, success of the depressurization method, when applied alone, in achieving high gas production rates relies on (a) reducing the pressure over a sufficiently large volume of the gas hydrate-bearing sediment, and (b) the availability of heat.

The *potential* for producibility of gas from gas hydrate can be evaluated based on an analogy with the production of other hydrocarbons or by modelling studies calibrated against laboratory experiments and short-term field tests on naturally occurring gas hydrates. In general, modelling and experimental evaluations identify an estimate for recoverable gas hydrates. More realistic estimates could only be obtained after pilot tests and predevelopment trials. The following discussion focuses principally on the depressurization technique but many of the relevant factors apply also to other methods, including thermal stimulation.

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31 As stated previously, effective thermal methods, such as the use of geothermal fluids, may be developed in the future for gas production from gas hydrate reservoirs.

The *Unconventional Gas Technology Roadmap* (2006) has suggested "sweet spot" identification (i.e., finding locations with particularly favourable conditions) as one of the two major objectives for long-term research into all unconventional gas. This two-pronged approach, which involves targeting field-development of sweet spots (encouraged by government incentives) along with long-term, low-cost R&D by universities and other research organizations, has proven successful in CBM development in the United States, as well as in the development of the oil sands in Alberta. Even in unfrozen sands, there remains a large variation in the development suitability of a given gas hydrate resource. In the following, the factors affecting the technical and economic producibility of gas hydrate in unfrozen sands are reviewed to identify (a) particular gas hydrate reservoirs that may be considered sweet spots, and (b) the particular technology requirements for successful future development of these sweet spots and those of lower attractiveness.[32]

The producibility of gas from gas hydrate is affected by a number of geological and geophysical factors including:

- availability and type of the free fluid (liquid water or natural gas) in contact with the gas hydrate
- thickness of the free fluid phase
- temperature, pressure, gas composition and salinity (these parameters determine the stability of the gas hydrate)
- availability of a seal
- reservoir permeability and porosity
- gas hydrate concentration
- reservoir thickness and volume of the gas hydrate interval
- lithology (i.e., the type of sediment formation and its physical character in terms of grain size), and
- gas hydrate reservoir heterogeneity (with respect to spatial distribution of hydrate concentration, rock properties, etc.).

Knowledge about these factors is needed for evaluating and prioritizing gas hydrate accumulations in Canada and, in particular, for identifying some initial sweet spots from which further learning can occur. The availability and type of fluid below the gas hydrate is of significant importance because the volume of gas hydrate that may be accessed by a production technique such as depressurization — and the rate of heat transfer required for gas hydrate

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32 Demonstrating success of the SAGD technology at the Underground Test Facility site (a sweet spot) constituted a major step towards commercial development of the oil sands using SAGD.

dissociation — are strongly affected by the presence of an underlying fluid. The most promising type of gas hydrate appears to be that underlain by free gas.

Producibility with Underlying Free Gas

When there is underlying free gas, production of gas from the gas hydrate can proceed in a manner similar to a conventional hydrocarbon reservoir by producing from the underlying free gas. This would initiate pressure reduction and decomposition across the gas hydrate/free gas interface. The free gas facilitates a large area for heat transfer and a large volume of dissociating gas hydrate. The gas generated from the dissociating gas hydrate supplements the gas produced from below, and extends the life of the free-gas reservoir.

Makogon (1981) reported that in the Messoyakha reservoir in Siberia — where part of the reservoir is free gas lying below the base of the gas hydrate stability zone — production of the underlying conventional gas led to the decomposition of the overlying gas hydrate by spontaneous depressurization. The only technical challenge reported in this case was due to frequent plugging by ice and/or gas hydrate re-formation, requiring injection of anti-freeze solutions. Several studies have suggested, however, that gas hydrate may not have significantly contributed to gas production in the Messoyakha field (see Collett and Ginsburg, 1998); hence no definitive conclusions can be drawn from this example.

Modelling indicates that for a gas hydrate accumulation with underlying gas, a significant portion of the gas hydrate could decompose naturally at promising rates (Masuda, 1993; Collett and Moridis, 2003; Hong and Pooladi-Darvish, 2005; Mohanty *et al.*, 2006). Some of these studies suggest that the thickness of the underlying free gas is not important. As long as a layer of free gas exists over an extensive area beneath the gas hydrate-bearing sands, pressure could be reduced effectively, and sufficient heat would be available for reasonably high rates of gas production. These studies suggest that anti-freeze agents or heating may be required, but only on a local basis and around the wellbores, provided that the operating conditions are designed to avoid excessive cooling (Pooladi-Darvish, 2004).[33]

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33 Excessive cooling could lead to self-preservation of gas hydrate, where a thin layer of water produced as a product of decomposition freezes around the gas hydrate particle, restricting its further decomposition (Handa, 1986a; Ershov and Yakushev, 1992; Yakushev and Collett, 1992). Similarly, the frozen water can plug the porous media, thus restricting fluid flow and further decomposition.

Methods for predicting the performance of gas hydrate reservoirs with underlying free gas have now advanced to the point where simple reservoir engineering models, analogous to those for conventional hydrocarbon reservoirs, have been developed. These allow determination of gas production rates and gas hydrate recovery (Gerami and Pooladi-Darvish, 2006; 2007). Such models incorporate probabilistic estimation, taking into account the uncertainty in properties associated with gas hydrate reservoirs. There do not appear to be any fundamental technical barriers to the development of gas hydrate reservoirs with underlying free gas. This strengthens the possibility that gas production from sweet spots could be accomplished technically within the next 10 years (Sloan, 2003). Nevertheless, the reliability of these models, as well as more sophisticated numerical models, remains uncertain as they have not been tested against long-term field data. Instead, these are being compared with one another in studies coordinated by the U.S. DOE, where Canadian, U.S. and Japanese modellers interact (Wilder *et al.*, 2008).

Producibility with Underlying Free Water

When the underlying fluid is water, depressurization may be achieved by producing (i.e., removing) the water. There are environmental and economic issues surrounding the handling of the produced water, as well as restrictions on the production of gas arising from the presence of the water (requiring additional pumping equipment). A modelling study that took into account operating and capital cost estimates indicated that the production of gas from gas hydrate with underlying water is less economically attractive than from gas hydrate with underlying gas (Hancock, Okazawa, *et al.*, 2005). An extensive water zone could restrict the extent of pressure reduction in the reservoir owing to water flow towards the wellbore. However, the relationship between the extent and the permeability of the water-bearing sands and the recoverability of the gas from gas hydrates is not fully understood. More research is required to better understand the economic and environmental issues of such operations. Ultimately, pilot and predevelopment field tests will be required to prove technical and economic recoverability of these gas hydrates.

Producibility with No Underlying Fluids

The rate of gas production from gas hydrate reservoirs without underlying free fluids — i.e., bounded by impermeable sediments at top and bottom — remains uncertain. In the presence of underlying free gas, as described above, the low pressures created at the wellbore propagate quickly through the free-gas zone, affecting the overlying gas hydrate over a large area. Without an underlying fluid, the pressure reduction at the wellbore has to propagate through the gas hydrate zone itself. The ease of fluid flow and pressure reduction (quantified by the permeability) in a rock partially filled with solid gas hydrate is much less than in the same rock filled with fluids.

The measurements at Mallik (Hancock, Dalimore, *et al.*, 2005; Kurihara *et al.*, 2005), and those at Mount Elbert, Alaska (Wilder *et al.*, 2008), indicate that the effective permeability in the presence of gas hydrate is four to six orders of magnitude smaller than in the absence of solid gas hydrate. As confirmed at the Mt. Elbert test well in Alaska (Hunter *et al.*, 2007), the low permeability severely restricts the rate at which the gas hydrate zone could decompose around the wellbore.[34] The reduction in permeability of the gas hydrate-bearing formation depends strongly on the gas hydrate concentration and its distribution within the pore space. Lower gas hydrate concentrations result in higher effective permeabilities, everything else being equal. However, this relation is not well understood.

A number of ongoing studies in Canada and elsewhere are underway to explore the permeability of sands with solid gas hydrates within, and to better incorporate these findings in reservoir modelling. Some of these studies suggest that in the absence of any underlying fluids, a number of other factors (including pressure, temperature and hydrate saturation) need to be favourable for economically attractive flow rates from gas hydrate accumulations to be possible (e.g., Moridis and Reagan, 2007; Zatsepina *et al.*, 2008).

Other Factors that Influence Producibility

There are several other factors that could affect technical and economic production of gas from gas hydrate reservoirs. For example, while conventional hydrocarbon accumulations require a top seal — since otherwise the hydrocarbon would have escaped — gas hydrates, because of their low permeability, might create their own seal in some areas. It is not well understood how the absence of an external seal might affect technical producibility of a gas hydrate accumulation.

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34 An analogy is the melting of ice vs. the melting of snow. While ice (at zero permeability) melts at the surface only, snow can melt more quickly because it melts from within, as well as from the surface. While ice melts based on propagation of heat, gas hydrate could decompose based on propagation of (reduced) pressure. Since propagation of pressure is generally much faster than that of heat, the effect of decomposition from within is much more for gas hydrate as compared with ice or snow.

The temperature of the gas hydrate-bearing zone is another important factor that affects the rate of gas production. The further the zone is above the freezing point of water and the closer to the equilibrium dissociation temperature (at the prevailing pressure), the more heat there will be for decomposition and the less chance there will be of pore-water freezing and/or gas hydrate plugging.

Factors such as saturation, thickness and heterogeneity, which affect producibility of conventional hydrocarbons, also affect production rates from gas hydrate. These factors are traditionally studied on a case-by-case basis. If and when the economic viability of a particular gas hydrate accumulation is assessed, established technologies for production of conventional reservoirs (such as horizontal wells, fracturing, etc.) could be applied.

Canadian Production Testing Experience

Canadian gas production testing from gas hydrate may need to follow the strategy of other unconventional resources, where testing of sweet spots provided the necessary confidence for further development. For example, in the case of development of oil sands in Alberta, the UTF may be considered to have been a sweet spot with a number of favourable conditions as discussed in Box 9.

The focus of gas production testing from gas hydrate in Canada has been at the Mallik site in the Mackenzie Delta. The gas hydrate resource in the Mackenzie Delta/Beaufort Sea area is the most attractive Canadian gas hydrate source investigated to date, provided that a Mackenzie Valley pipeline is eventually constructed. Among other attractive features of the gas hydrate accumulations in the Mackenzie Delta are:

- their onshore location
- the sandy nature of the gas hydrate-bearing formations
- better estimates of possible resource amount and delineation than for other locations in Canada, and
- the extensive experience gained at Mallik.

The Mallik accumulation is the only reservoir in Canada that has been studied in enough detail to permit sufficient analysis of production rate and volume.[35]

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35 Such reservoir modelling studies have been conducted by the Japanese, in preparation for the long production tests conducted in winter 2007 and 2008. These are not yet publicly available. The study conducted by Hancock et al. (2005) is a first step in this direction.

Gas hydrate-bearing sands of extensive thickness with high concentrations of gas hydrate have been confirmed. Some of these sands were at sufficient depth (and temperatures) to suggest that adequate rates of heat flow may be sustained naturally, provided an underlying fluid exists. While the information from the Mallik studies in 1998 suggested that underlying free gas may be present, the 2002 results showed that the underlying fluid is most likely water with a potentially small amount of gas. It is possible that gas hydrates with underlying gas exist in untested portions of the Mackenzie Delta region. A combination of seismic and logging techniques, as well as mapping the base of the gas hydrate stability zone, may be used to suggest the type of underlying fluid. Based on this information, initial reservoir modelling studies can be conducted to (a) examine the possible rates of gas and water production, and (b) explore the factors and parameters with the largest effect on the results (e.g., extent of the water zone, heterogeneity, strength of the sand following dissociation).

4.3 ECONOMICS OF GAS HYDRATE EXPLOITATION

Studies of the economics of gas production from onshore and offshore gas hydrate are limited (Hancock, Okazawa, *et al.*, 2005; Hancock, 2008). Those that do exist suggest that a number of factors interact to make gas production from a gas hydrate accumulation more costly than from comparable conventional gas reservoirs because a gas hydrate reservoir is predicted to:

- produce at a lower rate, primarily because of rate-limiting heat transfer required for continued dissociation.
- require compression from the beginning — since low pressure is required to initiate dissociation — and the compressor needs to be designed for peak or plateau production rate. Conventional gas reservoirs may require compression towards the end of their life, often when gas production rates have significantly declined.
- require more expensive completion due to:
  - the production of more water, therefore requiring lift and disposal of the produced water
  - the need for chemical injection equipment and/or local heating to avoid gas hydrate (re)formation and plugging, and
  - the application of suitable techniques to avoid production of sand.

Modelling results (e.g., Moridis and Reagan, 2007; Zatsepina *et al.*, 2008) indicate that production of gas from gas hydrate will be at a stable rate for a long time, or even at an increasing rate over time, in contrast with the production behaviour of conventional gas where a faster decline rate is typical. For comparable total volumes of produced gas over the lifetime of a well, the net present value of the revenue stream would usually be greater for conventional gas production.

It is also possible that producible gas hydrate reservoirs can be exploited in regions of the world where conventional gas does not exist, thus reducing the cost of transportation and increasing the security of supply.

Gas Transport Infrastructure[36]

In the Canadian context, it appears that gas production from gas hydrate would be more expensive than conventional frontier gas (e.g., the Mackenzie Delta). However, if the pipeline infrastructure was in place to connect Mackenzie Delta conventional gas to markets, the incremental cost of producing and connecting some gas from gas hydrate would likely be modest and competitive. Onshore gas-from-hydrate projects close to such a pipeline and those involving gas hydrate over free gas would be the least costly and most competitive. In general, the prospects for significant gas production from gas hydrate in Canada over the next 20 years or so depend on government policy decisions. These prospects also depend on commercial decisions of energy companies affecting whether or not infrastructure is put in place where favourable gas hydrate deposits exist in close proximity to conventional gas reservoirs.

The *Unconventional Gas Technology Roadmap* (2006) argues that the lack of transportation systems to bring natural gas from gas hydrate to market is the critical issue facing gas hydrate development in Canada. Further development of Mallik, or other gas hydrate accumulations in the Canadian Arctic, is therefore unlikely unless and until the Mackenzie Valley or other similar pipeline access is in place. Construction of the necessary infrastructure will require a huge capital investment. To underpin such a large investment, the energy sector must have confidence that the gas deposits are large, of high producibility and exploitable with known technology. This is precisely the situation with the Mackenzie Valley pipeline and the anchor fields of Taglu, Parsons Lake and Niglintgak, which have estimated recoverable gas reserves of approximately 170×10^9 m^3 (6 Tcf) over a 25- to 30-year life.

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36 Application of clathrate hydrate crystallization offers the possibility of the development of innovative technologies for natural gas storage and transportation. The idea is to convert natural gas to gas hydrate (gas-to-solid technology) and then store or transport it. Japan and Norway pioneered this technology, which has been demonstrated at a pilot scale (Susilo, 2008).

Secondary conventional gas opportunities have already been identified at Cameron Hills, Northwest Territories, and in the Beaufort Sea. If the pipeline were built, gas hydrate development could also be considered in the mix of options available to energy companies. If energy companies were familiar and comfortable with gas production from gas hydrate, it is conceivable that gas hydrate exploitation could occur before offshore Beaufort conventional gas in the development schedule.

An attractive prospect appears to be the Mallik gas hydrate resource in view of its location between the Beaufort Sea and the anchor fields (Mallik is about 20 km from the planned Taglu development hub). Furthermore, the nature of gas hydrate means that, despite a lower rate of production than from a comparable reservoir of conventional natural gas, gas from gas hydrate is expected to have a more sustained productive life, which is advantageous from the perspective of gas pipeline companies. This is a positive feature in terms of the development of pipeline and related infrastructure. In general, given the scale economies and long lives of such assets, confidence in the ability to keep utilization rates stable over a long period is a key determinant of economic viability.

The costs of finding and developing *offshore* hydrocarbon resources are sufficiently large that only a handful of major oil and gas companies are involved in these projects. The costs associated with offshore unconventional development would be even larger. Development prospects off the Pacific coast are further complicated by a general moratorium on all offshore energy exploration and development (see Chapter 5 for more information). Even on the Atlantic coast, where conventional oil and gas production is already established, existing production platforms are so few and far between that the lack of adjacent infrastructure would likely have a significant negative effect on the economics of production of gas from gas hydrate.

Data gathering is important for the development of gas hydrate in the vicinity of the conventional hydrocarbons. For example, in developing conventional gas in the Mackenzie Delta, while the initial target of companies is formations deeper than the gas hydrate-bearing sediments, measurements over the shallower (gas hydrate-bearing) intervals would allow the commercial potential of such gas hydrate reservoirs in the future to be assessed. In the absence of such data, the incentive for future development of the gas hydrate would appear to be much reduced.[37]

Natural Gas Price Scenarios

Natural gas accounts for 30 per cent of Canada's total primary fuel usage and is a large contributor to Canada's exports and government revenues.[38] In its recent examination of Canada's energy futures, the National Energy Board (NEB) projected natural gas supply and demand, and estimated prices, to 2030 under a range of scenarios that included, in addition to "continuing trends," cases where (a) environmental considerations were assumed to curtail gas production relative to trend; and (b) security of domestic supply considerations led to production being maintained roughly at, or even above, current levels (NEB, 2007). Within these scenarios, which sought to capture key uncertainties with respect to future policies, geopolitics and energy prices, the NEB did not include any production of gas from gas hydrates before the 2030 horizon of the scenarios.

A critical determinant of the prospects for commercial gas hydrate exploitation will be the cost of delivered production relative to the likely range of market prices for gas. Although these estimates would of course be revisited as the time for investment decisions approaches, the NEB's most recent natural gas price projections (2007) associated with its supply and demand scenarios through to 2030 cover a range from about $US6 per thousand cubic feet (Mcf; about $US5.70/gigajoule, GJ) to about $US12/Mcf (or about $US11.40/GJ) based on delivery at Henry Hub, Louisiana (the reference point for North American gas prices.) Taking into account the average costs of transportation, this range would translate into approximately $US5/Mcf ($US4.75/GJ) to about $US11/Mcf ($US10.45/GJ) measured at AECO-C,

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37 There is an analogy with CO_2 storage. While Encana was interested in CO_2 injection in its Weyburn reservoir in Saskatchewan for enhanced oil recovery, the government facilitated and encouraged a number of concurrent measurements and studies that might eventually lead to more effective means to sequester CO_2 underground to reduce greenhouse gas emissions into the atmosphere (*IEA GHG Weyburn CO_2 Monitoring & Storage Project – Summary Report 2000–2004*. In: M. Wilson and M. Monea (eds.)).

38 For example, in 2005 total gas production was 6.24 Tcf (0.18×10^{12} m^3), of which 3.72 Tcf (60 per cent) was exported. At an average price of $C7/Mcf, this translates into a total annual value of production of about $C44 billion and total annual exports of approximately $C26 billion (CAPP, *Statistical Handbook*).

the main gas hub in Alberta.[39] A rough estimate of the cost of transportation from the AECO-C hub to the Mackenzie Delta (assuming the Mackenzie or similar pipeline were to be constructed) would be around $US3/Mcf or possibly higher.[40] This would mean that the current NEB gas price forecast range noted above would translate into prices of between $US2/Mcf ($US1.90/GJ) and $US8/Mcf ($US7.60/GJ) measured at potential northern supply areas in the Mackenzie Delta region.

It is not possible to accurately forecast future energy prices, and these price scenarios simply reflect the most likely range of paths at the time the scenarios were generated. Given this, what can be said is that as of 2007 when the NEB's forecasts were developed, it would appear that in order to have a reasonable prospect of being considered viable, gas from northern onshore gas hydrate projects would have to be able to deliver gas to the northern inlet of the transportation system at costs well within this range (i.e., $US2/Mcf and $US8/Mcf or, assuming a long-term exchange rate of $US0.90 = $C1, within a range of approximately $C2.15/GJ to $C8.50/GJ).[41]

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39 AECO-C stands for the Alberta Energy Co.–Calgary hub. It is the main pricing point for Canadian natural gas.

40 See Wright Mansell Research, *An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development-Extended Analysis and Update* (prepared for the Government of the Northwest Territories, November 2007). Note that the transportation cost would likely be significantly higher in the early years of operation of the pipeline.

41 The price of gas in North America traditionally has some very rough correlation with the price of oil owing to a degree of substitutability between the two fuels. Since the recent world price of oil has substantially exceeded the longer-range prices assumed in the NEB scenarios, it might be thought that the NEB projected (real) gas prices for 2030 are much too low. While the existence of very substantial forecast uncertainties is acknowledged, it should be noted that (a) supply and demand conditions in domestic gas markets and global oil markets can be very different and thus the gas-oil price correlation could be very different in the future than in the past, and (b) the current spike in oil prices may or may not reflect the future. In the event that gas prices in the medium to longer term do exceed the NEB scenarios, the viability of gas from gas hydrate would be improved, other things being equal.

Prices and Gas Hydrate Producibility

Many technical issues concerning the production, safety and environmental costs associated with gas hydrate remain to be addressed. Until these are resolved, one cannot be definitive about the commercial viability of gas hydrate. At present, one can only provide a general indication of the likelihood that significant gas production from gas hydrate will be economic in the future.

It is generally believed that commercial development would most likely occur first in Arctic regions (U.S. DOE, 1998:80). The tests at Mallik mean that far more is known about this gas hydrate field than others in Canada. For that field, preliminary estimates by NRCan suggest that total capital and operating costs for onshore gas hydrates could be in the range of about \$C5 to \$C6/Mcf (or about \$C4.75 to \$C5.70/GJ) for gas hydrate over free gas to about \$C6.50 to \$C9.50/Mcf (or about \$C6.20 to \$C9.00/GJ) for gas hydrate over free water (Osadetz *et al.*, 2007: 8).[42] Osadetz *et al.* suggest that it is likely that some gas from onshore gas hydrate formations in the Mackenzie Delta could be commercially produced through depressurization at 2004 gas price levels if transportation were available.

Given the earlier noted range of expected future gas prices netted back to the inlet of a potential northern gas pipeline, and given the rough estimates of capital and operating costs for onshore gas hydrate over free gas of \$C4.75/GJ to \$C5.70/GJ, when royalties, taxes and returns to capital are included, it would appear that the costs of this gas could be competitive if gas prices were sustained near the upper end of the NEB gas price scenarios. Production of gas from gas hydrate with underlying free water or no underlying fluids would be more costly and require significantly higher prices to be economically viable.

Expressed differently, it can be argued that in a world such as that envisioned under the NEB's "Fortified Islands" scenario — i.e., where security of domestic supply becomes paramount — the economics of production of gas from gas hydrate, at least over free gas, may be attractive and could be profitable if the transportation infrastructure were in place. Further, it may be that gas production from gas hydrate on a small scale to meet localized needs in the North could be economic, even in a somewhat lower future price scenario.

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42 The costs are in 2005 Canadian dollars. The estimates of 'technical supply costs' for gas hydrate over free gas using a 0%, 10% and 20% discount rate are, respectively, \$5.74, \$5.09 and \$4.88/Million standard cubic foot (Mscf). The comparable estimates for gas hydrate over free water are: \$6.54, \$7.38 and \$9.60/Mscf.

Estimates of the production cost of natural gas from gas hydrate should be viewed with caution, particularly given the large technical uncertainties. Key factors affecting viability will be:

- access to gathering and transmission pipelines,
- the expected production life of reserves,
- the need for additional compression,
- artificial lift and water disposal (relative to conventional gas), and
- the cost of complying with potential regulations aimed at curbing greenhouse gas emissions.

The prospects for northern Canadian onshore gas hydrate development, over the long term, would substantially increase with the construction of the Mackenzie Valley pipeline and the associated development of northern conventional gas reserves. Although it has been planned to have an operating pipeline by 2015, considerable hurdles remain, including escalating capital costs, as well as regulatory and jurisdictional issues and concerns raised by some First Nations communities. In the absence of substantial public-sector investment, sustained gas prices in the range of $US7/Mcf to $US8/Mcf at Chicago will likely be necessary to generate a sufficient risk-adjusted rate of return to attract the required private investment to construct the pipeline.[43]

Security of Supply and Economic Development

While there will be a growing market for Canadian gas exports to the United States, these will have to compete with imported LNG. Based on supply cost estimates for frontier alternatives to LNG, Theal (2006) concluded that LNG is a viable threat to northern gas development, and this would of course also apply to northern gas hydrate development. According to Theal's calculations, the supply cost of LNG would be similar to northern gas supply costs, but LNG projects would involve lower capital and execution risk. Once major investments were made to accommodate large imports of LNG, its competitive advantage could become insurmountable. This suggests that a "security premium", or other such incentive for the development of domestic gas supplies, may be required to bring northern and perhaps other unconventional gas onstream. Given the recent escalation in LNG costs it may be that the size of any security premium requirement is declining. However, it should be recognized

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43 See Wright Mansell Research, *An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development-Extended Analysis and Update* (prepared for the Government of the Northwest Territories, November 2007, p.50).

that there would likely still be government incentives, at least in the early phases, to stimulate development of gas hydrate.

An important incentive to develop these domestic sources may be the associated local, regional and national economic impacts. Even modest recovery rates for the gas in northern Canadian gas hydrate formations would translate into very significant income, employment and balance-of-trade gains for Canada assuming that the local, regional and national economies were not already operating at full employment and capacity levels. As an example, the capital and operating costs associated with the development of northern gas production sufficient to justify the construction of the Mackenzie Valley pipeline (and excluding impacts associated with the construction and operation of the pipeline) have been estimated to generate total increases in Canadian real GDP, labour income, government revenues and employment of, respectively, \$26 billion, \$1.5 billion, \$8 billion and 28,000 person-years over the period 2010-35 (Mansell and Schlenker, 2004).

The prospective economic impacts for the North are large. In the case described above, approximately 20 to 35 per cent of the impacts would be in the Northwest Territories. As demonstrated in the southern provinces, natural gas development can be a key engine of growth and prosperity for a regional economy. There is no reason to believe that gas hydrate could not prove to be equally important to the development of a strong economic base in the North or in other gas hydrate-rich regions in the long term. But as seen in the many studies concerning northern pipelines and associated conventional gas development, there are many local issues that would need to be handled sensitively (see Chapter 5). For example, development would have to be managed so as to minimize the short-term construction impacts on local communities through the use of isolated construction camps, while maximizing long-term operating employment and income through appropriate education and training programs, and commitments to invest in the local communities.

4.4 SAFETY CONSIDERATIONS FOR DRILLING AND EXPLOITATION OF GAS HYDRATE

Safety issues associated with gas hydrates are as varied as the diverse environments in which they occur. The earliest indications of problems that could be caused by gas hydrate were related to flow assurance in onshore pipelines (Hammerschmidt, 1934; Wilcox *et al.*, 1941). Since that initial recognition, gas hydrate accumulations in man-made structures for storage and transmission of natural gas have been well-documented (e.g., Deaton and Frost, 1946).

What is less clear, and still poorly documented, are the safety concerns encountered when penetrating gas hydrates. Early efforts to address safety do exist (e.g., Bily and Dick, 1974), but, until recently, not much attention has been directed to this issue. Current knowledge of safety issues in natural settings is still mostly anecdotal, with only a few studies focused primarily on drilling and/or production problems (e.g., Yakushev and Collett, 1992; Hovland and Gudmestad, 2001; Collett and Dallimore, 2002; Nimblett *et al.*, 2005). There is a particular paucity of public information on gas hydrate-related safety because much of the information is proprietary, residing with national energy programs or, less frequently, in the commercial energy industry.

The safety issues associated with gas hydrates involve three separate concerns. The first arises when a well path penetrates gas hydrate-prone intervals on the way to testing for deeper, hydrocarbon targets — the exploration and appraisal phase. This is where most safety issues related to gas hydrate have been identified to date.

The second concern relates to production of deeper hydrocarbons when a well path passes through shallower, gas hydrate-prone intervals — the development phase. Because there is little known about the actual effects of hydrocarbon production over time through shallower gas hydrate-prone intervals, this report will address this activity briefly and without formal citations. Note that these first two safety concerns occur in the context of targeting deeper hydrocarbons, when a well path is actually designed to *avoid* encountering gas hydrate.

The third concern relates to the targeted production of gas from gas hydrate-prone intervals. For this activity, there are no examples because gas production from gas hydrate has yet to occur or be conclusively documented (e.g., the Messoyakha field in western Siberia discussed in Collett and Ginsburg, 1998). The first two concerns are addressed below, partially in the context of arctic and marine settings. The third concern, involving gas production from gas hydrate, is treated separately, from the perspective of the key issues that may be anticipated.

There are many more safety-related issues reported in arctic settings than in marine environments. This disparity may be explained by the fact that, as discussed in Chapter 3, larger gas hydrate accumulations have been found in arctic settings than in marine settings. The other contributing factor to the disparity could be the difference in operational procedures typically used to penetrate gas hydrate-prone intervals in both settings.

In arctic settings, the blow-out preventer (BOP) — a mechanical device used to seal off the well in an emergency — and associated casing are connected as a closed-circulation system to the rig floor at a very shallow depth below the sediment surface, frequently above the greatest concentration of gas hydrate. Sometimes this closed-circulation system may be connected at the onset of drilling, depending on the character of sediment in the uppermost subsurface interval. This situation would permit the gas that dissociates from the gas hydrate to be circulated back to the drilling rig floor, thus becoming a significant safety concern to the rig and rig personnel.

In marine settings, the BOP and associated marine riser — the specialized piping that connects the BOP at the seafloor to the drilling rig — provide the closed-circulation system back to the rig floor. However, the BOP and riser frequently are not connected until the well path reaches at least 600 m below the seafloor. This depth is usually far below the base of the marine gas hydrate stability zone. If gas hydrate is drilled and dissociates in the marine setting when the circulation system is open (i.e., fluid in the wellbore is circulated to the seafloor rather than back to the rig), the dissociated gas simply vents into the water column. Because of the deepwater depth and movement in the water column that would tend to disperse gas quickly, any dissociated gas vented at the seafloor would be unlikely to adversely impact the drilling rig floating on the sea surface far above.

Hence, the difference in depth below sediment surface (ground surface in the arctic vs. seafloor in the marine) for connection of the BOP provides a greater opportunity for gas accumulation from gas hydrate dissociation to be circulated to the rig floor in arctic settings than in marine settings. The former is much more hazardous, and may be reflected in part by the different experiences in arctic and marine gas hydrate-related safety.

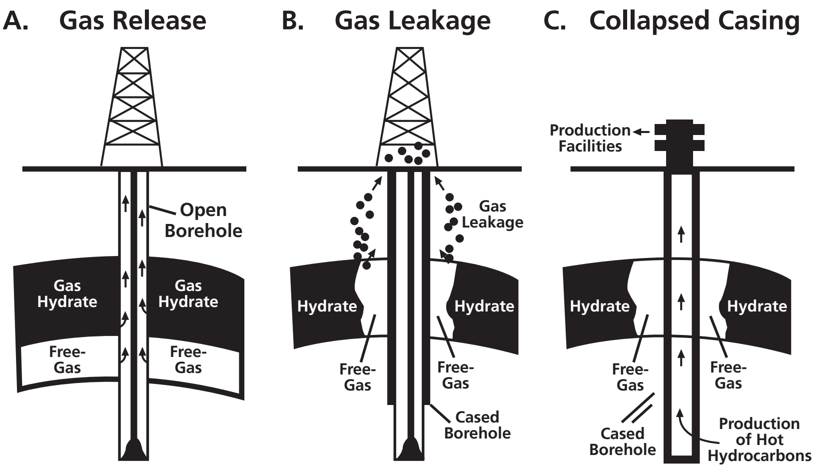
Arctic Settings

There is only limited documentation about drilling hazards encountered in arctic settings beyond what is mentioned by Yakuskev and Collett (1992) and compiled in Collett and Dallimore (2002). Documentation exists for drilling gas hydrates in at least four basins in the Arctic: North Slope of Alaska, Mackenzie Delta/Beaufort Sea region in Canada, Sverdrup Basin of the Queen Elizabeth Islands in far northern Canada, and the West Siberian Basin in Russia. The percentage of wells in these basins that contain gas hydrate is high, and safety incidents related to drilling are numerous.

Two general categories of drilling problems occur in the Arctic when trying to avoid gas hydrate — gas releases *during* drilling and well damage *after* drilling by gas release. Gas release during drilling is controlled by several factors, the most critical being the volume of gas hydrate, the size of borehole, the drill-bit penetration rates, the mud-circulating rates, and the temperature and weight of the circulating mud. If these parameters are not adjusted to address the drilling conditions in gas hydrate-bearing intervals, then an uncontrolled release of gas to the rig floor (a blow-out) or even a rig fire may ensue. Blow-outs have been recorded in the Russian Yamburg field, several western Siberia gas fields, the Kuparuk River field on the North Slope of Alaska, and the Canadian Beaufort Immiugak Prospect (Agalakov, 1989; Yakushev and Collett, 1992; Collett and Dallimore, 2002). Gas release (and thus a chance for a potential blow-out) occurs when gas hydrate is dissociated *in situ* by penetration with a drill bit, and gas moves up the open hole (Figure 4.3(a)).

Well damage *after* drilling has included casing installation difficulties, gas leakage outside the casing and casing collapse during production.[44] Gas leakage occurs after the gas hydrate-prone intervals are cased and cemented. In this condition, gas leaks to the surface outside of the casing, compromising the casing's ability to support itself (Figure 4.3(b)). Casing may also collapse after ongoing widespread dissociation of gas hydrate if casing collapse loads have not been adequately addressed in the well design (Figure 4.3(c)). This situation would be more common during the production phase, when heated hydrocarbons from deeper reservoirs pass through the gas hydrate-prone section promoting more rapid dissociation.

44 Such post-drilling problems have occurred in the Prudhoe Bay field on the North Slope of Alaska (casing installation), the Kuparuk River oilfield on the North Slope of Alaska (gas leakage outside casing), and in Heliocopter Bay on Ellef Ringes Island in the Canadian Arctic (casing collapse during production) (Alaska Oil and Gas Conversation Commission, 1981; Franklin, 1981; Collett and Dallimore, 2002).



(Collett and Dallimore, 2002)
Modified and reproduced with permission from Timothy Collett and Scott Dallimore

Figure 4.3
Typical safety issues encountered while drilling gas hydrate in the Arctic

Remedies to gas hydrate-associated drilling problems in the Arctic generally focus on the need to retard gas hydrate dissociation, usually by drilling with chilled mud and using special cement for the casing. These specialized techniques require substantial additional costs, so they are only employed when normal operating procedures are not able to contain gas generated when drilling gas hydrate. Temperature control (either cooling or heating) or the use of heavier casing may further increase the cost or complicate the logistics.

Marine Settings

Until recently, there were few publicly available studies addressing the safety of gas hydrate in marine settings (e.g., Nimblett *et al.*, 2005; Birchwood *et al.*, 2008). Most current understanding of these safety issues relies on a limited number of sites in specific geographic areas — e.g., Blake Ridge off the southeastern coast of the United States, and the Cascadia margin off the Pacific northwestern coast of the United States and southwestern Canada.

Marine gas hydrate drilling hazards have been mostly overlooked because of the difficulty in recognizing gas hydrates in marine settings (Hovland and Gudmestad, 2001; Nimblett *et al.*, 2005). In the offshore energy industry, exploratory wells in water depths greater than 500 m are usually drilled riserless[45] through the gas hydrate stability zone (generally a maximum depth of 400 m below the seafloor). This eliminates any practical means of sample catching, gas analysis or visual inspection for gas hydrate detection. Additionally, the only well data usually collected over the riserless interval of most deepwater wells are a suite of lower-resolution logging-while-drilling (LWD) logs, typically consisting of only gamma-ray and resistivity-logging tools.

As discussed earlier in this section, safety issues associated with marine gas hydrates have not been as severe as those documented for arctic settings. To date, the presence of gas hydrate in marine settings appears to be only a minor issue in the drilling of exploration and appraisal wells. As in the Arctic, the main concern is borehole instability related to gas hydrate dissociation after penetration by a drill bit, during or after drilling (Figures 4.3(a) and (b)). This may be due to the fact that the time interval during which warm fluid flows through the open wellbore or casing is limited to days, weeks or, at most, a few months. This short timespan may not be long enough for any substantial warming of gas hydrate-prone sediments in the surrounding formation.

There is little documentation of production through gas hydrate-prone intervals in marine settings. However, there is obvious concern for the impact of the constant flow of heated hydrocarbons through development wells in an active field designed to produce on a scale of years to decades. What is difficult to predict over this longer time period in a production-through-hydrate scenario is the shallow sediment stability profile around production casing in an active field, which is generating heat from the flow of hydrocarbons from a deeper reservoir below. Dissociation of gas hydrate around the casing may fluidize the sediments, causing a loss of the skin friction that supports the production casing by holding it in place (Figure 4.3(c)). This may lead to eventual casing failure. The exact nature of the gas hydrate/sediment interaction, when they are warmed, is currently a topic of great interest to energy companies and the subject of much proprietary research. However, until the warming of gas hydrate-prone intervals over time is fully understood, current practices dictate that if gas hydrate is detected at a development site, the most prudent approach is to simply avoid penetrating the gas hydrate-bearing intervals. Currently, this is usually accomplished by moving production wells to another part of the field area, away from known gas hydrate accumulations.

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45 Riserless means that drilling fluids pumped down through the drill pipe are circulated up through the borehole and are returned to the seafloor in an open system, rather than recirculated to the rig floor in a marine riser return system and reconditioned on the rig in a closed system. Riserless drilling of the upper 400 to 900 m below the seafloor is common practice in deepwater wells.

Exploitation of Gas Hydrate

As mentioned above, there is no public access to the very limited information on safety and operational issues encountered during production of gas from gas hydrate. The safety issues associated with developing gas hydrate reservoirs appear to be similar to those encountered in developing conventional natural reservoirs, with a few exceptions. These differences include:

- the shallow subsurface depth to the *top* of the reservoir (as little as a few hundred metres)
- potential borehole instability issues within the gas hydrate intervals
- large amounts of water associated with gas production from gas hydrate, and
- the increased degree of subsidence observed on the surface above a gas hydrate reservoir.

There would be a much shallower depth to the top of the reservoir when producing gas from gas hydrate, compared with the typically deeper depth of conventional gas production. The base of the gas hydrate stability zone in an arctic setting would be up to 1,000 m below the surface, whereas in the marine setting, the base of the stability zone could be up to only 500 m below the seafloor. Typical tops of conventional gas production rarely are shallower than 1,500 m below the surface and can be much deeper. Hence, gas hydrate reservoirs would be more dependent on critical seals to trap dissociated gas from leaking upward, which probably could be more prone to leakage by virtue of its shallower depth. Because production would be across unstable gas hydrate intervals, there would be substantial geomechanical changes around the borehole, which could induce substantial borehole instability issues over a short period of time. These types of problems would need to be carefully considered and wells adequately designed to avoid borehole instability and prevent the entire well from eventually collapsing.

Because the clathrate molecular structure of gas hydrate contains abundant water molecules, excess water would need to be removed from the reservoirs as gas hydrate dissociates. It would be possible to design a solution for this issue by evaluating the concentration and thickness of the gas hydrate before production. However, results from the winter 2008 production test at Mallik revealed very low volumes of produced water (see Appendix D). The removal and processing of large volumes of water is an issue that often occurs in conventional gas fields. Seafloor subsidence — i.e., vertical depression of the seafloor due to hydrocarbon withdrawal — can also be an issue during commercial gas production. The extent of seafloor subsidence caused by production from much shallower and possibly water-rich gas hydrate reservoirs could be a much larger issue than in conventional gas fields. Because this is an important concern for the development of all gas fields, the impact of subsidence can be addressed adequately with current practices, when planning for field development from gas hydrate reservoirs.

4.5 CONCLUDING OBSERVATIONS

This chapter considered the question of what fraction of the Canadian gas hydrate resource might be profitably extracted. Unfortunately, the uncertainties associated with the production of gas from gas hydrate are too great to permit a more precise answer without a great deal more research and exploration. Nevertheless, the panel has presented some information on the relevant controlling factors.

From a technical perspective, the recoverability of gas from gas hydrate may be evaluated if the hydrate occurs in unfrozen sandy sediments. The fraction of the Canadian gas hydrate resource occurring in such formations is not yet known. Among other factors, depth, temperature, type and extent of fluid (if any) underlying the gas hydrate, existence of cap rock, geotechnical behaviour of the rock, and internal heterogeneity, all can affect technical exploitation. The necessary research to gain a better understanding of the effect of these factors on recoverability is underway.

Despite uncertainties, it is believed that the application of conventional technology used in oil and gas production could lead to natural gas production from some gas hydrate accumulations. Gas production based on depressurization — with local heating or use of anti-freeze agents as necessary — from gas hydrate reservoirs with underlying fluids appears to be viable. Sophisticated numerical models, as well as more conventional reservoir engineering models, have been developed to predict gas production from such reservoirs. Nevertheless, these models have, at best, been calibrated only against short-term field tests. The lack of availability of long-term multisite field data, which demonstrate the producibility of gas from gas hydrate and allow the validation of mathematical models, remains a significant barrier to making reliable estimates of gas hydrate resources for extraction. Sloan (2007) suggests that "the main technology barrier is the lack of validated methods for economically viable production of natural gas from hydrate. An arctic site capable of supporting multi-year field experiments would enable significant progress beyond the present state of knowledge".

Factors such as proximity to infrastructure will play an important role in the potential future development of gas hydrate reservoirs. Stand-alone production of gas from gas hydrate reservoirs, considering their offshore and frontier locations, is less likely, based on what is known today. Instead, production and development may be considered where conventional hydrocarbons are also being produced. It should be recalled that the development of the CBM resource in southeastern Alberta occurred where availability of the infrastructure allowed profitable production from low-rate CBM wells together with the conventional resource.

The gas hydrate resource in the Mackenzie Delta/Beaufort Sea region would have access to market if the Mackenzie Valley pipeline were to be built and the conventional gas resource in the area were to be exploited. Much of this gas hydrate is estimated to be in unfrozen sandy formations (considered a necessity for assessing producibility of the gas hydrate resource).

By analogy with development of other unconventional hydrocarbons such as oil sands and CBM, the demonstration of producibility of gas from gas hydrate would be a crucial step before industry would consider development of the resource. The Mallik accumulation and other gas hydrate accumulations in the Mackenzie Delta provide potential opportunities for eventual gas production from gas hydrate. Their proximity to the main fields that would feed a Mackenzie Valley pipeline would also be advantageous. While the conventional hydrocarbons in the Mackenzie Delta are deeper than the gas hydrate-bearing sediments, measurements over the shallower, gas hydrate-bearing intervals would allow assessment of the commercial potential of the gas hydrate reservoirs. In the absence of such data, the incentive for future development of the gas hydrates is likely to be much reduced.

5. ENVIRONMENTAL, JURISDICTIONAL AND COMMUNITY CONSIDERATIONS

5.1 ENVIRONMENTAL CONSIDERATIONS

Both global and local environmental factors are important when considering the challenges for an acceptable operational extraction of gas hydrate in Canada. Recognizing, quantifying and managing environmental factors are key aspects of any large industrial process, and the large-scale development of gas hydrate would fall into that category. If gas hydrate was to be intentionally destabilized to recover the natural gas, the infrastructure required for this enterprise would have some impact on the global and surrounding ecosystems and human communities. This section considers the environmental issues associated with natural gas release from gas hydrate, whether global or local, and whether typical of other fossil energy recovery operations or unique to gas hydrate.

Global Climate Change Considerations

Natural gas (primarily methane) produced from gas hydrate would be a hydrocarbon and therefore generate CO_2 upon combustion, though in lesser amounts per unit of useful energy generated than either coal or oil. Methane itself is an even more potent greenhouse gas than CO_2. There could therefore be concern that the release of methane into the atmosphere could occur either by (a) the dissociation of certain gas hydrate reservoirs as a consequence of global warming, or (b) the unintended release of methane in the course of commercial gas production from gas hydrate.

The possibility that global warming may induce widespread gas hydrate dissociation (“melting”) causing release of large amounts of methane — thus accelerating warming via positive feedback — is the subject of research that seeks to explain historical climate change events and to project the climatic impact of gas hydrate into the future.[46] Research has been conducted, which seeks to understand the parameters that control the natural decomposition of gas hydrate, and to estimate the extent to which it has decomposed in the distant past and the likelihood that it may happen in the future. Numerous investigations of seabed cores suggest that larger releases of methane may have occurred from gas hydrate formations at specific times in the earth’s history,

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46 This has been the subject of research as well as commentary and speculation in mainstream and specialized media like *Scientific American*. See also recent work by Kennedy *et al.* in *Nature*, May 29, 2008, 453, and Archer, 2007, *Biogeosciences*, 4, pp. 521-44.

spanning eras from the Quaternary (the last 60,000 years) to about 600 million years ago (Dickens *et al.*, 1997; Katz *et al.*, 1999; Norris and Röhl, 1999; Hesselbo *et al.*, 2000; Kennett *et al.*, 2000; Padden *et al.*, 2001; Slujis *et al.*, 2007; Zachos *et al.*, 2007; Kennedy *et al.*, 2008; McFadden *et al.*, 2008; Zachos *et al.*, 2008). Contradictory evidence has emerged that counters the likelihood of large releases of methane in the late Quaternary. This evidence includes isotopic analysis from methane in ice cores (Sowers, 2006), carbon budget calculations determining the role of gas hydrate in the global carbon cycle (Maslin and Thomas, 2003), and modelling the "melting" of gas hydrate in natural settings (Sultan, 2007). These studies suggest that gas hydrate may be only a minor factor in seafloor instability over the last 10,000 years.

Very little is known about the magnitude of the contribution of methane hydrate in the earth to the global methane budget (Reeburgh, 2007). This is because the distribution and the rate of gas hydrate decomposition are not known. Furthermore, there are obstacles to methane reaching the atmosphere. The ocean can be considered to be a large reactor that effectively oxidizes methane (Reeburgh, 2007). Methane in the atmosphere is also transient because it reacts with hydroxyl radicals and eventually becomes CO_2 on a time scale of about a decade (Archer, 2007).

Because it is important to understand the likelihood of gas hydrate dissociation in marine sediments and permafrost in the context of near-term hazards, and because there have been no observations of such phenomena, several groups have modelled the process. In the early 1990s anticipated annual global temperature rise as a result of the physical processes involved in the greenhouse effect was considered to lie between the following three temperature rises for the following century: (a) 0.6ºC, a low-impact scenario (b) 3ºC, a moderate scenario, and (c) 8ºC, a catastrophic scenario (Schneider, 1990; Taylor, 1991). Hatzikiriakos and Englezos (1993) simulated the vulnerability of gas hydrate to the above climate change scenarios and estimated that a global temperature rise equivalent to 0.08ºC per year would result in a warming of the top of a typical permafrost gas hydrate zone (at a depth of 198 m) in less than 100 years. However, the melting of permafrost, and the fact that a temperature-driving force needs to develop for gas hydrate to decompose, extend this time scale to a few hundred years. On the other hand, suboceanic gas hydrate would start to be affected within a few thousand years.[47]

47 Note that more recent Intergovernmental Panel on Climate Change (IPCC) temperature rise scenarios are more moderate, with a maximal global surface warming of 4ºC over the 21st century.

Recently, Fyke and Weaver (2006) used an earth system climate simulator to model a series of climate sensitivity and future climate change scenarios. Their results indicate that the global marine gas hydrate reservoir is susceptible to greenhouse gas increases and that the regional seafloor temperature change dictates the timing and intensity of the response of the gas hydrate stability zone. Fyke and Weaver's results are similar to those of Archer and Buffett (2005) who noted that the potential for gas hydrate-related release of methane could far surpass human-caused climate warming on time scales of 1,000 to 100,000 years.

Arctic environments are especially sensitive to climate change (Zimov *et al.*, 2006; Archer, 2007), and gas hydrate on the polar continental margins is accordingly vulnerable to climate change (Kvenvolden, 1988b). Modelling and geophysical studies indicate that large sections of these margins have subseafloor permafrost that may be degrading because these areas are now covered by water (Rachold *et al.*, 2007). These permafrost layers overlie significant gas hydrate formations, whose stability is at least partly dependent on the integrity of the permafrost. The loss of permafrost results in both an increase in sediment temperature and a loss of the permafrost cap that seals free gas from leaking to the surface. Gas hydrate decomposition may be responsible for the pingo-like features on the seafloor in the Beaufort Sea, which contains high levels of methane (Paull *et al.*, 2007).

From investigations of continental margins and the extensive surveys by offshore energy companies, it is evident that *widespread* continental margin instability in general, and more specifically due to dissociation of gas hydrate, is not occurring today, nor has it been documented conclusively to have occurred over the past 5,000 years or so (e.g., Locat and Mienert, 2003; Lykousis *et al.*, 2007). It would appear that seafloor instability will have little impact on the development of gas hydrate as a resource, particularly when areas of suspected instability are usually recognizable and can mostly be avoided.

Although the methane in gas hydrate is not expected to be a near-term forcing agent of climate change for suboceanic gas hydrate, it is possible that permafrost gas hydrate may be affected over time scales of centuries in some specific locations, as also described by Archer (2007). The active removal of methane from gas hydrate for energy use has been proposed as a means to *forestall* the potential long-term impact of that methane on the global carbon cycle and climate change. However, the amount of methane that might be effectively produced from accessible gas hydrate formations in the future is small relative to the total amount of methane currently present in gas hydrate. Even aggressive production of the gas in gas hydrate could not be expected to remove enough methane to significantly moderate its climate change potential in the event it were to be released from gas hydrate due to eventual warming of the formations.

Sequestering CO_2 in Gas Hydrate

The long-term future use of any fossil energy resource appears destined to be paired with appropriate carbon capture and sequestration technologies. This already occurs in some places in the world where removal of oil from a reservoir is followed by injection of CO_2. An intriguing idea to combine methane recovery from gas hydrate with CO_2 sequestration has also been put forward (Hirohama *et al.*, 1996; Lee *et al.*, 2003; Goel, 2006; Park *et al.*, 2006). The German Gas Hydrate Organisation (GGO) and the U.S. DOE are devoting considerable effort in this area.[48] The idea is that CO_2 emitted from the burning of fossil fuels can be captured and sequestered in hydrate reservoirs where it is expected to displace methane hydrate such that the CO_2 can be stored as CO_2 hydrate. Indeed, gas hydrate can form from gaseous CO_2 and water (Morgan *et al.*, 1999). While this could be a novel solution to a carbon problem, there are equilibrium and kinetic limitations to the exchange process, and not all methane can be replaced by CO_2. A 64 per cent recovery of methane has been reported in laboratory tests. However, use of a CO_2/N_2 mixture (20 mol % CO_2) was found to achieve 85 per cent methane recovery. The CO_2/N_2 mixture is a model for a treated flue gas mixture that normally would contain CO_2, N_2 and O_2. Because N_2 and O_2 form hydrate crystals under approximately the same conditions, the treated flue gas is considered a CO_2/N_2 mixture. One of the complications of this process is that the methane replacement and recovery rate increases with increasing CO_2 partial pressure (Ota *et al.*, 2007). Since flue gases exit at nearly atmospheric pressure, the pressurization (compression) costs would increase accordingly.

The idea of sequestering CO_2 and extracting methane has only been investigated in bulk gas hydrate systems, and no attempt has yet been made to inject CO_2 into a gas hydrate reservoir to observe the exchange of hydrocarbon molecules with flue gases (Goel, 2006). This CO_2 sequestration through the formation of a gas hydrate should not be confused with so-called geological sequestration of CO_2 in deepsea sediments (House *et al.*, 2006). In that case, CO_2 is stored in a liquid phase. The pressure-temperature conditions are such that CO_2 liquid is denser than the overlying pore fluid, and thus is gravitationally stable.

48 http://www.netl.doe.gov/technologies/oilgas/FutureSupply/MethaneHydrates/projects/DOEProjects/MH_42666AssessProdMethods.html and http://www.german-gashydrate.org/

Although coupling methane extraction with CO_2 sequestration is conceptually attractive, the large-scale sequestration of CO_2 in spent oil reservoirs and other geological formations is likely to be at least two decades away, and there are many unanswered questions. The reservoirs that contain methane hydrates are expected to be more difficult with respect to extraction, and therefore an equivalent process for re-injecting carbon into these formations is also likely to be two decades away. Nevertheless, despite its speculative nature at present, exchange of CO_2 for methane appears to be desirable, and further investigation into the details and impacts of the idea warrants further support.

Other Environmental Considerations Common to all Hydrocarbon Production

The environmental issues associated with gas hydrate reservoirs are essentially the same as those encountered with many other geological formations that contain hydrocarbons. With years of experience accrued through the exploration and drilling of deep earth systems that contain fossil energy resources, there has been parallel development of knowledge aimed at minimizing the environmental impact of such large-scale efforts. Past evidence suggests that when problems occur related to resource recovery, practices change to minimize future occurrences of the problem. Although this does not obviate the problem at hand, the industry response usually moves towards recovery of such resources with reduced environmental disruption. Resource recovery operations, like those proposed for gas hydrate, would include environmental impacts related to exploration, characterization, recovery and processing of the gas in gas hydrate-bearing formations. For gas hydrates, the issues envisioned have been largely dealt with before, but there are some differences.

As discussed in Chapter 2, it is likely that there will be an increase in the demand for natural gas in the near future. There is considerable worldwide interest in reducing greenhouse gas (GHG) emissions to the atmosphere due to the collective data indicating that humans have increased the concentrations of these gases in the atmosphere on a global basis (IPCC, 2007). Most of the increase in GHG emissions can be attributed to energy sources, such as coal and oil, with high carbon emission per unit energy. “Decarbonised” energy sources will be favoured in the future (Baldwin 2002); however, the use of natural gas with lower carbon intensities than coal or oil is likely to increase in the course of reducing carbon in the energy mix (Moniz and Kenderdine, 2002). Pacala and Socolow (2004) recommend the replacement of coal-fired power plants with gas plants as one of their strategies to incrementally decrease carbon emissions to the atmosphere. Unconventional gas, a category into which methane from hydrate fits, is one fossil energy source that could be used in their scheme prior to the advent of truly sustainable energy sources (Jaccard, 2005). Natural gas is expected to be intensively sought as a fuel in the coming decades, and there will be impacts associated with the exploration, development, recovery and distribution of these resources. Canada's gas hydrates exist in sensitive terrestrial arctic and marine environments, and it is essential to manage the impacts in those locations.

As for any frontier or offshore energy development, activities recovering gas from gas hydrate would have impacts. In terms of overall impacts, extracting natural gas from gas hydrate presents a general scenario consistent with the recovery of other fossil energy resources, especially the recovery of conventional gas. Past experience with resource development in the Far North or in offshore marine settings should serve as models. For example, protocols related to Arctic impact were established through the Berger Commission consideration of the Mackenzie Valley pipeline (Berger, 1977).

Environmental Considerations Specific to Gas Hydrate

Chapter 3 revealed the presence of massive gas hydrate deposits near or at the seafloor surface. While these may seem accessible targets for exploitation, as explained in Chapter 4 (see in particular Figures 4.1 and 4.2), deposits trapped by an impermeable layer (and underlain by fluids) are much more accessible using conventional oil and gas technology. As such, we have focused our attention on those deposits deemed likely to be exploitable. We have not investigated the impact of exploiting massive seafloor and near-seafloor deposits.

Although the exploration for gas hydrate-bearing geological strata is typical of that conducted for conventional fossil energy resources, there may be some aspects of resource development and recovery of a gas hydrate resource that would be unique to the way in which gas hydrate occurs in the natural environment. The environmental issues that may be specific to gas hydrate, including the potential for methane leakage from hydrate formations, disposition of water co-produced with the methane, and the stability of gas hydrate formations, will now be considered. (These issues are also included in the discussion of safety considerations in section 4.4.)

The leakage of methane gas from a gas hydrate-bearing formation as a foreseeable result of production-related activities is not likely to be a serious problem. The methods conceived for producing such methane involve input of energy to the system in order to change the thermobaric conditions of the geological environment. The planned approach, which has been attempted in field tests (e.g., Mallik and Mt. Elbert wells), is to depressurize the gas hydrate-bearing formation (see Chapter 4). By discontinuing the depressurization, leakage of methane from such a formation could be controlled. Experiments designed to test and demonstrate such process control should be a part of any pilot-scale operations involving the release of methane from gas hydrate. It also seems probable that after completing methane production from gas hydrate-bearing strata, the gas hydrate would re-form, and the cold temperatures and high pressures would re-establish the thermodynamic controls needed to keep the methane in hydrate form. Inadvertent loss of methane would be detrimental for the economic, environmental and safety reasons discussed in detail in this report. Therefore, well operators would have an incentive to minimize the risk.

Any scheme to release the gas from gas hydrate would involve some co-produced water. Although significant amounts of water would be produced, the situation is similar to that for other hydrocarbon production processes. The environmental contaminants often present in co-produced water from oil or coal production operations (e.g., complex organic compounds and heavy metals) would be minimally present in the water co-produced with the gas from gas hydrate. As gas hydrates are destabilized, they produce water purified through the freshening effect (Hesse and Harrison, 1981).

In many locations, gas hydrate may decompose continuously — by natural process — at relatively modest rates. In marine systems, methane seepage through the sediments and into the overlying water is oxidized to CO_2 by either anaerobic methane oxidizing microbial consortia (typically in the sediments) or by aerobic methane oxidizing bacteria in the water column. (For a complete review of the biogeochemical cycling of methane in oceans, see Reeburgh, 2007.) Where there is a high flux of methane from the sediments, the oxidizing process can cause carbonates to form, resulting in the hard substrates required by some seafloor macrofauna, and a "chemoherm" may occur at stable "cold seep" sites (Teichert *et al.*, 2005). These are unique biologically-rich environments on the seafloor that originate from leakage of methane from deep in the sediments, but their distribution on the seafloor is not well mapped. Such chemoherm communities should be protected, as in the case of the Gulf of Mexico, at least until their distribution and abundance are well understood.

It should also be noted that gas hydrates offer special challenges due to their more remote and inhospitable locations, whether arctic or marine, than those of conventional hydrocarbons. Careful planning, spare parts and provision for response to accidents would be required to do all that is humanly possible to prevent accidents, and to react swiftly and effectively to all possible situations that might arise.

5.2 JURISDICTIONAL CONSIDERATIONS

The future development of gas hydrate would be affected by a number of jurisdictional issues particular to Canada. It is understood that:

- gas hydrate development would unfold within existing and evolving regulatory frameworks established for development of other resources
- although the starting point may be to treat gas hydrate as simply a form of natural gas, a separate set of agreements may evolve once there is a greater understanding of the science and the economics. For example, there may be special royalty rates, safety concerns and conditions for water disposal.
- while the provinces, but not the territories, own their land and natural resources, ultimately the federal government has the jurisdictional responsibility in resource development in frontier lands
- the jurisdictional and regulatory situations differ on the East, West and Arctic coasts. Only the East Coast has a detailed federal-provincial framework for resource development, the Atlantic Accords, and these may provide a framework for working out a comparable agreement on the West Coast. Arrangements in the Arctic are more likely to be influenced by the lessons learned from the Mallik gas hydrate testing programs, the agreements associated with developing the proposed Mackenzie Valley pipeline, and the debate on devolution of legislative authority to the territorial governments.
- any changes to regulatory frameworks will need federal-provincial/territorial co-operation and extensive consultation with local communities, and
- although it will take many years to put any new agreements in place, the regulatory/jurisdictional picture may have changed in specific regions by the time any gas hydrates come on stream.

Role of the Federal Government

The federal government's constitutional jurisdiction over mineral rights in offshore coastal areas has been resolved in the courts. The two main federal statutes governing oil and natural gas are:

- the *Canada Petroleum Resources Act* (CPRA), which deals with exploration, production and royalties, and

- the *Canada Oil and Gas Operations Act* (COGOA), which deals with safety, environmental protection, conservation of oil and gas resources, and joint production arrangements.

Although the provinces have ownership and control of their land and natural resources, the federal government has ultimate jurisdiction over what it calls *frontier lands*. The CPRA defines these as “lands that belong to Her Majesty in right of Canada, or in respect of which Her Majesty in right of Canada has the right to dispose of or exploit the natural resources, and that are situated in (a) the Northwest Territories, Nunavut or Sable Island, or (b) submarine areas, not within a province, in the internal waters of Canada, the territorial sea of Canada or the continental margin of Canada, but does not include the adjoining area, as defined in section 2 of the Yukon Act”. The CPRA defines gas to mean natural gas and includes all substances, other than oil, that are produced in association with natural gas. This would appear to include gas hydrate.

There are various federal bodies – with NRCan as the lead department — involved in managing natural resources in frontier lands:

- the Frontier Lands Management Division of NRCan manages offshore oil and gas interests
- Indian and Northern Affairs Canada (INAC) manages frontier lands in the Northwest Territories and Nunavut, and
- the NEB administers COGOA.

The regulatory framework network can be so complex and confusing that it constitutes, in and of itself, a major roadblock to resource development at every step of the process.

Atlantic Coast

On the East Coast, there are existing legal agreements that would apply to any gas hydrate development. The development of resources comes within the framework of the Atlantic Accords that the federal government negotiated with Nova Scotia and Newfoundland & Labrador in the mid-1980s (see Box 10 for a potential framework for working out comparable intergovernmental management agreements elsewhere). These agreements are enshrined in both provincial and federal legislation. The federal legislation specifically makes it clear that, with one minor exception, the provisions of both the CPRA and the COGOA do *not* apply offshore.

The Atlantic Accords set out the joint management of resources, a system of equalization payments to the provinces, and a revenue-sharing formula for offshore oil and natural gas royalties. The Canada Nova Scotia Accord Act included a 10-year moratorium on petroleum drilling and exploration on Georges Bank (in the Gulf of Maine), one of Canada's most productive fisheries. After a public review process was completed, Canada and Nova Scotia agreed to extend the moratorium until 2012. Although the Atlantic Accords have been in place for over 20 years, there is current political sensitivity around the new formula for calculating equalization payments included in the 2007 federal budget.[49]

Box 10 — How the Atlantic Accords Operate

Separate boards oversee the operation of the Canada-Newfoundland Atlantic Accord and the Canada-Nova Scotia Offshore Petroleum Resources Accord:

- The Newfoundland and Nova Scotia Boards have seven and five members respectively.
- Each government appoints an equal number of members to the board, who in turn appoint the board chair.
- The COGOA provides for an Oil and Gas Administration Advisory Board that:
  - brings together the different federal and provincial government departments or agencies involved in offshore oil and gas activities.
  - is made up of:
    - the Chairs of the Newfoundland and Nova Scotia Boards
    - the Chair of the NEB
    - a person that the Ministers of Natural Resource Canada and Indian and Northern Affairs Canada Development jointly appoint, and
    - two people appointed by the provincial ministers.
  - has a mandate to promote consistency and improvement in the administration of the regulatory regime and provide advice on how to do this.

49 For more information, see the Finance Canada website on Budget 2007 and the Budget paper, *Restoring Fiscal Balance for a Stronger Federation*; the Government of Newfoundland, Executive Council News Release, March 20, 2007; and the Government of Nova Scotia website.

Pacific Coast

On the West Coast, there is no legal framework for offshore resource development as on the East Coast. Gas hydrate development could not take place there until the federal and provincial moratoria on oil and gas exploration off the coast of British Columbia are lifted and a new regulatory regime is put in place. The scientific studies and reports conducted by both British Columbia and Canada since 2001 — when the Government of British Columbia started to reassess its position on the moratoria — have concluded that there is no scientific evidence to support maintaining the moratoria. In October 2001 the B.C. government appointed a scientific panel to examine the resumption of offshore oil and gas exploration. In its January 2002 report, the panel concluded that there was no fundamental inadequacy in the science or technology to justify maintaining the B.C. moratorium.[50]

In 2003-04, NRCan commissioned and initiated several studies and reports on the federal moratorium including:

- a scientific study by The Royal Society of Canada (RSC)
- a public review panel chaired by Roland Priddle, and
- a First Nations Engagement Process chaired by Cheryl Brooks.

In its February 2004 report, the RSC panel concluded that although science gaps did exist, it was not necessary to fill these gaps before lifting the moratorium as long as an adequate regulatory regime was put into place. The regulatory regime structure would ensure, once the moratoria were lifted, that the gaps would be filled before developing an oil and gas industry. The potential government-industry partnerships would enhance the opportunities to fill the science gaps.[51]

Both the Priddle and Brooks[52] reports highlight clearly the political perspectives and challenges for removing the federal moratorium on offshore oil and gas exploration and development. Participants recognized gaps in scientific

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50 *Report of the Scientific Review Panel*, Vol. 1, p. 51.

51 *Report of the Expert Panel on Science Issues Related to Oil and Gas Activities, Offshore British Columbia*, p. 121.

52 The Priddle report, *Report of the Public Review Panel on the Government of Canada Moratorium on Offshore Oil and Gas Activities in the Queen Charlotte Region*, and the Brooks report, *Rights, Risks and Respect*, were released in October 2004.

knowledge, together with gaps in the understanding of socioeconomic impacts. There were strong differences of opinion over filling these gaps while the federal moratorium was still in place or after it was lifted. The need to address First Nations' interests and concerns was the major area of near consensus. While ecosystem protection was a widely shared priority, there was fundamental disagreement about how to best achieve it: by keeping the federal moratorium, or by lifting it and relying on a modern regulatory regime.

The Government of British Columbia's submission to the Priddle panel advocated that lifting the federal moratorium was not a question of science but one of public policy. It also proposed that the federal policy for offshore British Columbia should be consistent with other parts of Canada. The province sees offshore oil and gas development as a potential source of government revenue to support health care, education and other vital public services; contribute to energy self-sufficiency and security; provide unique partnership opportunities with First Nations; and generate prospects for jobs and training, and businesses and investment. The province believes that lifting the federal moratorium will:

- facilitate the effective resolution of knowledge gaps
- allow British Columbia, Canada, First Nations and coastal communities to collaboratively pursue common interests around offshore development, and
- provide industry with an appropriate environment for responsible development.[53]

The Priddle panel concluded that:

- the strong polarized views it heard did not provide a ready basis for any kind of public policy compromise around the federal moratorium
- the polarization of views may have been a result of the public review's focus on the specific question of keeping or lifting the federal moratorium, and
- developing a program to gather and assess scientific, socioeconomic and other information might reduce the degree of polarization and help build consensus.[54]

53 British Columbia, *Perspective on the Federal Moratorium*, p. 21.

54 *Report of the Public Review Panel on the Government of Canada Moratorium on Offshore Oil and Gas Activities in the Queen Charlotte Region*, p. 106.

The First Nations Engagement Process report was clear on the position of First Nations on the federal moratorium: "Many of the meeting participants prefaced the discussion with the caveat that from the First Nation perspective this process was not to be construed as 'consultation'."[55] The report went on to say that although none of the First Nations involved in the process "endorsed the lifting of the moratorium, many First Nations indicated a preparedness to more fully explore the issue of offshore oil and gas exploration provided they are adequately resourced and given enough time to do so".[56] The Expert Panel on Gas Hydrates heard similar views when they met with Chief Simon Lucas and Gary Wouters.[57]

The provincial government's 2007 energy plan affirms the Government of British Columbia's commitment to lifting the federal and provincial moratoria simultaneously. The plan also refers to working with the federal government on an environmental management and community engagement program to examine ways of sharing benefits with coastal communities and First Nations. While the provincial position is clear, the policy paper notes that the federal government "has not formally responded to the review reports".[58]

The public policy challenges of lifting the federal and provincial moratoria are considerable. The regulatory regime that needs to be established would be complex, as is evident from what is already in place on the East Coast. One study has estimated that 60 federal statutes and 38 provincial statutes apply to offshore activity (O'Rourke, 2005). In addition to jurisdictional considerations, there remain ambiguities about ownership of inland waters. A federal-provincial agreement on revenue sharing would also need to be negotiated. It is possible that the scientific and technical knowledge gaps on gas hydrate may well be filled before the regulatory regime has been resolved.

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55 *Rights, Risks and Respect: A First Nations Perspective on the Lifting of the Federal Moratorium on Offshore Oil & Gas Exploration in the Queen Charlotte Basin of British Columbi*a, p. 1.

56 Ibid., p. 3.

57 Vancouver, August 27, 2007.

58 *The BC Energy Plan: A Vision for Clean Energy Leadership*. http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan_Oil_and_Gas.pdf, February 27, 2007.

The Arctic

The jurisdiction and ownership of natural resources in the Arctic is much clearer than on the other two coasts. The federal government has not turned over ownership of the land and natural resources to the territories although the territories, with the support of the provinces, are pushing for this change. Given that it took 25 years for the Prairie provinces to obtain ownership of their lands — and territories do not start with the same rights as provinces — this change is not likely to happen in the foreseeable future. Under the 2003 devolution agreement, Yukon "assumed administration and control over public lands and natural resources from the Government of Canada". Yukon is also able to collect royalties from these natural resources up to an agreed maximum. What is more likely is a revenue-sharing arrangement that includes offshore resources, with a commitment to ongoing consultations with the other two territorial governments, the Inuit and other local communities.

The federal government is currently placing greater priority on Canada's Arctic regions because they contain much of the country's future energy potential. There are outstanding sovereignty issues to resolve. Canada could use development and regulation of offshore resources, including gas hydrate, to reinforce its claim over its Arctic territory. With global warming and the retreat of ice in the Arctic, shipping through the Northwest Passage, the status of which is a source of disagreement between Canada and the United States, is no longer a dream, but a distinct possibility. There are other boundary disputes in the Arctic: with the United States off the Yukon coast, with Denmark over Han Island, and possibly with Russia. Given these outstanding issues, the Government of Canada is focusing far more attention on the North and exercising Canadian sovereign rights there.

In announcing the acquisition of naval patrol vessels, Prime Minister Stephen Harper said: "More and more, as global commerce routes chart a path to Canada's North and as the oil, gas and minerals of this frontier become more valuable, northern resource development will grow ever more critical to our country" (News release, July 9, 2007). In August 2007 the prime minister outlined plans for increasing Canada's military presence in the North (News release, August 10, 2007).

Part of the October 16, 2007 Speech from the Throne focused attention on the Arctic and the need for Canada to exercise its sovereign rights in the Arctic. One of the first steps was "a comprehensive mapping of Canada's Arctic seabed. Never before has this part of Canada's ocean floor been fully mapped". In late May 2008 the Minister of Natural Resources participated in a meeting of the Arctic Council held in Greenland with representatives from Denmark, Norway, Russia and the United States to "discuss how to proceed with economic and social development in the North". In an interview before the meeting, Minister Lunn said: "We're a long way from resources development, but we need to make sure that no project proceeds until proper protections are in place" (*The Globe and Mail*, May 27, 2008, p. A4.).

5.3 COMMUNITY IMPACT CONSIDERATIONS

The social, cultural and economic development considerations related to the exploitation of gas hydrate in northern and offshore areas are similar to those associated with conventional gas production in frontier areas. While the specific circumstances of every proposed project will need to be addressed, the production of natural gas from gas hydrate does not appear to present social and cultural issues unique to *gas hydrate*, as distinct from conventional gas reservoirs of comparable extent. The many lessons that have been learned about resource development in environmentally and culturally fragile areas, and the protocols that have been developed to ensure that local consultation and due process are respected, must apply to any future gas hydrate development in Arctic and offshore areas. And since there is inevitably a long lead time before commercial exploitation of gas hydrate could occur, there will be ample time for potentially affected individuals and communities to become well-versed on the issues and their implications.

Resource Development in Fragile Communities

The many resource-based communities on the East, West and Arctic coasts are located in places where the marine and terrestrial ecosystems are fragile, some already badly damaged. Most inhabitants, both aboriginal and non-aboriginal, depend socially, economically and culturally on their local natural environments. The communities, particularly in northern and western coastal regions, tend to be widely dispersed, remote from urban areas, and suffering resource degradation and underemployment. While it might appear that gas hydrate development could provide welcome short-term opportunities for jobs and wealth to places in dire need of new options, any development could have potential long-term impacts on the culture, heritage, social cohesion, education, health and livelihood of coastal and northern communities. Development could also have a detrimental effect on regional fisheries, aquaculture, and eco- and adventure-tourism.

In the past, many resource development and hydroelectric projects inflicted serious long-term environmental, economic and social damage because they did not sufficiently take into account the impact of development on the environment and on the people residing in the area. On the other hand, there are also examples of major inquiries and studies in Canada that have carefully assessed the socio-cultural risks and benefits of anticipated development, and analyzed the impact of the development on community well-being. These include the impact assessments of the James Bay Hydro development (Quebec) and the Mackenzie Valley pipeline (Berger Inquiry).

Many Canadians see the Berger Inquiry in particular as a good model for evaluating the impact of future resource development projects in Canada. The 1977 report, *Northern Frontier, Northern Homeland*, called for a 10-year moratorium to deal with critical issues like aboriginal land claims and setting aside conservations areas. The report warned that the impact on the ecosystem would be significant — equivalent to building a railway across Canada. It also warned that an oil pipeline would be built, creating an *energy transportation corridor* that would necessitate immense infrastructure of roads, airports, maintenance bases and new settlements.

As a result of the Berger Inquiry and similar experiences, there is now much greater awareness of the potential impacts of resource development and of the need for thorough and genuine consultation with those who would be affected. The current discussions about an energy corridor along the Mackenzie River valley and the possibility of a pipeline along the Alaska Highway illustrate new sensitivity to the social, cultural and environmental dimensions of resource projects.

To identify the key socioeconomic and local community issues that must be considered in any gas hydrate development project, the panel invited input from stakeholders in Canada's coastal and northern regions and commissioned a paper entitled *Impacts on communities: Issues of social science and impact assessment in relation to gas hydrates in Canada* from Hugh Brody, an authority on the impact of development on aboriginal cultures in Canada (Appendix C).

Issues Identified by Coastal Stakeholders

Local opposition to any plan to develop natural resources could be significant because of the negative experiences of many communities with development projects in the past. The feedback and responses of all coastal stakeholders (see Box 11) to the possibility of future gas hydrate development were clear and unified in their emphasis on the importance of:

- carrying out a transparent, in-depth consultation process with full participation from local communities and any aboriginal organizations and band councils. The process should address economic, environmental, cultural, social and legal issues
- beginning this consultation in the early stages of developing the impact assessment guidelines, strategy and process, and continuing it throughout the development project
- treating local communities as equal partners and including any local knowledge in the discussions from the outset
- using independent experts to prepare reports and studies that can be easily understood and digested by local communities within a reasonable timeframe, and
- achieving consensus on mitigation processes because responses to environmental and economic contingencies will need to be prepared ahead of time.

Box 11 — Feedback from Coastal Stakeholders

With the acceleration of resource extraction projects, local communities are increasingly viewed as one of many factors to be dealt with. In many cases, the community is the last to hear of a proposed development project.

Arthur Bull, Chair of Coastal Communities Network, Nova Scotia

We are lucky to get an independent panel review. However, consulting companies are able to table thousands of pages of evidence. On the surface of it, from a managerial point of view, it looks like the evidence is put on an even table and that it will be an evidence-based decision. But in fact, this puts the community at a disadvantage — the table is tilted towards the proponent. Social science consultants often say there will be no adverse effects on the community; what they are really reflecting is the fact that the community did not have enough money to hire more social scientists.

Arthur Bull, Chair of Coastal Communities Network, Nova Scotia

On the West Coast, people see through a project pretty quickly. Cases when a consultation appears only as part of an existing mandate or lacks integrity are seen by communities as public relations exercises.

Barry Janyk, Mayor of Gibsons, British Columbia

Meaningful openness and engagement, which come at the very beginning of a project, are best. Moving too fast and unilaterally provokes First Nations to use rights and title to fight (and ultimately delay or stop) a development if they don't understand it.

Gary Wouters, Policy Consultant, Coastal First Nations, British Columbia

Consultations and discussions in the context of resource development or proposals must take account of the people and their belief system. It is important to understand the depth of First Nations' spirituality and to respect a culture that has lived on the land for eons.

Simon Lucas, Nuu-chah-nulth Territory

The problem with energy development is the fragmentation: cumulative impacts are a huge issue of concern. Projects come in on a piecemeal basis, and opportunities to analyze the broader implications are not provided.

Deborah Simmons, Professor, Department of Native Studies, University of Manitoba

Communities must be involved from the outset. One must get involved, and support socioeconomic impact analyses and traditions from the outset, rather than the 11th hour, by which time community support and trust are lost and unnecessary delays in the development have occurred.

Deborah Simmons, Professor, Department of Native Studies, University of Manitoba

Last year on gas hydrate exploration, 85% of all contracts and a significant percentage of the jobs were filled by local employees (Inuvialuit contractors and locals). Individual Inuvialuit businesses can and do exist to provide this support. Many are anxious for gas hydrate projects to proceed in order for businesses to stay alive.

Nellie Cournoyea, CEO/Chair, Inuvialuit Regional Corporation and Former Premier, Northwest Territories

A cost-benefit analysis of gas hydrate exploration will lead to different outcomes, depending on the nature and interests of each community. Gas hydrates could be seen in some communities as a lifeboat, a way to provide for residents. Other communities may oppose a project on the basis of its environmental risks. Gas hydrate exploration will be community dependent: environmental concerns may be subjugated to other (economic, social) concerns.

Barry Janyk, Mayor, Gibsons, British Columbia

Atlantic Coast – In recent years, the East Coast has experienced accelerated extraction of non-renewable resources. While some communities have been overwhelmed by the amount of information coming from a number of resource developments simultaneously, others, often communities closest to a new extraction area, have been the last to hear about a development. Many consultation processes have been excessively brief, completed within a three- to four-month timeframe. There have been significant disconnects between local and scientific knowledge, and between knowledge and funding (Ommer *et al.*, 2007).

Pacific Coast – On the West Coast, any development must respect the unique culture and beliefs of First Nations. The spiritual and cultural significance of the ocean in First Nations culture must be considered, together with environmental and economic issues. Any consultation process must begin with involving the appropriate First Nations representatives. As discussed in section 5.2, gas hydrate development could not take place unless and until the moratoria are lifted, and coastal concerns about the implications for social and ecological health are resolved.

Arctic Coast (including the Arctic islands) – In the Far North the cultural heritage of Aboriginal Peoples must also be respected. That done, the economic needs of local communities may create a more welcoming attitude to the creation of jobs, the development of the skills of local people and the support for local businesses that would accompany gas hydrate development.

The first step in any consultation process must be to genuinely engage the Inuit and other aboriginal organizations and communities with a stake in the relevant territory. In general, energy development projects are shifting away from a narrow consultation process to a more holistic perspective on relationships with local communities that consider broader social, cultural, economic and environmental implications for the entire region. The 2007 Mackenzie Gas Project Socio-Economic Agreement between industry and the Government of the Northwest Territories is a good example of the substantial progress that has been made in laying out social and economic responsibilities and accountabilities, and in developing appropriate processes and approaches for dealing with the many complex issues surrounding resource development in Canada's Far North (see Box 12). Local groups like Alternatives North, however, have criticized the agreement for being unenforceable and non-binding, claiming that it does not make government and industry commitments mandatory.

Box 12: The 2007 Mackenzie Gas Project Socio-Economic Agreement

The agreement was signed on January 22, 2007 by industry and the Government of the Northwest Territories after two and a half years of consultation and negotiations. Its intention is to:

- supply employment, training, business opportunities and other economic benefits for residents of the Northwest Territories including setting up a $10 million training fund for the first 10 years of the project
- help promote culture preservation and support social commitments such as healthy lifestyle maintenance, community wellness and public safety
- hold industry accountable for any commitments made in the regulatory review process, and
- provide monitoring and ongoing assessment of socio-economic impacts and economic opportunities including setting up an advisory board of industry, government and aboriginal representatives for the life of the project.

Guidelines for Impact Assessment

Consistent with the input from coastal community leaders, the paper prepared for this panel by Hugh Brody (reproduced in Appendix C) outlines issues that must be considered when developing guidelines for the impact assessment for gas hydrate developments:

- how communities are kept informed about the potential development
- how communities are kept informed about, and given a real chance to have input into, the plans for social, economic and cultural research that will answer questions about impacts on their members and resources
- having social science and environmental studies carried out at the highest possible level by independent experts
- allowing time for consultation to be authentic and background research to be done well, as impact assessments can be of optimal value only if they are an integral part of project design and completed well in advance of actual development, and
- conferring with community leaders and First Nations elders, as well as communities as a whole, during the process — community hearings would be essential.

Professor Brody goes on to emphasize the importance of developing a clear understanding of:

- the proposed industry, how it will unfold as a set of economic and social issues, and the likely timelines involved
- the cultural identity, sensitivities, vulnerabilities and needs of each community potentially affected, and
- the level of self-government and status of land-claims settlement in each community.

Considerable time is needed to build community collaboration and consensus. For a significant gas hydrate development project, it could take at least 10 years to complete an acceptable and open process of establishing the science and technology, creating the necessary infrastructure, consulting in meaningful ways with local communities, creating policy guidelines, and building local knowledge and consensus. Most of these steps must precede detailed design and construction. The organizations responsible for planning major gas hydrate projects must take these long timeline requirements into consideration.

6. PROSPECTS FOR GAS HYDRATE DEVELOPMENT IN CANADA

Canada could be well-positioned to be among the world leaders in gas hydrate exploitation if it were to invest sufficiently in exploration, research, development and production. A long-term government commitment would be needed, together with sustained encouragement of industrial involvement and appropriate environmental regulation, because commercial production of gas from gas hydrate is otherwise unlikely in Canada within at least the next two decades.

6.1 CANADA'S KEY STRENGTHS AND OPPORTUNITIES

Canada has a number of significant advantages and strengths:

- Canada has some of the world's most favourable conditions for the occurrence of gas hydrate. Potential gas hydrate resources are large in quantity and include some that could be exploited more readily than is likely in many areas of the world where gas hydrates are being explored.
- Canada has previous experience in major pioneering technological projects and resource development, including some, like the oil sands, that are related to energy.
- There is heightened interest in exercising Canadian sovereign rights in the Far North and in providing better opportunities for residents of remote coastal communities. Gas hydrate research and eventual commercial development could contribute to both objectives.
- Despite Canada's modest financial investment, Canadian governmental and academic researchers have played a significant and pioneering role in understanding the chemical structure and physical properties of gas hydrate. Canada has a core of knowledgeable scientists and engineers with specific expertise related to gas hydrate, as well as a larger group with broad expertise related to the various technical, environmental, cultural and social issues that are relevant to the challenges of exploiting gas hydrate.
- Canada has hosted intensive field studies of arctic gas hydrate at Mallik in the Mackenzie Delta, and of natural marine gas hydrate offshore in Cascadia. Active participation in Mallik, the world's major gas hydrate demonstration drilling and production test program, has given Canada a knowledge base that is among the most advanced in the world.
- Much of the infrastructure for gas hydrate development, at least in the early stages, could be piggy-backed on development of remote natural gas fields in the Mackenzie Delta and/or off the Atlantic coast.

6.2 SOME WEAKNESSES AND CHALLENGES

Before it would be possible to exploit gas hydrate as an energy source in Canada, several weaknesses and challenges would need to be overcome. Some — like the first six listed below — are more Canada-specific, while others represent more general challenges to the commercial development of gas hydrate, regardless of location.

- The volume and location of gas hydrate that might ultimately be profitably produced in Canada cannot be adequately quantified without considerable further research and exploration. The commercial development of this potential resource would depend on entrepreneurial initiative and substantial private-sector investment together with a long-term government commitment.
- While capable in scientific and engineering knowledge, Canadian-based energy companies have so far made unknown, but what appears to be limited, investment in gas hydrate. Involving industry in gas hydrate R&D, exploration and technology development represents a considerable challenge.
- There are issues relating to ownership of gas hydrates and uncertainties as to who would exercise regulatory responsibility for different aspects of any major development project.
- The moratoria on offshore oil, gas and seismic exploration continues to cause uncertainty about the future of any resource exploitation off the coast of British Columbia. In addition, bureaucracy and inconsistencies related to obtaining approvals for offshore seismic exploration are proving to be impediments to further research and mapping.
- Resource development on either the West Coast or in the Arctic requires ongoing discussions with First Nations and the Inuit. The previous three items, coupled with governmental bureaucracy, present a potentially confusing array of obstacles that would have to be negotiated in any resource development process.
- As with conventional gas in areas remote from existing infrastructure, there would be significant transportation issues associated with bringing the gas to market by pipeline or ocean vessels. Transportation challenges would be particularly significant in the Far North, but would be greatly mitigated if pipeline investment could be shared with conventional arctic gas.
- Utilization of natural gas, whether derived from gas hydrate or conventional resources, generates CO_2 and thus exacerbates climate change. On the other hand, displacing coal and oil, which have lower hydrogen-to-carbon ratios, with natural gas could reduce greenhouse gas emissions relative to the current fuel distribution.

- Future markets for natural gas from gas hydrate are uncertain, especially in light of the potential for major supplies of LNG from overseas, and alternative unconventional natural gas resources.
- Given that the exploitation of gas hydrate in commercially significant amounts is likely to be at least one to two decades away, there is great uncertainty about future market conditions and environmental acceptability.
- There are difficulties in applying existing extraction technologies to the permafrost and marine environments where gas hydrates are found.
- These marine and permafrost environments tend to be ecologically fragile and thus vulnerable to damage from major technological developments. Any large-scale development occurring in these environments should follow practices that have been developed in order to minimize the impacts to these sites and also to monitor the impacts of development at these sites.
- Gas hydrate in the Far North poses particular challenges of access, augmenting safety risks and increasing costs associated with exploration, production and delivery to markets.
- Gas hydrate extraction and processing may lead to water management issues because hydrocarbon-saturated water is produced together with the natural gas.

6.3 HOW CANADA COMPARES WITH OTHER COUNTRIES

Despite being an early leader in basic research and geological exploration for gas hydrate, Canada has not kept up during the past decade, especially with applied research and exploration. Other countries like Japan, Korea, China, India, United States and Norway have been investing vigorously in exploration and technology. Fortunately, Canada has a number of individual researchers in the academic and government sectors, whose work remains internationally recognized. Moreover, the Mallik project has been an extraordinary opportunity for Canadians to participate in a major international program and gain valuable experience at a low cost to Canada.

A factor that differentiates Canada from other countries is its wide range of alternative energy sources. In addition to significant resources of conventional fossil fuels like coal, oil and natural gas, Canada is endowed with unconventional hydrocarbons like oil sands, heavy oil and CBM, as well as hydroelectric, nuclear and biomass energy, together with many opportunities to take advantage of wind, solar, geothermal and tidal energy resources. The availability of these energy options reduces the incentive to devote major resources to any one unconventional energy resource. Many of the countries that are more heavily investing in gas hydrate are highly dependent on imported energy and have limited resource options. On the other hand, Canadian supplies of conventional hydrocarbon fuels — particularly natural gas in the western Canadian sedimentary basin — are declining, while unconventional hydrocarbons, nuclear, biofuels and new hydroelectric sources all present challenges to further development. Looking forward two to three decades, Canada should not be complacent about its energy resources, especially natural gas.

While foreign investment could play an important role, opportunities for gas hydrate exploitation in Canada would need to compete for investment with gas hydrate resources belonging to other countries. This competitive situation constitutes an important difference between gas hydrates and oil sands. From an investment standpoint, although developing the oil sands was an enormous challenge for Alberta and Canada, the oils sands became increasingly attractive to foreign investors because of the large size of the resource and the fact that they could be developed within a favourable and stable economic and political environment. This was in the context of declining opportunities in other parts of the world for foreign investors seeking oil production. Along with the increased economic and political risks in many cases, large areas of opportunity had become captive to state-owned oil companies.[59]

Canada's gas hydrate resource would be competing for exploration and development investment with resources that are likely to be less remote and inhospitable — for example, gas hydrate deposits on continental margins close to large populations. A significant portion of the Canadian resource, however, may have the advantage of being accessible from land. Ultimately, a decision to develop a gas hydrate deposit will depend on a great many location-specific factors, in addition to the general technological state-of-the-art and the broad economic, environmental and energy security considerations that would apply to all potential gas hydrate projects worldwide.

6.4 THREE BROAD APPROACHES FOR THE FUTURE

As earlier chapters have outlined, there are many uncertainties in scientific knowledge and understanding of gas hydrate. To address the knowledge gaps over the next 20 to 30 years, Canada must choose, explicitly or implicitly, a level of involvement and investment. The participation of governments — federal, provincial and territorial — might be based on one of the following three broad approaches:

59 The environmental aspects of the development of the oil sands that followed the early investments are outside the scope of this report.

Research Only: Canada could continue to perform scientific research on gas hydrate while leaving, for the foreseeable future at least, its development as a resource to other countries with more pressing needs for alternative sources of energy. Government and academic researchers would carry out the research, while encouraging the participation of industry (e.g., through matching programs). This approach could go as far as establishing a fully interdisciplinary, federally-funded Centre of Excellence involving academics, government, industry and local people. This effort would help develop Canadian expertise in resource assessment, as well as provide a better understanding of coastal and northern resources.

Research and Limited Development: Canada could devote considerably more funding and effort than at present to research and development of gas hydrate to:

- better understand the extent and nature of the resource
- develop the expertise needed for extraction
- assess the magnitude of the resource that can be extracted given the proper economic environment, and
- foster Canadian expertise with the intention of maintaining Canada's international leadership role in a limited subset of the many scientific, technical, environmental and associated unknowns related to the gas hydrate resource, while leaving the major development efforts to other countries.

This approach would acknowledge that gas hydrate represents only one of the many possible future energy sources in Canada that require R&D funding until their relative merits are more clearly delineated. Following this approach would keep the gas hydrate option open and enable its future development on a larger scale, if required. In addition to sponsoring research, the federal government would maintain a close watch on other countries' gas hydrate R&D activities. The investment in funding and effort would be measured, significantly more than in the first approach, but much less than in the third. It would also likely be more focused on one or two sweet spots than in the third approach.

Major Targeted Research and Development: Alternatively, the federal government could make a determined effort to be an international leader in gas hydrate development with gas hydrate exploitation as a national priority. This effort would require a combination of massive investment, focused strategic R&D, infrastructure facilitation and development of training programs. Such an approach would view gas hydrate as one of the best options for bridging to a future where carbon emissions are greatly reduced and North American energy security is more assured. Canada would undertake a major national program that would include all of the actions outlined in section 6.5 below.

There are risks associated with all three approaches. The *Research Only* approach would protect the environment and fulfil the need for Canada to better understand its physical resources. This approach would mean, however, that Canada could lose the opportunity to be in the vanguard of what might become a major global development. There is some financial risk associated with the *Research and Limited Development* approach, and more significant financial risk with the *Major Targeted Research and Development* approach, because gas hydrate exploitation may turn out to be not economically viable or not necessary if other energy options are preferable. The latter approach could be undertaken as a contingent extension of the second approach because a great deal of preparatory work is needed before committing to full-scale commercial development. The initial difference between the second and third approaches is therefore one of ambition and degree of aggressiveness. If Canada ignores gas hydrates altogether, more damaging ways of meeting energy needs could be adopted, and Canada could lose out competitively to other countries, perhaps even to the point of having others exploit Canadian resources. On the other hand, as climate change escalates, carbon-based energy sources may become unacceptable to Canadians.

6.5 ACTIONS CANADA COULD IMPLEMENT

Given the various challenges and opportunities, there are several specific actions that Canada could take to strengthen its gas hydrate position. In view of the great uncertainty and risk associated with the commercial potential of gas hydrate, the federal government would need to provide significant funding and/or assume some risk with respect to many of the following activities. The activities are listed roughly in order from research to commercial development. The *Research Only* option outlined above would pursue only the first two actions, whereas the *Major Targeted Research and Development* approach would undertake all of them. The intermediate *Research and Limited Development* approach would likely address about half of the items listed. Canada could implement the following actions:

- Undertake geological, geophysical and geochemical studies, involving work in the field, laboratory and numerical simulations, to better delineate the extent, location, quality and potential recoverability of Canada's gas hydrate resource.

- Participate more fully in opportunities for international collaboration in gas hydrate research such as Canada becoming a full participating member of the IODP and the ICDP, which would provide excellent training opportunities for young scientists.
- Undertake a wide range of basic and applied research to gain a better understanding of the environmental issues related to a) exploitation of gas hydrate b) natural release, and c) enhanced release due to climate change. For example, attention is needed to questions related to the greenhouse gas potential of gas hydrate including, for example, the intriguing possibility of replacing methane hydrate with CO_2 hydrate (see section 5.1).
- Support R&D in all aspects of gas hydrate extraction technology including drilling, production technologies, associated services and reservoir simulation software.
- Wherever possible, involve industry in all aspects of R&D.
- Encourage the private sector to collect and report data about the occurrence and location of gas hydrate in the course of commercial drilling through gas hydrate formations during exploration for hydrocarbons in northern and offshore areas.
- Similarly, identify opportunities for developing new technologies specifically for gas hydrate related to exploration, field data collection, drilling and stimulation, and onshore processing, thereby creating technology export opportunities if gas hydrate development should be pursued strongly in other countries.
- Support educational and training initiatives for developing personnel with skills and expertise relevant to gas hydrate.
- Include gas hydrate on the agenda for ongoing discussions of community development in coastal and northern communities and with Aboriginal Peoples to ensure they have a basic understanding of gas hydrate and the issues associated with its development.
- Undertake one or two major demonstration production/testing projects to extend the engineering and scientific expertise already in place and ensure that there is improved knowledge and continuing evolution of government and academic research. For example, after reviewing the results of the Mallik 2006-08 project, Canada could proceed, preferably again in collaboration with international partners and industry, with a new Mallik program featuring new objectives, such as those related to production rates over prolonged periods, to extend the lessons learned in the earlier programs. Any new project would need a full environmental impact assessment. Other alternatives might include participation with the United

States on the North Slope of Alaska. Long-term testing would be better suited to a site accessible year-round within current oil industry infrastructure areas. The North Slope of Alaska may be the only North American site that meets that criterion.

- Collaborate with provinces and territories to establish taxation and other measures to ensure that (a) clear rules govern the exploitation of gas hydrate resources, and (b) affected areas receive a return of benefits that assist local communities and help develop renewable energy technology and greenhouse gas sequestration.
- Evaluate the incremental costs, risks and benefits of including gas hydrate extraction, before deciding whether or not to proceed with conventional natural gas extraction projects in the Far North and off the east and west coasts.

7. SUMMARY RESPONSE TO THE CHARGE TO THE PANEL

This chapter summarizes the report's overall messages and outlines the panel's responses to the charge from Natural Resources Canada.

7.1 OVERALL MESSAGES FROM THE REPORT

- Natural gas hydrate — an ice-like solid compound containing hydrocarbon that occurs in marine and permafrost environments — is a potentially vast, but yet untapped, global energy source covering a huge range as shown in Table 3.1.
- Because Canada appears to have some of the world's most favourable conditions for the occurrence of gas hydrate, and has played a leadership role in geophysical and laboratory gas hydrate assessments, Canada is well-positioned to be a global leader in exploration, R&D, and exploitation of gas hydrate. Given that there may be significant social and environmental costs, research is required, at the very least, to fulfil a responsibility to gain a more comprehensive understanding of Canada's physical resources.
- Gas hydrate yields natural gas. Therefore, most of the environmental, safety, regulatory, and social considerations related to its exploitation, whether in the North or offshore, are similar to those associated with conventional gas production in frontier areas.
- No insuperable technical problems are foreseen in producing gas from gas hydrate, though this would be more costly than producing gas from conventional reservoirs in similar environments.
- The most promising method of production appears to be to dissociate gas hydrate via pressure drawdown within the reservoir. The most favourable conditions are when the gas hydrate occurs in marine and subpermafrost sand formations.
- Gas from gas hydrate is a hydrocarbon. Although its combustion generates less CO_2 per unit energy than coal or oil, the proportion of gas hydrate, and other hydrocarbons, in the future energy mix will depend on decisions on how best to mitigate the anthropogenic drivers of climate change.
- The volume and location of gas hydrate that might ultimately be profitably produced in Canada cannot be adequately quantified at this time. Ongoing exploration and research will be required to delimit the resource and to determine the technical factors that would govern gas production.
- Commercial production of gas from gas hydrate in Canada would likely begin in association with existing natural gas fields — on the same sites, and using their associated infrastructure.

- In view of the need for further exploration and appraisal of the resource, construction of new transport infrastructure and various permitting approvals from government, large-scale, stand-alone commercial production of gas from gas hydrate is unlikely to take place in Canada within the next two decades.
- The economic, environmental and certain technical uncertainties that affect the commercial prospects of gas hydrate, when considered in the context of current alternative opportunities for energy companies, imply that the private sector on its own is unlikely to undertake development of gas hydrate in Canada at this time. Industry must be effectively engaged if significant progress is to be made. Government-industry partnerships could create the option to include gas hydrate in a diversified energy portfolio for the future.

7.2 SUMMARY RESPONSE TO THE CHARGE TO THE PANEL

The panel has been asked by Natural Resources Canada: *What are the challenges for an acceptable operational extraction of gas hydrates in Canada?* More specifically, the charge comprises three subquestions, the responses to which may be summarized as follows.

What share of the total Canadian reserves [of gas hydrate] can be profitably extracted?

The term, reserves, as used in the energy industry, applies only to resources that are either in production, under development or planned for imminent development. Although there are no gas hydrate reserves by this definition, there are certainly resources, and the panel has interpreted the question as applying to these resources.

It is impossible at this time to provide an accurate assessment of the extent of Canada's exploitable gas hydrate resources. This is due to a number of factors (outlined in Chapter 3), including limited production testing, limited regional exploration and mapping, the high variability of local geology, and the nature of the gas hydrate deposit itself. The most that can be stated is that the gas hydrate resource is potentially large, possibly one or more orders of magnitude larger than conventional hydrocarbon resources. Indications are that gas hydrate underlies coastal areas off the west, north and east coasts of Canada, and that there are also significant amounts beneath the permafrost in the Far North.

The extraction of commercial quantities of gas from gas hydrate depends on development of a practical and relatively efficient way to decompose the gas hydrate into its water and gas constituents and to produce the resulting natural gas. The most attractive gas hydrate deposits are those associated with sand below permafrost. Depressurization appears to be the most promising extraction technique.

Extraction of gas hydrate relies on methods similar to those used to extract conventional natural gas. In fact, companies drilling for natural gas in coastal and northern areas often drill through gas hydrate formations before reaching conventional gas fields. Relative to conventional natural gas production, gas hydrate production appears to yield lower flow rates; to need more compression; to involve higher production of water; to require more heating, and; to need more expensive well completion techniques. On the positive side, the production rate should be more uniform, or even increasing, over the life of the well.

From an economic point of view, exploitation of gas hydrate is most likely to take place when conventional gas extraction is well underway or exhausted in drilled sites or offshore, by completing the well where the gas hydrate has been found when drilling in the first place. Because the gas hydrate is simply natural gas once it has dissociated ("melted") and the gas has been released, the essential infrastructure, including pipeline transport, will already be in place.

The profitability of gas hydrate extraction will depend on further development of efficient means of production, as well as on many of the same critical factors that will govern the future profitability of conventional natural gas including:

- the growth in demand for energy overall and for natural gas in particular
- the extent, strategies and pace of reducing greenhouse gas emissions, including development of new technologies for carbon capture and storage
- competition from CBM and imported LNG
- pressures to assure energy security for North America
- the ability of alternative energy resources to displace hydrocarbons
- the performance, including safety and environmental records, of early demonstration gas hydrate production projects
- the attitudes and degree of co-operation with local communities in regions directly affected by resource development, and
- the pace of gas hydrate development in other countries, some of which (e.g., Japan, India, China, Korea) may well give priority to gas hydrate as a future energy source.

The foregoing factors are extremely difficult to predict, especially given the likely 20 to 30-year timeframe before gas hydrate could become a commercially meaningful source of Canadian energy production. Earlier chapters of this report address the relevant considerations in respect of many of these factors. Under some circumstances, and with substantial investment, gas hydrate could be a significant source of energy for Canada in the future. However, it is also possible that other alternatives will become more economically and environmentally attractive, to a point where gas hydrate could not compete in the foreseeable future.

What are the science and technology needs for the safe use of energy from gas hydrates?

Issues related to this question are addressed in Chapters 4 and 5. Although industry has already developed most of the technology needed to find, delineate, extract, handle and transport conventional natural gas from remote offshore and onshore sites, direct experience in producing from gas hydrate reservoirs is very limited. Recent successful short-term testing in Alaska and at Mallik in the Northwest Territories is encouraging, but production periods were too brief to provide a reliable indication of the longevity and long-term prospects of gas production.

Before any substantial investment in gas hydrate exploitation is undertaken, it is critical that large-scale demonstration projects prove that safe production can be sustained at sufficient rates to justify the financial and production risks of major new projects. The current level of uncertainty is simply too great to expect a significant level of private-sector investment without major involvement of public funds. A starting point, if the Mackenzie Delta natural gas project should proceed, would be to offer inducements so that gas hydrate is mapped and extracted as an integral part of the overall project.

There do not appear to be significant safety issues, unique to the production of gas from gas hydrate, that are not already encountered and addressed in the course of more conventional natural gas production, both onshore and offshore.

What are the environmental considerations related to the use, and the non-use, of this resource?

The environmental issues are addressed primarily in Chapter 5. The panel has chosen to broaden the scope to also include social challenges and the jurisdictional and regulatory framework under which exploitation would need to proceed.

From an environmental point of view, gas produced from gas hydrate is essentially identical to conventional natural gas, with methane as the main product. Hence, gas hydrate would add to the production of natural gas, a fossil fuel leading to emission of CO_2 (a greenhouse gas) when the gas is used as a fuel. In the short term, it could displace some oil and coal (fossil fuels with greater greenhouse gas emissions per unit of energy), but in the long term, carbon-bearing fuels will need to be curtailed and/or subjected to substantial capture and sequestration.

Since methane is a much more potent greenhouse gas than CO_2, great attention will be needed to prevent gas escape from gas hydrate during production. This can be addressed through appropriate regulation and careful well engineering, and it is in the interest of commercial producers to minimize the loss of gas. Research is also needed to establish whether methane present in hydrate form could be safely displaced and replaced by CO_2 as discussed in section 5.1.

The question also arises as to the environmental considerations relevant to the "non-use" of the gas hydrate resource. We believe that this part of the question is asking us to consider the risk that very large amounts of gas hydrate may dissociate, due to global warming, causing a release of methane into the atmosphere that would feed back and further accelerate global warming. Might the exploitation of gas hydrate pre-empt, or at least mitigate, this accelerated dissociation, with net positive implications for climate change? In response to this question, we note that any conceivable exploitation of gas hydrate in the current century would extract and convert such a small fraction of the overall resource that it would have negligible impact on the overall quantity of gas hydrate and on the eventual release of methane due to massive and long-term global warming.

There is some uncertainty about the time until global warming could begin to cause a massive or chronic release of gas hydrate to the atmosphere, causing what would likely be a catastrophic climate positive feedback, given the elevated greenhouse gas potential of methane. But extracting gas hydrate to prevent its release is not an option in view of its widely distributed occurrence. Other means must be found to minimize hydrocarbon use and/or safely store large volumes of greenhouse gases.

Regarding other regulatory, jurisdictional and social considerations that affect development prospects for gas hydrate, the panel concluded as follows. If the current moratoria on exploration and development off Canada's West Coast continue, gas hydrate could not be exploited there — however, the future of these moratoria is uncertain. On the East Coast, the Atlantic Accords are likely to provide a regulatory framework under which gas hydrate development could proceed. Federal/territorial government co-operation would be critical if development were to proceed in the North where there is strong pressure to find projects that can support local employment. At the same time, there is considerable sensitivity, based on past experience, to the need to involve local communities and Aboriginal Peoples from the earliest stages of any resource development on the East, West or Arctic coasts.

In Conclusion

The overarching question addressed in this report is: *What are the challenges for an acceptable operational extraction of gas hydrates in Canada?* Operational extraction — interpreted here as the production of commercially significant quantities of natural gas from gas hydrate in Canada — is likely to be feasible only if the economic conditions in the coming decades are such that natural gas functions in a major bridging role to reduce greenhouse gas emissions by displacing coal and oil, and if gas from gas hydrate can compete economically with imported LNG and other alternative sources such as CBM. In the long term, methods of avoiding or sequestering CO_2 will be critical.

Although there do not appear to be any insurmountable technological issues regarding the production of gas from gas hydrate, major demonstration projects would be needed to establish the longevity and safe operational practices before any major private investment in gas hydrate is likely. In the next 10 to 20 years, the best prospects for testing gas hydrate would appear to be in sand deposits below permafrost, and in those cases where gas hydrate is adjacent to conventional natural gas sources — thereby extending the lifetime of those sources that have been justified based on the conventional resource alone. Challenges will also include dealing with issues that have proven to be of central importance in other natural resource extraction projects, including satisfying local communities and all levels of government.

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Appendix A – History of Gas Hydrate Activities in Canada

Gas hydrate research in Canada emerged as an activity of note starting around 1960 with contributions in three areas:

- physical and molecular sciences, curiosity-driven at NRC
- petroleum engineering issues, initiated at the University of Alberta to solve flow assurance problems, and
- earth and ocean sciences and engineering, which arose naturally at Energy Mines and Resources Canada (now NRCan) as an extension of dealing with permafrost and offshore mapping.

Since natural gas hydrate has become a subject of great international interest, the three streams, although still distinct, have become more integrated in tackling global gas hydrate issues. Industry and government have also played a role because drilling into and through gas hydrate formations has required the development of safe practices.

Gas hydrate research in Canada differs from that in other countries for the following reasons:

- **Gas hydrate research has been driven largely by individuals rather than by policy.** Without an overarching national policy or strategy, individuals have had to raise their research funding by submitting research proposals through regular channels available to academic researchers (NSERC), or by convincing government organizations (such as NRC and NRCan) that institutional funding should be made available.

- **Canada is endowed with three gas hydrate regions – off the Atlantic and Pacific coasts and in the Arctic.** Because of early and sustained research efforts, two sites have become natural laboratories for gas hydrate field work: the Cascadia margin offshore Vancouver Island and Mallik in the Northwest Territories.

- **Once gas hydrate research started in a group or institution, such efforts were often sustained for many years.** This expertise and experience eventually brought Canadian gas hydrate research to the forefront when the global importance of gas hydrate became recognized. Canadian researchers became partners of choice for collaborative work, leading to opportunities for research partnerships and international funding.

Despite the modesty of the funding available from within Canada and the lack of a national program, Canada assumed a leadership role in gas hydrate research.

LABORATORY RESEARCH

Early Years

William Crowell Bray was the first Canadian known to have worked on gas hydrate. While working in Leipzig, he recognized that a reaction of chlorine dioxide (ClO_2) with water resulted in the formation of a gas hydrate (Bray, 1906). Although the reaction had been described earlier by Millon (1843), Bray's work was a first example of using hydrate formation to stabilize a reactive material (ClO_2 by itself is explosive). In 1922 Maass and Boomer at McGill University reported the phase diagram of the hydrate of ethylene oxide, an unusual hydrate former because it is completely water soluble.

By 1960, gas hydrate, both as a fundamental international scientific subject and as an engineering material, was at a stage where rapid progress could be made in theoretical and practical areas. Canadian academic researchers were interested in Linus Pauling's clathrate model for liquid water (Pauling, 1961) and in his speculations that anaesthesia in animals and humans was somehow linked to gas hydrate because the same small molecules that induced anaesthesia also served as guests in hydrates (Pauling, 1964). Stanley Miller suggested that gas hydrates might exist naturally. For example, he saw the planet Mars as the likely location, with CO_2 hydrate forming its polar *ice caps* (Miller, 1961).

The NRC Hydrate Group

The gas hydrate group at NRC is a recognized world leader in the molecular science of gas hydrate. Gas hydrate science at NRC developed from the interest of one NRC scientist, Don Davidson, in fundamental gas hydrate properties, i.e., as curiosity-driven research. As a consequence, when natural gas hydrate was discovered in Canada in the early 1970s, NRC was able to contribute to the regulatory side of establishing safe drilling practices, as well as to the National Energy Program. When this program was terminated, gas hydrate science at

NRC reverted to strictly fundamental work, although NRC did receive natural gas hydrate samples for molecular-scale characterization from the first samples recovered under the U.S. DOE hydrate program. This has been the model for gas hydrate research at NRC ever since: a core fundamental science component with the ability to contribute to problems of national and international concern by means of collaboration.

Around 1960, Don Davidson, a physical chemist in the Colloid Chemistry Section of NRC's Division of Chemistry, became interested in clathrate hydrates. Davidson wrote a paper on clathrate hydrates in Felix Frank's well-known series, *Water: A Comprehensive Treatise* (1973), which included all significant scientific achievements in gas hydrate science up until that time.

In 1974 the first reports on the presence of natural gas hydrate in the Canadian Arctic were published (Bily and Dick, 1974). Concerns were raised about the risks associated with drilling through gas hydrate formations. An important discovery during this time was that the prevailing hydrate structure had to be measured because hydrate structures are not predictable just from knowing which guest molecules are present (Davidson *et al.*, 1984). NMR spectroscopy led to the first measurements of guest distribution in hydrate cages, providing experimental evidence that could be used for evaluating the quality of gas hydrate prediction models (Ripmeester and Davidson, 1981). This work also provided experimental values for parameters underpinning the van der Waals and Platteeuw (1959) model for gas hydrate, which, in various forms, had been incorporated into a number of software packages for predicting gas hydrate phase equilibria. Calorimetry provided a new direct experimental approach for measuring heats of formation and the composition of natural gas hydrate (Handa, 1986b), the data being by far the best obtained — a distinction that still stands.

Natural gas hydrate was also seen as a vehicle for testing new concepts and experimental approaches in molecular science. Along the way, the NRC group developed multitechnique approaches for the laboratory analysis of gas hydrate, both natural and synthetic, and contributed discoveries in areas other than gas hydrate science. In the early 1980s, NRC, in collaboration with the U.S. DOE, received gas hydrate samples from the Gulf of Mexico and Blake Ridge that showed, for the first time, that hydrate structures I and II exist in nature (Davidson *et al.*, 1986). Observations on these samples led to the development of NMR methods, now in common use, for quantitative determination of hydrocarbon guest distributions and the composition of natural gas hydrate (Ripmeester and Ratcliffe, 1988).

When it was first reported that gas hydrate had anomalously low thermal conductivity, NRC initiated experimental work taking advantage of the expertise in thermal measurements in the Division of Physics (Cook and Leaist, 1983). The work on thermal conductivity (Tse and White, 1988) is especially pertinent to field studies because this property affects the geothermal gradient, which helps identify where gas hydrates can be found.

When Davidson died in 1986, the Colloid and Clathrate Chemistry Section continued under the leadership of John Ripmeester. News of a new gas hydrate structure, dubbed structure H, was reported (Ripmeester and Ratcliffe, 1988). Structure H was the first new gas hydrate *family* since structures I and II were reported 25 years earlier. A sample recovered from Cascadia in 2007 confirmed the prediction that structure H would be found in nature (Lu *et al.*, 2007).

In 1990 a major reorganization at NRC spread the clathrate team over different groups and institutes. The group became known for its multitechnique approaches to the characterization of microporous materials. Paul Handa, of the Institute for Chemical Process and Environmental Technology, carried out pioneering projects on hydrate formation in porous media using calorimetric approaches (Handa and Stupin, 1992) — the first serious attempt to see how porous media might change the conditions for gas hydrate formation in nature.

The increased international interest in gas hydrate brought hydrate science back into the spotlight. Japanese delegations visited Canada in search of gas hydrate science expertise, and several joint Canada-Japan workshops were held. An important outcome was the NRC group's analysis of hydrate samples from the first international Mallik project, which eventually led to establishing a laboratory protocol for preserving and characterizing natural gas hydrate.

Experimental work was undertaken to understand nucleation and growth phenomena, e.g., from the reaction of vapour-deposited or hyperquenched water droplets with gas hydrate formers (Tulk *et al.*, 1999). One revelation was that supposedly homogeneous kinetic processes, observed macroscopically, appear very inhomogeneous when small volumes are studied (Moudrakovski *et al.*, 2004). Molecular scale mechanisms therefore play an important role in validating or discounting models, which may account for macroscopic observations such as hydrate nucleation, formation and decomposition.

In summary, experience has shown that gas hydrate problems tend to be complex, and problem-solving requires a broad perspective that incorporates fundamental considerations typical of molecular science and practical approaches more prevalent in engineering and the geosciences. NRC's work has served as a bridge between molecular-scale hydrate science and the communities that encounter gas hydrate in natural and industrial settings. The NRC group has contributed more than 150 publications on gas hydrate science and has been an international model for other gas hydrate laboratories.

University of Alberta

D.B. Robinson started reporting work on gas hydrate in the late 1950s, motivated by the needs of the developing gas processing industry in Alberta. In particular, he reported phase equilibrium data on hydrates from natural gas components and mixtures. The work included comprehensive studies on the effect of thermodynamic inhibitors (methanol and glycols), as well as gas hydrate formation from liquid hydrocarbons. This work complemented fundamental thermodynamics work in Robinson's laboratory (Ng and Robinson, 1976).[60] The data provided information for the safe and economic design of gas processing facilities, and led to a stringent database for testing predictive computational methods for calculating gas hydrate formation conditions.

Robinson's group also developed one of the most successful engineering thermodynamic models for calculating the equilibrium properties of fluid mixtures. The celebrated Peng-Robinson equation of state was published in 1976 and has been cited more than 2,600 times since then — a rare achievement for an engineering publication. This model transformed the way engineers conduct routine design calculations, with a shift from tables and nomographs to more sophisticated software, evolving into process simulation packages. Robinson and colleagues founded the D.B. Robinson and Associates Company in Edmonton, which became one of the most successful university spin-off companies in Canada. Beginning as a small, independent oil and gas services firm providing data, equipment and software, it grew considerably until Schlumberger acquired it in April 2002.

60 Most of the resulting data were published as Research Reports from the Gas Processors Association (Tulsa, OK).

University of Calgary

In 1976 P.R. Bishnoi's group began investigating the impact of gas hydrate formation on the spread of oil in arctic waters in case of a well blow-out. Bishnoi proposed macroscopic mechanistic models that have been used for simulating well blow-outs in cold or deep waters, gas hydrate plug decomposition, gas hydrate reservoirs and gas storage via hydrate formation. The Kim-Bishnoi gas hydrate decomposition model is an essential component of gas hydrate reservoir simulation used by non-equilibrium models for evaluating gas production from gas hydrate (Kim *et al.*, 1987). Subsequent work by David Topham from the Institute of Ocean Sciences in British Columbia showed that in an oil well blow-out under arctic conditions for wellhead depths beyond 800 m, all the gas would be converted to gas hydrate before reaching the surface.

Mehran Pooladi-Darvish works on reservoir simulation, a crucial field for developing gas hydrate production methods because it helps assess the bounds of the energy efficiency of a gas recovery process. Jocelyn Grozic aims to determine the geomechanical response of gas hydrate–sediment mixtures by studying the behaviour of deepwater marine clays containing gas and gas hydrate.

University of British Columbia

Peter Englezos's group presented the first numerical heat transfer model that takes composite media and permafrost phase change into account to compute the critical time required for gas hydrate to begin *feeling the effect* of current global warming (Englezos and Hatzikiriakos, 1994). The work showed that gas hydrate below permafrost could begin melting within the next 100 years, while gas hydrate below the ocean floor should be *protected* by the water layer for a significantly longer time. The group is also exploiting gas hydrate crystallization to develop technology for transporting natural gas, capturing CO_2 from conventional power plants, and separating fuel gas from gasification plants into CO_2 and hydrogen.

Geological Survey of Canada

Laboratory investigations at the GSC address practical geologic issues with direct relevance to field operations for gas hydrate production testing. Working with Russian scientists in the 1990s, Wright *et al.* developed conceptually simple, but highly effective, gas hydrate testing cells that have clarified key variables, like salinity and grain size, on gas hydrate in natural reservoirs. Fred Wright, Scott Dallimore and Mark Nixon used similar technology to develop a dielectric tool for quantifying gas hydrate amounts in laboratory specimens and in the field. They also directly measured the thermal conductivity of gas hydrate-bearing sediments under simulated *in situ* pressure-temperature conditions. This work has had significant impact on the development of numerical models of gas hydrate production, with findings incorporated into research and industrial models in Canada, Japan and the United States.

FIELD RESEARCH

Canada has been a leader in field research of naturally occurring gas hydrate deposits for decades. Significant deposits are found off all three coasts and in the permafrost environment of the Far North. Most notably, and unique to Canada, are the two natural laboratories: the Mallik research well in the Mackenzie Delta in the Northwest Territories, and the Cascadian continental margin, off Vancouver Island. These are probably the best studied natural gas hydrate environments in permafrost and continental margin settings anywhere in the world.

Field research in Canada has involved collaborative work among many institutions, both nationally and internationally. Canadian academic researchers from the University of Victoria (UVic), the University of Toronto (U of T), McGill University, Dalhousie University and the University of Alberta (UAlberta) have worked closely with government researchers from the GSC in the field, and with laboratory researchers at NRC.

Early Field Work

Soon after the Russian natural gas hydrate experience became known to the West in the late 1960s, gas hydrates were inferred to exist naturally in marine and onshore locations outside the USSR. Stoll and co-workers (1971) used seismic data to suggest that marine gas hydrate existed on the Blake Ridge, offshore South Carolina. In the Canadian Arctic, two Imperial Oil geologists, Bily and Dick (1974), reported gas in drilling mud while penetrating gas-bearing reservoirs. Problems with drilling through gas hydrate zones were identified and suitable solutions given — slow penetration rates and the use of chilled drilling mud.

Safe Drilling Practice and Industry Involvement

The need for the scientific, technical and political sectors to work together became apparent shortly after the first indications of the presence of gas hydrate in Canada's Far North. One focus was safety because drilling through gas hydrate formations, even for conventional hydrocarbon exploration, could be hazardous.

Sudden decomposition of gas hydrate, when contacted by a drill bit, could release large quantities of gas, thus violently ejecting the drill string.

Lindsay Franklin (private communication, 2008) mentioned that drilling through gas hydrate zones in the 1960s likely took place without a great deal of awareness. Only when gas hydrate decomposition was noted in the drill cuttings was it clearly evident. Franklin (1983), after joining Panarctic Oils in 1980, provided an early discussion of the potential of gas hydrates and possible extraction methods: "The large gas reserves are within easy reach if a safe, economical method to melt the hydrate is developed. To solve the problem, industry has tried application of heat from outside sources, and circulation of methanol or ethylene glycol. None of these methods appears economically attractive so far, but a new approach, allowing free gas to influence the melting of associated hydrates, may prove a viable technique." This is much the same concept as is considered most viable today for gas production — free gas in contact with a gas hydrate zone.

GSC

GSC involvement in gas hydrate research began in the 1970s when it helped industry address problems encountered during exploratory drilling in the Mackenzie Delta, the southern Beaufort Sea and Canada's Arctic islands. GSC scientists have long recognized the need for better techniques to quantify gas hydrates in different geologic settings. Field programs conducted on permafrost and marine gas hydrate have enabled assessment of different seismic systems (in collaboration with UVic and Dalhousie), electromagnetic profiling (downhole and marine surveys in collaboration with U of T), heat flow and high resolution geothermal studies (with UVic), seafloor compliance (with U of T), swath mapping (with the University of Washington), coring (with UVic), and research drilling (ODP, IODP and Mallik). Considerable progress has also been made on theoretical and modelling work, which has allowed the development of improved techniques for processing industry seismic data and for geothermal modelling of gas hydrate development and dissociation. GSC researchers have contributed more than 100 peer-reviewed papers on gas hydrates in Canada, often in collaboration with individuals from industry, academia and other government agencies.

Arctic Gas Hydrate

GSC scientists like Scott Dallimore, Fred Wright and Mark Nixon have played a leading role in all three gas hydrate research well programs at the Mallik site in the Mackenzie Delta. Researchers involved in the Mallik programs have come from academic institutions across Canada and abroad. These programs have led to incremental improvements in gas hydrate drilling and coring methods, and the recovery and characterization of the first intra- and subpermafrost gas hydrate cores. The three Mallik programs have provided an opportunity for testing a wide variety of technologies including:

- advanced well-logging tools for quantifying *in situ* gas hydrate amounts
- deployment of downhole monitoring devices to measure reservoir responses to drilling and production testing, and
- the first scientifically documented gas hydrate production tests by thermal stimulation and depressurization techniques.

The first two Mallik efforts were arguably the most international of all gas hydrate activities, providing world-class contributions of coring and field work. Mallik is the best-studied gas hydrate site, with extensive geophysical and geological publications (Dallimore and Collett, 2005).

Mallik 1998 Research Well Program with Japan National Oil and Gas Corporation (JNOC): GSC developed and tested techniques for drilling, coring and logging of gas hydrate occurrences, and collected the first subpermafrost core samples.

Mallik 2002 Gas Hydrate Production Research Program with seven international partners from five countries: New coring methods were tested along with a state-of-the-art open-, cased- and crosshole logging program, installation of distributed temperature sensors (DTS) outside-of-casing cables to define thermal fields, first small-scale production testing by depressurization and extended thermal stimulation testing.

Mallik 2006-08 Gas Hydrate Production Research Program with JOGMEC: The goal is to conduct long-duration production testing by the depressurization method. R&D activities include installing and testing a novel suite of *in situ* monitoring devices and extensive open- and casedhole logging. A three-day production test was carried out to assess completion methods and to gain engineering data for more prolonged tests planned for 2008 (see Appendix D).

Marine Gas Hydrate

Pacific Coast - On Canada's Pacific coast, GSC researchers first discovered gas hydrate BSRs in multichannel seismic surveys in 1985 and 1989. Since that time, there have been extensive multidisciplinary surveys and studies by the GSC, Canadian universities and scientists from over a dozen other countries, as well as around 25 research cruises by Canadian and international ships. There have been approximately 20 graduate research theses and numerous postdoctoral studies on gas hydrate occurrence in this area, establishing the area off Vancouver Island as one of the best studied in the world. There has also been great success in developing and testing systems for detecting, mapping and quantifying marine gas hydrate.

The accretionary prism — the wedge of sediments scraped off the Pacific plate as it subducts beneath the Juan de Fuca plate — off Vancouver Island has been the focus of many marine geological and geophysical studies over the past two decades. What may be the most intensively studied gas hydrate deposits in Canada are found in the vicinity of the ODP Leg 146, Site 889 (Westbrook *et al.*, 1994), off Vancouver Island, on the northern Cascadian continental margin. The recently completed IODP Expedition 311 provided an opportunity to calibrate data to gas hydrate content. A large range of geophysical, geotechnical and geological methods for detecting, mapping and characterizing gas hydrate have been tested on the Cascadia margin (Hyndman *et al.*, 2001; Spence *et al.*, 2000) including:

- scientific drilling (ODP and IODP)
- single and multichannel, 2D and 3D, seismic imaging (GSC, UVic, Dalhousie)
- seafloor compliance studies (U of T, GSC)
- controlled-source electromagnetic surveys (U of T, GSC)
- OBS (GSC, UVic, Dalhousie)
- heat flow determinations (GSC, UVic)
- piston coring with measurements of sediment physical properties and pore-fluid geochemistry (GSC, UVic)
- seafloor video observation, (UVic, GSC), and
- sampling with an unmanned submersible ROPOS (GSC, UVic).

Of particular interest over the last 10 years are cold vents and pingos, which represent local occurrences of high concentrations of massive gas hydrate in regions where gas hydrate more commonly is disseminated in low concentration. Cold vents are identified by seismic blank zones in the gas hydrate stability field. Early Canadian results on cold vents have been confirmed by research on continental margins worldwide. Samples take from pingos, mounds and massive outcrops of gas hydrate revealed that these deposits contain higher-order hydrocarbons than methane. Laboratory characterization revealed structure II hydrate and even structure H hydrate with hydrocarbons ranging from C1-C8 in the hydrate cages (Lu *et al.*, 2007). The Bullseye cold vent and the Barkley Canyon pingos will be sites studied by a new seafloor observatory to be installed in 2008 (see Future activities).

Atlantic Coast - In the mid-1980s and early 1990s, the GSC sponsored consultants to study the occurrence of gas hydrate off Canada's east coast. Several reports were published based on interpretations from industry geophysical well logs and seismic data, establishing a basis for assessing offshore gas hydrate. Although recognized on industry seismic data, the identification of a BSR off the Nova Scotia margin did not appear in a refereed publication until 2004. Using extensive industry seismic data, GSC, university (Dalhousie) and industry researchers documented locations of BSRs along the Nova Scotia and Newfoundland margins. Using an industry-donated 3D seismic cube over a BSR on the Scotian shelf has enhanced recent research. Follow-up field investigations included an OBS and heat flow studies to characterize the gas hydrate. Other research has focused on developing geochemical indicators of the presence and origin of gas hydrates (Cranston, Mosher). Three GSC expeditions over the past five years have been dedicated to gas hydrate on the east coast margin. Samples have yet to be recovered, although industry has encountered them during exploratory drilling.

Future Activities

The North-East Pacific Time-series Undersea Network Experiments (**NEPTUNE**) project is expected to be fully installed in late fall 2008. NEPTUNE, a major collaborative project, will be the world's largest cable-linked seafloor observatory. Power and Internet will be provided for a variety of scientific instruments at six nodes on the Juan de Fuca plate, off Vancouver Island. Two of these nodes have dedicated gas hydrate experiments: the Barkley Canyon site and the Bullseye cold vent. For the first time, scientists will have an opportunity to observe the evolution of these marine gas hydrate systems over time. NEPTUNE's scale and interdisciplinary nature will allow scientists to investigate the relationship among diverse data sets. Using geophysical imaging of gas hydrate sites and earthquake data from a co-located seismometer, cientists will also investigate relationships between seismicity, the gas hydrate content of sediments and venting of free gas at the seafloor.

The Barkley Canyon observatory is spearheaded by Ross Chapman, a UVic researcher, and focuses on monitoring at the seafloor, in particular by employing rovers (from the International University of Bremen, Germany), controlled over the internet, to deploy and transport experimental equipment for monitoring. McGill researcher, Michael Riedel, is Chief Scientist of the ODP 889/Bullseye node, which will continuously monitor the subsurface with a stationary controlled-source electromagnetic array developed by U of T (Edwards' group) to monitor resistivity and a U of T (Willoughby) compliance installation. Sporadic venting observed at the surface will be monitored by a UVic (Spence) sector-scanning sonar installation (Willoughby *et al.*, 2008).

Appendix B – Questionnaire on Gas Hydrate Research and Exploration Internationally

We hope you will be able to take a few minutes to complete this short questionnaire on activities related to gas hydrates research and exploration in (name of country). The Council of Canadian Academies (www.scienceadvice.ca) has been asked by the Government of Canada to appoint an independent expert panel to assess the challenges of an acceptable operational extraction of gas hydrates in Canada. To place Canada's past, present and future activity in context, it is important that the panel's report include a summary of gas hydrate research and exploration internationally. Your response to this questionnaire, complemented by documentary material being assembled by the expert panel, will help ensure that our assessment is as up-to-date and authoritative as possible.

1. (a) **Please describe in general terms the type of gas hydrate research conducted in your organization. More specifically, which of the following are themes of particular focus?** Please elaborate briefly on those you have identified:

   ❑ Gas hydrate energy assessment

   ❑ Gas hydrate production modelling and testing

   ❑ Methane vents

   ❑ Natural gas storage and transport

   ❑ CO_2 capture and sequestration with hydrates

   ❑ Other (Please specify____________________________)

   (b) **Is your research effort managed under a national gas hydrate program?**

   ❑ YES ❑ NO

(c) **If yes, what factors have primarily led to its creation?** (**Check as many as apply**)

❑ Security of energy supply

❑ Environmental/Climate Change

❑ Co-operation with other gas hydrate research programs

❑ Other (Please specify____________________________)

2. **Who are the key players in gas hydrate research and exploration in your country?**

❑ Government agencies

❑ Private sector firms

❑ Universities

❑ Other (Please specify____________________________)

3. **What is (approximately) the current total annual expenditure on gas hydrate research and exploration in your country?** (Please provide your best estimate, or indicate why a meaningful estimate cannot be given.)

4. **What have been some of the milestone events related to gas hydrates research in your country? Examples might include major research discoveries in the lab or in the field; initiation of a national gas hydrates research/development/exploration program; or participation in a major international undertaking.** (Please provide some references to a historical account of gas hydrate research in your country.)

5. **How does gas hydrate fit within your country's medium-to-long-term energy strategy? For example, is gas hydrate activity seen primarily as a long-term research project; or as a realistic potential contributor to energy supply within a decade or so; or as a potentially significant source of energy but in a longer time-frame? Is the activity expected to be carried out primarily by government agencies; by the private sector; or by government-industry partnerships?**

6. **In your country, are there other expert groups, or individuals that you think our panel should contact?** (Please provide contact information – e.g. name, email or phone or postal address)

Appendix C – Impacts on Communities

IMPACTS ON COMMUNITIES: ISSUES OF SOCIAL SCIENCE AND IMPACT ASSESSMENT IN RELATION TO GAS HYDRATES IN CANADA

By Hugh Brody, Canada Research Chair in Aboriginal Studies University College of the Fraser Valley

Background

The following notes have been prepared in response to discussions with Rosemary Ommer, and phone calls with John Grace and Christina Stachulak. In these conversations, you will have raised questions about the kind of social, economic and cultural impact assessment that might be an essential component of any overview of Gas Hydrate developments in Canada. This memo sets out some preliminary thoughts about these questions, and can be seen as a small step towards ensuring that the social, cultural and economic implications of development of gas hydrates for communities in the impact zones have their place in all aspects of planning and, in due course, ensuring maximum benefits and avoidance of harm.

I have no specialised knowledge of how the gas hydrate industry is likely to unfold, and am therefore able to suggest no more than a series of questions that impact assessment should be able to answer. However, documents I have read show the immense potential of gas hydrates for the Canadian economy, with the resource spread across very extensive regions. This spread includes much of the coast of British Columbia, much of the Atlantic coast, including all of Labrador, as well as the far north, from the Arctic archipelago to the southern extent of the permafrost. There are First Nation, Inuit and other small communities in all these regions, as well as regional centres where Aboriginal and other peoples are dealing with complex social and economic problems, new kinds of jurisdiction or ongoing attempts to achieve new forms and balances of governance, along with difficult questions about cultural identity. The scale of potential development of gas hydrates in Canada therefore opens a prospect of many kinds of impact on distinctive and, in some cases, highly vulnerable communities.

Estimates of the gas hydrates resource speak of a reserve of something like double all other equivalent energy sources in Canada and refer to "national security of supply" of energy long into the future. This in turn invites a prospect of great social and economic benefits to the nation. Thus it is also said that the development of gas hydrates could contribute "to the economic security of northern, coastal and aboriginal economies that reside in the vicinity of the resource."

Confidence of this kind in the benefits of industrial development to Aboriginal communities is sure to be questioned. Over the past thirty-five years, there have been many lines of inquiry into the impacts of various forms of development in Canada's north and west that have sought to assess where benefits and costs of such developments might lie. Assessment of the impacts of the James Bay Hydro developments in northern Quebec, the Berger Inquiry into the Mackenzie Valley Pipeline, followed by similar examinations of the potential impacts of the Alaska Highway Pipeline in both the Yukon and northern British Columbia, up to the new and ongoing debate about an energy corridor along the Mackenzie, are all resonant with questions about the short and long term consequences of these kinds of development for small, isolated and often disadvantaged communities. People who find themselves at the edge, or in the path, of large scale developments have tended to be sharply divided in their own judgment of whether and in what ways such development is in their interests. Social science has paid a good deal of attention to what kinds of change actual developments have brought, as well as raising awareness of how large scale development has the potential to cause damage as well as bring benefits to the people who live nearest to development sites. At the same time, researchers have often asked about the ways changes to environment can have profound affects on local, especially renewable resource based, economies. Similar questions will be asked about the impacts of a gas hydrates industrial frontier, where the scale and extent of the potential appears to be greater than any of the energy developments that we have seen thus far.

Awareness of gaps in understanding about the nature of gas hydrates and how they could be extracted without causing an unacceptable increase in global warming, has led to the Council of Canadian Academies (CCA) being asked to undertake an assessment of gas hydrate research in Canada. This "will include a review of the science and engineering underpinning this field, the gaps in knowledge of pertinence to Canada and an assessment of the merits of forming a science and technology, multi-partnered, national gas hydrate research program." Alongside the need for further understanding of the science and engineering, and a view of where the pertinent gaps in knowledge may lie, there is a parallel need for best possible assessment of the relevant social science. It may well be that the CCA can make a contribution of immense importance to the long term wellbeing of the communities that could be affected by gas hydrates developments by including social, cultural and economic impact assessment within its terms of reference.

Gas hydrates may well mean that the interests of people across the north and along the two coasts of Canada are at issue in complex and vital ways. The time to begin to address these interests is in advance of the development. The point where scientists and engineers are being looked to for their expertise, and the academic community has the important task of identifying gaps in knowledge, is also the point where social science and understanding of communities should be brought to the table. As in the case of science and engineering, there is experience and knowledge of social impacts to be found both in Canada and other countries. As the CCA considers recommendations it may want to make, it might consider the possibility of a social science and community based research programme that is developed alongside those in science and technology. It may also want to look at commissions of inquiry and broad evaluation process that have been used in Canada and elsewhere to build the widest possible understanding of large scale developments.

The following notes are a first and quick attempt to set out the kinds of questions that social science needs to be able to address in any social and economic impact assessment that is focused on local communities. I have divided these questions into areas of inquiry. Each of these constitutes an aspect or dimension of impact assessment, but they have obvious overlaps and interconnections.

The order of the items here does not imply any hierarchy of priorities, though the first has implications for assessment as a whole and for the methodologies for work in the others.

Further, I do not mean to suggest that this list covers all possible areas of concern. These should become much clearer as the specific of gas hydrate development emerge and it becomes possible to see where social, economic and environmental impacts do and do not impinge on local communities and their resources.

Thus:

1. Process

Impact assessment that seeks to generate a full and reliable account of how industrial development is going to affect communities has to be based on good, independent social science along with community based processes. Many social scientists would now argue that these two objectives – highest possible quality of research and community participation – are interdependent. Communities that stand to benefit or lose from externally driven developments are especially sensitive to the nature of information-gathering: if research is not carried out in partnership with community leaders, elders and specialists, resistance to process can create a sharp and troubling divide between the assessment and those whose lives are being assessed. This divide can lead to resistance to, misinformation about, and alienation from development.

This has implications for the range and quality of data that are gathered, as well as longer term implications for how developments are going to be perceived and understood. This, in turn, has implications for potential benefits and risks. At the same time, research and investigation procedures have to be done with real expertise and independence. Thus the challenge to impact assessment of this kind is to develop a balance between community based input and good social science. There is a well-established methodology for some aspects of this balance, and a need to pay careful attention to process to ensure that the two sides of the work proceed in ways that are mutually reinforcing.

A consultative process is not easy to get right. Leaders and elders have crucial parts to play in discussions. But many communities also have experts who have specialised, culturally shaped knowledge of both the social and natural world. And there should not be a too confident assumption that consultation with individuals will necessarily mean a full, transparent or consultative relationship with a community. There may be a need for a process that reaches key individuals while also being able to share information with and learn from community members more widely. This speaks to the advantages of a commission of inquiry of some form, where social (and other) science and people's concerns are both drawn upon and drawn together.

In developing guidelines for impact assessment, therefore, careful attention must be given to how:

(i) Communities are kept informed about the potential development
(ii) Communities are kept informed about, and given a real chance to have input into, the plans for social, economic and cultural research that will answer questions about impacts on their member and resources
(iii) Social science and environmental studies are done to the highest possible level by independent experts

(iv) Time is allowed for consultation to be authentic and background research to be done well. Impact assessment can be of optimal value if and only if it is done as part of project design and in advance of actual development on the ground.
(v) Process includes conferring with leaders and elders as well as communities as a whole. This may mean that some kind of community hearing is included in the schedule of consultation

2. The industry

Social, economic and cultural impact assessment depends on a clear description of what the industry is, how it operates and the time-lines that are likely to be in effect. We have to understand what the industry looks like as an industry, and how it will unfold as a set of economic and social activities. To see how communities are going to be affected by development, some basic simple questions have to be answered, including:

(i) Is the industry site-specific or widely dispersed? What is the geography of its potential impacts?
(ii) What kind of infrastructure (eg roads, airstrips, rail lines, shipping terminals) does the industry require?
(iii) Does infrastructure and/or long-term running of the industry's sites mean expansion of existing communities or towns, or creation of new towns?
(iv) What are the employment needs of the industry in the short term? Is there front-end need for low-skilled labour / high-skilled labour etc?
(v) What are the longer term employment needs? Is there a prospect for long-term jobs for First Nations individuals?
(vi) How many employees would be coming into communities, and on what basis? Eg short term residential, rest and recreation breaks, long term residential?
(vii) What kind of waste / environmental side-effects does the industry create?

3. Who are the people in the communities?

Communities in northern and western Canada have much in common – for the most part, they are small in size, have been through difficult histories as a result of European settlement and internal colonialism, are engaged in land claims negotiations or settlements and share a range of social problems and vulnerabilities. At the same time, they are distinctive, with cultural differences that are of immense historical as well as everyday importance. The complex of peoples along the west coast of Canada share some economic and social characteristics, but also vary greatly in language, traditions and relationships to resources. Similarly, the peoples of the Arctic and Subarctic include several Inuit dialects and traditions as well as speakers of Athabascan and Algonquian languages. On the east coast, Inuit, Innu, Settler and some highly mixed communities constitute a range of heritage, economic and social systems. In all these communities there are also people who are not Aboriginal, with their own relationships to community and environment. Impact assessment has to be based on a good understanding of who all these different people are, looking at what they share as well as what makes each group distinctive.

An area of crucial importance here is the kind of vulnerability that the affected populations are experiencing. Many of the peoples in the north and along both the west and east coasts of the country have been showing alarming indicators of social and individual distress. Since the late 1980s, suicide and attempted suicide rates in these areas have become the focus of great concern. In many communities, rates continue to be high. These and other signs of stress may point to needs and vulnerabilities that are of great relevance to the affects of any new forms of industrial development in or adjacent to these communities. Are there ways in which development can create new risks, or can they offer new kinds of opportunity for reducing social and economic problems?

Similarly, there are vulnerabilities that come from environmental impacts. Many if not most of the First Nation and Inuit communities along the coasts and in northern Canada have strong relationships with and dependence upon renewable resources. Hunting, fishing and trapping have continued to be at the centre of much Aboriginal identity, while development of these resources for income (eg marketing and tourism) are of actual and potential importance in many communities. Also, managing of renewable resources has been a feature of all First Nations and Inuit land claims negotiations. Any possible change to environment that can cause change in animal and fish populations are of special relevance to First Nations.

The above reflections are part of a long and complex set of questions that impact assessment has to answer. These questions include:

(i) What are the characteristics of each of the peoples to be affected? Eg populations size, demographics, forms of governance, cultural identity?
(ii) What parts of this identity are given clearest priority by the people themselves?

(iii) What are the economic realities for the community? e.g., resource base, reliance on income from land based activities, short term and long term employment, transfer payments etc.
(iv) What are the economic needs?
(v) What are the social realities for the peoples? e.g., indicators of wellbeing and stress, health considerations, levels of breakdown and pathology, etc.
(vi) What do the people themselves see as their most important needs and vulnerabilities?
(vii) What is the level of self-government / land-claims settlements in each community? How are these best supported /. Where do the risks to these lie?

4. Jurisdiction and governance

I have referred already to the relevance of land claims process and settlement to any impact assessment in the Canadian north or along either of its coasts. Some recent social scientific work has been looking at links between community wellbeing and community control and levels of governance. Some of the questions raised by this issue are:

(i) How will existing and prospective land claim settlements bear on ownership and management of gas hydrates?
(ii) How will these agreements bear on planning of developments both in communities and on their territories?
(iii) How can the developments be designed to recognise and strengthen rather than undermine community institutions, rights and jurisdiction?

5. Issues of culture

The above notes have referred to or implied the importance of identity and self-respect. Social impact assessment has to give attention to how different communities look to, depend upon or given special priority to cultural heritage, practice and knowledge. In many First Nations and Inuit communities there is a difficult and often troubled attempt to balance issues of culture (eg language, links to heritage, spiritual practices, location and protection of sacred sites or burial grounds, respect for elders, teaching of Aboriginal culture in schools etc) with acceptance of or need for economic development. In advance of further developments, especially on the scale suggested by development of gas hydrates, attention must be paid to how communities are going to be able to maintain the kind of balance between culture and development that they say they need. This suggests a number of questions, including:

(i) In what ways does each community see its cultural needs and vulnerability?
(ii) What process can be put in place to ensure that concerns about culture are heard and given best chance of being acted upon?
(iii) What kinds of institution or support can be put in place to protect cultural sites, practices and knowledge that each community identifies as of core importance?
(iv) How can the necessary or preferred balance between cultural and developmental pressures / priorities be sustained in the course of each phase of development ?

6. A note on transparency and methodology

In each sector of social and economic impact assessment, there is an issue of transparency. People in the regions to be affected have to know what is being planned, and, where appropriate and possible, have a place in the planning process. As we look at the different kinds of impact assessment that must be done, it is important to find ways in which data and impacts can be seen and understood. In Canada and elsewhere (often much influenced by Canadian experience and expertise), community-based research projects have made use of maps and map making both to gather data from individuals in communities and to make these and other data accessible to as many people as possible.

The way in which the proposed developments impinge on communities can be understood as a map overlay: the developments onto the communities. This can be done with simple mapping techniques, creating a visual representation of an overview of potential impacts. If this is possible, a map that depicts the area where gas hydrate developments are likely to be concentrated, with high and low intensities of activity as well as time-sequencing of activities, can be overlaid on a map of all communities of the regions at issue.

An overlay of this kind can provide a very basic guide to the geography of potential impacts, and may indicate which communities are most in need of impact assessment studies and process.

As understanding of potential impacts increases, the detail and sophistication of this kind of overlay can be increased, with additional overlays being generated. This means that at each stage of the development, there is visual representation of the issues that can be shown to communities and social scientists alike.

This kind of basic overlay can be a fist step in a map-based dimension to impact assessment. Methodology for this kind of work has advanced in very valuable ways over the past ten years, with special attention being given to how mapping of impacts can be a way of ensuring community participation and representations of data that are relatively easy for community members to understand. Given the paramount importance of research and planning processes that are transparent, it may be appropriate for your panel to recommend that methodology of this kind be used at the earliest possible stages of any academic work into the potential of gas hydrate development. The extent of a resource can be shown in a way that *ab initio* shows some of its potential impacts. In this relatively simple way, those whose lands and lives are potentially affected can begin to see the outlines of the new realities. And therefore can begin to consider, and help others to consider, what these could mean to them.

7. Concluding overview

We can learn from the history of development as also from the way in which impacts were and were not assessed, predicted and mitigated. It is important to look at how different forms of inquiry have and have not been successful in putting together the necessary kinds of impact assessment. The scale of the assessment required in the case of gas hydrates matches the potential of that development: this will be very large and complicated task, involving many communities and cultures. Risk assessment, cost-benefit analysis and community participation have to be built into a process of assessment. This will require a great deal of analysis of models and paradigms as well as consultation across a wide spectrum of community members as well as social and environmental sciences. I trust that you be able to urge that this set of tasks and challenges be given the fullest possible consideration, while the other, scientific and engineering, aspects of gas hydrates development are being examined. If social and environmental impact assessment is tagged on as an afterthought, with little or no chance of shaping development plans, mitigation of impacts and delivery of benefits will both be all the harder to achieve.

Examples of process

The importance of a full, consultative evaluation process can be seen with the help of some examples. Perhaps the most important of these is the Mackenzie Valley Pipeline Inquiry, known as the Berger Inquiry. This had the status of a Royal Commission focussed on the potential energy corridor along the route of the Mackenzie River, but Justice Berger saw his task as a full exploration of environmental, social and economic issues for both the valley and northern Canada as a whole. Indeed, through hearings across the country, the Inquiry created a series of forums at which Canadians could address their vision for the nation as a whole.

A great strength of the Berger Inquiry lay in its focus on each level of potential impacts, with special attention being given to the First Nation communities that would experience some of the most direct and large-scale impacts. In this dimension of the work, Berger insisted that the inquiry team stay in each community for as long as was needed, ensuring as best it could that communities take the time they needed to set out their concerns. This was a remarkable commitment to local understanding of issues and participation in the process. At the same time, the Inquiry also commissioning expert reports from all relevant disciplines and all sides of the argument. In this way it created a basis for its conclusions that was built with maximum local input and high level environmental, natural and social science. Among its most important findings, the Inquiry concluded that the proposed corridor should be put on hold for at least ten years, to allow crucial political and social processes to take their course. This affirmed the importance of lead time, during which the rights and needs of those vulnerable to development can be defined and brought to bear on its implementation. As is well known, the government of Canada accepted this recommendation, as a result of which the present consideration of the Mackenzie Valley energy corridor has some of the great advantages that the Berger Inquiry foresaw and put in place. In these ways, I would see the Berger Inquiry as a possible model for the kind of investigation that may be appropriate for the potential development of gas hydrates.

The Berger Inquiry was not the first example of extensive and effective assessment of a major development in Canada. In the early 1970s, negotiations that surrounded Hydro-Quebec's development of James Bay hydro-electric production also included high level impact assessment and, most important of all, an intensive consideration of how both infrastructure and flooding would impact the Cree communities of the area. The environmental and social-scientific work here came from a series of legal battles and then through the negotiation of the James Bay Agreement. The agreement has its critics, but the mitigative measures put in place were based on a great deal of impact-assessment, community input and, in the end, a set of measures that included land rights, co-management powers and income support for those most dependent on the land. That this emerged from a highly charged conflict is a tribute to the quality of the consultation and research that were given a place in the process, as well as to the financial and political support coming from the Federal Government of the day.

On the other hand, hydro-electric developments across Canada and the United States are marked by lack of appropriate impact assessment and mitigation. A series of developments took place in the 1950s, when concern for environmental impact, social costs and the rights of those being displaced were rarely if ever given any due attention. Thus the Churchill Falls project in Labrador went ahead without the Innu whose lands were being flooded even knowing about the project. Similarly, the W.A.C.Bennet dam on the upper Peace River inundated the lands and homes of the Injenika community without any concern, at the time, for their vulnerabilities or rights. Similarly, the reservoirs behind the dams and the dams themselves on the Snake River in Idaho were planned and created with minimal if any consultation with the Nez Perce and other communities that lost their fisheries, fishing sites and other resources as a result of these developments. In retrospect, we can see that both Canada and the United States should have put in place a series of impact assessment processes and some kind of overall view of the nature of hydro development.

This kind of concern did not belong in those times, so no such evaluation of either environmental or human impacts was put in place. As a result, there are peoples who endured severe losses, landscapes that were transformed and rights that were disregarded. The costs of these to the regions and nations concerned are cumulative: poverty, bitterness and environmental fall-out do not go away. In some cases - the Injenika people and the W.A.C. Bennet dam, for example, - harm and losses have been addressed after the fact. These can involve expensive and demoralising legal cases, and circumstances in which due remedies or mitigation are not really possible. It is important that the downstream impacts of development do not include these kinds of cumulative harm to environment, damage to communities and families, missed opportunities for joint management and local share of potential benefits, as well as disregard or even violation of local people's rights.

The way to meet the needs of local communities, the environment and the nation as a whole is through a full, consultative and scientifically sophisticated assessment process. The Berger Inquiry is one model. There are others. Part of the advance research at this stage of gas hydrate development could be a detailed review of the inquiry and impact assessment experience, models and options.

Appendix D – Update on Mallik

Submitted by Scott R. Dallimore, J. Frederick Wright*,*
and Koji Yamamoto†

OVERVIEW OF GAS HYDRATE RESEARCH AT MALLIK

Gas hydrates were first identified at the Imperial Oil Mallik L-38 discovery well drilled during the winter of 1971-72 (Bily and Dick, 1974). The geological setting and physical properties of gas hydrate deposits at the Mallik field were further documented through two international research well programs conducted in 1998 and 2002.

The 1998 Japex/JNOC/GSC Mallik 2L research well program collected the first gas hydrate core samples from a permafrost environment, and generated substantive scientific and engineering data (Dallimore *et al.*, 1999). The Mallik 2002 Gas Hydrate Production Research Well Program, conducted by a five-nation international partnership, built upon the achievements of the 1998 program to enable a variety of new multidisciplinary investigations, and provided a first opportunity to undertake a well-constrained gas hydrate production test (Dallimore and Collett, 2005). Three research wells, drilled and completed in 2002, enabled advanced well logging and a highly successful coring program (including comprehensive post-field laboratory studies). A five- day, full-scale thermal production test (featuring downhole hot water circulation) was undertaken, as were several short-term, small-scale Modular Dynamic Formation Tester (MDT) pressure drawdown tests. Advanced reservoir monitoring and measurement techniques included cross-well geophysics for deep-penetration reservoir monitoring, and Distributed Temperature Sensing (DTS) fibre optic systems for obtaining high-resolution formation temperatures.

The primary objective of the 2006-08 Mallik gas hydrate production research program was to measure and monitor the production response of a terrestrial gas hydrate reservoir to stimulation by pressure drawdown. JOGMEC, together with NRCan, provided program funding and leadership for research and development studies. Aurora College/Aurora Research Institute was designated as the operator for the field program. The results of this work, including tests of production of gas via pressure drawdown, are described in the body of the text.

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Winter 2007 – The primary objectives of the winter 2007 field activities were to: install physical installations for production testing and re-injection of produced water; to deploy and evaluate new geophysical tools and monitoring systems; and to undertake a short-term pressure drawdown test to gain critical insights prior to undertaking a longer-term production test planned for the winter of 2008. On April 2, 2007 a short pressure drawdown production test was undertaken to evaluate equipment performance, and to assess the short-term production response of the Mallik reservoir. Testing of a 12-m gas hydrate interval (from 1,093 to 1,005 m) was undertaken. As described in several papers by Dallimore and Collett (2005), sediments within the production interval are typical of a fluvio-deltaic depositional environment (see Figure 1).

A fine-grained interbedded silt succession was found to dominate above 1,085 m, interspersed with occasional thin coal and sand beds, with a thick sand interval occurring between 1,070 and 1,078 m. Below 1,085 m, a thick sand succession, characterized by occasional thin silt interbeds, was found to be dominant. Core observations and well-log estimates confirm that the gas hydrate occurs primarily as pore-filling material within the sands (50 to 90 per cent pore saturation) with only occasional visible gas hydrate observed as coatings on sand grains. Little or no gas hydrate was observed in the silt-dominated intervals, suggesting a strong lithologic control on gas hydrate occurrence. A sharp basal contact (at 1,107 m) between hydrate-saturated and water-saturated sands marks the bottom of the lowermost gas hydrate zone, and is interpreted as a salinity-conditioned, thermally-defined base of the gas hydrate stability field (Figure D1). Estimates of formation permeability within the production interval range from 0.1 to 1 mD, whereas the permeability[‡] of gas-hydrate-bearing silt is generally less than 0.1 mD. In contrast, the permeability of the water-saturated sands below the base of the gas hydrate stability field may be in the order of 100 to 1,000 mD. Sediment porosities in both wells range from 30 to 40 per cent.

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‡ Permeability is measured in “darcys” (D). A medium with a permeability of 1D permits a flow of 1cm/s under a pressure gradient of 1 atmosphere/cm. 1mD (millidarcy) is 10^{-3} D.

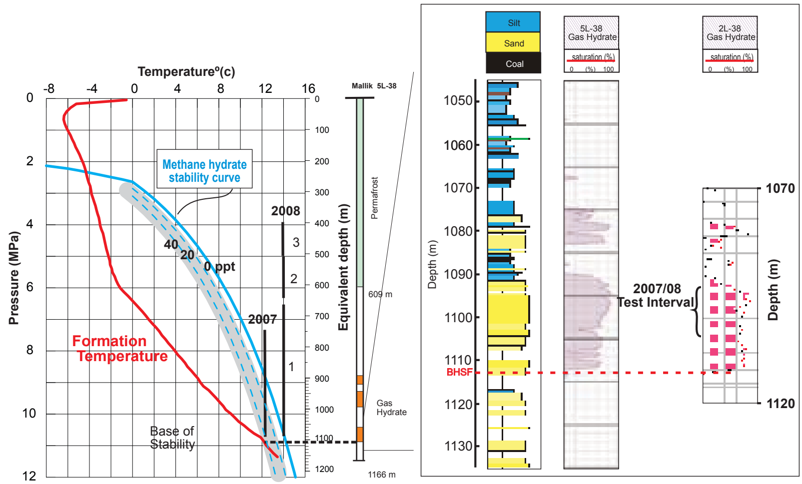

Figure D1

(a) shows estimated formation temperature for Mallik reservoir relative to envelope of temperature and pressure conditions thought to represent *in situ* stability. The solid lines show the pressure changes induced during the 2007-8 production testing program. (b) shows detailed stratigraphy and gas hydrate concentration for Mallik 5L-38 and Mallik 2L-38 for the 2007-8 production interval.

The presence of gas hydrate appears to contribute substantively to the strength of the sediment matrix. In simple terms, gas hydrate serves as a binder for the individual sand grains, thereby providing the bulk of the material strength. Field data suggest that natural fractures are ubiquitous to the gas-hydrate-bearing interval at Mallik, and that indeed they may behave essentially as open fractures in terms of flow response. A short 24-hour pressure drawdown production test was completed in April 2007. The test was controlled by reducing the fluid level in the well using an ESP pump, configured to re-inject fluid into a lower perforated zone. The test achieved a minimum bottomhole flowing pressure (BHP) of approximately 7.3 megapascals (MPa), which represents a drawdown of ~3.7 MPa below the *in situ* reservoir condition.

A conscious decision was made to undertake the 2007 test without implementing sand control measures in order to assess whether the reduction in sediment strength caused by gas hydrate dissociation would result in sediment inflow into the well, or conversely whether any mobile sediment would simply reconsolidate in the near-wellbore area as a packing around the casing perforations. In fact, a substantial inflow of sand into the bore did occur, causing operational problems that limited the drawdown pressure achieved and constrained the duration of the test to approximately 24 hours.

Despite the short duration of the test, considerable practical experience was gained. The 2007 test results revealed the extreme mobility of gas hydrate-bearing sediments at Mallik as the gas hydrate (which bonds the sandy reservoir sediments) is dissociated. Despite the sand inflow to the well bore, several flow responses were observed, with the flow rate during the latter part of the test exceeding 5,000 m^3/day (180 Mcf/day) (Figure D2). Flow rates higher than predicted by numerical simulation studies raise the possibility of a non-uniform formation response, possibly as a function of geologic heterogeneity, leading to the formation of enhanced permeability conduits ("wormholes") during sand production (Dallimore *et al.*, 2008).

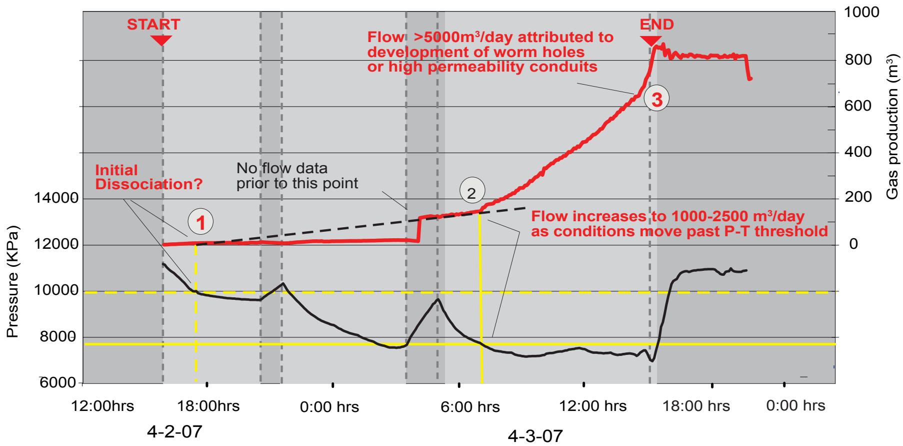

Figure D2
Cumulative production (red line) and derived bottom hole flowing pressure (black line) from pressure draw down test completed on Mallik production interval April 2-3, 2007. As described by Numasawa *et al.* (2008), operational problems during the test caused intermittent pump operations (light shaded times) with periods when the pump did not operate (dark shaded times). Unfortunately no flow data was recorded during the early stage of the test. Annotations on the figure show changes in flow response over the course of the test.

Winter 2008 – The goal of the winter 2008 field activities was to undertake longer-term production testing on the same gas hydrate interval (1,093 to 1,005 m) that was perforated and tested in 2007. A service rig and support facilities were mobilized by ice road from Invuik to the Mallik site during January, 2008. To prevent the specific operational problems encountered in 2007, sand screens were installed across the production interval to hold back the coarse-grained (sandy) sediments while allowing some movement of the finer silts and clays into the wellbore. The completion assembly included an

ESP pump, downhole sensing instrumentation and an electric borehole heater to prevent re-formation of gas hydrate within the production tubing. Gas, water and sediment produced during the test were brought to the surface where each component was separated and measured. Production testing was conducted from March 10 to March 16 and demobilization of the well was completed on April 1, 2008.

Overall, the test was an unqualified operational success, with excellent equipment performance. Three pressure drawdown targets were achieved, with a BHP of approximately 7.3 MPa, 5 MPa and 4 MPa. Fluid flow to surface was realized within minutes of the start of the test, with approximately 12,300 m^3 (430 Mcf) of methane gas being measured by the surface equipment. An average flow of 2,000 m^3/day (70 Mcf/day) was sustained during the test, with peak rates as high as 4,500 m^3/day (160 Mcf/day). Total water production during the test was less than 100 m^3 (3,500 ft^3). While the raw test data and detailed interpretation of results remain confidential (May 2008), it has been confirmed that sustained gas flows ranging from 2,000 to 4,000 m^3/day (70 to 140 Mcf/day) were maintained throughout the course of the six-day test and that physical operations proceeded very smoothly during the progression to three target drawdown pressures.

Conclusions – Over the course of two field seasons in 2007 and 2008, the Mallik program has acquired a wealth of practical learning regarding gas hydrate production by the depressurization technique. A state-of-the-art open- and cased-hole geophysical well-logging program was carried out in 2007, with a number of new tools deployed to quantify *in situ* reservoir properties and the response of a sand-dominated gas hydrate-bearing reservoir to production stimulation. The 2007/08 Mallik Production Research Program successfully demonstrated proof-of-concept for gas hydrate production by depressurization. The Mallik tests indicate that sustained gas flow can be achieved from a sand-dominated, clastic gas hydrate reservoir through reduction of bottomhole pressures using conventional oilfield technologies adapted for an arctic gas hydrate system. The results from the Mallik program, including a comprehensive project database, will be publicly released at a future date by the project participants with the hope that they will be of value to the research community for verification of reservoir simulation models and design of future production testing programs at other sites in the world.

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