Paper #1-4

ARCTIC OIL AND GAS

Prepared by the Arctic Subgroup
of the
Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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* Replaced by Robert C. Scheidemann, Jr., in April 2011.
** Individual has since changed organizations but was employed by the specified company while participating in the study.

Abstract

The North American Arctic contains significant oil and natural gas volumes and is believed to contain substantial unproven reserves in Alaska, Canada and Greenland. This topic paper describes: 1) the onshore and offshore exploration and development history of this region; 2) the significant volumes discovered and produced to date; 3) the mean, risked, undiscovered oil and gas resource potential of each prospective basin; 4) the challenges facing future oil and gas exploration and development in this cold and remote region; 5) an attempt to describe a range of future production forecast scenarios; and 6) Findings and Recommendations that attempt to frame the issues and stimulate a rational approach to enabling the safe and timely evaluation of Arctic oil and gas resources (with a focus on Alaska). This last item takes on an even greater significance, as dwindling oil input into the Trans Alaska Pipeline System is providing operational challenges and may limit the lifespan of this important delivery option.

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I. INTRODUCTION

I.A. Objectives

Because this Topic Paper may sometimes be read separately from the main Study report, the drivers and objectives outlined by the Department of Energy (DOE) and the mission definitions provided by the Resource & Supply Task Group (RSTG) Chair are outlined below for context.

In September 2009 Energy Secretary Chu requested the National Petroleum Council (NPC) to undertake a study of "Prudent Development of North American Natural Gas and Oil Resources" that would be "…consistent with government objectives of environmental protection, economic growth, and national security." This became known as the North American Resource Development (NARD) Study that was to contain detailed assessments through 2035 and implications through 2050.[1]

The NARD Study was organized with a Leadership Committee, a Coordinating Subcommittee (CSC) and three Task Groups, one of which was the RSTG. The RSTG comprised 9 Subgroups (SGs), one of which was the Arctic Subgroup (ASG), whose work is described in this Topic Paper.

The RSTG proposed the following Mission Definition for the ASG:

Describe the resource, production history and development status
Describe recent studies of the potential supply outlook
Refer to regulatory, access, infrastructure or environmental challenges
Analyze the main drivers that would facilitate or constrain development
Produce a Topic Paper

It was emphasized that the NARD Study would be a "study of studies", i.e. it should be based upon publicly available information. In addition, great care was taken to ensure that no anti-competitive material was shared between the participating companies.

As the Study progressed, each Subgroup was tasked to produce Findings that were major conclusions derived from an analysis of constraints and challenges, which, if mitigated, would produce additional supply.

Where appropriate, the CSC Policy Subgroup used these Findings as the basis for formulating policy recommendations.

I.B Arctic Definition and Characterization

Our Arctic definition encompasses those areas in the greater North American-Greenland region that have Arctic–like conditions (Figure 1.B.1). It is defined by ice and permafrost conditions rather than being strictly north of the Arctic Circle.

Arctic areas in the U.S. and Canada are clearly within scope of the NARD Study, and we have chosen to include Greenland, since its potential for development and production, particularly on its western side, will almost certainly impact North American supply.

Future references to the Arctic in this Topic Paper will refer to those U.S., Canada and Greenland areas lying within the Arctic boundary defined in Figure 1.B.1.

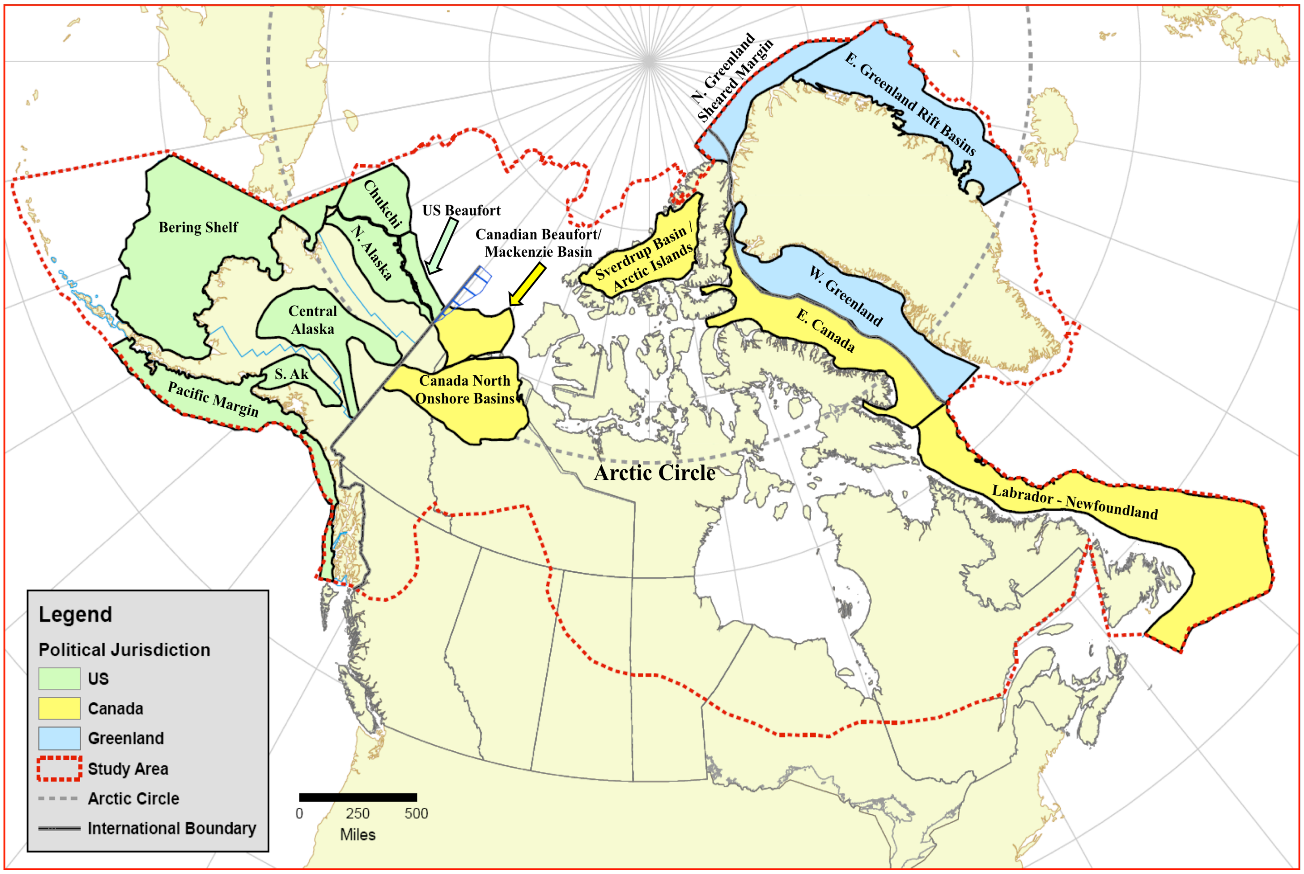

Figure 1.B.1 – Arctic Subgroup Study Area outlined with red dash. Prospective Basins within the study area highlighted by color: U.S. green, Canada yellow and Greenland blue.

The North American Arctic conventional oil and gas potential can be characterized as follows:

Large discovered undeveloped (stranded due to lack of infrastructure) and a very large undiscovered conventional hydrocarbon resource potential (Figures 1.B.2 and 1.B.3, Table 1.B).

- Note that possible Arctic unconventional hydrocarbon resources such as tight gas sand (oil and gas), shale gas, coal bed methane, and hydrates are not captured nor reflected in this report.

Significant supply potential in the medium to long term (2025+)

Long lead times (exploration to development to production), so near-term action is required to significantly impact future production 2025 and beyond[2,3,4]

Remoteness and cost of doing business in the arctic is a significant issue.

- Intrinsically high supply cost (in current climate conditions) compared to most Lower 48 States (L48) and non-Arctic Canada arenas.
- Economic transport to market is a significant issue

Technology challenges are not a major issue in the Arctic except advances will need to be made in development technology for opportunities, such as

- In areas where water depths exceed 100 m

- Iceberg management capability (due to their size) in areas such as NW Greenland

Access/regulatory/environmental complexities and uncertainties discourage investment

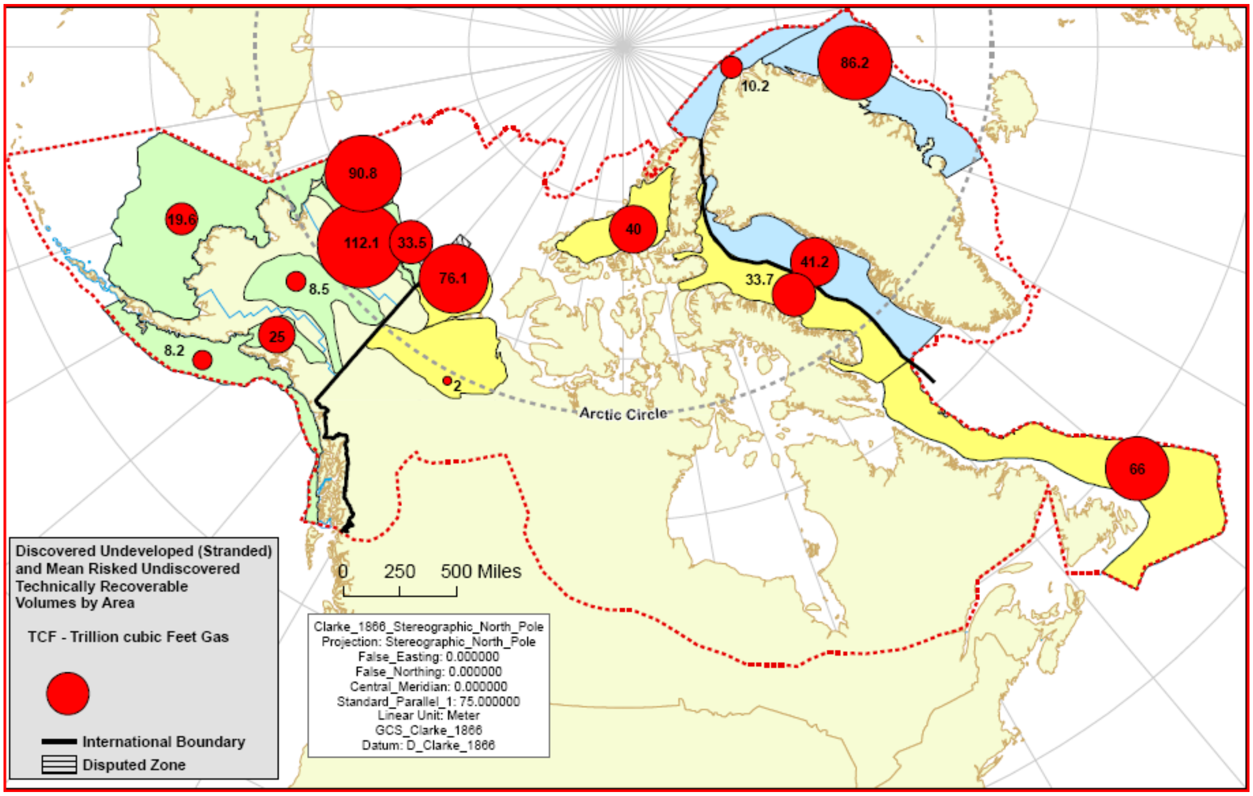

Figure 1.B.2 – Arctic Gas Potential (in trillion cubic feet or TCF) by Basin (discovered, undeveloped "stranded" volume, plus the mean, risked, technically recoverable, undiscovered volume). References for volumes are cited at the conclusion of Sections IV-VII.

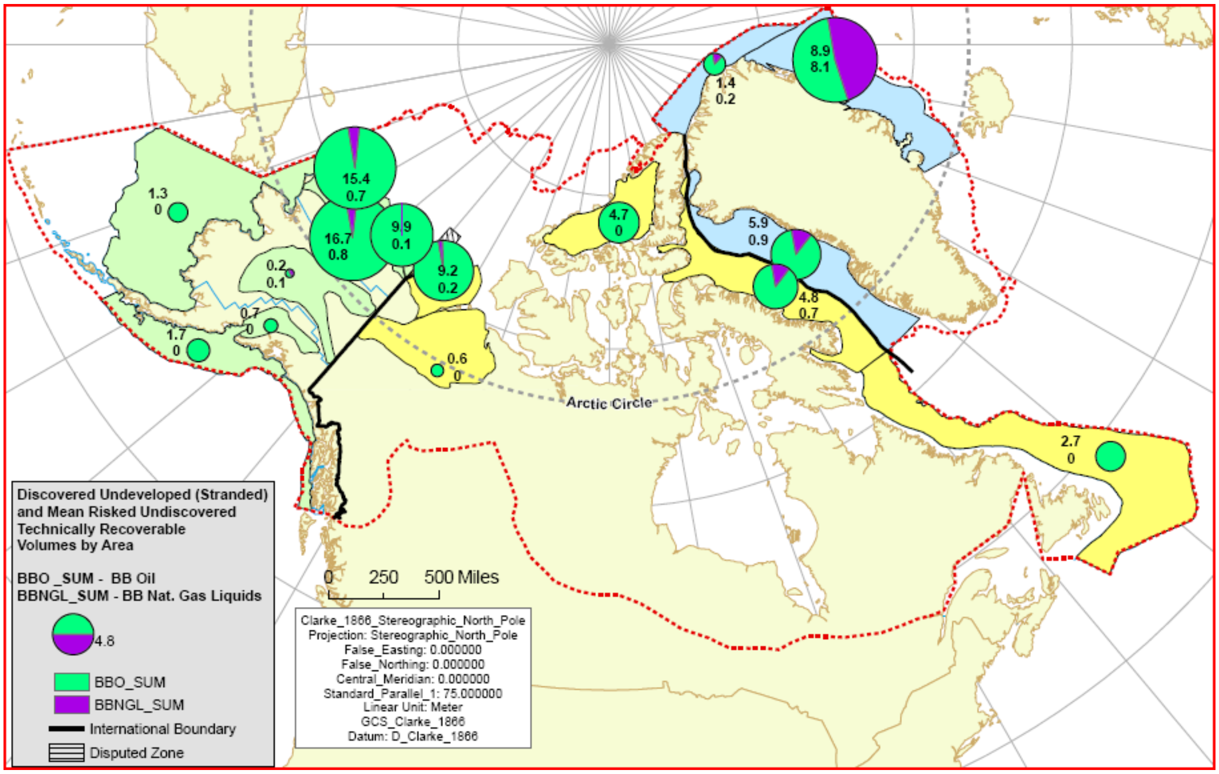

Figure 1.B.3 - Arctic Oil and Natural Gas Liquids (NGL) Potential by Basin (discovered, undeveloped "stranded" volume, plus the mean, risked, technically recoverable, undiscovered volume). Oil expressed in billions of barrels (BBO) in green and natural gas liquids BBO in purple. References for volumes are cited at the conclusion of Sections IV-VII.

Table 1.B Discovered Undeveloped "Stranded" Volumes & Mean Risked Technically Recoverable Undiscovered Volumes				
Country	Basin Area	Mean Billion Barrels Oil	Mean TCF GAS	Mean Billion Barrels Natural Gas Liquids
US Alaska	North Slope Onshore & State Waters (includes ANWR 1002 Volumes)	16.7	112.1	0.8
US Alaska	Beaufort OCS (includes USGS Alaska Passive Margin OCS)	9.9	33.5	0.1
US Alaska	Chukchi OCS	15.4	90.8	0.7
US Alaska	Bering Shelf OCS (includes N. Aleutian Basin OCS Volumes)	1.3	19.6	No Volume Reported
US Alaska	Pacific Margin OCS	1.7	8.2	No Volume Reported
US Alaska	Central Alaska Onshore	0.2	8.5	0.1
US Alaska	South Alaska Onshore (Includes State Portion Cook Inlet)	0.7	25	No Volume Reported
Canada	Canadian Beaufort & Mackenzie Delta	9.2	76.1	0.2
Canada	Sverdrup Basin-Arctic Islands	4.7	40	No Volume Reported
Canada	USGS Canadian Passive Margin (area outboard of CB & AI/SB)	2.4	15.1	0.2
Canada	Canada North Onshore Basins	0.6	2	No Volume Reported
Canada	Canada East Offshore Labrador-Newfoundland	2.7	66	No Volume Reported
Canada	East Canada Offshore "Baffin Bay" Region	4.8	33.7	0.7
Greenland	West Greenland Offshore	5.9	41.2	0.9
Greenland	East Greenland Rift Basins "Offshore"	8.9	86.2	8.1
Greenland	North Greenland Sheared Margin (Onshore & Offshore)	1.4	10.2	0.2

Table 1.B –Discovered, Undeveloped "Stranded" Volumes, and Mean, Risked, Technically Recoverable, Undiscovered Volumes (Yet to be Found). References for volumes are cited at the conclusion of Sections IV-VII.

The North American Arctic contains approximately 208 Billion barrels oil equivalent (BBOE) of discovered, undeveloped, plus mean, risked, technically recoverable, undiscovered, conventional hydrocarbon potential (Figure 1.B.4). To date, only about 10% of this BBOE has been discovered and is remote from development and production facilities. The total is split approximately 50/50 between oil and gas. Section IV describes the undiscovered, conventional hydrocarbon potential of the North American Arctic in more detail.

It should be noted that approximately ~28 Billion barrels oil equivalent resides within areas that are under moratoria or are unavailable for leasing/licensing at this time, with the U.S. Alaska region having a large portion of this restricted volume (~14 BBOE), especially in terms of oil (~11 Billion barrels oil) (Figures 1.B.5 and 1.B.6).

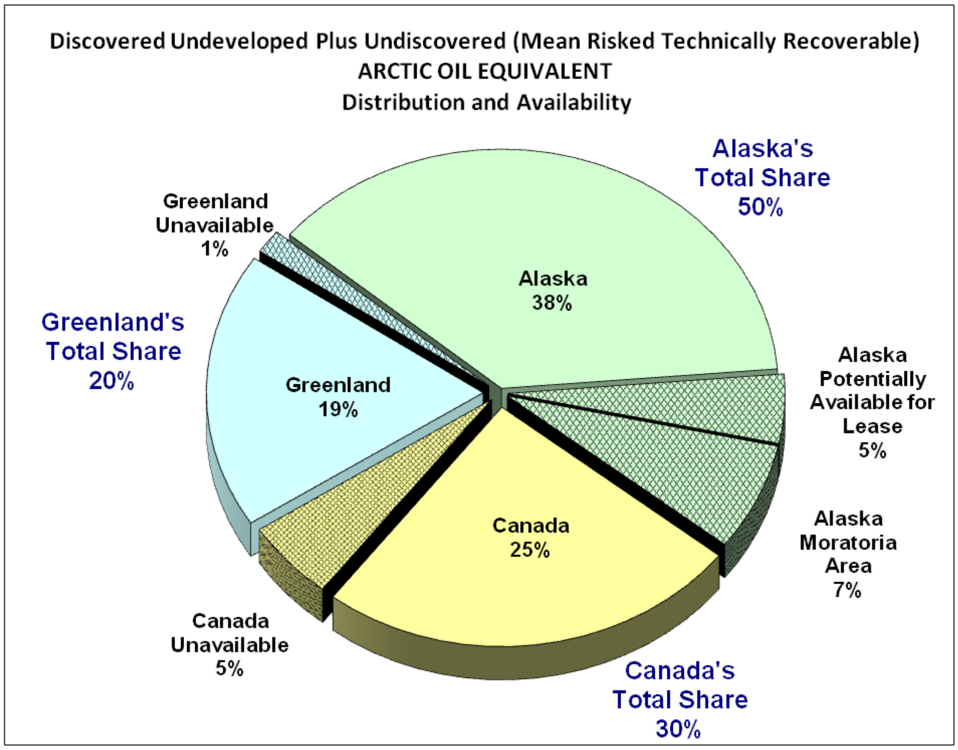

Figure 1.B.4 – Split of Arctic Hydrocarbon Potential BBOE (discovered, undeveloped "stranded" volume, plus the mean, risked, technically recoverable, undiscovered volume). Note that this figure also includes natural gas liquids component. References for volumes are cited at the conclusion of Sections IV-VII.

For perspective, the conventional hydrocarbon resource potential of the North American Arctic (~208 Billion barrels oil equivalent) compares favorably with the conventional hydrocarbon resource potential in the U.S. L48 (~270 Billion barrels oil equivalent) [5, 6] and non-Arctic Canada (~41 Billion barrels oil equivalent).[7]

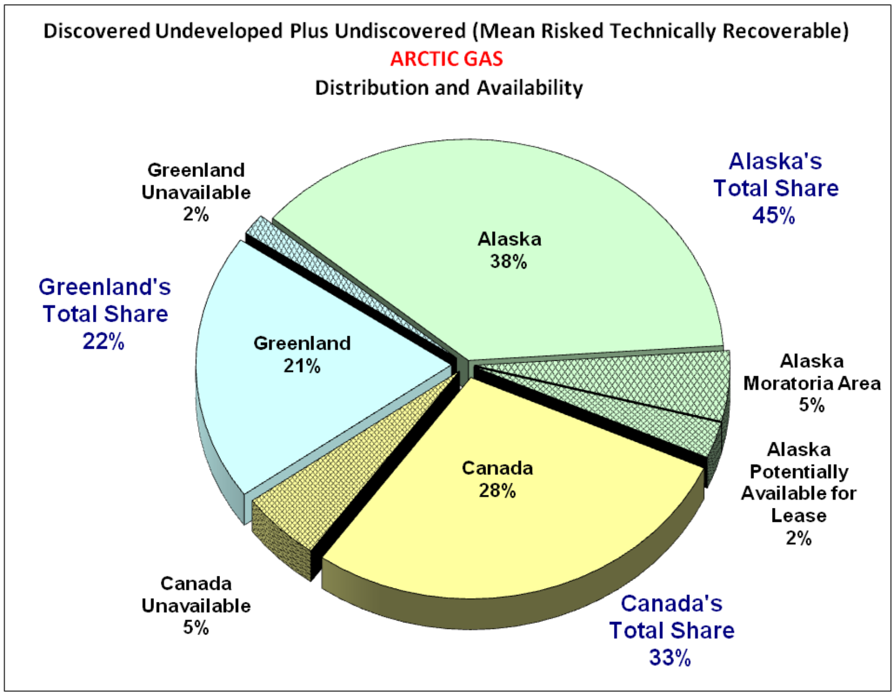

Figure 1.B.5 – Split of Arctic Gas Potential TCF (discovered, undeveloped "stranded" volume, plus the mean, risked, technically recoverable, undiscovered volume). References for volumes are cited at the conclusion of Sections IV-VII.

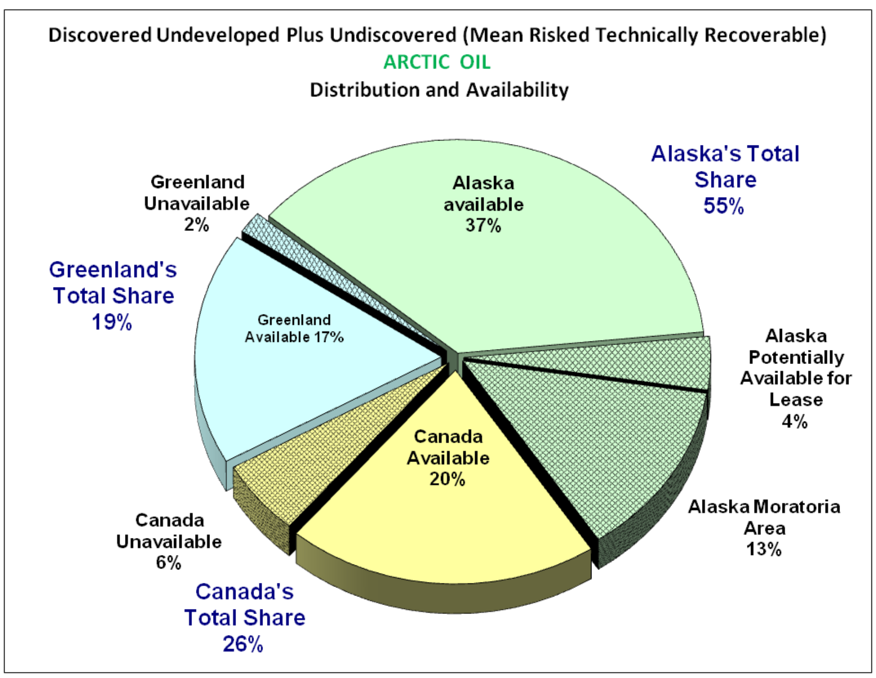

Figure 1.B.6 – Split of Arctic Oil Potential BBO (discovered, undeveloped "stranded" volume, plus the mean, risked, technically recoverable, undiscovered volume). No natural gas liquids included. References for volumes are cited at the conclusion of Sections IV-VII.

1.C Work Methodology

The ASG team members were recruited from a representative cross-section of the oil and gas industry and government, and each had valuable Arctic experience. Team members are listed below:

Tim Fleming - Anadarko
Dan Smallwood - ConocoPhillips
Bill Scott – Chevron Canada
Jennifer Wyatt – Chevron Canada
Brent Sheets – Research Manager University of Alaska Fairbanks
Darryl Jordan – DOE Consultant
Carl Mazzo – ExxonMobil
Gerry Worthington – "Retired" ExxonMobil
Geir Utskot – Schlumberger Canada
Bob Scheidemann – Shell

The backgrounds of the team members includes a spectrum of arctic expertise in geology/exploration, drilling/engineering, development, field operations and regulatory arenas.

<u>Team members took responsibility as primary author(s) for each of the chapters in this Topic Paper with the exception of Sections III and IX. Thus each chapter will have a slightly different writing style.</u> Conference calls were generally held weekly and ad hoc face-to-face meetings were held in Houston, Anchorage, Washington DC and Calgary.

<u>I.D Arctic Topic Paper Outline</u>

The Paper is divided into 11 sections. Following the Introduction, we present an Executive Summary (Section II) and our Findings and Recommendations (Section III) with enough narrative that the busy reader may understand our conclusions without going further.

We then review the Arctic's Exploration History and Mean, Risked, Technically Recoverable, Undiscovered Resource Potential (Section IV) to demonstrate the Arctic's very large, conventional hydrocarbon potential and, taken as a whole, its relative exploration and development immaturity.

Sections V, VI and VII describe the discovered volumes with existing and future Arctic development opportunities in the U.S., Canada and Greenland, as well as some of the challenges.

Offshore Ice Challenges (Section VIII) is thematic rather than geographic, and describes the issues related to offshore exploration and development in different ice conditions and severities.

Section IX presents a discussion of common issues centered on the Challenges and Findings.

Section X discusses three future production scenarios: 1) Reasonably Constrained; 2) Most Likely; and 3) Reasonably Unconstrained, as described by our group, as well as an overview of the few public domain forecasts, and the status of the proposed gas pipelines.

Finally Section XI (Summary and Conclusions) provides a short recap of the Arctic Topic Paper.

All references are included at the end of each section.

I.E Cited References

[1]Letter from Secretary of Energy, Steven Chu to NPC Chair, Claiborne Deming; September 16, 2009

[2] Northern Economics in Association with Institute of Social and Economic Research, University of Alaska, 2009, Economic Analysis of Future Offshore Oil and Gas Development: Beaufort Sea, Chukchi Sea and North Aleutian basin

[3]Northern Economics in Association with Institute of Social and Economic Research, University of Alaska, 2011, Potential National-Level Benefits of Alaska OCS development

[4]Thomas *et al*, "Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline? Addendum Report", 267p, U.S. DOE/NETL/Arctic Energy Office, April 2009.

[5] EIA, Annual Energy Outlook 2011

[6]EIA, Annual Energy Outlook 2010

[7]National Petroleum Council, Prudent Development of North America Oil and Gas Resources, Resource and Supply Task Group, Data/Studies Subgroup Topic Paper (2011, in press)

II. EXECUTIVE SUMMARY

"It is the policy objective of the United States to protect our Nation from the serious economic and strategic risks associated with our excessive reliance on foreign oil and the destabilizing effects of a changing climate. All energy uses and supply sources must be reexamined in order to enable the transition towards a lower carbon, more sustainable energy mix" --Sept 16, 2009 letter from Secretary of Energy Steven Chu to Claiborne P. Deming, Chair NPC

As recognized in Secretary Chu's letter, our nation is at serious economic risk because we are not making sufficient use of all of our energy supply sources. We are especially failing to recognize the danger of making the Arctic resource beyond our reach, by placing increasing restrictions on exploration and development. Prudent development and use of the Arctic Alaska's vast potential oil and natural gas resources will: (1) reduce dependence on foreign energy; (2) quicken the transition to natural gas because it is often collocated with higher valued oil found in the Arctic; and (3) fill up the Trans-Alaska Pipeline System (TAPS) which is already at risk of shutting down because of low-flow issues[1] and thereby stranding billions of barrels of discovered and undiscovered oil reserves.

Despite its remoteness and harsh operating conditions, safe development of the Arctic region is possible and essential for meeting the policy goals of the U.S. Finding 1 describes the huge oil and gas resource potential that resides in the North American Arctic, but exploration needs to occur *now* in order to arrest the production decline that is threatening the viability of TAPS. Findings 2 and 4 note that the limiting factor in recovery of the Arctic's vast energy resources is not necessarily technology, but the real concern is regulatory uncertainty and risk of litigation (particularly in the U.S.). Finding 3 describes U.S. specific challenges associated with carrying out an effective and safe exploration and appraisal program in the Arctic, given the present 10-year lease terms, as only 70 to 105 days (offshore) and 70 – 150 days (onshore) are realistically available for such activities each calendar year. Other findings discuss the negative impact that the Jones Act, lack of infrastructure, lack of revenue sharing, and how the U.S. is falling behind other nations in terms of arctic tankering capability.

This collective study supports the idea that action by the U.S. Federal Government is warranted, if these critical resources are to be validated and safely developed in a prudent manner for America's benefit.

Finding 1 Overview: The large, advertised, undiscovered conventional hydrocarbon resource base needs to be validated. Arctic exploration, and especially Alaska exploration, needs to occur now if discoveries are to enter the market in time to keep the TAPS viable, and to contribute to the energy market in the 2035 timeframe.

The U.S. continues to rely upon crude oil imported from other regions around the globe despite vast resources in its own back yard—the American and Canadian Arctic. The U.S. Geological Survey (USGS) estimates that as much as one-third of the world's undiscovered oil resources are to be found in the Arctic and approximately 45% of this resource is expected to be found in the U.S. and Canadian Arctic.

In Alaska, federal acreage, both offshore and onshore, is largely untapped. Similarly, in Canada exploration is limited and development north of the Arctic Circle has yet to occur. Meanwhile, outside of the North American continent, countries such as Russia and Norway continue to aggressively develop their Arctic energy resources, both onshore and offshore, and Greenland hopes to be next. The U.S. Government should support and enable timely leasing, exploration and appraisal programs (both seismic acquisition and drilling by industry), to validate whether or not the petroleum resource volumes advertised by the USGS and Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) truly exist.

TAPS is a national asset that has successfully delivered billions of barrels of oil to America. With the current lack of exploration and development in Alaska, this critical asset could be decommissioned sooner than forecast, as the existing North Slope oilfields continue their production decline. Indeed, at current levels of throughput (about 650,000 barrels of oil per day during the winter of 2010-2011), there are concerns about whether TAPS could be restarted in the winter if the pipeline experiences a lengthy downtime period in the midst of Alaska's bitter cold winters. In turn, this would necessitate the shutting in of all of the North Slope production causing a spike in crude oil prices in the U.S., and possibly around the world. According to testimony by Tom Barrett, President of Alyeska Pipeline Service Company which operates TAPS, before the Alaska legislature's House Finance Committee in February 2011, TAPS is experiencing challenges today which will only worsen without increased throughput. [2]

In addition to the mechanical risk associated with low-flow volumes, there is an economic risk which is more difficult to quantify. As throughput falls, the price per barrel for transportation increases because there is less volume across which to spread the fixed costs of operating the pipeline. Because of the mechanical and economic challenges associated with operating TAPS with a relatively low volume of oil, there is a real risk of stranding as much as 85 BBOE of potential resources from the north Alaskan offshore and onshore region, creating strain on the North American energy market.

Findings 2 & 4 Overview: Access to promising areas within the U.S. Arctic needs to be allowed by removing regulatory uncertainty and by limiting exposure to endless legal challenges which introduce additional uncertainty. Numerous Arctic producing fields exist around the world, both onshore and offshore, which are operating safely. Technology and practices to prevent and mitigate environmental risks already exist and will continue to be enhanced.

The sensitive ecosystems of the Arctic must be maintained and protected, and indeed this view has been incorporated into many environmental regulations designed to maintain the pristine nature of the region since the 1960s. This environmental awareness has helped advance some of the greatest technological advances within the oil industry for enabling safe resource extraction with minimal disturbance to the environment. To cite two examples among the many, the oil and gas industry developed the Rolligon which enables the carrying heavy loads across the arctic tundra with minimal ground pressure and disturbance, and horizontal- and extended-reach drilling technology which enables multiple wells to be drilled from a single pad at less cost and a with a smaller environmental footprint than the traditional multiple pad approach. Even so, developing the Arctic's resources frequently meets with regulatory and legal challenges, with opponents often alleging that technology is not yet mature enough, or not tested enough, to reliably operate in Arctic climates.

Without a doubt, technology and practices to prevent and mitigate environmental risks associated with the Arctic will continue to be enhanced. Therefore, it was a finding of the Arctic Subgroup that exploration and development technology, both onshore and offshore, is not expected to be a limiting factor in future development of conventional Arctic resources. Innovation will continue as new challenges are identified. There are numerous Arctic producing fields on-land, and safe development and production of offshore Arctic reserves has occurred since the late 1960s (e.g., in Alaska's Cook Inlet), which demonstrates that resource extraction can occur in the midst of sensitive ecosystems.

While technology is not expected to be a limiting factor, the lack of a coordinated permit approval process between U.S. regulatory bodies is. The existing regulatory regime should be improved to allow for a more efficient and timely permitting process. The benefits of adopting a coordinated approach, similar to what Norway or Greenland have adopted, are predicable project schedules, an end to redundant analyses between agencies, and development of common baseline databases vetted and acceptable to all parties.

Finding 3 Overview: Existing 10-year lease terms are not long enough to ensure sustained exploration and appraisal of oil and gas resources in the U.S. Arctic basins, particularly in the offshore. Infrequent lease sales, lengthy permitting procedures with multiple agencies, high incidence of litigation, and short drilling windows discourage exploration and appraisal operations, and the ultimate development of economic volumes in this relatively short time span of 10 years.

The realistic drilling window for offshore operations in the Arctic U.S. is typically 70 - 105 days per year. The drilling window for onshore exploration in the Arctic U.S. is longer, perhaps up to 150 days in a good year. In the Gulf of Mexico, the potential drilling window is almost 365 days per year. Both the Arctic and Gulf of Mexico offer initial lease terms of 10 years. Broadly speaking, this requires the operator to be in the position to carry out a multiyear exploration program involving the collection of biological baseline studies, conventional seismic, and shallow hazard survey/archaeological data (collection and assessments) prior to submitting an Exploration Plan (EP) and an Approval for Permit to Drill (APD) to the BOEMRE, in order to be allowed to drill an exploration well on a selected portion of their leased acreage. It typically takes four to five years from first permit application until the initial exploration well is spudded. Current regulatory practices and policies make it extremely difficult to perform more than one of the required sequential activities in a single year. If hydrocarbons are discovered in the initial exploration well then the operator may be required to collect additional data to support the permitting of an appraisal drilling program. The appraisal drilling program is designed to determine if the discovery will be large enough to be economically developed. If successful the appraisal program will enable the operator to move into considering submitting a development plan and convincing the administering U.S. agency that the leases should be extended beyond their 10-year term by granting a production unit for the identified leases. This process is possible in the Gulf of Mexico, but is a daunting challenge in the Alaska offshore due to: 1) limited operating season; 2) lengthy permitting process with numerous different U.S. and State government agencies which have overlapping jurisdiction and agendas; and 3) constant litigation against the various U.S. government agencies, challenging their work or findings.

Adopting some form of the Canadian Significant Discovery License (SDL) for use in Alaska's Arctic could help mitigate some of the risk and uncertainty associated with exploring in the U.S. Arctic offshore regions. An SDL is different from a production unit determination (U.S.) in that the operator, following a discovery, is allowed to retain the Canadian licenses via an SDL until the discovered field is economically capable of being developed and produced. In the U.S., a development plan and timeline is required as part of a unit approval and adherence to the unit schedule may force the operator to abandon the leases if the ever-changing economic climate will not support the commercial venture within the allocated production unit timeline. An American version of the SDL could provide some reasonable assurance, to the initial explorer, that marginal oil and gas discoveries could be economically developed at some point in the future.

Finding 5 Overview: The Merchant Marine Act of 1920, better known as the Jones Act, requires that all goods transported by water between U.S. ports be carried in U.S.-flagged, constructed, owned and operated vessels. There are no U.S.-flagged, commercial, ice-breaking vessels in existence. The only non-commercial U.S.-flagged icebreaker in service in the U.S. is the United States Coast Guard (USCG) Healy. The U.S. is lagging other nations in Arctic development and deployment of icebreakers, arctic-class support vessels and arctic-class ice-resistant tankers due to this Act. Either exemptions are required to use foreign-flagged vessels in the Arctic, or the higher cost of Jones Act-compliant ships translates into the need for larger minimum economic field sizes in the Arctic.

Twenty percent of the U.S. shipping under the Jones Act services Alaskan ports, and 97% of those ships are moving Alaskan oil. Those U.S.-Flagged vessels cost more to build by a factor of three, as compared with foreign-flagged tankers. Although tankering only accounts for a portion of the cost of Arctic oil and gas development, the International Trade Commission estimates that a 52% reduction in transportation cost could be realized if foreign-flagged tankers were not barred by the Jones Act. No requirement similar to the Jones Act exists in Canada. Thus free access, with modest duty payments, is available to foreign-flagged vessels that meet current regulatory standards.

While technology exists to find and extract the Arctic energy, a viable solution should be sought to improve the inherent cost premiums associated with complying with the Jones Act. A more reasonable policy would enable the future development of economically sub-marginal and marginal fields.

Finding 6 Overview: Alaska coastal communities have concerns about the impact that off-shore drilling might have on their subsistence lifestyle and communities. Because coastal communities perceive there is some risk to their livelihood if an accident were to occur, then the community should also share in the benefits that such development may bring to the community. This can be accomplished by Federal revenue sharing with the State. The State, in turn, should allocate a portion of the Federal revenues to the affected coastal community.

There is a precedent for nearby communities benefiting from development of Alaska's hydrocarbon resources. Most recently the village of Nuiqsut started receiving natural gas from the nearby onshore Alpine Field facility. And on a broader scale, all of Alaska's North Slope Borough receives tax revenue from North Slope oil companies producing from fields located onshore or within State waters. No such taxing mechanism exists for Federal offshore development since the Borough's jurisdiction does not extend into the sea. Still, the local jurisdictions may be impacted by offshore development. Some form of Federal revenue sharing with the State, which in turn it would share with the coastal community, would be one way of compensating the coastal communities for assuming perceived risks associated with oil development in their backyards.

Finding 7 Overview: Oil tanker transportation from the Arctic to consumer markets is currently a viable export method and will become increasingly more attractive due to declining year-round ice cover.

Declining Arctic ice suggests that ice-resistant tankers may provide a more cost-effective means of transporting oil in the future rather than building new pipelines across onshore regions with overlapping jurisdictions. Tankering within or from the Arctic is not a new idea. Circum-Arctic communities have relied on marine transport to deliver diesel oil to supply their energy needs over the last 3 to 4 decades. In August 1969, Exxon tested the concept in hopes of proving tankers viable for transportation of the Prudhoe Bay crude oil. After modifications, the S.S. Manhattan, a U.S. tanker, was escorted by a Canadian icebreaker on a round trip voyage that successfully passed through the Arctic waters.

Presently, oil tankering through the Barents Sea is common, and this tankering capability is expected to be greatly accelerated in the near future. The Norwegian Barents Secretariat is anticipating that the volume of oil tankered through the Barents Sea will to increase to 2 Million barrels oil per day over the next 5 years. In the Russian Arctic, ice-breaking oil tankers are being loaded for export to North American and European markets via an ice-resistant floating storage facility located about as far north of the Arctic Circle as Prudhoe Bay. The sea export system will allow the transport of Russian Arctic crude at minimum cost and in quantities expected to be as much as 240,000 barrels of crude oil per day. Two Russian tankers, accompanied with ice breakers, will test a commercial voyage to Southeast Asia later this year. This planned passage is designed to demonstrate Russia's ability to safely deliver Arctic oil, to the pacific region and potentially to the west coast of the U.S. in the future. It should be noted that Russian imports to the U.S. went from zero to 100,000 barrels per day in 2010, and are expected to increase as Alaska production continues to decline.

The tankering of oil in ice-resistant tankers can and will provide a lower cost and more flexible transport option for evacuating crude from multiple onshore and offshore locations in the Arctic, than the building of new pipelines. The Trans-Alaska pipeline is approximately 1000 miles in length and the tariff is about $4.50 per barrel transported. In contrast, a barrel tankered from Valdez, Alaska to America's West coast is believed to incur about half of the transport cost of the same barrel transported by the pipeline, despite being two-to-three times the distance (depending on the location of the refinery). This is consistent with crude oil tankering prices from the Persian Gulf or West Africa to the Gulf of Mexico which averages $2.16 per barrel. Lower transport costs increases the economic viability of projects and therefore increases production potential as well as benefiting commercial and public end-users. This tankering option is currently being employed to produce oil offshore Newfoundland, Canada.

<u>II.A Cited References</u>

[1]2011, Low Flow Impact Study Final Report, Prepared by the Low Flow Study Impact Team at the Request of Alyeska Pipeline Service Company for the Trans Alaska Pipeline System (TAPS)

[2]Petroleum News March 7, 2011edition

III. FINDINGS & RECOMMENDATIONS

This section characterizes the main findings and recommendations of the Arctic Subgroup and applies primarily to the U.S.

The main consequence common to the majority of these findings and recommendations is that the huge resource base, as described by the USGS, BOEMRE, National Energy Board of Canada (NEB), Geological Survey of Canada (GSC) and the various State and Provincial government resource agencies for the North American Arctic region, will not be available when needed in the 2025 – 2050+ timeframe if the status quo is maintained.

Finding 1: The North American Arctic (U.S., Canada and Greenland) has a large (world scale) discovered undeveloped (6.4 Billion barrels oil, 0.9 Billion barrels natural gas liquids and 83 TCF gas)[1] resource and a very large undiscovered (80.1 Billion barrels oil, 11.1 Billion barrels natural gas liquids and 595 TCF gas)[2] resource. Development lead times are very long (historically 10 to 20 years or longer from discovery to first production).[3]

Recommendation 1: To ensure the future energy security of the U.S., near- and medium-term exploration drilling by industry should be promoted by the U.S. Government to validate the resource estimates and identify the most promising regions.

Finding 2: Exploration and development technology, both onshore and offshore, is not expected to be a limiting factor in future development of conventional U.S. Arctic resources, within the timeframe of this study. Areas for further innovation and technological advances will be required in areas where water depths exceed 100 m or regions that require iceberg management capability (Greenland). There are numerous Arctic producing fields on land, and safe development and production of offshore Arctic reserves has occurred globally since the late 1960s, which collectively demonstrates that resource extraction can occur in the midst of sensitive ecosystems. Innovation will continue as new challenges are identified.

Recommendation 2: Industry has always risen to the challenge, and if allowed, they will continue to advance elements of Arctic exploration and development technology to reduce the operational footprint and safely produce oil and gas. Near-term advances in offshore pipeline trenching will be important across the Arctic especially in prospective regions with deepwater conditions (> 100m) such as the Continental Slope region of the Canadian Beaufort or Greenland. Advances in iceberg management will also important for Greenland and portions of the Canadian Atlantic offshore.

Finding 3: Existing 10-year lease terms are not long enough to ensure sustained exploration and appraisal of material Arctic oil and gas resources in the U.S. Arctic basins. Infrequent lease sales, lengthy, multifaceted permitting procedures, a high incidence of litigation and a required

[1] *Mean, discovered, technically recoverable* volume estimate. These discovered volumes are remote to existing development and production infrastructure. References for all quoted volumes cited in Sections IV, V, VI and VII of this report.

[2] *Mean, risked, technically recoverable, undiscovered, yet-to-find volumes.* References for all quoted volumes cited in Sections IV, V, VI and VII of this report.

[3] Thomas *et al*, "Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline? Addendum Report", 267p, U.S. DOE/NETL/Arctic Energy Office, April 2009. Tables 2.5 and 2.6.

sequential set of data-gathering and permitting activities coupled with short drilling windows (onshore winter and offshore summer) reduce the ability to identify, appraise and develop economic volumes in this short time span.

Recommendation 3: Adopt a licensing system for Alaska that is similar but improves upon Canada or Greenland's system in recognition of the limited seasonal operating period, particularly for the U.S. Federal offshore areas (70 – 105 days per year). Canada offers large tracts (vs. 3 square mile blocks) with a work commitment bid that covers nine years if a well is drilled within the first 5 years (still problematic and should be extended given the challenges of the Arctic and the new regulatory requirements), and is extended indefinitely if producible hydrocarbons are discovered on the tract. Greenland offers similar-sized tracts and exploration terms and is extending the initial license term to 16 years for its NE Greenland offshore round that will be held in 2012.

Finding 4: There is no clear, dependable, regulatory path for gaining approval of submitted exploration or development permit applications. This is due to a multitude of U.S. Government agencies/regulatory bodies which have overlapping authority, and each have their own independent permit review and approval schedule.

Recommendation 4: Streamline regulatory permitting processes and promote collaboration and coordination of the numerous Federal agencies/regulatory bodies, to avoid redundant analyses and jurisdictional overreach. A coordinated approach would provide predictable project scheduling and a more efficient use of human resources within the Federal Government and industry.

Finding 5: The Merchant Marine Act of 1920, otherwise known as the Jones Act (codified in 2006) was established to regulate cabotage (the coastal shipping of cargo and passengers) within the U.S. The Act requires cabotage in U.S.-flagged, constructed, owned and operated vessels. The Jones Act rules on tankers and support vessels mandate largely unavailable and uncompetitively priced ships, unduly increasing the cost of operations in the U.S. Arctic. Few U.S.-flagged, ice-classed vessels are available for U.S. Arctic offshore operations, so either exemptions are required to allow the use of foreign-flagged vessels that are able to meet U.S. Arctic shipping standards, or excessive delays and costs (~3 x $'s to build a U.S.-flagged fleet) will be incurred to comply with this statute.

Recommendation 5: Continue to provide exemptions to the Jones Act for the non-U.S.-flagged, ice-class vessels used in U.S. Arctic exploration and appraisal operations. This will ensure that ice-class vessels are available at competitive rates given the long lead times required for Arctic offshore operations.

Finding 6: Alaska Coastal communities only receive tax revenue from onshore facilities related to oil and gas development in the onshore and State waters areas of Alaska, which leads to local opposition of Outer Continental Shelf (OCS) exploration and development in the U.S. Arctic.

Recommendation 6: The U.S. should consider a Federal revenue sharing program for the Alaska State and local coastal governments of potentially impacted communities, perhaps initiating a program similar in mechanism to the Gulf of Mexico Energy Security Act (GOMESA) in which

37.5% of the revenue from new Gulf of Mexico leases after 2007 is distributed to local coastal political subdivisions (http://www.boemre.gov/offshore/GOMESARevenueSharing.htm).

Finding 7: Oil tanker transport from the Arctic to consumer markets is currently a viable export method. Year-round tankering of crude oil from the Arctic to market will likely be viable cost effective alternative to pipeline transport in the future. Tankering offers greater flexibility of evacuating crude oil from multiple onshore or offshore development facilities than new pipelines. Lower transport costs increases the economic viability of projects and therefore increases the production potential.

Recommendation 7: Prepare for this transportation option in the future. The U.S. needs to catch up with, and then expand, the technological advances, which when combined with the possibility of more open seas later within the timeframe of this study, will provide for America's energy needs. In the long term, America may lose the TAPS due to diminishing flow (2039 to 2045 timeframe) unless immediate efforts are made to find and develop more oilfields to stem the decline in oil production and maintain adequate flow in the pipeline. Failure to act will result in the loss or serious deferment of any oil potential until well beyond the 2050 horizon.

IV. EXPLORATION HISTORY AND RESOURCE POTENTIAL

IV.A Introduction

The North American Arctic (Figure 4.A.1) has world-scale, undiscovered oil and gas resources (based on analysis by various governmental agencies) that need to be validated by exploration drilling to enable development and production in the 2025 - 2050 timeframe.

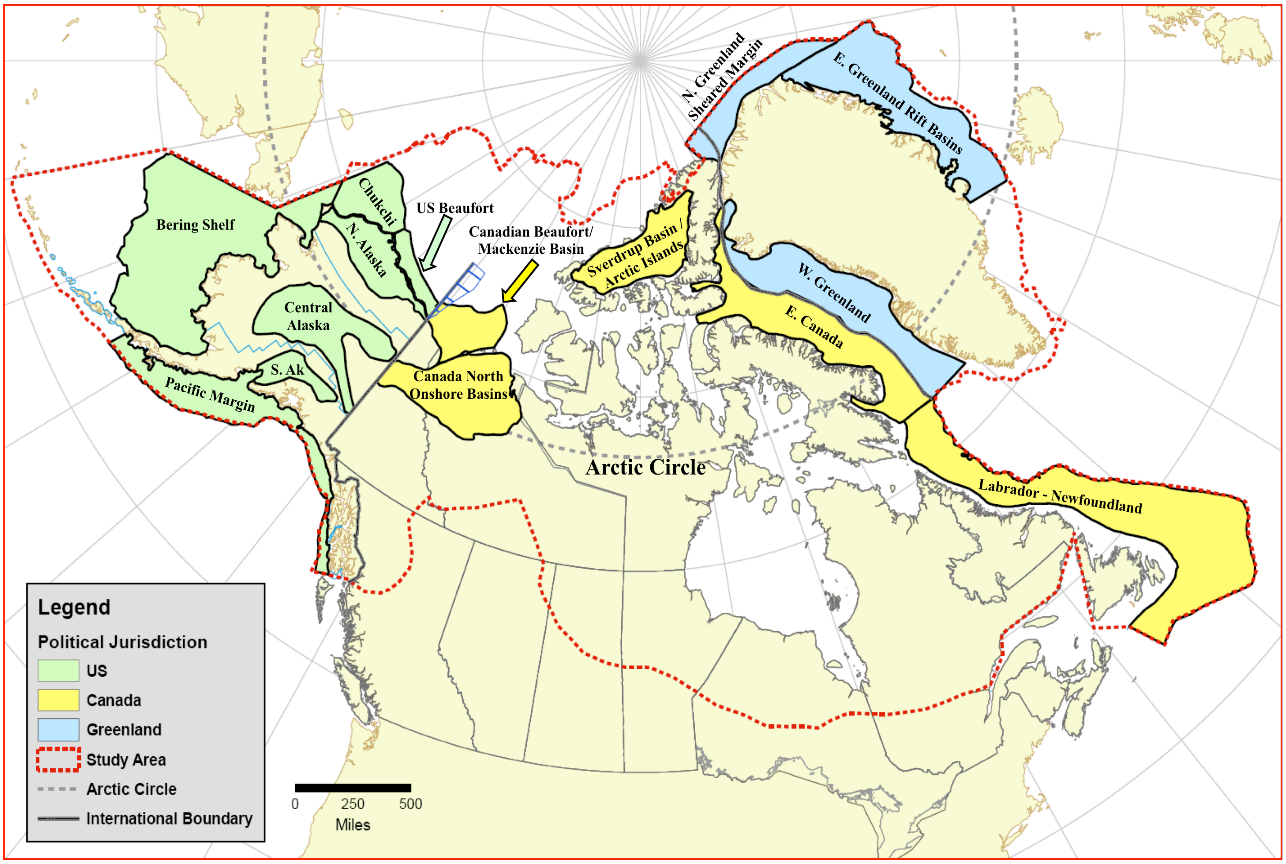

Figure 4.A.1 - Prospective Basins (colored) within the NA Arctic (U.S. green, Canada basins yellow and Greenland blue).

There has been a long history of onshore and offshore oil and gas leasing/licensing and exploration drilling (Figure 4.A.2) in this region, resulting in the discovery of significant oil and gas reserves some of which have been developed and produced, as well as numerous stranded discoveries (no development / production facilities and / or pipelines), as described in Sections V, VI and VII. This region also is believed to contain significant, yet-to-be-found volumes, based on numerous government agency estimates and supported by industry interest (leasing/licensing, historic 2D seismic and modern but limited 3D seismic and renewed attempts to secure regulatory permission to drill particularly in the offshore). Most of the significant, yet-to-be-found volumes are believed to be contained in the offshore, beneath the present day continental shelf and slope (Figures 4.A.3 and 4.A.4 and Table 4.A).

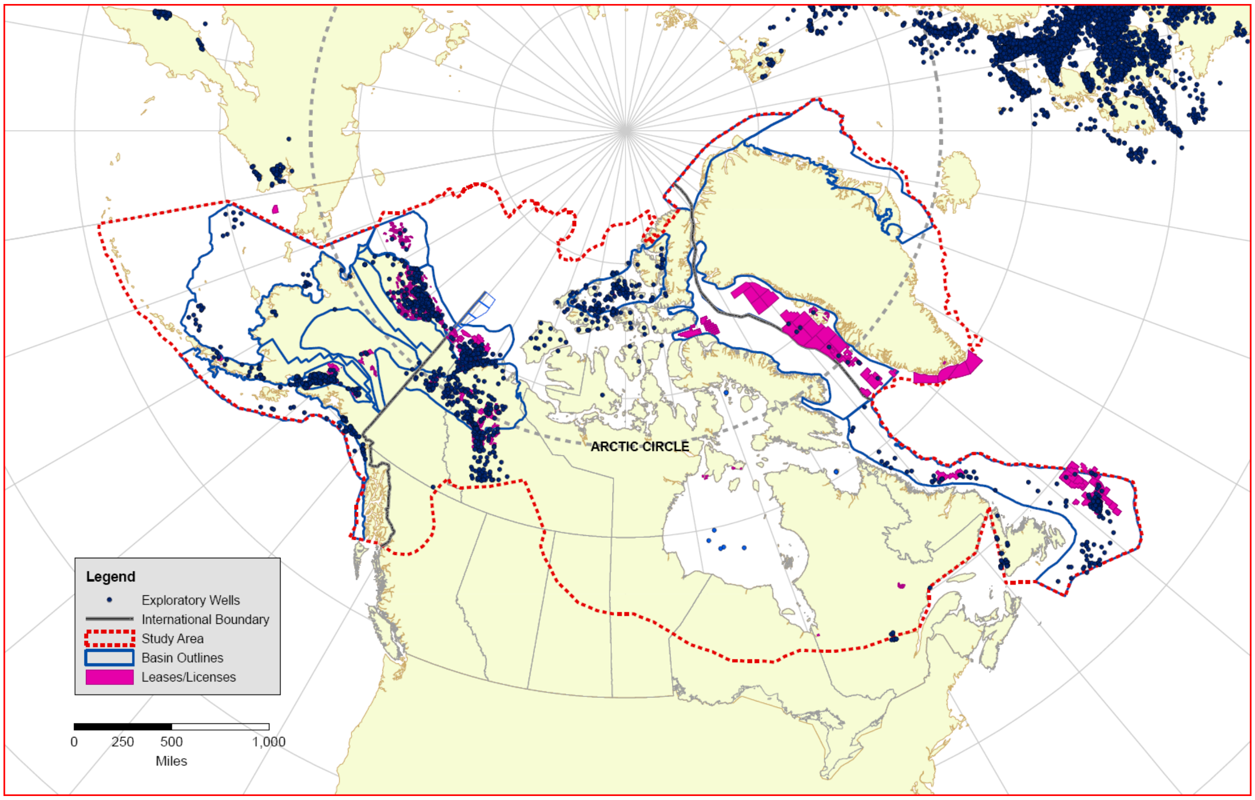

Figure 4.A.2 - Historic exploration wells drilled in the N. American Arctic region (Current active leases/licenses also highlighted).

A summary description of the <u>mean, risked, undiscovered, technically recoverable oil, natural gas liquids and gas volumes</u> for the North American Arctic, as described by the USGS, BOEMRE, Alaska Department of Natural Resources (ADNR), and NEB follows:

North Alaska (north of the Brooks Range) is expected to have mean, risked, undiscovered, technically recoverable volume of 39.8 Billion barrels oil, 209.3 TCF gas and 0.8 Billion barrels natural gas liquids:

- Chukchi Sea Offshore: 15.4 Billion barrels oil and 76.8 TCF gas
- Beaufort Sea Offshore: 9.2 Billion barrels oil and 33.5 TCF gas
- North Slope Onshore and State Waters: 15.2 Billion barrels oil, 99 TCF gas and 0.8 Billion barrels natural gas liquids

South and Central Alaska (south of the Brooks Range) is expected to have mean, risked, undiscovered, technically recoverable volume of 3.8 Billion barrels oil, 61.3 TCF gas and 0.1 Billion barrels natural gas liquids:

- Central Onshore: 0.2 Billion barrels oil and 8.5 TCF gas
- South Onshore and State Waters: 0.6 Billion barrels oil and 25 TCF gas
- Bering Shelf Offshore: 1.3 Billion barrels oil and 19.6 TCF gas
- Pacific Margin Offshore: 1.7 Billion barrels oil and 8.2 TCF gas

The Canadian Arctic is expected to have mean, risked, undiscovered, technically recoverable volume of 20.2 Billion barrels oil, 186.8 TCF gas and 0.9 Billion barrels natural gas liquids:

- The Mackenzie Delta Onshore/Canadian Beaufort Offshore: 8.1 Billion barrels oil, 67.1 TCF gas and 0.2 Billion Barrels natural gas liquids
- Canadian North Onshore Basins: 0.3 Billion barrels oil and 1 TCF gas
- Sverdrup Basin/Arctic Islands Onshore/Offshore region: 4.3 Billion barrels oil and 28 TCF gas
- East Canada Basin (Baffin Bay Offshore): 4.8 Billion barrels oil, 33.7 TCF gas and 0.7 Billion barrels natural gas liquids
- Labrador-Newfoundland Offshore: 2.7 Billion barrels oil and 57 TCF gas

Offshore Greenland is expected to have a mean, risked, undiscovered, technically recoverable volume of 16.1 Billion barrels oil, 137.6 TCF gas and 9.93 Billion barrels natural gas liquids

- West Greenland Basin Offshore: 5.9 Billion barrels oil, 41.2 TCF gas and 0.9 Billion barrels natural gas liquids
- East Greenland Rift Basin Offshore: 8.9 Billion barrels oil, 86.2 TCF gas and 8.1 Billion barrels natural gas liquids
- North Greenland Sheared Margin: 1.3 Billion barrels oil, 10.2 TCF gas and 0.2 Billion barrels natural gas liquids

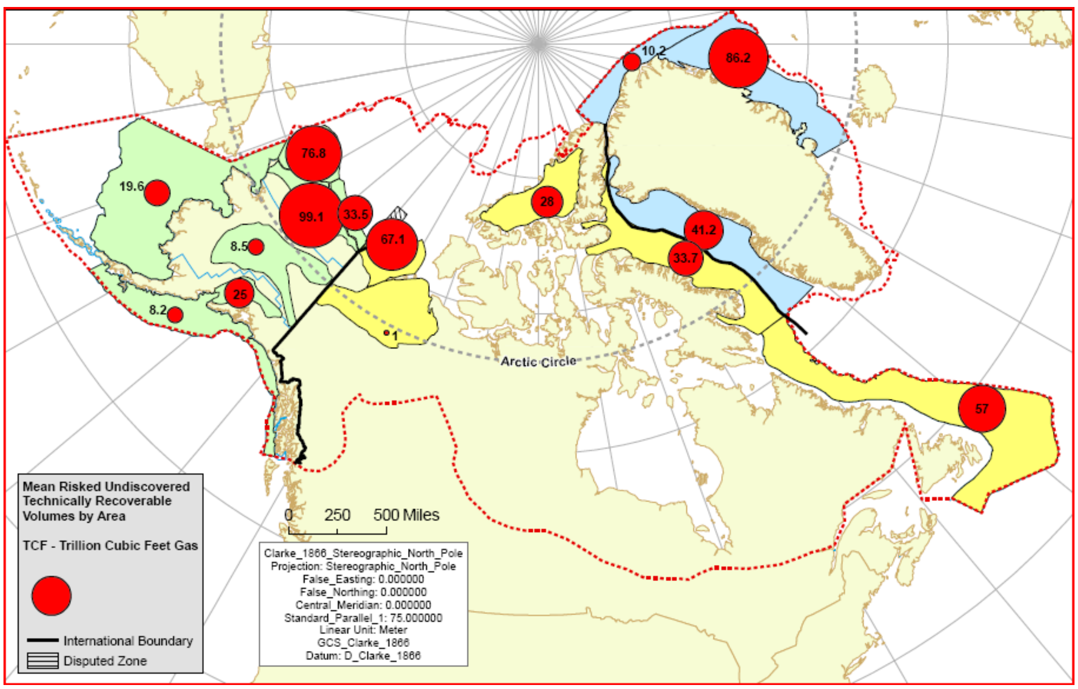

Figure 4.A.3 - Arctic Gas Potential (TCF) by Basin (mean, risked, technically recoverable, undiscovered volume). Prospective basins highlighted (Alaska green, Canada yellow and Greenland blue). References for numbers cited at the conclusion of Section IV.

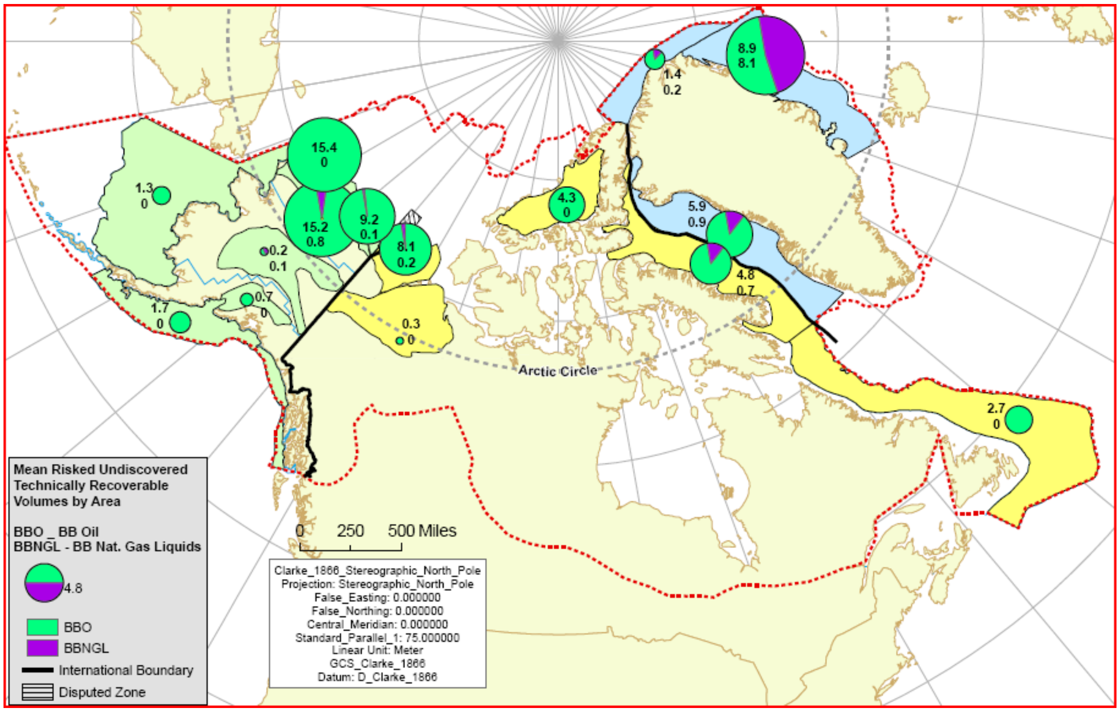

Figure 4.A.4 - Arctic Oil and NGL Potential (Billion barrels) by Basin (mean, risked, technically recoverable, undiscovered volume). Prospective basins highlighted (Alaska green, Canada yellow and Greenland blue). References for numbers cited at the conclusion of Section IV.

Table 4.A Mean Risked Technically Recoverable Undiscovered Volumes				
Country	**Basin Area**	**Mean Billion Barrels Oil**	**Mean TCF GAS**	**Mean Billion Barrels Natural Gas Liquids**
US Alaska	**North Slope Onshore & State Waters** (includes ANWR 1002 Volumes)	15.2	99.1	0.8
US Alaska	**Beaufort OCS** (includes USGS Alaska Passive Margin OCS)	9.2	33.5	0.1
US Alaska	**Chukchi OCS**	15.4	76.8	No Volume Reported
US Alaska	**Bering Shelf OCS** (includes N. Aleutian Basin OCS Volumes)	1.3	19.6	No Volume Reported
US Alaska	**Pacific Margin OCS**	1.7	8.2	No Volume Reported
US Alaska	**Central Alaska Onshore**	0.2	8.5	0.1
US Alaska	**South Alaska Onshore** (Includes State Portion Cook Inlet)	0.7	25	No Volume Reported
Canada	**Canadian Beaufort & Mackenzie Delta**	5.7	52	No Volume Reported
Canada	**Sverdrup Basin-Arctic Islands**	4.3	28	No Volume Reported
Canada	**USGS Canadian Passive Margin** (area outboard of CB & AI/SB)	2.4	15.1	0.2
Canada	**Canada North Onshore Basins**	0.3	1	No Volume Reported
Canada	**Canada East Offshore Labrador-Newfoundland**	2.7	57	No Volume Reported
Canada	**East Canada Offshore "Baffin Bay" Region**	4.8	33.7	0.7
Greenland	**West Greenland Offshore**	5.9	41.2	0.9
Greenland	**East Greenland Rift Basins "Offshore"**	8.9	86.2	8.1
Greenland	**North Greenland Sheared Margin** (Onshore & Offshore)	1.4	10.2	0.2

Table 4.A – Mean, Risked, Technically Recoverable, Undiscovered Volumes (Yet-to-be-Found). References for numbers cited at the conclusion of Section IV.

IV.B North Alaska

The North Alaska Onshore region is defined as the lands onshore, as well as the submerged lands in State and Federal waters region north of the Brooks Range (Figure 4.B.1). Multiple Federal and State agencies, as well as private entities, manage the acreage: The Bureau of Land Management (BLM) administers the National Petroleum Reserve in Alaska (NPR-A) and Arctic National Wildlife Refuge (ANWR 1002) Areas, the State of Alaska administers the North Slope Coastal Plain, North Slope Foothills and coastal State submerged land (3 mile area outboard of coastline) areas and the remainder is controlled by the various private Alaskan Native Corporations, the largest of which is the Arctic Slope Regional Corporation (ASRC). A significant portion of this onshore subsurface region is largely underexplored.

The North Alaska Offshore region contains the U.S. Chukchi Sea OCS Area to the west and the Beaufort Sea OCS area to the east. The U.S. Chukchi area shares a well defined border with Russia while the U.S. Beaufort Sea shares a disputed border with Canada to the east (Figure 4.B.1). The BOEMRE, formerly the Minerals Management Service (MMS), administers the U.S. Chukchi and Beaufort OCS regions. These two OCS areas features similar plays, trapping styles and exploration opportunity (prospects) as the adjacent North Slope onshore area and are largely under-explored.

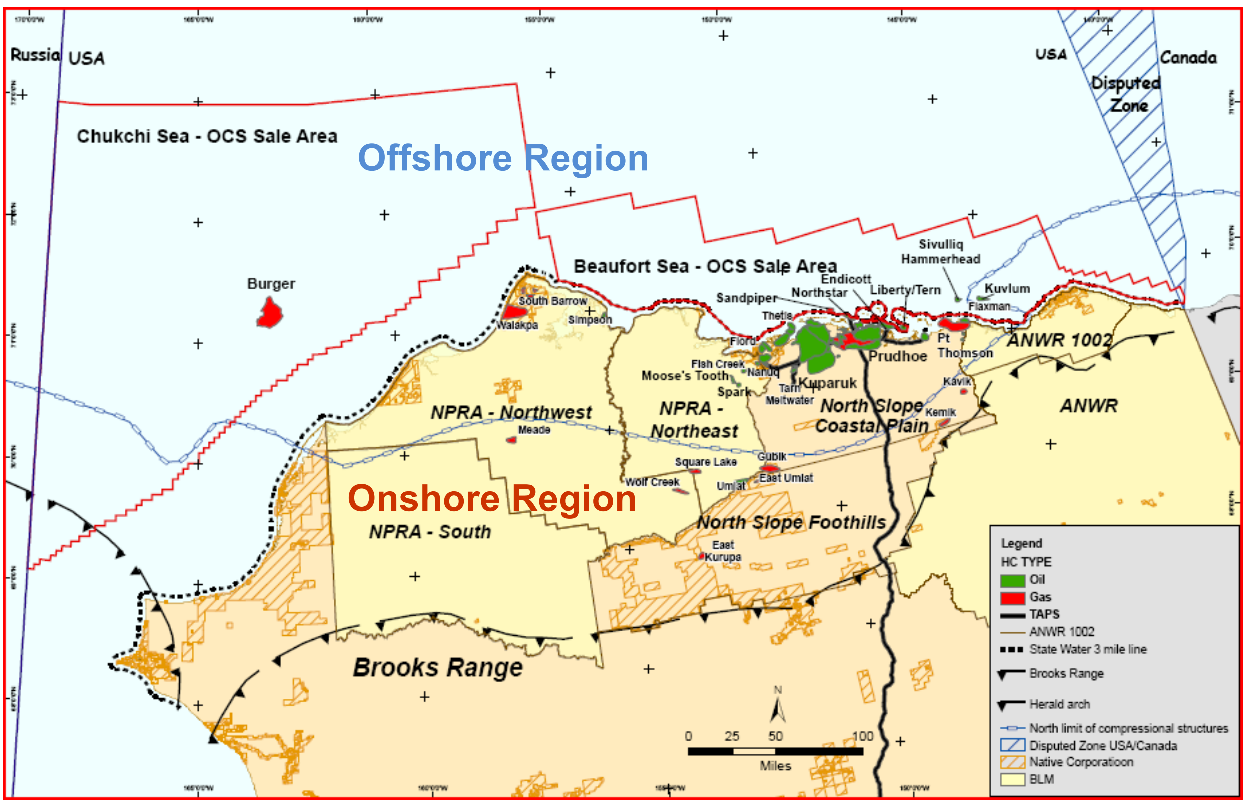

Figure 4.B.1 - North Alaska Onshore and Offshore administrative areas, discovered oil and gas accumulations, oil infrastructure, and international borders.

IV.B.1 Onshore Region

Exploration of this region was initiated in 1909 with the discovery of active oil seeps in the Cape Simpson area of what is now the Northwest Planning Area of NPR-A). The first exploration drilling was initiated in 1945 and resulted in noncommercial gas discoveries near Barrow (Figure

4.B.1). Drilling and testing of the South Barrow Gas Field began in 1948, and regular production serving the local community began in 1949.[1]

The discovery of the giant Prudhoe Bay Field (15 Billion barrels oil and 27 TCF gas recoverable) in 1968, helped drive the building of TAPS (completed in 1977), and ushered in a new era of exploration in Alaska. Over 400 exploration wells have been drilled within this region, with the bulk residing within the North Slope Coastal Plain, and have resulted in the discovery of numerous fields of which many are currently producing (Figure 4.B.1.1). The northern discoveries are primarily oil and gas, while the southern discoveries are largely non-associated gas with some possibility of oil. Natural gas is not exported due to the lack of a gas pipeline and the bulk of the gas is reinjected back into producing reservoirs to enhance oil recovery. Prospective areas outside of the North Slope Coastal Plain (NPR-A, North Slope Foothills and the ANWR 1002 area) are significantly underexplored.

The North Slope Foothills gas play is located in the foothills of the Brooks Range spanning southern NPR-A and the Central North Slope regions. The older source rocks here were deeply buried into and below the gas generation window, thus the region is predominantly gas prone. Potentially trapping structures are expressed at the surface, and in the 1940's and 50's soon after the formation of NPR-A, exploration began based on surface structure mapping and some sparse 2D seismic data. One modest sized shallow oil field was found (Umiat) and several other gas accumulations were discovered (Figure 4.B.1). In the 1970's and 80's a few wells were drilled to deeper formations and flowed gas to surface with little or no water. In 2008, Anadarko, Petro Canada, and BG drilled a two season 4 well program targeting the potentially large gas accumulations in the Foothills. Efforts to commercialize these accumulations and potentially bring gas to the Anchorage market are ongoing.

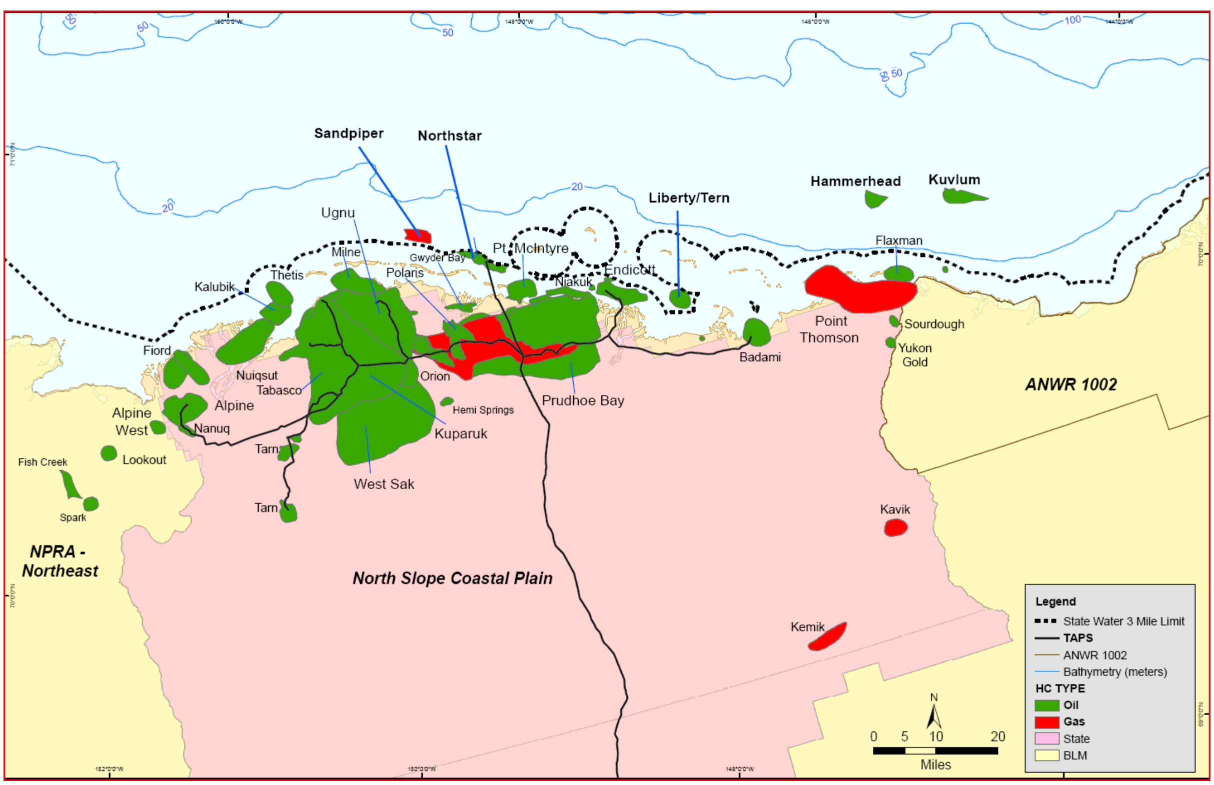

Figure 4.B.1.1 - Detailed area map of North Alaska including the Alaska State Waters and the Beaufort OCS area illustrating producing fields, oil infrastructure, and undeveloped onshore and offshore discoveries.

The most current USGS mean estimates of risked, undiscovered, technically recoverable resource for this region total 15.2 Billion barrels oil, 99 TCF gas and 0.8 Billion barrels natural gas liquids. Their breakdown by area is as follows: NPRA 0.9 Billion barrels oil and 53 TCF gas;[2] Central North Slope (onshore and offshore state lands) 3.9 Billion barrels oil, 37.5 TCF gas and 0.5 Billion barrels natural gas liquids;[3] and the ANWR 1002 area 10.4 Billion barrels oil, 8.6 TCF gas and 0.3 Billion barrels natural gas liquids.[4] The ANWR 1002 area is currently subject to a moratorium which prohibits exploration and development in this area.

IV.B.2 North Alaska Offshore Area

For purposes of this discussion, the North Alaska Offshore area is subdivided into the Beaufort Sea and Chukchi Sea areas, as based on the Alaska OCS planning areas and assessment provinces (Figures 4.A.1, 4.B.1 and 4.B.2.1).

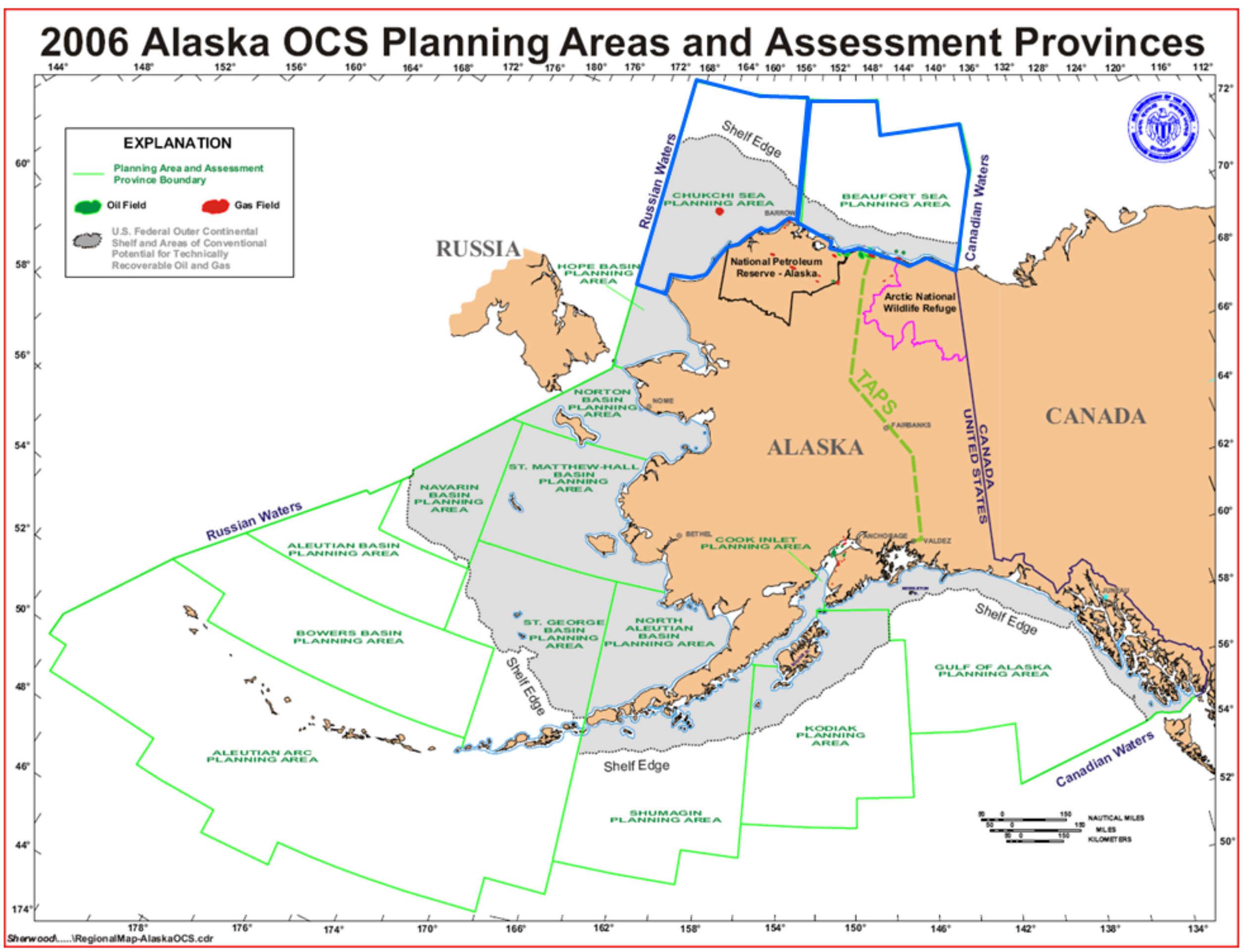

Figure 4.B.2.1 - BOEMRE Alaska OCS Planning Areas and "Shelf" Assessment Provinces (shaded in grey) courtesy of BOEMRE. The shaded areas contained within the planning areas outlined in blue have been offered for leasing during the last decade (2005 – 2008). [4]

IV.B.2.a Beaufort Sea

Exploration drilling of the Federal portion of the Beaufort Sea area (Figure 4.B.2.a.1) began in earnest following the 1968 discovery of the Prudhoe Bay Field (onshore) and the completion of TAPS in 1977. The first offering occurred in a joint Federal / State lease sale held in 1979. This and subsequent OCS lease sales, the most recent of which was held in 2007, have allowed access to the waters beyond the three-mile limit. Exploratory efforts post 1970 (~90,000 miles of 2D seismic and 30 exploration wells) have yielded four prospects that have been deemed capable of production and have been termed significant discoveries by both the BOEMRE[5,6] and the Alaska Division of Oil & Gas (ADOG).[7] Three of these prospects Hammerhead (Sivulliq), Sandpiper, and Liberty, are completely in OCS waters but have not been developed (Figure 4.B.1.1). The fourth discovery, Northstar, underlies both Federal and State waters and has been developed and producing oil since 2001. These four offshore prospects reside in water depths ranging from 21 feet to 120 feet. The Northstar Field is the most proximal to existing infrastructure (~ 6 miles to Prudhoe Bay pipeline tie in point), while the Hammerhead (Sivulliq) and Kuvlum discoveries are the most distal (~ 16 miles to Pt. Thomson Field onshore and then and additional 22 miles to the nearest pipeline tie-in point at the Badami Field). The legacy subsurface data (30 exploratory wells and 2D seismic data), combined with newly acquired 3D seismic, suggests that this basin is significantly underexplored.

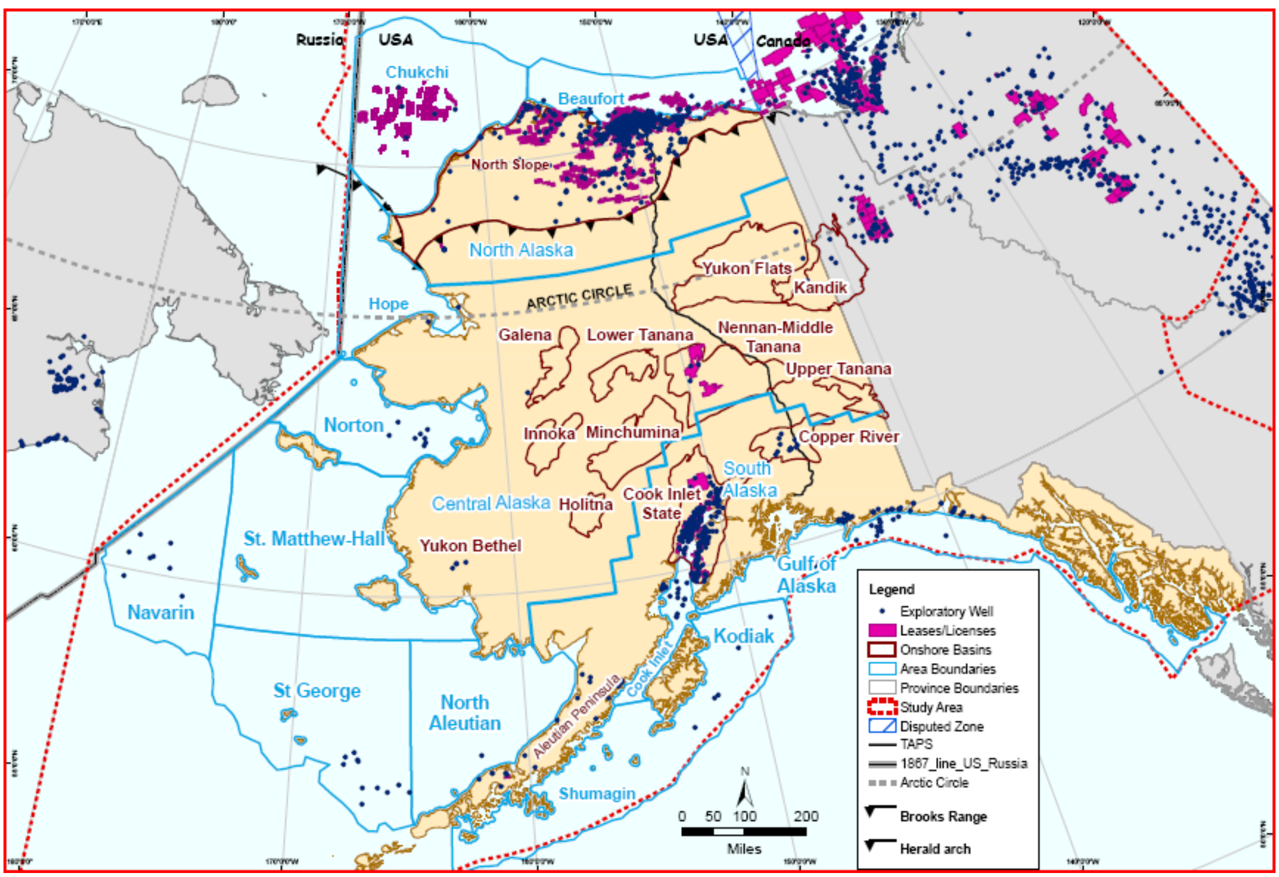

Figure 4.B.2.a.1 - Alaska region with main geographic areas, basins, protraction areas, exploration wells and current leases depicted.

Industry spent a collective ~$88.9 million on 207 leases containing ~1.09 million acres at the last two OCS sales (Figure 4.B.2.a.1). These recently leased tracts have not been drilled since the lease sales were held (OCS Sale 195 held in 2005 and OCS Sale 202 held in 2007), due to a variety of issues beyond the control of the lessees, the most recent being the suspension of planned exploration drilling in the U.S. Arctic by the U.S. Department of Interior (DOI), due to the Horizon Incident in 2010.

The combined BOEMRE and USGS total mean estimate of risked, undiscovered, technically recoverable resources for the Beaufort Sea is 9.2 Billion barrels oil, 33.5 TCF gas and 0.06 Billion barrels natural gas liquids. Their breakdown is as follows: 1) the BOEMRE mean estimate of risked, undiscovered, technically recoverable resources for the Beaufort Sea "Shelf" Assessment Area is 8.2 Billion barrels oil and 27.7 TCF of gas (it should be noted that no volumes for condensate or natural gas liquids are quoted by the BOEMRE as these volumes have been included within the oil volume),[5,6] and 2) the USGS has assessed the U.S. Beaufort OCS region (outboard of the 2006 BOEMRE assessment) and has generated a mean estimate of risked, undiscovered, technically recoverable resources of 0.97 Billion barrels of oil, 5.89 TCF gas and 0.06 Billion barrels of natural gas liquids.[8]

IV.B.2.b Chukchi Sea

In the early to middle 1980s, the BOEMRE (formerly known as the MMS) determined, based on an extensive 2D seismic data base, that the Chukchi Sea area had a large resource potential and that long-term oil pricing would support exploration and development in this region. The BOEMRE held the first lease sale (Sale 109) covering this prospective area in 1988, offering more than 25 million acres. Companies spent ~$ 478 million on 350 leases containing ~1.98 million acres. Industry safely drilled 5 exploration wells from 1989 – 1991 (Figure 4.B.2.a.1), and demonstrated a working petroleum system with strong affinities to the North Slope and Beaufort Sea regions. Four of the five wells contained reservoirs with oil and gas "pay" as defined by the BOEMRE and the fifth well demonstrated oil and gas shows.[6] These wells were drilled 60 or more miles or more offshore in water depths ranging from 137 feet to 152 feet. Although none of the prospects were deemed commercial at the time, the demonstrated existence of a working petroleum system remained intriguing. A later study by the BOEMRE which was first released in 2001 and then updated in 2004, described a stranded, mean outcome, most likely case, recoverable volume assessment of 14 TCF gas and 0.72 Billion barrels of natural gas liquids for the Burger Prospect.[9]

The legacy 2D seismic data combined with the initial exploration well results suggests that this basin is significantly underexplored. This area was assigned a total mean estimate of risked, undiscovered, technically recoverable resources for the Chukchi Sea "Shelf" Program Area (Figure 3.B.2.1.1) of 15.4 Billion barrels oil and 76.8 TCF of natural gas.[10] It should be noted that no volumes for condensate or natural gas liquids are quoted by the BOEMRE as these volumes have been included within the oil volume.

In 2008 the BOEMRE reoffered the Chukchi OCS area for oil and gas leasing (OCS Sale 193). Prior to the lease sale, several companies acquired modern 3D over a portion of the area. Industry spent ~$2.67 Billion on 487 leases containing ~2.76 million acres, including $1.56 Billion spent on 41 leases on the Burger Prospect (Figures 4.B.1 and 4.B.2.a.1). These recently leased tracts have not been drilled since the 2008 lease sale due to a variety of issues beyond the control of the lessees, the most recent being the suspension of planned exploration drilling in 2010 in the Arctic by the DOI due to the Horizon Incident in the Gulf of Mexico.

IV.B. 2.c South and Central Alaska

The South and Central Alaska region encompasses the land as well as the State and Federal waters region south of the Brooks Range (Figure 4.B.2.a.1). This region is divided into the onshore region including the State portion of Cook Inlet Basin (both onshore and State waters), and an offshore region including the western Bering Shelf OCS Region and the southern Pacific Margin OCS region. Each of these areas can be subdivided further as they each contain numerous under-explored sedimentary basins. A number of these basins will be described in the following sections.

IV.B.2.c.1 Onshore Region

The central portion of the onshore region includes the Yukon Flats, Kandik, Kotzebue, Galena, Innoka, Minchumina, Yukon-Bethel, Holitna, Upper Tanana, Nenana-Middle Tanana, and Lower Tanana Basins (Figure 4.B.2.a.1). This large geographic region is administered by the State of Alaska, the BLM and various Alaskan Native Corporations. The region is lightly explored with very limited amount of seismic data and only 12 exploration wells. A 1995, USGS oil and natural gas assessment estimated that the entire Central Onshore Region contained a total mean, risked, undiscovered, technically recoverable resource of 0.5 Billion barrels oil and 2.8 TCF gas.[11, 12, 13]

The Yukon Flats basin is the most prominent in the area. The historic wells in this area contain hydrocarbon indicators and demonstrate adequate reservoir and seal characteristics. A more recent 2004 assessment or the Yukon Flats area describes a total mean estimate of risked, undiscovered, technically recoverable resources of 0.2 Billion barrels oil, 5.5 TCF gas and 0.13 Billion barrels of NGL's.[14] The other basins are believed to have reserve potential, but none have received a modern resource assessment. A recent Alaskan Native Corporation study described a range of 1 to 6 TCF of gas may be expected to be discovered in Nenana Basin.[15] The numerous basins in the central portion of the onshore region are lacking a consistent modern resource assessment and the reported volume potential for this region may be understated.

The southern onshore region includes a number of basins (Figure 4.B.2.a.1) including the Cook Inlet (both the onshore and State waters portion), Copper River, Gulf of Alaska (onshore and State waters), and the Aleutian Peninsular (onshore Bristol Bay and State waters). This large geographic region administered by the State of Alaska, the BLM and various Alaskan Native Corporations.

The Cook Inlet Basin covers some 15,000 square miles, with almost half lying offshore under the waters of Cook Inlet. The Cook Inlet onshore and State waters area has over 300 exploration wells and numerous mature fields that have been producing oil and gas since the early 1900s onshore and 1960s offshore (Figure 4.B.2.c.1). Exploration in this basin rapidly waned upon the discovery of the giant Prudhoe Bay Field in north Alaska in 1968. The basin is generally looked upon as a mature province. The mean, risked, undiscovered, technically recoverable resources for the Cook Inlet area (onshore and State Waters area) are 0.7 Billion barrels oil and 25 TCF gas.[16]

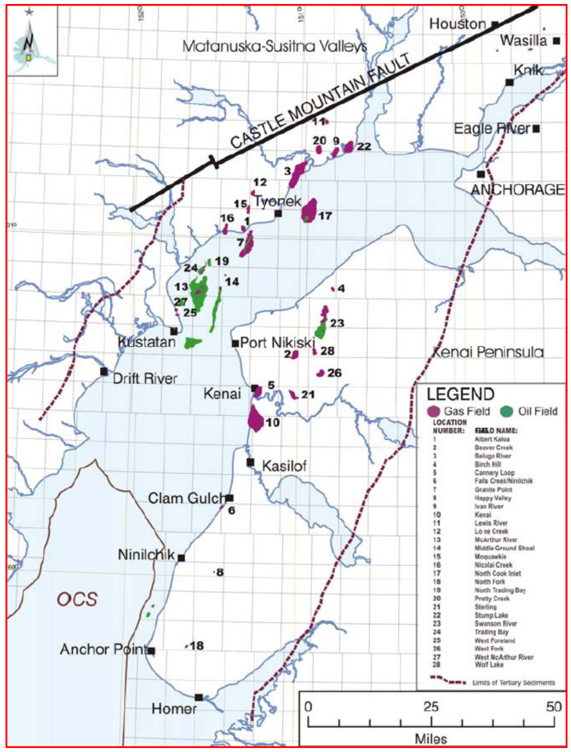

Figure 4.B.2.c.1 - Discovered oil (green) and gas (purple) fields in Cook Inlet (Onshore and State Waters).[16]

The other basins in this region (Aleutian Peninsular (onshore Bristol Bay and State waters), Gulf of Alaska (onshore and State waters), and Copper River) are believed to have undiscovered reserve potential but lack a modern resource assessment (Figure 4.B.2.a.1). The narrow Aleutian Peninsular (including Bristol Bay region) flanks the volcanic chain and has had over 36 exploration wells drilled. Various elements of a working petroleum system have been demonstrated, but none of the wells have contained pay. The Gulf of Alaska onshore and State waters area has had historic drilling (55 exploration wells), and features an oil field that produced a total of ~154,000 bbls before being abandoned in 1933. Finally, field work over the last half century in the Copper River basin has confirmed that the Mesozoic and Tertiary strata correlate with the highly productive stratigraphy of the Cook Inlet oil and gas province. These correlations strongly suggest that hydrocarbon reservoirs and source rocks should be present even though they have not been seen in any of the 11 exploration wells.

IV.B.2.c.2 Offshore Region

For the purpose of the following discussion, the central and south offshore Alaska OCS planning areas and assessment provinces have been ascribed, based on geography, into either the Bering Shelf or Pacific Margin areas (Figure 4.B.2.c.2.a.1).

IV.B.2.c.2.a Bering Shelf

The prospective Bering Shelf Basins, as defined by the BOEMRE are illustrated in (Figure 4.B.2.c.2.a.1). The Bering Shelf area contains the Hope, Norton, St. Matthew-Hall, Navarin, St. George and North Aleutian Planning and Assessment areas (Figure 4.B.2.1). This extensive and underexplored offshore region is administered by the BOEMRE and ranges in water depth from 10 feet to greater than 4000 feet. Five of the six offshore shelf basins have been partially or completely offered at six previous Federal lease sales (1983-1991) while six stratigraphic test wells and twenty-four exploration wells (Figure 4.B.2.a.1) have been drilled in the offshore portion of four of the basins. All of the stratigraphic test wells and exploration wells were drilled between 1976 and 1985 and collectively demonstrated elements of a working petroleum system.

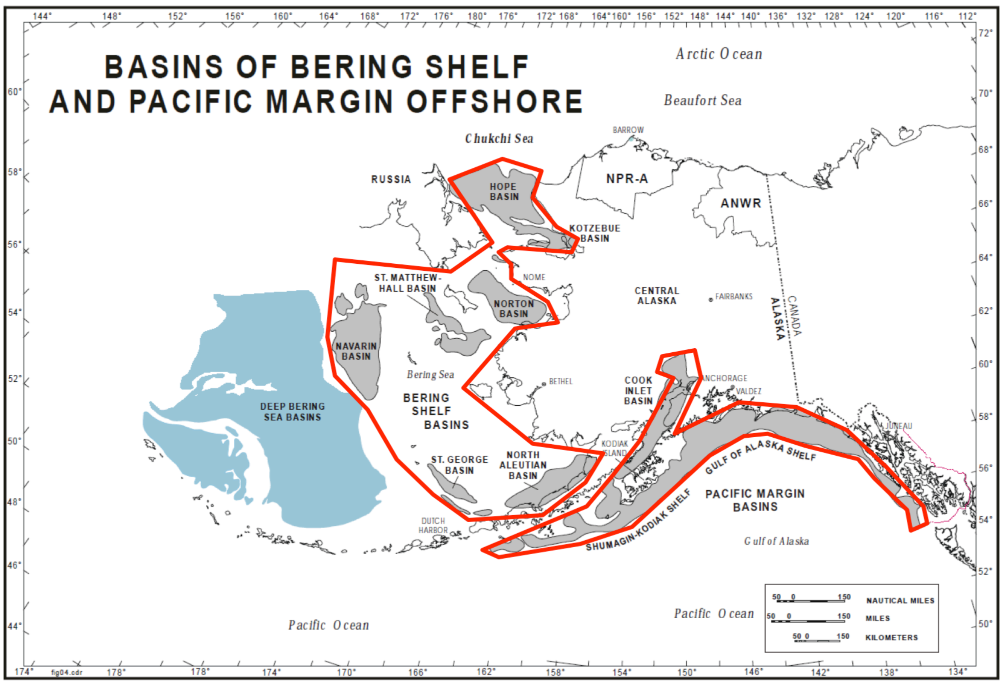

Figure 4.B.2.c.2.a.1 - The Bering Shelf and Pacific Margin Basins (shaded in grey and outlined in red) that have been assessed by the BOEMRE for conventional hydrocarbon potential. [12]

The resource potential of the Bering Shelf OCS area was characterized by Sherwood in 1998[6] and most recently updated by the BOEMRE in 2006.[5] The following basins, Hope, Norton, St. Matthew-Hall, Navarin, St. George and North Aleutian have been assessed and are expected to contain an estimated mean, collective volume of 1.3 Billion barrels oil and 19.6 TCF gas (risked, undiscovered, technically recoverable).[5, 6] No volumes for condensate or natural gas liquids are quoted by the BOEMRE as these volumes have been included within the oil volume.

It should be noted that the North Aleutian Basin (Figure 4.B.2.c.2.a.1) is believed to be the most prospective of the Bering Shelf Planning Areas as it contains numerous large, untested structures. One offshore stratigraphic test well has been drilled in the basin and it validates the presence of a working petroleum system (Figure 4.B.2.a.1). BOEMRE expects this basin to contain a mean, risked, undiscovered, technically recoverable volume of 0.75 Billion barrels oil and 8.62 TCF gas.[5] The quoted oil volume is expected to be "mostly" condensate and natural gas liquids that would be recovered as a byproduct of gas production. This area was offered at a Federal Lease Sale (OCS Sale 92) in 1988. Industry bid ~$95.4 million on 23 leases containing 121,757 acres. A moratorium was imposed after the Exxon Valdez oil spill in 1989, and the leases were subsequently bought back by the Federal Government. The moratorium was lifted in 2007, and this planning area was once again considered for leasing within the current 5 Year Leasing Program (2007-2012). OCS Sale 214, scheduled for 2011, was removed from the sale schedule by the Secretary of Interior in the spring of 2010, and the area is under a Presidential withdrawal from lease sales until June 2017.

IV.B.2.c.2.b Pacific Margin

The prospective Pacific Margin Offshore Basins (Figures 4.B.2.1 and 4.B.2.a.1) are defined and administered by the BOEMRE. The Pacific Margin is divided into four planning areas: Shumagin, Kodiak, Gulf of Alaska and the Federal portion of Cook Inlet. Water depths over this extensive area range from 10 feet to greater than 4000 feet. Two of the four offshore Planning areas (Gulf of Alaska and Cook Inlet) have been offered at eight Federal lease sales from 1976-2004. Stratigraphic test wells have been drilled in all four of the Planning Areas: six in Shumagin-Kodiak; and one each in the Gulf of Alaska and Cook Inlet. Thirteen exploration wells have been drilled in Cook Inlet and twelve exploration wells have been drilled in the Gulf of Alaska. All of the stratigraphic test wells and exploration wells were drilled between 1976 and 1985 and collectively demonstrated elements of a working petroleum system. This region is significantly underexplored.

The resource potential of the Pacific Margin OCS area was characterized by Sherwood in 1998[6] and most recently updated by the BOEMRE in 2006.[5] The Shumagin-Kodiak, Gulf of Alaska and Cook Inlet assessment areas are expected to contain an estimated mean collective volume of 1.7 Billion barrels oil and 8.2 TCF gas (risked, undiscovered, technically recoverable).[5, 6] It should be noted that no volumes for condensate or natural gas liquids are quoted by the BOEMRE as these volumes have been included within the oil volume.

The Cook Inlet OCS Assessment Area (offshore Federal waters) is believed to be the most prospective of the Pacific Margin Offshore Planning Areas in terms of liquids, while the Gulf of Alaska OCS Assessment Area offers the greatest natural gas potential. The BOEMRE expects the Cook Inlet OCS to contain a mean volume estimate of 1.0 Billion barrels oil and 1.2 TCF gas (risked, undiscovered, technically recoverable) and the Gulf of Alaska OCS to contain a mean volume estimate of 0.6 Billion barrels oil and 4.6 TCF gas (risked, undiscovered, technically recoverable).[5, 6] Again, it should be noted that no volumes for condensate or natural gas liquids are quoted by the BOEMRE as these volumes have been included within the oil volume.

IV.C Canadian Arctic

The Canadian Arctic region as defined by the Resource and Supply Task Group encompasses a broad geographical area extending from the Alaska border in the west to Greenland in the east

(Figs. 4.C.1). For the purpose of this report the Canadian Arctic Region has been partitioned into two geographic areas: the Canadian North and the Canadian East.

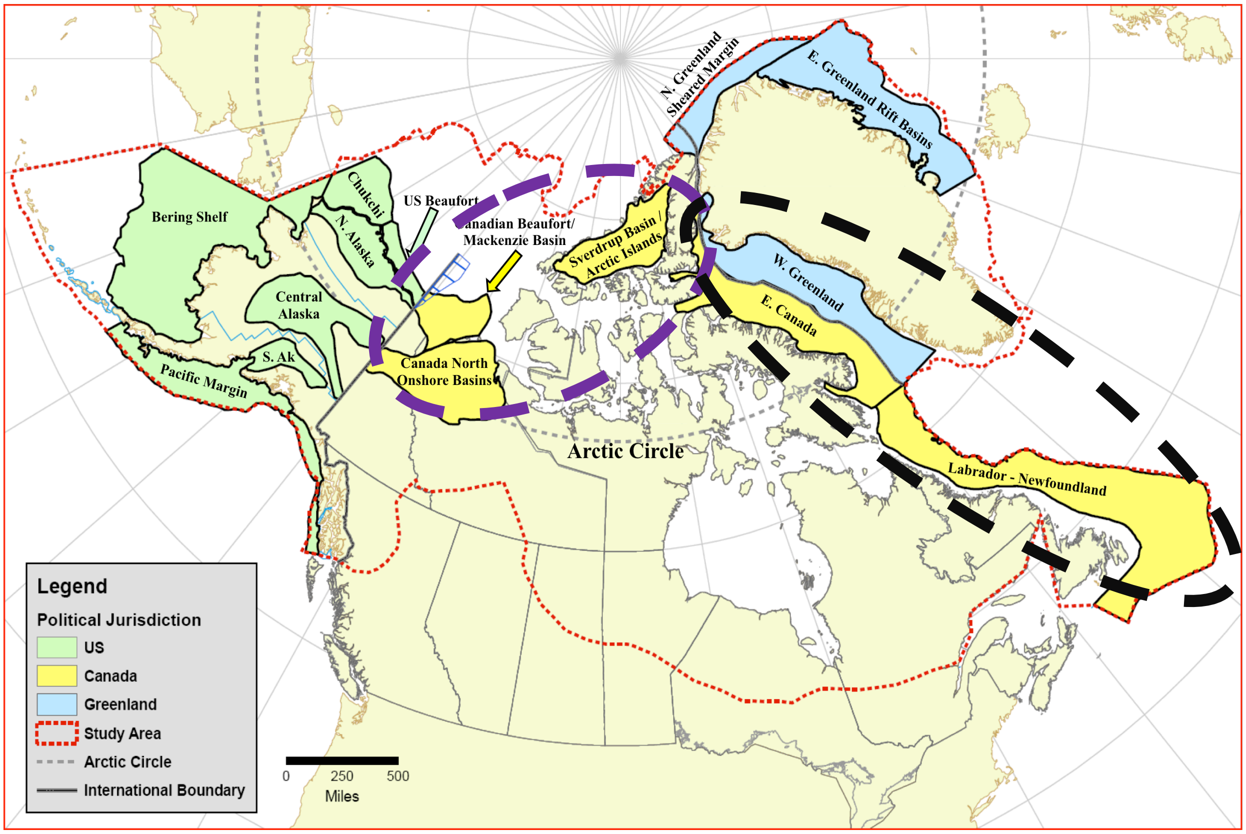

Figure 4.C.1 - Relationship of Arctic Canadian North region (purple dashed outline) and Arctic Canadian East region (black dashed outline) prospective basins (yellow) in relation to Alaska and Greenland.

IV.C.1 Canadian North

The Canadian North region contains the onshore basins in British Columbia, Yukon, Northwest Territories, and Mackenzie Delta region, as well as the offshore Canadian Beaufort Sea area, and the Arctic Islands/Sverdrup Basin region (Figure 4.C.1.1). These regions are managed by several Canadian Government agencies (national and provincial).

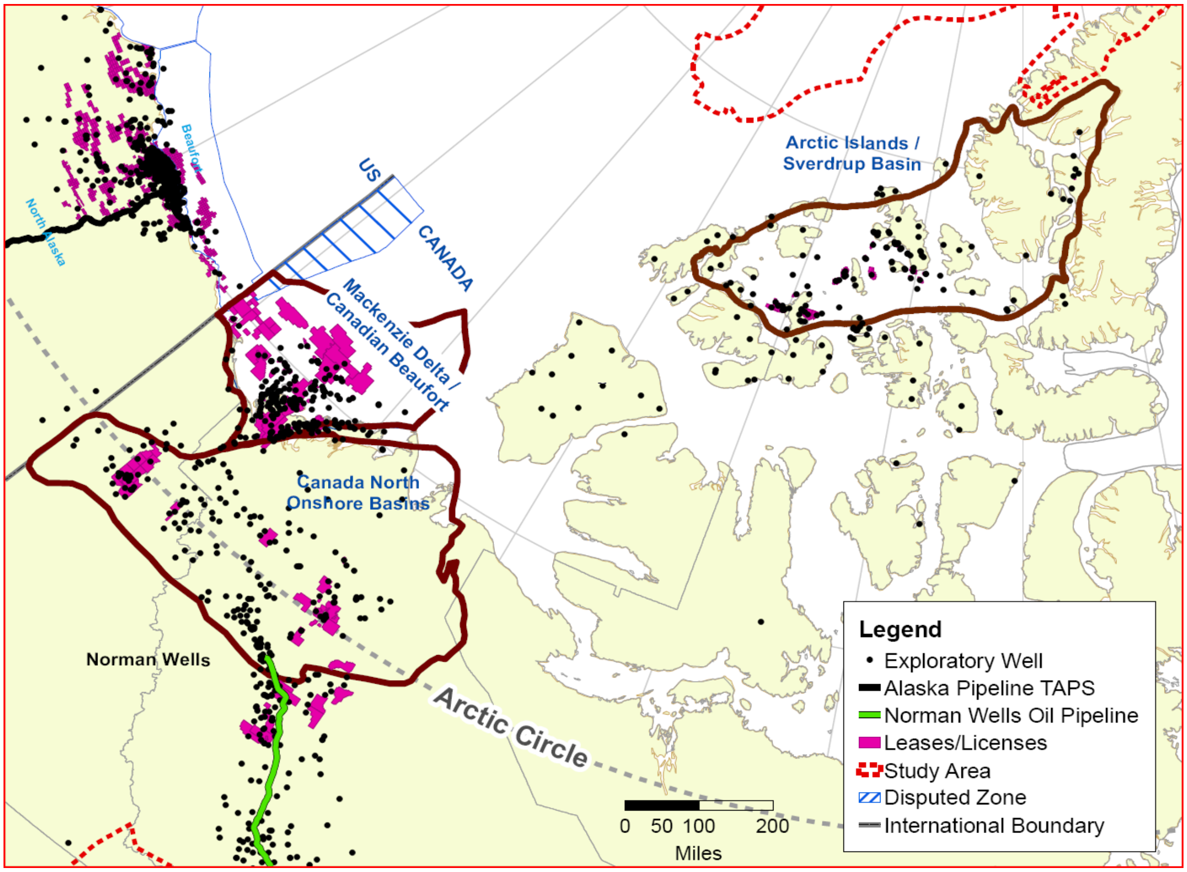

Figure 4.C.1.1 - Canadian North prospective basins with exploration wells and active licenses and the closest pipeline depicted.

Oil and gas exploration has a long history in the Canadian North, dating back to the recognition of oil seeps in the 1700s and the 1920 discovery of the Norman Wells oil field (0.3 Billion barrels oil recoverable). The late 1940s and 1950s saw increased exploration in the southern portion of the Northwest Territories. Exploration then moved northward above the Arctic Circle into the Mackenzie Delta in 1960 (Figure 4.C.1.2), the Arctic Islands and Sverdrup Basin in 1961 and finally the Canadian Beaufort Offshore in 1972. Many significant oil and gas fields (Parsons Lake, Taglu, Niglintgak, Drake Point, Adlartok, Tarsuit, Issungnak, Amauligak, and Kopanoar accumulations) were found. These discoveries were the result of an extensive exploration effort that resulted in 213 wells drilled in the onshore Mackenzie Delta, 174 wells in the Arctic Islands / Sverdrup Basin and 87 wells in the offshore Canadian Beaufort. Drilling activity in these areas subsided in the late 1980s but high global energy prices of 2004-2008 combined with the proven occurrence of oil and gas have renewed industry's interest in this region. Canadian Beaufort licensing rounds in 2007-2010 have had significant industry interest. As a result, six exploration licenses covering 3 million acres were issued to ExxonMobil/Imperial, BP, ConocoPhillips and Chevron for working commitment of $1.89 billion Canadian. Exploration activities commenced in 2008-2009 with the acquisition of 3D seismic and exploratory drilling may commence as soon as 2014.

The NEB estimates the mean, risked, undiscovered, technically recoverable resources for the Canadian North Onshore basins as containing 0.27 Billion barrels oil and 1 TCF gas.[17]

The NEB estimates the mean, risked, undiscovered, technically recoverable resources for the Mackenzie Delta / Canadian Beaufort Basin area as containing 5.7 Billion barrels oil and 52 TCF gas.[17]

The NEB estimates mean, risked, undiscovered, technically recoverable resources for the Arctic Islands/Sverdrup Basin as containing 4.3 Billion barrels oil and 28 TCF gas.[17]

In addition, the USGS has assessed the Canadian Beaufort Outer Continental Slope region (outboard of the Canadian Beaufort and Arctic Islands/Sverdrup Basin areas) and estimates a mean, risked, undiscovered, technically recoverable resources of 2.4 Billion barrels oil, 15.1 TCF gas and 0.15 Billion barrels of natural gas liquids.[8]

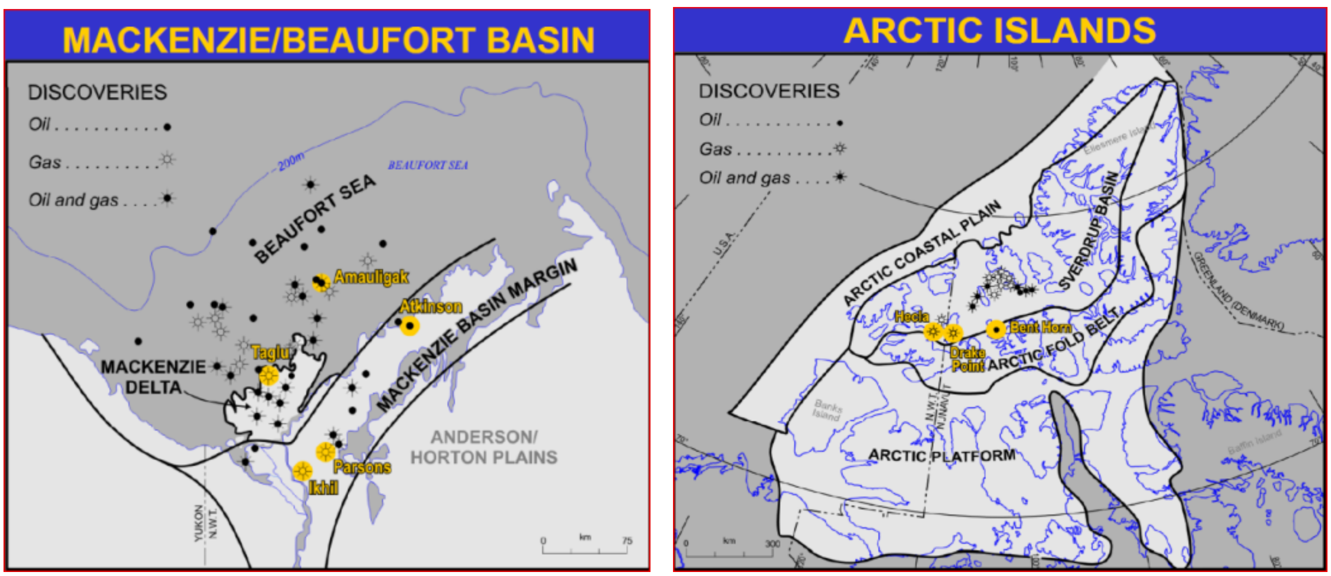

Figure 4.C.1.2 - Exploration wells and results within the Arctic Islands/Sverdrup Basin, and the Mackenzie Delta (onshore)/Canadian Beaufort (offshore) Basin.[18]

IV.C.2 Canadian East

The Canadian East region is divided into the Canadian Baffin Bay area (adjacent to West Greenland) including a large portion of the Nunavut region and the Labrador / Newfoundland Shelf (Figure 4.C.1). The exploration history and reserve potential of the Canadian Baffin Bay region is included in the West Greenland discussion (Section IV.D). The southern limit of the study area excludes the Scotian Shelf (Figure 4.C.2.b.1) and associated developments at Sable Island. Information on the Scotian Shelf, as well as additional discussion on the Labrador / Newfoundland Shelf can be found within the NPC Offshore Subgroup White paper).[19]

IV.C.2.a Canadian Baffin Bay

Discussion of this area can be found within the West Greenland discussion (Section IV.D). For the purpose of this study, we have ascribed 45% of the USGS assessment to the Canadian portion of this region resulting in a mean, risked, undiscovered technical recoverable volume of 4.8 Billion barrels oil, 33.7 TCF gas and 0.7 Billion barrels of natural gas liquids.[20]

IV.C.2.b Labrador-Newfoundland Shelf

The Labrador-Newfoundland Shelf region contains the Saglek, Hopedale, Hawke, Orphan, Jeanne D'Arc and Flemish Pass offshore basins (Figure 4.C.2.b.1). These basins reside along the Continental margin in water depths that range from less than 300 feet to greater than 9800 feet. The exploration in this offshore region commenced in 1966 with the collection of geophysical data. Wildcat drilling started in 1971 and continued through 1984. This collective exploration campaign resulted in numerous gas discoveries along the margin: Bjarni (1973); Gudrid (1974); Snorri (1975); Hopedale (1978); and North Bjarni (1980) (Figure 4.C.2.b.2). Discoveries along the Newfoundland portion of this margin have yielded significant oil and gas reserves in the Jeanne D'Arc Basin including the giant Hibernia Field (1979), as well as the Terra Nova (1983), White Rose (1984) and Hebron-Ben Neviss Fields (1981). Development of the Hibernia Field, as well as the Terra Nova and White Rose fields, has resulted in the cumulative production of over one Billion barrels of oil as of 2009 and development of Hebron-Ben Neviss is planned. [21, 27]

A second wave of exploration licensing and exploratory drilling was kicked off in this region in 2004 in the Flemish Pass and Orphan Basin areas, outboard of the historic discoveries. Several wells have been drilled with an announced discovery in the Flemish Pass area.

The NEB estimates the mean, risked, undiscovered, technically recoverable resources for the Labrador-Newfoundland Shelf area as containing 2.7 Billion barrels oil and 57 TCF gas.[17]

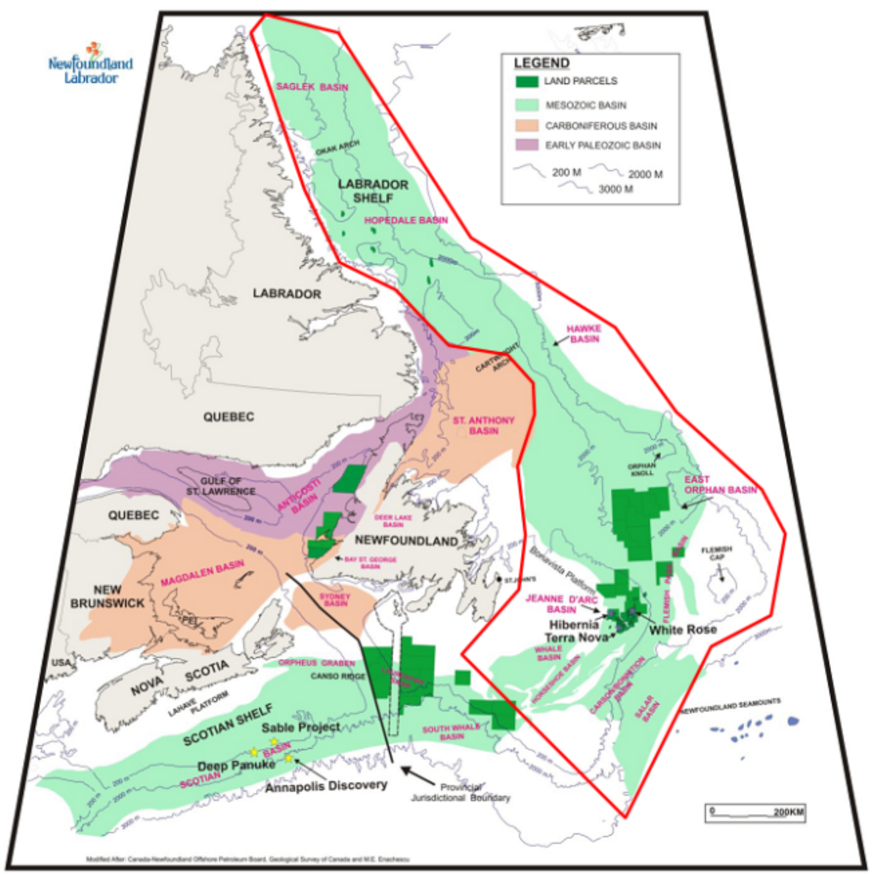

Figure 4.C.2.b.1 - Canadian East area (excluding Canadian Baffin Bay Region) illustrating key basins, offshore licenses and location of Hibernia Field.[22]

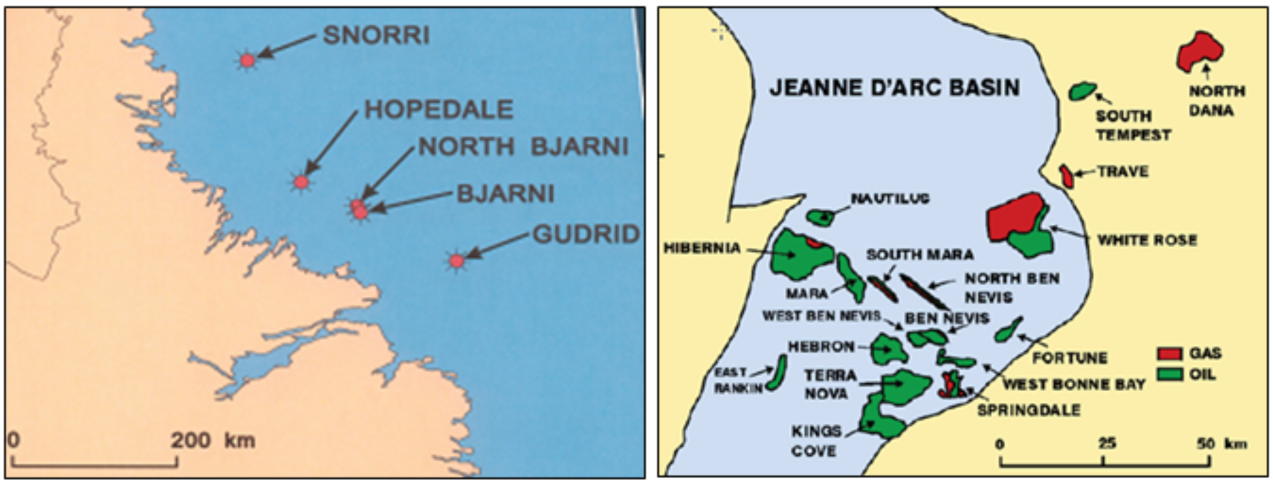

Figure 4.C.2.b.2. - Significant Discoveries on the Offshore Labrador-Newfoundland Shelf region (Saglek, Hopedale and Jeanne D' Arc Basins).[22]

IV.D Greenland

The resource potential for the West Greenland-East Canada Province (Canadian Baffin Bay), North Greenland Sheared Margin Province and the East Greenland Rift Basins Province has been characterized by the USGS (Figure 4.D.1 and 4.D.2).[20, 23, 24] The USGS believes that the majority of conventional oil and gas potential resides immediately offshore basins with very little potential in the adjacent onshore areas. Further, no quantitative assessments have been conducted for the south and southeastern offshore margin of Greenland. The offshore acreage in Greenland is administered by the Greenland Bureau of Minerals and Petroleum.

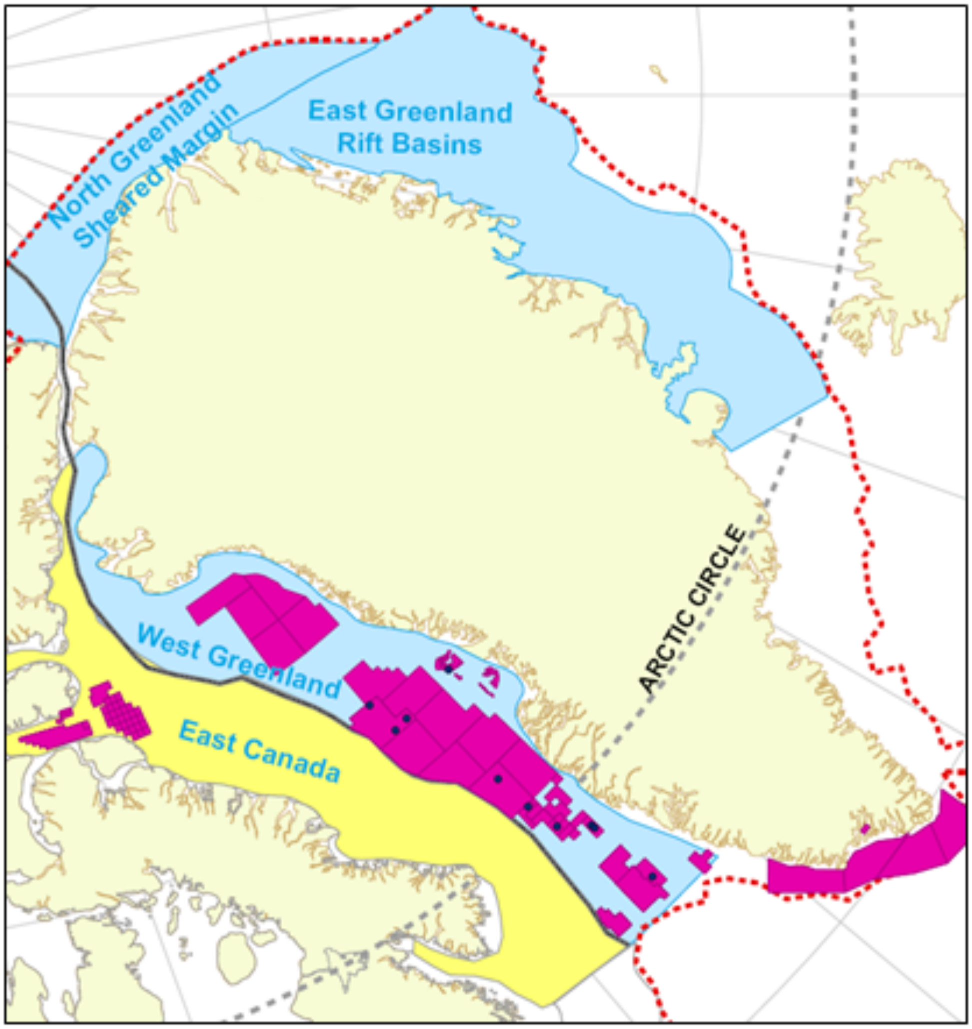

Figure 4.D.1 - Key Greenland Offshore basins (including the Canadian portion of the Baffin Bay area in yellow). Exploration wells (black dots) and active exploration licenses (pink tracts) depicted.

IV.D.1 West Greenland (including the Canadian portion of Baffin Bay)

The West Greenland-East Canada Province primarily describes the offshore region of eastern Canada and western Greenland north of from approximately latitude 63 north to 80 north (Figure 4.D.2). Oil seeps have been sampled and described from Nuussuaq Peninsula, Disko Island and Fossilik outcrops on the west coast of Greenland and also have been reported at Scott Inlet on the Canadian side (Figure 4.D.2). Thirteen exploration wells (3 wells on the Canadian side and 10 wells on the Greenland side) have been drilled in this area and several have demonstrated the presence of thermal hydrocarbons.

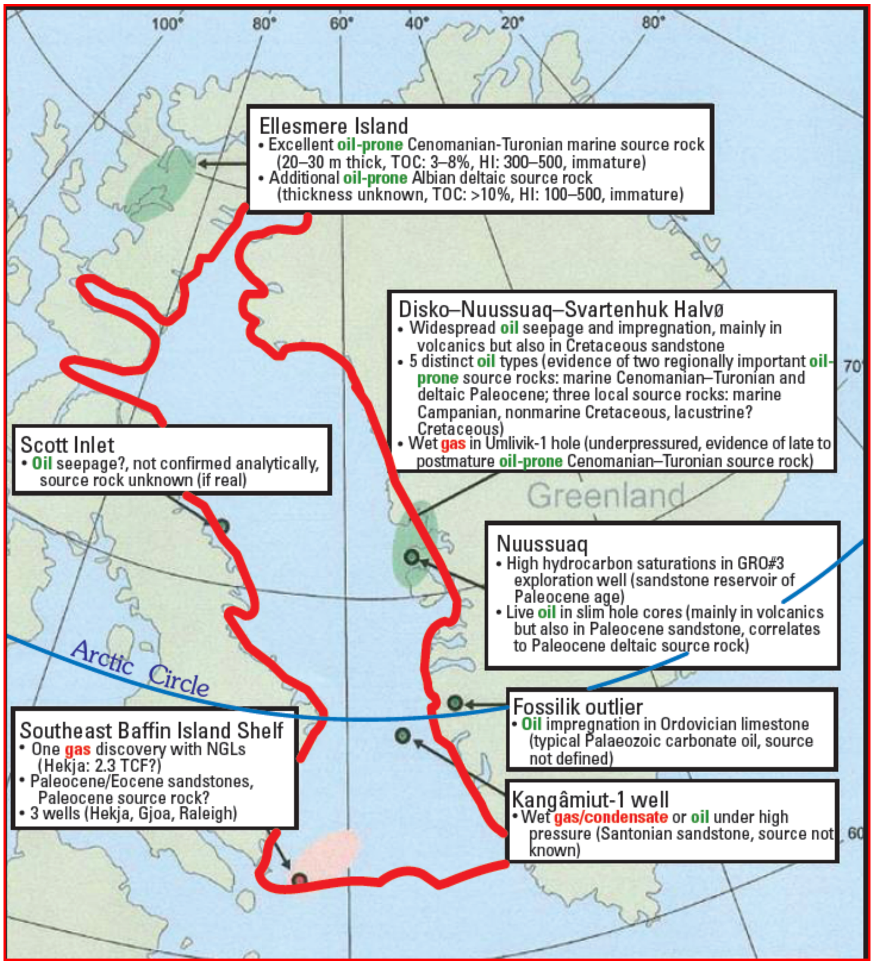

Figure 4.D.2 - Reported hydrocarbon occurrences (exclusive of 2010 Cairn exploration drilling campaign). Red polygon illustrates the West Greenland-East Canada USGS Assessment area.[20]

Licensing of numerous tracts has continued on the Greenland portion of the basin with the most recent licenses being awarded in 2010. Cairn Oil drilled three exploration wells on their offshore licenses in 2010 and announced that two wells had encountered thermal gas and that one well encountered oil.[25] Cairn plans on returning to drill four (4) additional offshore exploration wells in 2011 and also acquire 3D seismic.[26]

The USGS mean, risked, undiscovered technical recoverable volume of 10.7 Billion barrels oil, 74.9 TCF gas and 1.7 Billion barrels of natural gas liquids for this bisected basin.[20] For the purpose of this study, we have ascribed 55% of the assessment to the Greenland portion of this region as follows: a mean, risked, undiscovered, technical recoverable volume of 5.9 Billion barrels oil, 41.2 TCF gas and 0.9 Billion barrels of natural gas liquids.

IV.D.2 North Greenland Sheared Margin Province

The North Greenland Sheared Margin Province characterizes the extreme northern continental margin of Greenland and includes a portion of the North Greenland Platform, North Greenland Foldbelt and Wandel Sea Basin (Figure 4.D.1). No wells have been drilled within this province.

The USGS ascribes a collective mean, risked, undiscovered, technical recoverable volume of 1.35 Billion barrels oil, 10.21 TCF gas and 0.27 Billion barrels of natural gas liquids.[23]

IV.D.3 East Greenland Rift Basins Province

The East Greenland Rift Basin describes the northeast margin of Greenland from approximately latitude 65 north to 85 north (Figure 4.D.1). The basin straddles the coastline with the prospective area lying offshore in the Greenland Sea to the north of the Arctic Circle. No industry exploration wells have been drilled in this province, although several Offshore Drilling Project (ODP) and Deep Sea Drilling Project (DSDP) sites provide some limited shallow "surficial" stratigraphic information in and adjacent to this province. Stratigraphy from onshore outcrops provided by the Geological Survey of Denmark and Greenland (GEUS) was extrapolated offshore, tied to limited offshore 2D seismic data and mapped in the basin. The basin consists of seven subbasins: 1) North Danmarkshavn Salt Basin; 2) South Danmarkshavn Basin; 3) Thetis Basin; 4) Northeast Greenland Volcanic Province; 5) Liverpool Land Basin; 6) Jameson Land Basin; and 7) Jameson Land Basin Subvolcanic Extension. This area is going to be offered in future exploration licensing round scheduled for 2012 and 2013.

The USGS ascribes a total collective mean, risked, undiscovered, technical recoverable volume of 8.9 Billion barrels of oil, 86.2 TCF gas and 8.12 Billion barrels of natural gas liquids for this province.[24]

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V. ALASKA DEVELOPMENT

V.A Introduction

About ten percent of all domestic oil currently produced in the U.S. comes from State-owned lands on the Alaska North Slope (ANS) and the adjacent State waters area, an arctic region with abundant wildlife, fragile tundra, and continuous permafrost. Oil and gas production also occurs in South Alaska in the State-controlled portion of the Cook Inlet Basin (onshore and offshore State waters) which is discussed in Sec V.E. Alaska holds about half of America's remaining proved oil reserves, almost a quarter of its proved natural gas reserves, and over half of its hypothetical coal resources.

> Alaska contains almost 25% of the total U.S. remaining proved oil reserves (5.2 billion barrels/22.3 billion barrels). [1,2]
> Alaska contains 13% of total U.S. remaining proved natural gas reserves (34.8 trillion cubic feet/272.5 trillion cubic feet). [1,2]
> Alaska produces 10% of total U.S. oil production (0.6 million barrels per day/5.4 million barrels per day). It was as high as 25% of the nation's domestic oil production until Prudhoe Bay began to decline in 1988.[3,4]

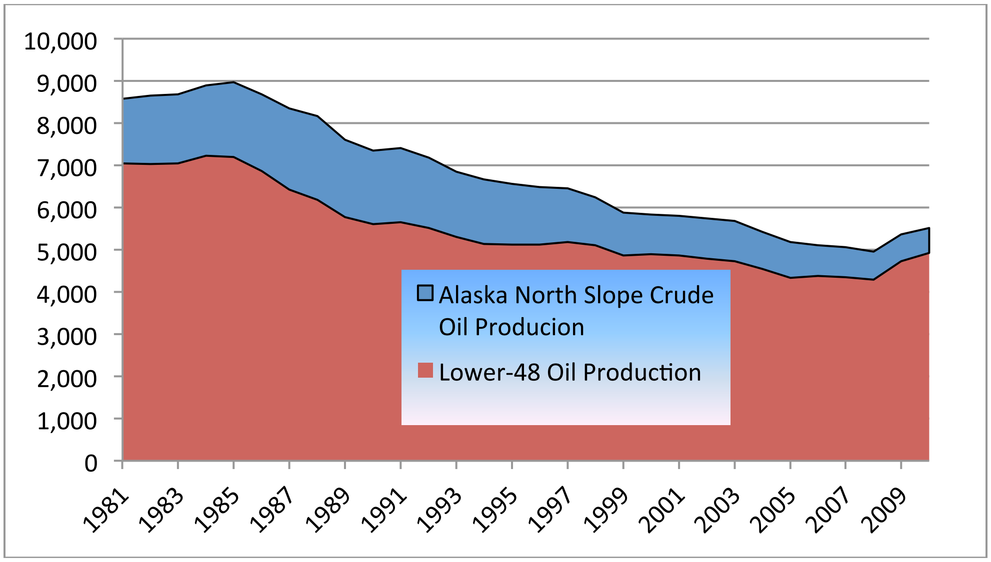

Figure 5.A.1 Lower 48 and Alaska crude oil production (thousands of barrels per day).[3]

As noted in Section IV.B.1, the North Alaska Onshore region is defined as the lands onshore as well as the submerged lands in State waters region north of the Brooks Range (Figures 4.B.1 and 4.B.1.1). The BLM administers the NPR-A and ANWR 1002 Areas, the State of Alaska administers the North Slope Coastal Plain, North Slope Foothills and coastal State submerged land (3 mile area outboard of coastline) areas and the remainder is controlled by the various private Alaskan Native Corporations, the largest of which is the Arctic Slope Regional Corporation (ASRC). The ANS is slightly larger than Minnesota, mostly roadless, and is remote from commercial markets. A significant portion of this subsurface is largely under-explored.

The North Alaska offshore region contains the U.S. Chukchi Sea OCS Area to the west and the Beaufort Sea OCS area to the east and both are thought to be highly prospective. Exploration wells featuring oil and gas discoveries have been drilled in each of these offshore areas (1984 – 2002) and recent Federal Lease Sales (193, 195, & 202) held between 2005 and 2008 have demonstrated industry's renewed interest in these two OCS areas. Industry has recently submitted Plans of Exploration permit applications for exploratory drilling in both the Chukchi and Beaufort seas. The U.S. Chukchi area shares a well-defined border with Russia, while the U.S. Beaufort Sea shares a disputed border with Canada to the east (Figure 5.B.1). The BOEMRE administers the U.S. Chukchi and Beaufort OCS regions. These two OCS areas are largely under-explored.

Other regions in Alaska (Central Alaska onshore, South Alaska Onshore, Bering Shelf OCS and Pacific Margin OCS are deemed to have reduced undiscovered potential, and do not feature proven nor developable reserves with the exception of the State controlled portion of Cook Inlet (as discussed further in Section V.F.1).

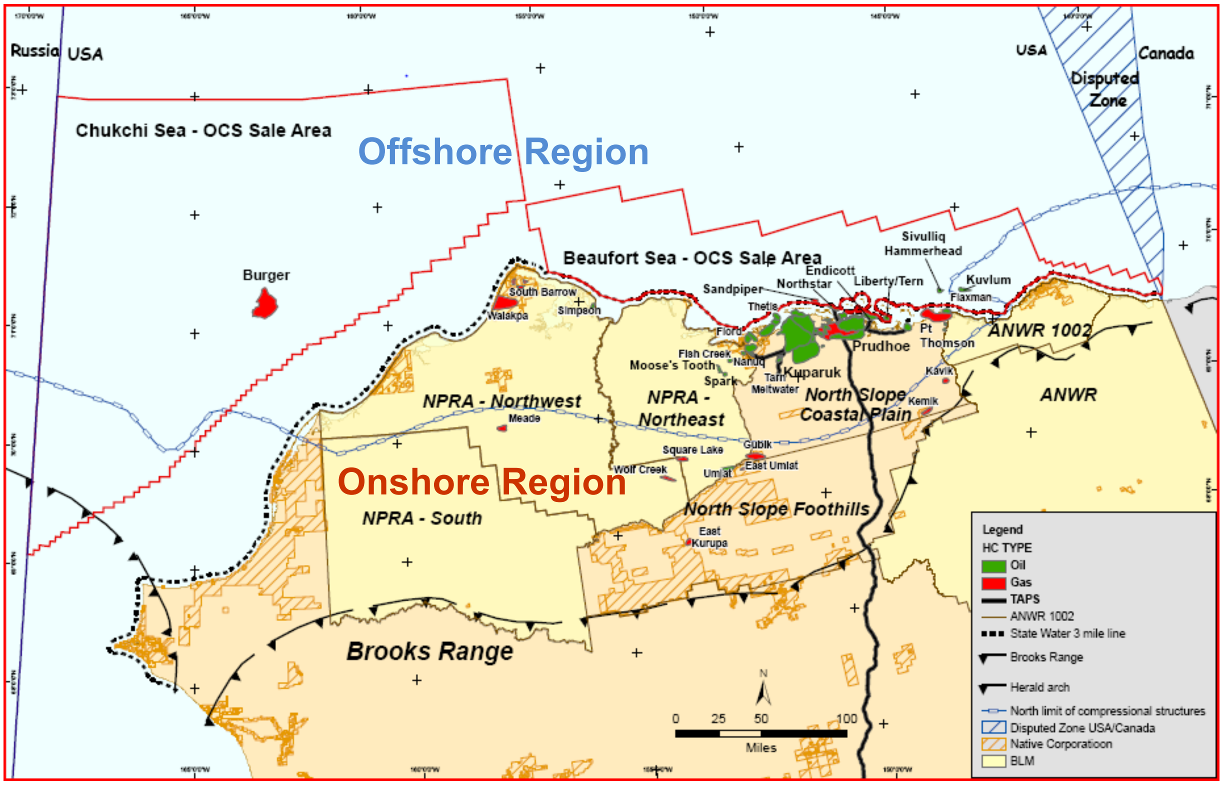

Figure 5.B.1 - North Alaska onshore and offshore regions showing discovered oil and gas accumulations, oil infrastructure, acreage jurisdiction/administrative areas, and international borders.

V.B North Alaska Onshore Region

All oil production in the North Alaska region to date has been from fields in the Central Arctic (Colville-Canning area) on State lands and adjacent waters of the Beaufort Sea (Figures 5.B.1 and 5.B.2) with the exception of the Northstar Unit, which produces from both State and Federal waters in the Beaufort Sea. By the end of 2009, ANS oil fields had produced 16.2 billion barrels of oil, or about 73% of the estimated technically recoverable oil from the currently developed fields. The remaining technically recoverable oil from these producing fields, as well as those undeveloped, "stranded" fields is about 5.2 billion barrels.[4]

Gas production on the ANS is mostly used for field operations. Prudhoe Bay's gas production rate is currently about 7.8 billion cubic feet per day, of which about 7.2 Billion cubic feet per day is reinjected. Natural gas reinjection has had a positive impact on oil recovery efficiency in the Prudhoe Bay Unit (PBU) and in other nearby producing fields. In addition, miscible rich gas injection (MI), using a combination of natural gas and natural gas liquids, has been used effectively for enhanced oil recovery (EOR) processes in Prudhoe Bay, Kuparuk River and Alpine oil fields.

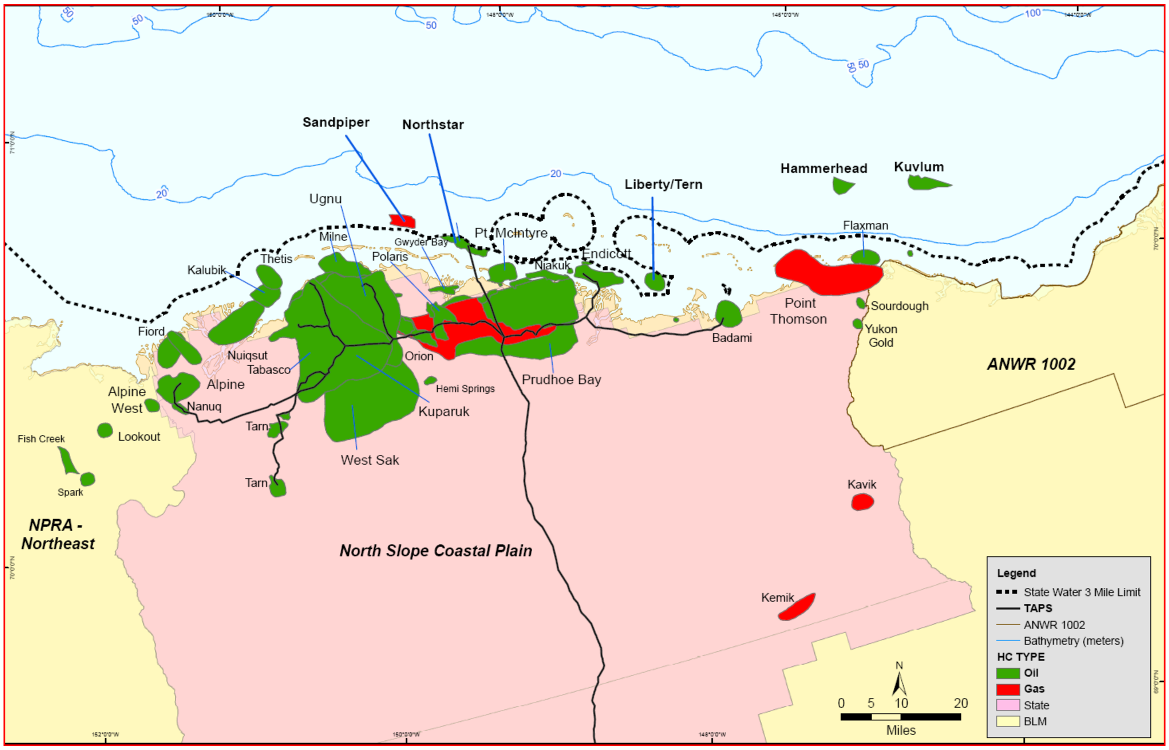

Figure 5.B.2 - Detailed area map of North Alaska including the Alaska State Waters and the Beaufort OCS area illustrating producing fields, oil infrastructure, and undeveloped onshore and offshore discoveries.

Natural gas injection and water flooding are also being used to enhance recovery from the huge viscous, heavy oil resource overlying the Prudhoe Bay, Kuparuk River, and Milne Point field areas. There, a portion of the 25 to 30 billion barrels of original oil in place (OOIP) can be recovered economically when coupled with new technology (multilateral horizontal wells and new completion and production technology).

Enhanced oil recovery using ANS natural gas is expected to continue to be an important and profitable use for natural gas even after an Alaska gas pipeline is constructed to deliver ANS gas to market. Carbon dioxide that must be removed from Prudhoe Bay and Point Thomson natural gas prior to sale is expected to be used for EOR and heavy oil production.

Based on estimated decline rates for oilfield production, flow rates through TAPS would drop below the 200,000-barrel-per-day mechanical limit for the pipeline by 2039, with that date being extended to 2045 if new oil comes online from fields currently being developed or under evaluation (Figure 5.B.3).[4] A shutdown of the pipeline in 2045 would potentially strand about 1 Billion barrels of known oil reserves.[4]

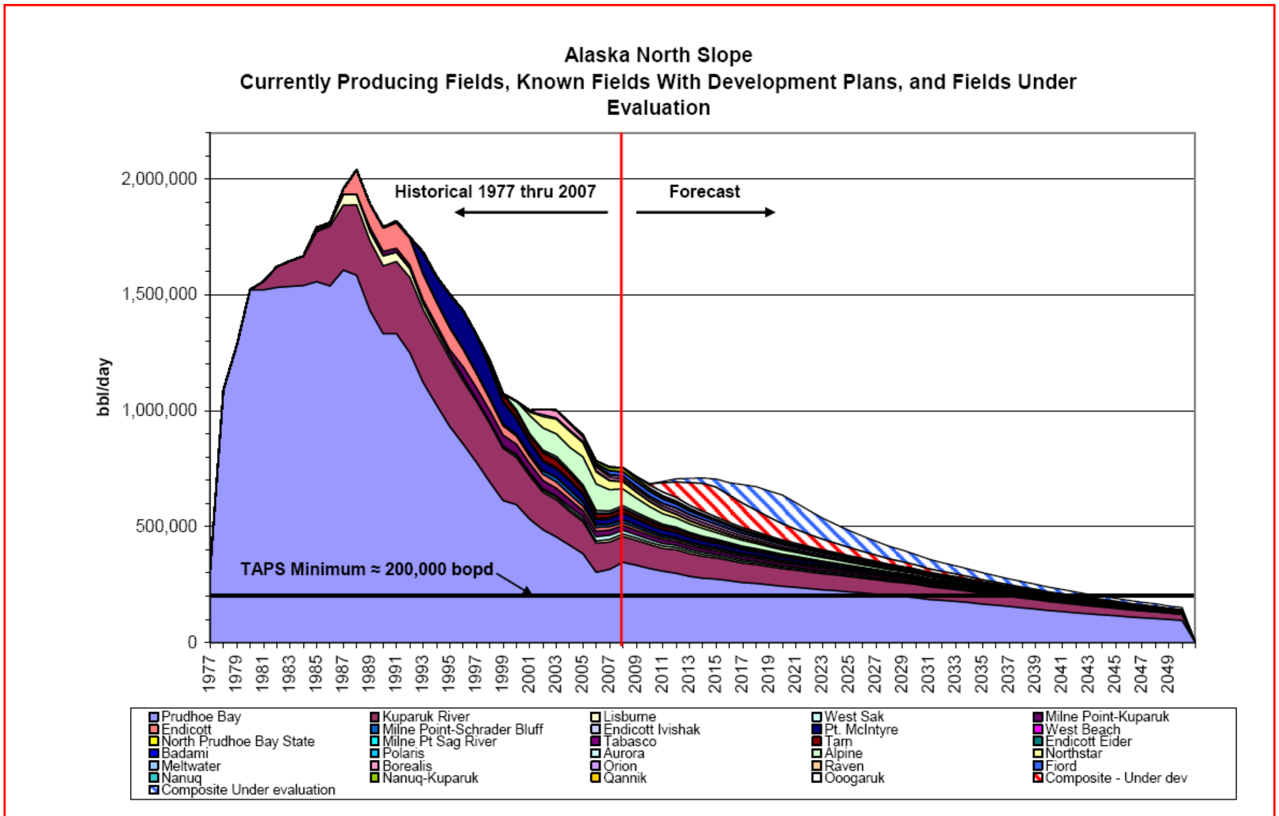

Figure 5.B.3 Alaska North Slope historical and forecast production.[4]

It is not generally recognized that once TAPS operations are discontinued, then the pipeline and associated infrastructure must be removed and the right-of-way remediated (except as otherwise approved in writing by the Pipeline Coordinator), forever removing the possibility of refurbishing and restarting the pipeline.[5]

Exportable hydrocarbon natural gas reserves (produced gas less carbon dioxide - CO_2) and lease use, local sales, and shrinkage) are estimated at 23.7 TCF for the Prudhoe Bay Unit (PBU) and 8 TCF for the Point Thomson Unit (PTU), for a total of 31.8 TCF. A higher recovery factor for PBU and PTU, or additional amounts from other currently producing fields, will be required to provide the total of 35 TCF frequently referred to in discussions of ANS gas reserves.

Natural gas is not currently exported off the North Slope because there is no gas pipeline or tanker capability to transport the gas to markets. Alternatives such as building a gas-to-liquids (GTL) plant, which could convert the natural gas to a higher density liquid product for transport through TAPS, has reportedly been studied, but as recently as 2010 the major energy companies determined that building a natural gas pipeline may provide the most economic method for moving the natural gas to market. Until an export capability is developed, the majority of the gas is re-injected into the producing reservoirs to enhance oil production, or used locally for energy and heating.

Two competing pipeline projects the Alaska Pipeline Project (TransCanada and ExxonMobil) and the Denali Gas Pipeline (ConocoPhillips and BP) held open seasons during 2010 to solicit commitments from gas producers to ship gas on the pipeline (see Section X - Figures 10.A.3 and 10.A.4). On May17, 2011 the group backing the proposed Denali Gas Pipeline project announced that they were "ending their efforts because of a lack of customer support" and that were going to withdraw their pipeline application.[6] In spite of this announcement, the status of the other gas pipeline (the Alaska Pipeline Project) is unknown. If this latter pipeline group has successfully captured an adequate number of subscribers, then project can move into final project design, permitting and construction. It is estimated that the project will take a minimum of 10 years to permit and build, with an estimated cost range of $26 and $42 billion.

A 2009 U.S. Energy Information Administration (EIA) report titled "Crude Oil Production"[3] estimates that the negative impact of natural gas sales on crude oil production should be minimal since, by the time the pipeline is constructed, approximately 85 percent of the original oil in place will have been produced.

Building a pipeline to Valdez, and then processing the North Slope gas for liquefied natural gas (LNG) export has also been examined; indeed, the TransCanada/ExxonMobil pipeline project (Figure 10.A.4) includes "the LNG" option as an alternative to completing the pipeline to Edmonton (Figure 10.A.3). TransCanada added the option to meet the needs of potential Asian markets and the Alaskan Gasline Port Authority, who teamed up with Japan's Mitsubishi Corporation for the continued investigation of this option.[7]

In the "*2011 Annual Energy Outlook"*[2], the EIA assumes that the Alaska natural gas pipeline is uneconomical in its reference case, and therefore will not be built, and does not contemplate a GTL scenario. Reasons given by EIA for removing Alaska natural gas from their reference case are; 1) the increased cost estimates for building the pipeline; and 2) the lower gas prices as a result of abundant natural gas available from the unconventional plays in non-Arctic Canada and the LWR 48 (shale gas and tight gas sand plays).

Even if the Alaska Natural Gas Pipeline moves forward, it most likely will not be ready for first gas until 2020 at the earliest.[8] Regardless of whether or not the Alaska Natural Gas pipeline is built near-term emphasis on the North Slope will be focused on oil development.

V.C North Alaska Offshore Region

There is currently no production from the Federal waters of the Beaufort except for the Northstar field which straddles State and Federal waters (previously discussed in Section IV.B.2). Northstar had produced 0.122 Billion barrels oil as of January 1, 2008 and has an estimated ultimate recovery of 0.210 Billion barrels oil.[4]

Currently there are five discovered fields contained within the Federal portion of the offshore, four in the Beaufort[9] and one in the Chukchi[10] that are undeveloped, in part, due to the distance to established infrastructure. BP is considering plans to drill extended reach development wells from their "onshore" Endicott field to their nearby Liberty field (0.15 Billion barrels oil recoverable) [4] which resides offshore in Federal waters (Figure 5.B.2). The Sivulliq field with ~0.200 Billion barrels[4], the Kuvlum field with 0.400 Billion barrels[4] and the 0.150 Billion barrel Sandpiper field[4] are current examples of stranded oil due to economic viability.[11] All of these will require new infrastructure (development platforms and pipelines) to enable production and tie-backs into TAPS. The Burger discovery in the Chukchi Sea to the west is believed to contain significant volumes of gas and condensate (Figure 5.B.1). The BOEMRE[9] has described the Burger structure as having a mean most likely gas resource of 14 TCF gas and a mean most likely condensate resource of 0.72 Billion barrels natural gas liquids based on the discovery by Shell Western Exploration and Production Inc. et al.'s OCS-Y-1413 #1 well that was drilled over two seasons in 1989 and 1990. At the present time, any discovery in the adjacent Chukchi Sea would require a new 60-mile (minimum distance) subsea pipeline to shore as well as a new 200-mile onshore pipeline across the NPR-A to be built to enable oil production into the existing TAPS infrastructure. In addition to a multi-billion dollar infrastructure addition, the timeline is estimated to add 10 to 15 years to the delivery of any oil and/or gas found in the Chukchi.[12]

In the offshore Chukchi and Beaufort Sea OCS areas the regulatory environment is very complex and subject to frequent changes from new regulations. Permits for most lease activities are required from numerous Federal and State of Alaska agencies which lack a coordinated collective review process and in turn stymie the timely assessment of oil and gas resources. Repeated attempts by Shell to conduct exploratory drilling in the Beaufort and Chukchi Seas have been held up since 2007 due to permit delays, litigation against the Federal Government for lack of scientific due diligence, and Presidential moratoriums (2010 post-Deepwater Horizon incident in Gulf of Mexico). Currently all future lease sales in the Chukchi Sea and Beaufort Seas under the 2007-2012 Five Year Program have been cancelled by the Department of Interior.

V.D Central Alaska Onshore and Bering Shelf Offshore Areas

There have been no significant discoveries of hydrocarbons and there has been no commercial development of oil or gas from either the Central Alaska onshore basins or the Bering Shelf Federal offshore areas, as previously described in Sections IV.B.2.c.1 and IV.B.2.c.2.a. Although the undiscovered potential of these two regions is small (Figures 4.A.1, 4.A.2, 4.A.3, 4.A.4 and 4.B.2.a.1, and Table 4.A) both regions are significantly underexplored.

V.E South Alaska Onshore, Pacific Margin Offshore Areas and Alaska State Waters Cook Inlet

This large region has been explored off and on since the early 1900's with limited development, as described in Sections IV.B.2.c.1and IV.B.2.c.2.b of this report, other than the State controlled portion of the Cook Inlet Basin (onshore and offshore). The undiscovered potential of these region is small (Figures 4.A.3, and 4.A.4, and Table 4.A) and there appears to be little industry interest in conducting renewed exploration and development activity in this region, with the exception of the State of Alaska's portion of the Cook Inlet Basin as described below.

V.F.1 Cook Inlet Basin (State of Alaska onshore and offshore area)

All modern oil and gas production has been the result of exploration and development activities in the Cook Inlet basin since the late 1950s with the onset significant production from the offshore starting in the 1960s. This region has produced 1.338 Billion barrels of oil and 7.769 TCF of natural gas, as of January 2010. Exploration in the Cook Inlet Basin has been sporadic since 1968, as industry shifted its focus following the giant discovery at Prudhoe Bay and the identification of other giant prospects in the expansive North Alaska region. Thus, the existing Cook Inlet oil and gas fields are largely depleted and production is waning (Figures 5.F.1 and 5.F.2). Oil production peaked in 1970 at 227,000 barrels per day, and gas production peaked in 1998 with the production of 0.22 TCF per year.[13] The average production in 2009 was just over 7,500 barrels of oil per day (2.7 Million barrels per year) and about 380 Million cubic feet of gas per day (138.6 Billion cubic feet per year).

The historic oil production has been used to power the Alaskan local marketplace. On the other hand, the extensive historic gas production has not only been utilized to provide energy and heating to Alaskans, it has also been: 1) converted to fertilizer; and 2) converted to LNG and exported to Japan. These two latter uses have been terminated in the last few years, as the basin's dwindling gas production resource has been targeted to maintain critical energy and heating demand within south and central Alaska. This region of Alaska will need to start importing natural gas in the near future if new local supplies are not forthcoming. The State of Alaska Division of Oil and Gas estimates the proven producible remaining reserves to only be an additional 0.034 Billion barrels of oil and 1.495 TCF of natural gas.[13]

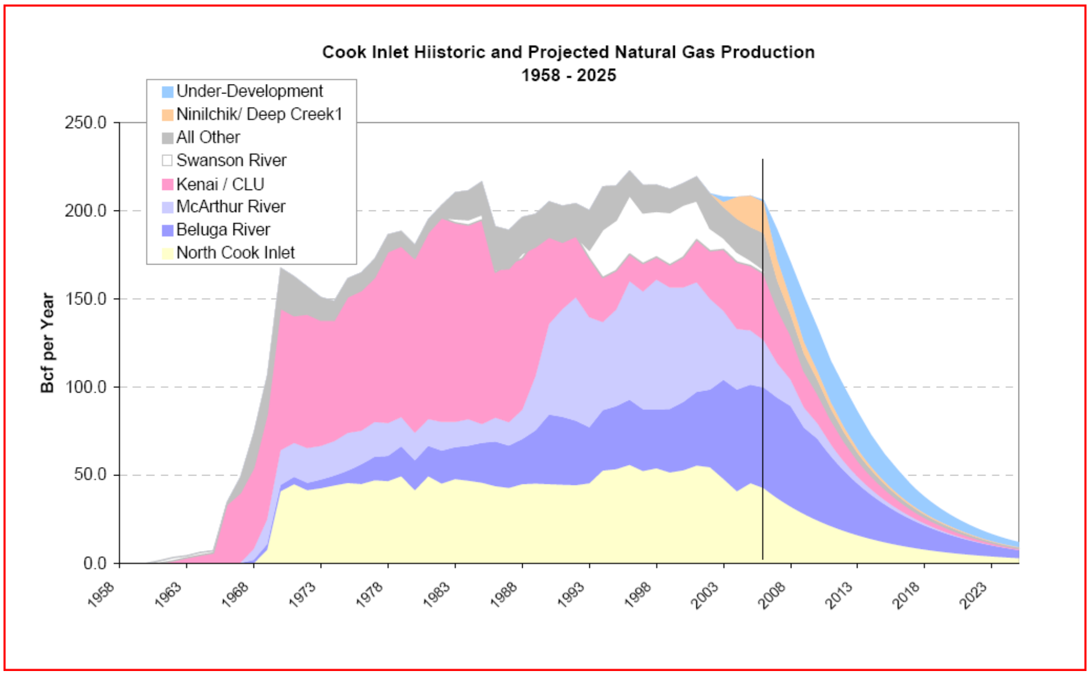

Figure 5.F.1 - Cook Inlet Basin, Natural Gas production (Historic and Projected) Alaska Division of Oil and Natural Gas Annual Report, 2006. [13]

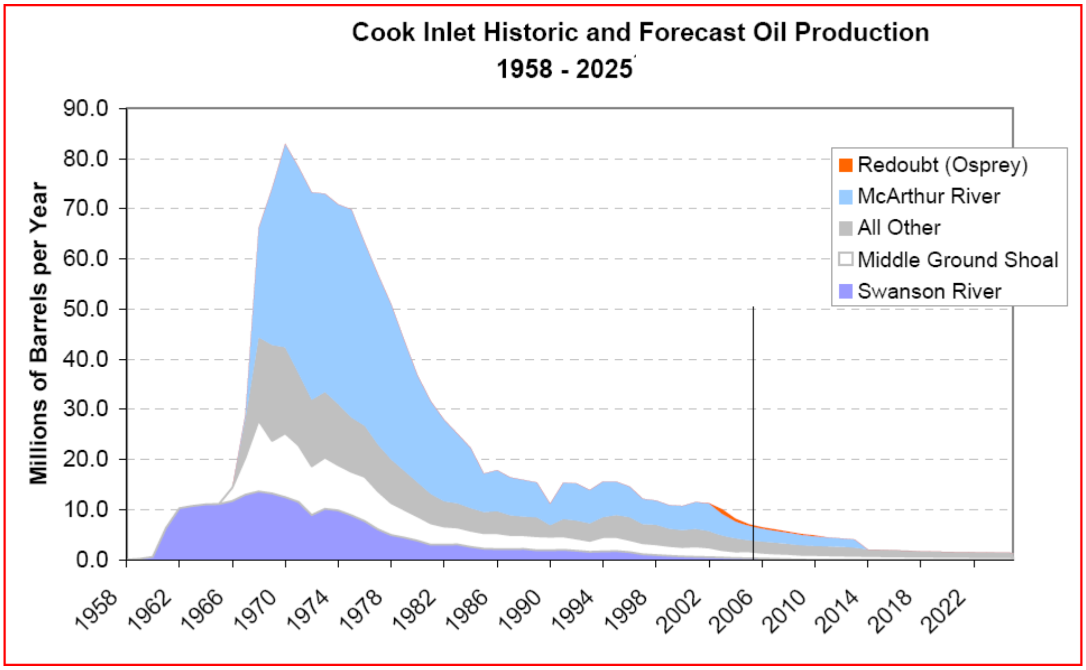

Figure 5.F.2 - Cook Inlet Basin, Oil production (Historic and Projected) Alaska Division of Oil and Natural Gas Annual Report, 2006. [13]

As previously discussed in Section IV.B.2.c.1, Cook Inlet basin is generally looked upon as a mature province and is expected to contain mean, risked, undiscovered, technically recoverable resources of 0.7 Billion barrels oil and 25 TCF gas.[1] This undiscovered potential, coupled with south and central Alaska's near-term energy needs, is starting to rekindle the concept of exploration and appraisal drilling for these additional reserves. These additional unproven reserves will be found in a variety of hard-to-image, structural and stratigraphic traps that will require the application of the newer technologies (3D seismic, multilateral and/or horizontal drilling, etc.).

The possible magnitude of potentially recoverable, undiscovered, conventional and unconventional natural gas is impressive, but it is encumbered with constraints and limits on industry's ability or willingness to explore and develop its fullest potential. Factors that may serve to preclude development of all or a significant portion of this potential resource include: 1) the cost of exploration and development activities in Cook Inlet and surrounding areas; 2) development and utilization of technology that will facilitate exploration for accumulations and reduce drilling problems; 3) accessibility of lands (waters) that may hold a major portion of these undiscovered reserves; and 4) development of unconventional sources or supplies such as coal bed methane, underground coal gasification, and coal-to-liquids.

Enabling technology such as 3D seismic acquisition and extended-reach drilling could help unlock the perceived undiscovered oil and gas resources, but their use will be tempered by the scale and cost of such programs. Although 3D seismic acquisition is difficult in this basin (extreme daily tidal flux in the offshore region and rapidly varying topographic/geographic conditions in the onshore region that ranges from marsh to mountainous), it has been applied in a limited fashion. Offshore exploration drilling rigs (such as Arctic Class Jackup rigs) will need to be brought back into the basin to drill the new traps (if they are revealed by the 3D seismic). No such exploration rigs currently reside in the Cook Inlet Basin, but several operators are discussing the possibility of mobilizing one of these rigs from the Gulf of Mexico to Alaska. Once new commercial accumulations are discovered, new bottom-founded development and production platforms capable of utilizing extended-reach drilling techniques will need to be built, and then brought into and deployed in the basin.

V.G Pacific Margin Offshore Area

There have been no significant discoveries of hydrocarbons and there has been no commercial development of Pacific Margin Federal offshore area. Although the undiscovered potential of this region is small (Figures 4.A.1, 4.A.2, 4.A.3, 4.A.4 and 4.B.2.a.1, Table 4.A) it is significantly underexplored.

V.H Cited Literature

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[2] EIA, Annual Energy Outlook 2011

[3] "Crude Oil Production", EIA, Dec 2009. http://www.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm

[4] Thomas *et al*, "Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline? Addendum Report", 267p, U.S. DOE/NETL/Arctic Energy Office, April 2009.

[5] "Right –of-Way Lease for the Trans-Alaska Pipeline between The State of Alaska and Amerada Hess Corporation, ARCO Pipeline Company, Exxon Pipeline Company, Mobil Alaska Pipeline Company, Phillips Petroleum Company, Sohio Pipe Line Company, and Union Alaska Pipeline Company"; Section 1.10.1., p. A-16; Aug 27, 1970. (See Also Alaska Statute 38.35.120(d))

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[9] Sherwood, K.W., ed., 1998, Undiscovered Oil and Gas Resources, Alaska Federal Offshore (As of January 1995), U.S. Minerals Management Service, OCS Monograph MMS 98-0054, p. 528

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VI. CANADIAN DEVELOPMENT

VI.A Arctic Introduction

Newfoundland and Labrador manage the rights through the Canada Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) which is also the local regulator.[1] The Government of Yukon manages the rights on land in the Yukon Territory in cooperation with local aboriginal groups.[2] The offshore rights are managed by the Federal Government in cooperation with the Government of Yukon under a December 2008 Memorandum of Understanding (MOU) and in cooperation with the Inuvialuit (local aboriginal group that are a key stakeholder in the northern region of the Northwest Territories (NWT)). Offshore Aboriginal Affairs and Northern Development Canada (AANDA), previously known as Indian and Northern Affairs (INAC)[3] manage the licenses and the NEB is the regulator.[4] In Nunavut and the Northwest Territories (NWT) AANDA manage the licenses on Federal land, while the local aboriginal groups manage their own land and NEB is the regulator. The offshore licenses are managed by AANDA and NEB is the regulator (Figure 6.A.1).

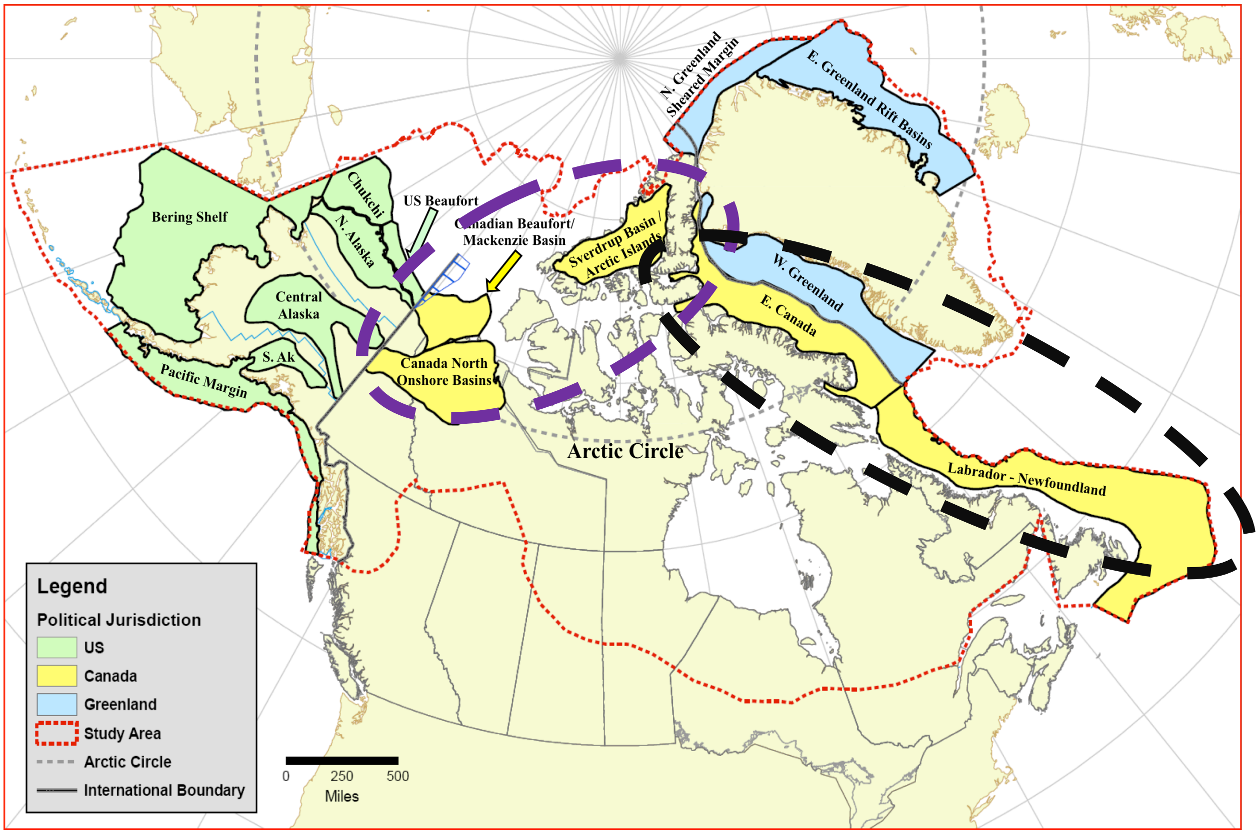

Figure 6.A.1 - Relationship of Arctic Canadian North region (purple dashed outline) and Arctic Canadian East region (black dashed outline) prospective basins (yellow) in relation to Alaska and Greenland.

VI.B Canadian North Onshore Basins

Potential in this general region was recognized early on as oil seeps had been reported by aboriginal people, explorers and traders along the Mackenzie River in the Northwest Territories (NWT) since the 1700s. Early exploratory drilling in 1920 by Imperial Oil yielded the discovery of Norman Wells Field (0.3 Billion barrels oil ultimately recoverable). Because of the remoteness of the discovery only 9 wells were drilled before 1940 feeding a small scale refinery that supplied the north and local mining industry. Large scale development did not take place before 1942 when the field was developed to help support the U.S. and Canadian war efforts (the Canol Road pipeline that ran from Norman Wells to a refinery in Whitehorse, Yukon). A modern pipeline was built in 1985 to bring the oil south to Alberta for access to major markets (Figure 4.C.1.1).

As of March, 2011 a total of 1,266,179 Hectares (3,128,797 Acres) have been leased for work commitments of $145 million on land in the Central Mackenzie Valley region. A new licensing round for 11 leases in the Norman Wells area, covering a total of 897,888 Hectares (2,218,730 Acres) closed in June 2011. AANDA does a call for nominations every year and if industry nominates land a licensing round follows.

Yukon currently has 17 existing Exploration Licenses (16 at Eagle Plains and 1 on the Beaufort Sea shore) that cover almost 1.4 million acres (565,000 hectares). They issue a call for nominations every year and if industry nominates, than a licensing round follows.

These onshore regions have seen several waves of exploration since the discovery of Norman Wells. This effort has demonstrated a working petroleum system (0.3 Billion barrels oil and 1 TCF gas)[11] but has failed to uncover commercial reserves that would justify extension of the existing pipeline network.

VI.B.1 Mackenzie Delta/Beaufort Sea

The exploration activity moved north into the Mackenzie Delta around 1960. A total of 40 Significant Discovery Licenses (SDL) covering 137,532 Hectares (339,839 Acres) have been granted in the Mackenzie Delta (Figure 4.C.1.1).

Offshore drilling in the Canadian Beaufort started in 1972 from artificial islands built in shallow water depths, and continued in 1978 from drill ships, in 1981 from gravity based structures and finally from floating drilling platforms in 1983 (Figure 6.B.1.1). A total of 38 Significant Discovery Licenses (SDL) covering 205,636 Hectares (508,138 Acres) have been granted in the Beaufort Sea.

The NEB reports that 1 Billion barrels oil and 9 TCF gas have been discovered in this collective region.[11]

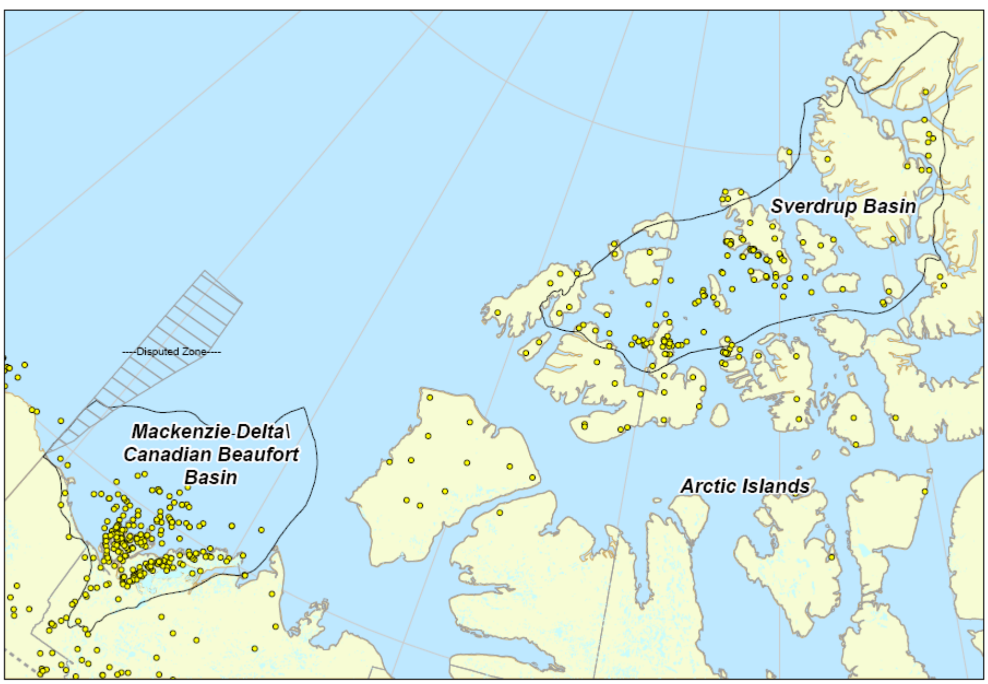

Figure 6.B.1.1 - Location map of Mackenzie Delta/Canadian Beaufort Sea Basin, as well as the Sverdrup Basin and Arctic Islands regions. Note exploration wells depicted by yellow circles.

In spite of the number of discoveries, the initial wave of exploratory drilling came to a halt in the late 1980s. Further, none of the discoveries have been developed, as they tend to have a high gas mix and are remote from existing pipelines and consumer markets. Nonetheless, the recent global demand for oil linked to higher prices, coupled with relatively open access to large acreage tracts within a proven petroleum province has spurred renewed interest in this region. This is reflected by the upswing in recent exploration activity in both the onshore and offshore areas:

- Devon's Paktoa 240 million barrel offshore oil discovery (drilled in 2005-2006).[15]
- BP/Chevron/MGM drilled 9 wells onshore in 2007 to 2009.
- Recent offshore License Rounds both onshore and offshore resulting in licenses being taken in water depths ranging from 40 – 1500 meters.
- Modern 2D and 3D acquisition both onshore and offshore; ExxonMobil/Imperial offshore 3D 2008, BP offshore 3D 2009, GXT-Ion Multi-Client ArcticSPAN offshore 2D and Ocean Bottom Cable (OBC) still ongoing since the start in 2006, MGM Energy land 2D and 3D since 2007.
- Pending plans to drill by Imperial/ExxonMobil, BP and Chevron. Imperial Oil/ExxonMobil was planning to start drilling in 2013 and BP was planning to start in 2014. These plans have been put on hold as the NEB is reviewing their current Arctic drilling regulations, thus it is not expected that drilling activity will start before 2014 at the earliest.

As of March 2011 a total of 2,518,987 Hectares (6,224,553 Acres) have been leased for work commitments of $2.11 billion. A new licensing round for 3 leases, 2 in the Beaufort Sea and 1 in Ballantyne Strait, covering a total of 386,267 Hectares (954,487 Acres) has just been completed. AANDA does a call for nominations every year and if industry nominates land a licensing round follows.

As previously discussed in Section IV, the western boundary between Canada and the U.S. in the Beaufort Sea is disputed (Fig. 6.B.1.1). This disputed offshore region is contains some very large prospects and resolution of this international boundary issue might enable future licensing/lease sales to occur in this prospective area.

VI.B.2 Arctic Islands-Sverdrup Basin

Exploration activity gained traction in the Arctic Islands/Sverdrup Basin area when the initial well was spud by Dome Petroleum in 1961. Drilling took off in 1968 with the formation of Panarctic Oils, which was a partnership between industry and the Government of Canada (the government held 45% of the company and assumed operatorship) that resulted in the first major discovery at Drake Point (5.4 TCF of recoverable gas) in 1969. The initial wave of exploration came to a halt around 1986 and saw 174 exploratory wells drilled both onshore and offshore (Figure 6.B.1.1), as well as the collection of 2D seismic data in this remote area. This exploration effort resulted in the awarding of 19 SDL's with 14 of the 19 discoveries occurring in the offshore (Figure 4.C.1.1). These 19 SDL's contain a collective discovered, unproduced, recoverable volume of 0.4 Billion barrels oil and 12 TCF gas.[11]

A total of 19 SDL's (plus a Production License for the Bent Horn discovery in the Franklin Fold Belt) covering 332,882 Hectares (822,569 Acres) have been granted in the Sverdrup Basin.

VI.C Canadian East Offshore Region (Eastern Canada Offshore)

Since exploration started in 1966 a total of 366 wells have been drilled in the Eastern Canadian Offshore region (East Canada "Baffin Bay" and the Labrador/Newfoundland continental shelf area). Numerous gas and oil accumulations (2 Billion barrels oil and 9 TCF gas)[11] have been discovered (Figures 4.C.2.b.1, 4.C.2.b.2 and 4.D.2) and have resulted in 50 Significant Discovery Licenses (SDL) covering 184,002 Hectares or (454,679 Acres) and 8 Production Licenses (PL) covering 45,705 Hectares (112,940 Acres).

The collective region has produced 1.2 Billion barrels of oil and 1.6 TCF of gas (Figure 6.C.1). None of the gas has been commercially produced, and almost all of the associated gas has been re-injected for pressure support in producing oil reservoirs.[7]

WELL EVALUATION, OPERATIONS AND RESOURCE ASSESSMENTS

The C-NLOPB's most recent reserve/resource estimate and production totals are provided in Table 5.

Table 5 Petroleum Reserves[1] and Resources[2] Newfoundland and Labrador Offshore Area

Field	Oil		Gas	NGLs[3]
	Originally in place **MMbbls[5]**	Produced[4] MMbbls	BCF[6]	MMbbls
Grand Banks				
Hibernia	1244	680.18	1796	202
Terra Nova	419	294.30	53	4
White Rose	305	141.93	3023	96
North Amethyst	68		315	-
Hebron	581		-	-
Ben Nevis	114		429	30
West Ben Nevis	36		-	-
West Bonne Bay	36		-	-
Mara	23		-	-
North Ben Nevis	18		116	4
Springdale	14		238	-
Nautilus	13		-	-
King's Cove	10		-	-
South Tempest	8		-	-
East Rankin	7		-	-
Fortune	6		-	-
South Mara	4		144	8
North Dana	-		472	11
Trave	-		30	1
Subtotal	2906		6616	356
Labrador Shelf				
North Bjarni	-		2247	82
Gudrid	-		924	6
Bjarni	-		863	31
Hopedale	-		105	2
Snorri	-		105	2
Subtotal	0		4244	123
Total	2906		10860	479
Produced		1116.41	0	0
Remaining	1790		10860	479

[1] "Reserves" are volumes of hydrocarbons proven by drilling, testing and interpretation of geological, geophysical and engineering data, that are considered to be recoverable using current technology and under present and anticipated economic conditions. The Hibernia field oil reserves include the Ben Nevis/Avalon and Hibernia reservoirs. The Terra Nova field oil reserves are producing from the Jeanne d'Arc reservoir. The White Rose field oil reserves consist of the Ben Nevis/Avalon and Hibernia reservoirs. The North Amethyst field oil reserves consist of the Ben Nevis/Avalon reservoir.

[2] "Resources" are volumes of hydrocarbons, expressed at 50% probability of occurrence, assessed to be technically recoverable that have not been delineated and have unknown economic viability. Resources in the Jeanne d'Arc basin include all other oil reservoirs not listed in the reserves section, gas volumes and natural gas liquids.

[3] Natural gas liquids (NGLs) are derived from natural gas, which is the portion of petroleum that exists in either the gaseous phase or in solution in crude oil in natural underground reservoirs.

[4] Produced oil reserves also include a small quantity of NGLs. Produced volumes as of March 31, 2010.

[5] MMbbls = million barrels.

[6] BCF = billion cubic feet.

Figure 6.C.1 - C-NLOPB's resource estimate and production totals for the Grand Banks and Labrador Continental Shelf Offshore Region, east Canada.[7]

VI.D Canadian East Development and Renewed Exploration

The Labrador/Newfoundland region collectively produces about 340,000 barrels of crude oil per day, or about 12.5% of Canada's total crude oil production. Although over 300 exploration wells have been drilled offshore Labrador/Newfoundland, only 24 have resulted in hydrocarbon discoveries, and most of these are concentrated in the Jeanne D' Arc Basin of the Grand Banks region offshore Newfoundland. Three of these fields have been developed and are currently producing (Figures 6.C.1 and 6.D.2). These are Hibernia, Terra Nova and White Rose. Development of a fourth major field complex, Hebron-Ben Nevis, is planned in the near future. [13]

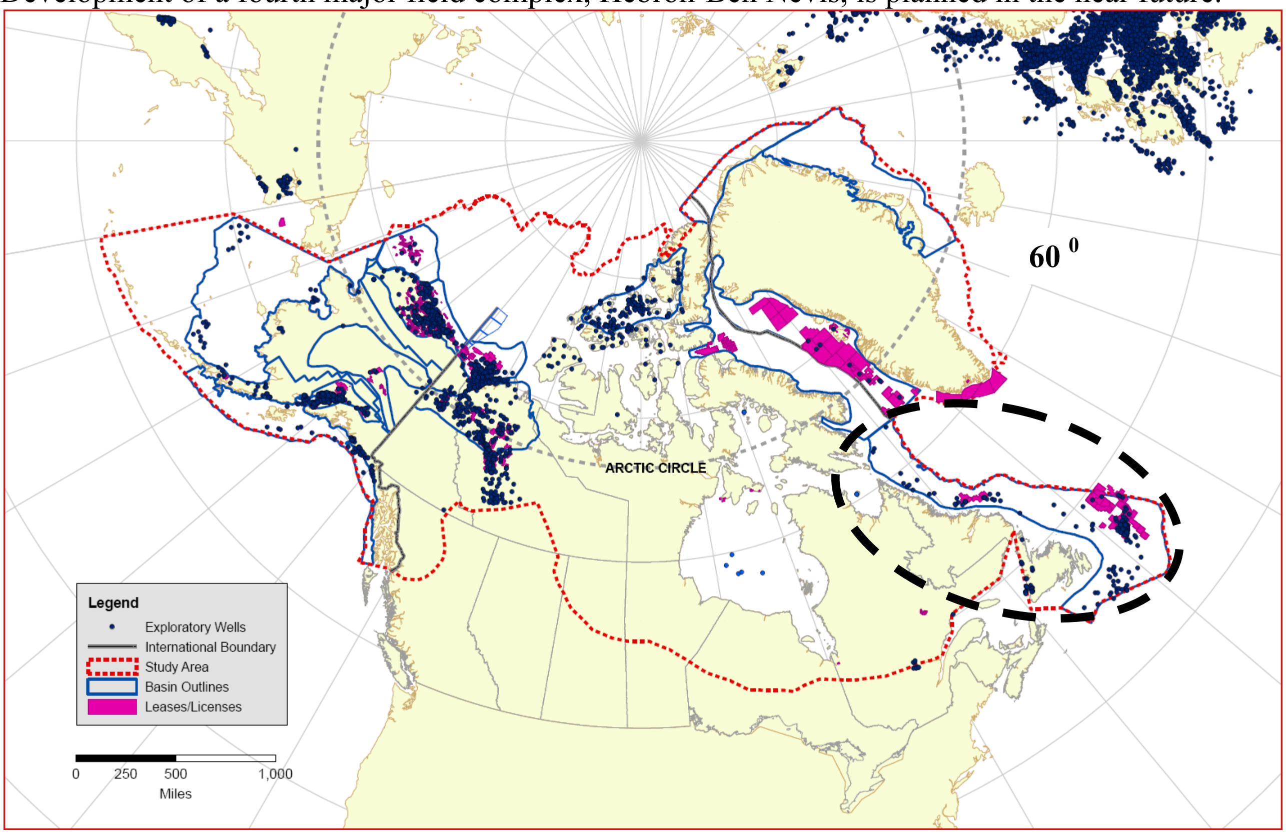

Figure 6.D.1 - Historic exploration wells drilled in the N. American Arctic region. Current active leases/licenses also highlighted. Note the Labrador/Newfoundland region within dashed black oval.

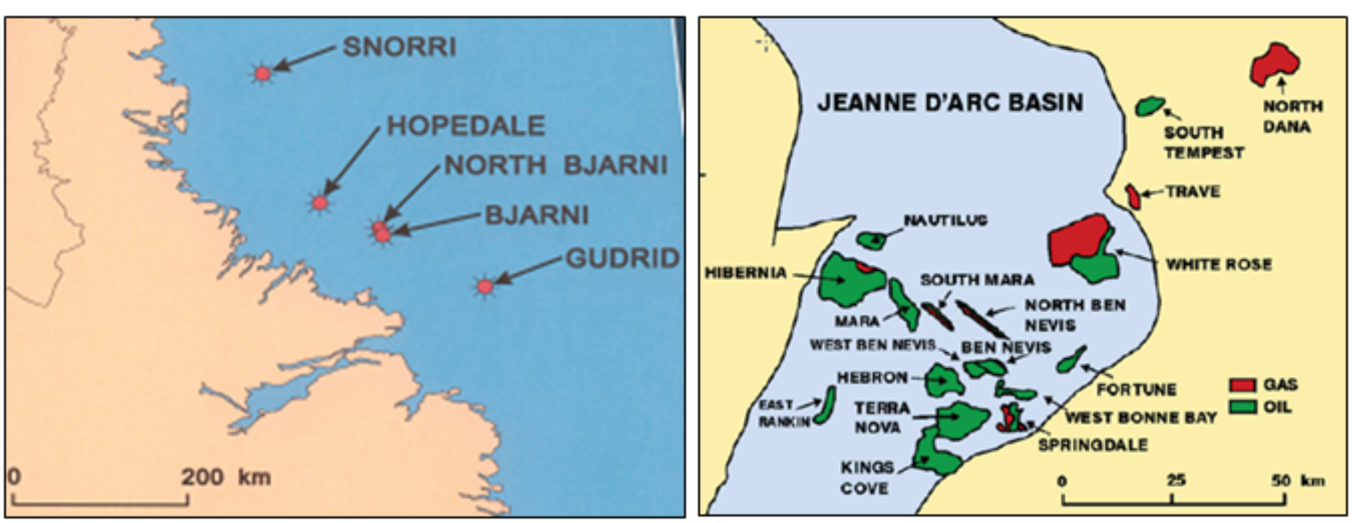

Figure 6.D.2. - Significant Discoveries on the Offshore Labrador-Newfoundland Shelf region (Saglek, Hopedale and Jeanne D'Arc Basins).[12]

Hibernia Field originally contained over 1.2 billion barrels of recoverable oil, of which well over 40% remains to be produced. The production system is a 224 meter tall gravity based structure (standing on the sea-floor as opposed to floating) weighing 1.2 million tonnes. Oil is stored within the structure and transported to shore by shuttle tankers. Field life capital costs are estimated to be $5.8 billion.[16]

Unlike Hibernia, Terra Nova Field was developed using an FPSO (Floating Production Storage and Offloading) system. The subsea production system is protected from iceberg scour by "glory holes" excavated in the seabed. Estimated original recoverable reserves are over 419 million barrels and field life capital costs are expected to be $2.8 billion.[16]

White Rose Field was also developed using an FPSO. Estimated recoverable reserves are 305 million barrels of oil.[16] The total White Rose project capital cost was $2.04 billion.[16] Development of the Hebron-Ben Neviss discoveries are planned in the near future and this complex is estimated to contain 581 million barrels of oil, although the oil is of poorer quality (heavier) than in the other three Jeanne d 'Arc developments.[13]

A second wave of renewed exploration licensing and drilling was begun in the last decade in the greater Labrador/Newfoundland offshore region (Flemish Pass, Orphan, Whale, Horseshoe, Carson/Bonnition, and Salar basins) (Figure 4.C.2.b.1). Several wells have been drilled and only one discovery has been announced in the Flemish Pass area (Statoil Mizzen O-16 discovery).[14] The other recent exploration wells have met with limited success, validating petroleum system elements but failing to find significant oil or gas accumulations.

VI.D Summary

The Canadian North may be somewhat underexplored; as a comparison the Gulf of Mexico OCS has well over 105,000 wells and the southern North Sea has over 15,000 wells drilled. Less than 1,600 wells have been drilled north of 60° latitude in Canada and less than 1,000 of those have been classified as exploration wells (Table 6.D.2.1). Another fact is that even in heavily explored areas like the Norwegian North Sea where 5,000 wells have been drilled over the last 45 years the exploration success is still high; in 2010 65 exploration wells resulted in 28 new oil and gas discoveries.

Sum of WellCount	Latitu																			
RR Decade	60	61	62	63	64	65	66	67	68	69	70	72	73	74	75	76	77	78	79	Grand Total
1920	1	1			1	5														8
1940					2	18														20
1950	29	16	4																	49
1960	100	56	18	5	2	11	30	17	4	5				1		3				252
1970	46	31	16	10	20	31	25	23	29	75	12	5	4	5	11	32	12	7	4	398
1980	32		1		8	9	8	7	6	33	19		1			4	5	1		134
1990	25				2	11				4										42
2000	16			1	9	6	7	7	2	16										64
Grand Total	249	104	39	16	44	91	70	54	41	133	31	5	5	6	11	39	17	8	4	967

Table 6.D.2.1 - Summary of Canadian Arctic exploration wells by decade and latitude.

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[2] Yukon government http://www.emr.gov.yk.ca/index.html).

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[4] http://www.neb-one.gc.ca/clf-nsi/rcmmn/hm-eng.html)

[5] reference cited Larry Hicks GSC PPT).

[6] (GSC Chen & Osadetz 2010).

[7] CNLOPB 2010 Annual Report, Page 35

[8] http://www.ngps.nt.ca/report.html

[10] http://epe.lac-bac.gc.ca/100/200/301/inac-ainc/road_improvement-e/ri08-eng.pdf)

[11] Wall, B. 2010, NEB, 2010 Personal Communication

[12] Hicks, L., 2010, Petroleum Resources of Newfoundland & Labrador Canada, Department of Natural Resources, Government of Newfoundland & Labrador, 17 slide PowerPoint presentation

[13] Oil & Gas Journal, May 3rd Edition, ExxonMobil to Develop Hebron oil field off Canada

[14] http://www.thetelegram.com/Natural-resources/2009-04-09/article-1439235/StatoilHydro-strikes-pay-dirt/1

[15] Drummond Consulting, http://drummondconsulting.com/N60Drummond.pdf

[16] CNLOPB, http://www.cnlopb.nl.ca/pdfs/project_benefits08.pdf

VII. GREENLAND DEVELOPMENT

VII.A Introduction

Greenland is divided into the West Greenland-East Canada Province (Canadian Baffin Bay), North Greenland Sheared Margin Province and the East Greenland Rift Basins Province for resource analysis by the USGS (Figure 7.A.1). All of the historic and modern drilling and development activity has occurred on the southwestern portion of the Greenland margin. Section VII will focus on Greenland as a whole instead of considering each province individually.

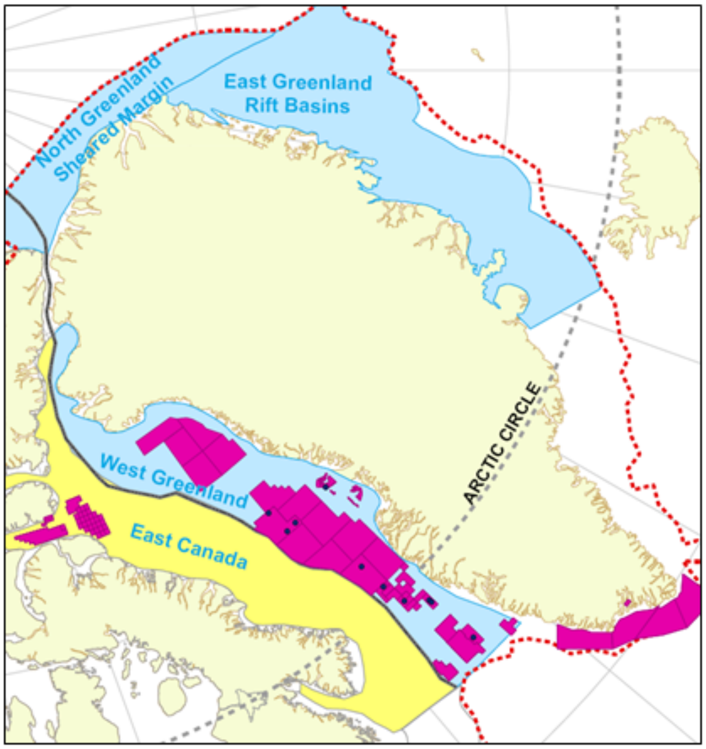


Figure 7.A.1 - Key Greenland Offshore basins (including the Canadian portion of the Baffin Bay area in yellow). Exploration wells and active exploration licenses depicted in pink. Cairn's northern blocks are located north of the Arctic Circle.

Oil and gas exploration in Greenland started after oil was discovered in the North Sea. Field work designed to understand Greenland's outcrops aided exploration in both the North Sea, as the northeastern Greenland shelf was basically the western part of the North Sea (before the opening of the Atlantic). None the less, the first well (Kangamiut-1) was drilled in the West Greenland offshore basin (due to less harsh drilling conditions) by Total in 1976 (Figure 4.D.2). An additional four wells were drilled offshore in 1977, one onshore well was drilled in 1996, one offshore well was drilled in 2000 and most recently Cairn Energy LLC drilled three offshore exploration wells on their northern blocks in 2010 (Figure 7.A.2).

Two of Cairn's 3 exploration wells encountered thermogenic hydrocarbons (gas and oil) in un-commercial quantities[3] and Cairn have announced plans to drill another 3 to 4 exploration wells offshore Southwest Greenland in 2011.[4]

The South Greenland offshore margin may be gas prone, as plate reconstructions (see Figure 7.A.2) indicate that this region was adjacent to the present day Labrador Shelf during the time of hydrocarbon generation.[2] As described previously in Section VI the present day Labrador Shelf contains several undeveloped gas and condensate accumulation which were drilled in the 1970's (Figure 6.D.2).

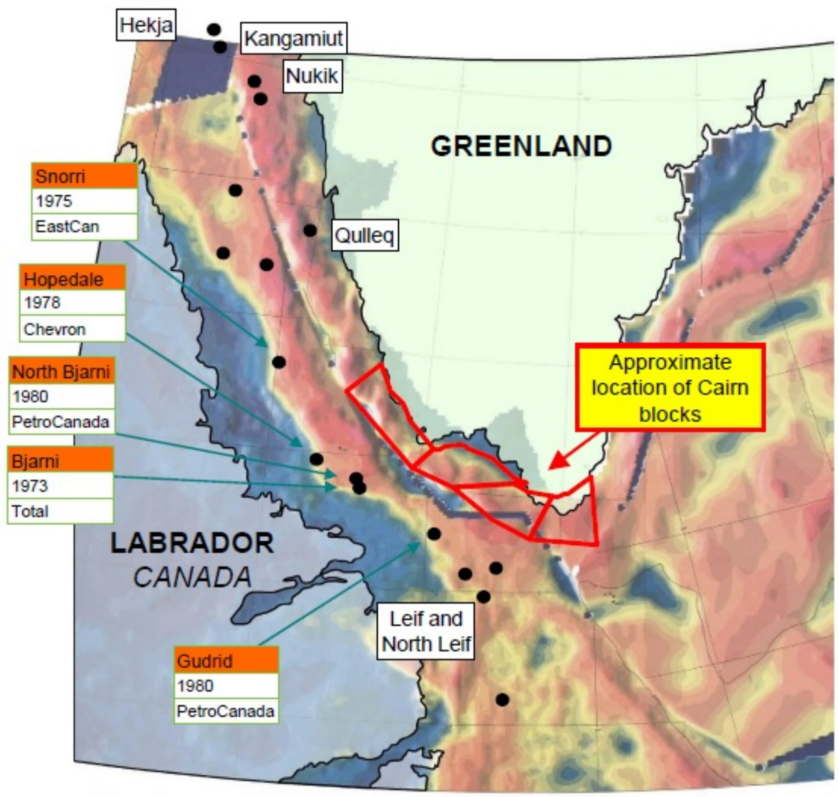


Figure 7.A.2 - Plate tectonic reconstruction (during hypothesized hydrocarbon generation phase) showing tip of SW Greenland adjacent to the Canadian Labrador Shelf and position of Cairn's southern blocks. [2]

Extensive seismic surveys have been completed both in the West and Northeast Greenland offshore areas since 1970. Between 1990 and 2005 over 70,000 km of 2D data was shot and since then there has been a number of both 2D and 3D surveys completed.

Greenland has regular licensing rounds every 2 to 3 years. The licensing is administered by the Bureau of Minerals and Petroleum (BMP). Exploration licenses are offered for 10 years in the west and 16 years in the north east of Greenland. A total of 20 licenses covering about 50 million acres were awarded in the November 2010 Davis Straight and Baffin Bay licensing round (average license size 2.47 million acres). The next licensing round will be for the East Greenland Rift Basin in 2012.

In 1990 a group called KANUMAS consisting of BP, Shell, Exxon, Chevron, JOGMEC, Statoil partnered with the National Oil Company (Nunaoil) carried out exploration field work including 2D seismic in the both northwestern and northeastern Greenland. Group members have been given preference and will bid in a licensing pre-round in December 2012. Any of the 7.4 million acres offered in the pre-round that are not licensed as well as an additional 4.9 million acres will be offered in an open licensing round in October 2013.

VII.B Development and Production History

There have been no fields discovered to date, thus no commercial development of fields or production of hydrocarbons has transpired for the Greenland Continental Margin (East Greenland Rift Basins Province, West Greenland-East Canada Province and North Greenland Sheared Margin Province).

VII.C Findings

Greenland is largely underexplored with 10 wells drilled offshore West Greenland, an area that is similar in size to the North Sea where 15,000 wells have been drilled to date. The area is essentially unexplored. By comparison, even after more than 45 years of exploration and 5,000 wells drilled, the 65 exploration wells drilled on the Norwegian shelf in 2010 still yielded 28 oil and gas discoveries.[1]

Both NW Greenland (Baffin Bay) and NE Greenland have very challenging ice conditions and new technology (ice strengthened seismic and drill ships, streamer deployment methods) will be required for seismic and drilling in the areas. Because of the challenging ice conditions it would be preferable to establish 16 year lease periods in both northwest and northeast Greenland (currently only available for northeast Greenland)

There is no oil and gas export infrastructure in Greenland and this will be a challenge for development due to the offshore conditions. The seasonal presence of ice and icebergs will need to be managed, and future developments, particularly in the northeast Greenland offshore, will most likely require subsea to beach or subsea to a nearshore GBS solution, as the water depths are too deep for gravity based structures and the ice conditions will make floating production challenging.

VII.D Potential Development

Because of the relatively mild ice conditions on the southwest side of Greenland (south of Disko Island), future oil discoveries could be developed with existing Floating Production Storage Offloading (FPSO) / Floating Production Unit (FPU) concepts. A subsea to a near-shore GBS production system could also be a viable development alternative for some of the near-shore licenses. Ice-class tankers could trans-load in either the ice-free port of Nuuk or in Newfoundland thereby reducing transport cost to long distance markets or alternatively ship directly to refineries in Canada and the northeast U.S.

The licenses on the south tip of Greenland may be gas prone, and subsea to beach developments like the one used by Statoil in the Snohvit development in the Barents Sea, may be a viable development option. A Floating LNG production facility might also be an alternative this far south. Both Europe and the northeast U.S. would be viable markets.

VII.E Cited Literature

[1] Neilson, JS 2010, Welcome to Greenland Day 2010, Bureau of Minerals and Petroleum Presentation, http://www.bmp.gl/images/stories/minerals/events/perth_dec_2010/Perth-jsn.pdf

[2] Cairn Energy presentation at the Greenland Conference in Copenhagen, May 2009

[3] Greenland Operations Update, Cairn Energy 26-Oct-2010 **http://www.cairnenergy.com/NewsDetail.aspx?id=1363**

[4] http://www.worldoil.com/Cairn_to_resume_drilling_offshore_Greenland.html?LS=EMS529189

VIII. OFFSHORE CHALLENGES / ENABLERS

VIII.A Introduction

There has been a rich history of offshore arctic exploration throughout North America which commenced in the 1960s and continues through to the present day. Since exploration has touched virtually all of the major North American arctic basins it was decided that, as a basis for this assessment, the exploration learning's from these basins would be utilized to identify the major technical / operational challenges in these areas through 2050. By inference, this experience has been applied to identify the emerging challenges of new basins such as NW and NE Greenland.

The chart below shows the distribution of offshore arctic wells by basin and country (Figure 8.A.1). This chart does not include the historic offshore data from the Bering Shelf or Pacific Margin of the Alaskan OCS nor the ongoing offshore drilling program being conducted by Cairn Energy in the West Disko area in West Greenland. It does however provide the reviewer with a good appreciation for the extensive and wide ranging level of arctic offshore activity that has occurred in the North American Arctic Offshore.

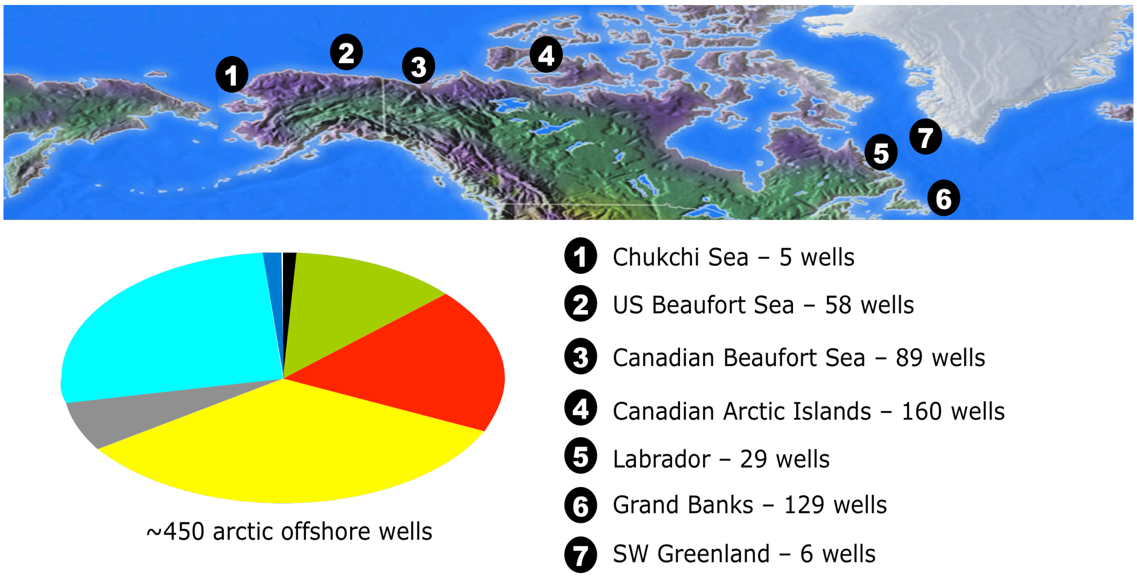


Figure 8.A.1 - Wells drilled in the offshore Arctic.

The North American offshore arctic experience has the benefit of having operated in the three main types of ice regimes: Land-Fast, Pack Ice and Iceberg / Pack Ice conditions in addition to periods of open water (Figure 8.A.2).

The World Metrological Organization (WMO)[1] provides definitions for each of these three ice conditions. Land-fast ice is described as ice that forms and remains fast along the coast where it is attached to the shore. The extent of the land-fast ice is dependent on the basin, for example in the Canadian Beaufort Sea land-fast ice extends to the 20 m water depth contour. According to WMO, sea ice composed of discrete floes present in significant concentrations which is not land-fast is referred to as pack ice. The remnants of a glacier's calving are referred to as icebergs. Icebergs are observed in a variety of shapes (tabular domed, or blocky for example) and are categorized based on size (small, medium, large and very large).

Figure 8.A.2 - Offshore ice conditions in the Arctic.

This wide range of operating experience in North America allows assessment of new and emerging basins to be made with some confidence based on previous operating experience.

VIII.B Assessment Criterion

In order to perform a scoping analysis, each basin was assessed in terms of Ice Regime Comparison and Development Challenge Comparison.

VIII.B.1 Ice Regime Comparison for Exploration and Development Planning

To develop a comparison, the Ice Regime was characterized and assessed for each basin in terms of Open Water Season, Pack Severity Index and Iceberg Conditions which are described below. This Ice Regime applies to both exploration and development challenges.

Open Water Season – This directly impacts the following exploration and development parameters:

- Seismic acquisition cost & duration
- Directly drives well costs through
  - Mob/demob costs
  - Suitability of drilling equipment and support fleet including oil-spill clean-up capability
  - Drilling season duration
    - Frequency of multi-season wells
    - Number of years required for appraisal activities post-discovery
- The efficiency of relief well operations and associated oil-spill clean-up operations
- Construction / installation windows
- Potential conflict with seasonal activities i.e. subsistence hunting, fishing (subsistence or commercial), etc
- Most regions show considerable variability in the length of the open water season, in their start and end dates (i.e. in ice clearance and freeze-up dates) and also, in the time frames characterized by low, moderate and high ice concentrations

Pack Severity Index – This directly impacts the following exploration and development parameters:

- The ice rating & capability of:

- Seismic vessels
  - 2-D seismic acquisition in moderate pack ice conditions (+2-3/10ths ice over) is extremely challenging both technically & economically
  - 3-D seismic acquisition not feasible when pack ice > 1/10ths ice cover

- Exploration drilling vessels
  - Bottom founded rig (for example SDC)
  - Ice strengthened jack-up
  - Anchored Drillship or Drilling Vessel (for example Kulluk)
  - Dynamically Positioned Drillship (for drilling in water depths >100 m)

- Directly drives drilling uptime through the application of Ice Alert Procedures
  - Marine support vessels including ice breakers and oil-spill clean-up capability

- Re-supply logistics

- Tanker export options

- The cost & practicality of extended season operations such as:

  - Development drilling with floaters (anchored or dynamically positioned)
  - Relief well operations
  - Oil-Spill clean-up operations

- Capital Expenditures (CAPEX), Operating Expenditures (OPEX) and schedule, thus project economics

Iceberg Conditions – this directly impacts the following exploration and development parameters in a restricted subset of areas (primarily the offshore portions of Greenland and eastern Canada and sometimes in the Canadian Beaufort Sea where ice islands, equivalent to an iceberg, may be present although their occurrence is very rare):

- Directly drives drilling uptime through the application of Ice Alert Procedures
  - Marine support vessels including ice breakers

- Directly drives the Gravity Based Structures (GBS) design through the following:
  - Extreme ice loads

- Water depth limits

- Ice loading will be a key parameter in constraining the maximum water depth for the deployment of a GBS in any given basin. Generally speaking most GBS units are, practically and economically limited to water depths of around 100m. This limitation, coupled with the extensive areal extent of the many of the geological targets that does allow the majority of wells to be easily drilled and completed from the GBS in areas with iceberg conditions. This, in turn, leads to a greater reliance on:

- Floating drilling in pack ice
- Increased range of sub-sea tie-back technology

- Larger icebergs in the offshore portions of Greenland result in ice scour of the seafloor in water depths up to ~250m, thus requiring the development of a deepwater pipeline trenching system that is currently unavailable (this does not apply to any of the U.S. OCS areas).

VIII.B.2 Development Challenge Comparison

To develop a comparison, Development Challenges were characterized and assessed for each basin in terms of GBS Limitations, Transportation, and Technology / Regulatory:

- GBS Limitations – this directly impacts the following exploration and development parameters:
  - Water depth limitations on a GBS are region dependent due to high ice loading
  - As discussed previously, GBS bathymetric limitations may directly drive:
    - Reliance on floating drilling and subsea tiebacks to GBS
      - Advances in Arctic sub-sea technology
    - Pipeline length / deepwater trenching
    - Some prospective areas of some basins (water depths > 100m) may only be accessible by floating systems
      - May limit economic accessibility within portions of some arctic deepwater basins (water depths > 100m)

Transportation – this directly impacts the following development parameters:

- Availability / accessibility of transportation infrastructure
  - Offshore buried pipeline to shore
  - Onshore pipeline to market place
  - Future year round tanker export
- In the case of oil export, the ice conditions (pack/iceberg) will directly impact the following:
  - Marine CAPEX
  - Marine OPEX

  - Tanker transit speeds
  - System efficiency
  - Complexity of oil-spill management

Technology / Regulatory – these criteria directly impact the following exploration and development parameters:

- From a technology standpoint:
  - Current arctic GBS designs limited to a maximum of ~100m water depth
  - Deep pipeline trenching to avoid ice scour in >100m has not been demonstrated (this does not apply to the U.S. OCS Continental Shelves)
  - 2-D seismic acquisition in moderate pack ice conditions (+2-3/10ths ice over) is extremely challenging both technically & economically
  - 3-D seismic acquisition not feasible when pack ice > 1/10ths ice cover
  - High reliance on sub-sea oil tie-backs required to open up many deepwater (> 100 m water depth) arctic basins especially those where activities are straddling the Shelf / Slope boundary such as the Canadian Beaufort, NW Greenland and potentially NE Greenland in the future.
  - Quick disconnect systems required to allow efficient, late season pack ice drilling (exploration and development wells)
  - Enhanced BOP and well containment systems (exploration and development wells)

- From a regulatory standpoint:

  - Relief well / oil spill containment
  - Environmental footprint
  - Socio-economic impacts
  - Impact with local subsistence hunting /harvesting
  - Financial liability

Having established the assessment criteria, it now remains to address the assessment methodology. This is outlined in Section VIII.C

<u>VIII.C Assessment Methodology</u>

It is felt that the following list of basins provides an appropriate assessment base to characterize the broad range of arctic operating challenges across both North American and Greenland.

U.S. Chukchi
U.S. Beaufort
Canadian Beaufort
Labrador
Grand Banks
SW Greenland
NW Greenland

NE Greenland

Key characteristics of each basin are described in Table 8.C.1. ISO 19906[2] was consulted to develop the table. Information presented for each basin provides a general overview of the entire basin. It is important to note that ice conditions may differ between sites located within the same basin.

Table 8.C.1 - Selected characteristics of Offshore Arctic Basins.

	U.S. Chukchi	U.S. Beaufort	Canadian Beaufort	Labrador	Grand Banks	SW Greenland	NW Greenland	NE Greenland
Significant Wave Height, Annual Max (m)	6	3.5	3.5	11.4	11.7	7	7.9	5
Max Water Depth of Lease Areas (m)	50	100	1500	1000	150	1100	1000	500
Open Water Season	Mid June – Early Nov.	Mid July - Early Oct	Mid July - Early Oct	July - Dec	Usually year round	Usually year around	Late July - Mid Oct.	Year Round Ice Presence
Near-shore Land-Fast Ice - Present?	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
Pack Ice - Present?	Yes	Yes	Yes	Yes	Yes, Occasional	Yes, Occasional	Yes	Yes
FY Level Ice Thickness, Average Annual Max (m)	1.4	2	2	1.5	1.2	1.2	1.6	2
FY Keel Draft Depths, Average Annual Max (m)	10	30	25	8	5	6	8	25
MY Level Ice Thickness, Average Annual Max (m)	4	6	6	5	1.5	NA	5	6
MY Keel Draft Depths, Average Annual Max (m)	8	30	30	10			10	30
Icebergs, Time of Year	Rare Ice Islands + Fragments June - Oct	Rare Ice Islands + Fragments July - Oct	Rare Ice Islands + Fragments July - Oct	Icebergs All Year	Icebergs April-July	Icebergs All Year	Icebergs All Year	Icebergs All Year
Icebergs - Frequency	Very Rare	Very Rare	Very Rare	Moderate	Low	Moderate	Very High	Moderate
Typical Max Gouge Depth Below Seabed (m)	0.5 – 2.5	0.5 - 3	2 - 5	2 - 7	1 - 2	2 - 4	3 - 8	3 to 7
Max Water Depth at Max Gouge Depth Below Seabed (m)	50	50	50	250	150	250	300	200

FY = First year Ice
MY = Multiyear ice

The criteria listed on Table 8.C.1 were utilized to generate assessment sheets on the various Arctic areas. Each criterion was assessed on a scale of 1 - 10 by a group of very experienced Arctic Subject Matter Experts (Brian Wright, Bill Scott and David Dickins). When all of the basin assessments were completed, the individual assessments were then cross referenced for consistency. It is important to note that this analysis was developed for screening purposes only and, as such, should be utilized on a qualitative basis only.

When both the Ice Regime and Development assessments were completed all of the indices were simply added together to provide a qualitative assessment of the challenges associated with exploration and development operations in any given basin. When complete a further comparative basin assessment was made to ensure that the results were compatible from one basin to another. Examples of the Assessment Sheet that was utilized are shown in Figures 8.C.1 and 8.C.2 for the Canadian Beaufort and U.S. Chukchi respectively.

OPEN WATER SEASON			PACK SEVERITY INDEX			ICEBERG SIZE/CONCENTRATION		
LONG	MED	SHORT	LOW	MED	HIGH	LOW	MED	HIGH
7			7			Not Applicable		

- Shorter open water season (~70 days) with entry from west sometimes difficult due to ice at Pt Barrow
- Primarily, first year ice, although multi-year ice intrusions can occur in both summer & winter
- No icebergs are present

Figure 8.C.1 - Sample Assessment Sheet – Canadian Beaufort.

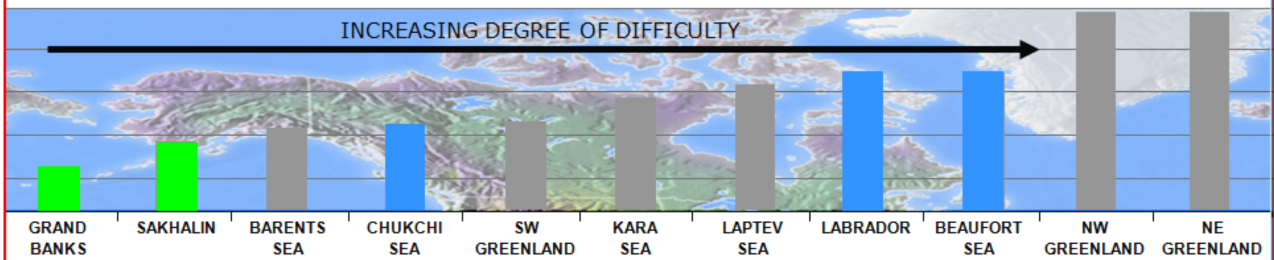
OPEN WATER SEASON			PACK SEVERITY INDEX			ICEBERG SIZE/CONCENTRATION		
LONG	MED	SHORT	LOW	MED	HIGH	LOW	MED	HIGH
	5			6			Not Applicable	

- Relatively long open water season (~105 days) and reliable access through open water from the south
- Primarily, first year ice, although multi-year ice intrusions can occur in both summer & winter
- No icebergs are present

Figure 8.C.2 - Sample Assessment Sheet – U.S. Chukchi.

The combined Ice Regime and Development Challenge Comparison shown in Figure 8.C.3 places the studies U.S., Canadian and Greenland offshore basins in a global context.

Combined Ice Regime & Development Challenge Comparison



- Significant levels of oil and gas production are already being produced from Arctic basins such as the Grand Banks (Canada) and Sakhalin (Russia) in both pack ice and pack ice / iceberg operating environments
- Significant operating experience has been successfully gained in several of the more challenging arctic basins i.e. U.S. Chukchi & Beaufort ~ 35 wells in open water to pack ice, Canadian Beaufort ~90 offshore wells in both open water and pack ice, and Labrador ~ 30 offshore wells in pack ice and pack ice / iceberg operating environments
- A strong history of successful exploration and production operations across a wide range of arctic operating conditions and challenges has demonstrated that industry can explore and develop oil & gas safely in the arctic

Figure 8.C.3 - Ice Regime Development Challenge Comparison based on the collective assessments.

VIII.D Summary

Figure 8.C.3 provides a visual comparison of the assessments that illustrates the comparative ranking between ice regime and development challenges for the subject basins. This assessment shows that these recognized arctic challenges have already been safely met at both the exploration and development phase in several basins.

Arctic offshore exploration experience is centered in North America and has a demonstrated capability throughout the full range of arctic operating conditions with over 450 wells already drilled. Since this experience spans a period from the 1960s through to the present day, it comes as a surprise to many that industry has accumulated such a wealth and diversity of successful operating experience in arctic offshore exploration. The strong historical operating experience gained in challenging operating environments such as in the Canadian Beaufort Sea and the Labrador Sea (Canada) provides confidence that industry has both the tools, procedures and experience to operate safely throughout the offshore arctic.

Arctic offshore production history reflects the same level of success as demonstrated through the drilling of over 450 exploration wells. While this screening assessment only cited major production centers such as the Grand Banks (Canada) and Sakhalin (Russia) there are other examples such as Cook Inlet and the various near-shore production islands along the U.S. Beaufort Sea coastline. These projects have demonstrated the ability for industry to design production facilities consistent with the regulatory and environmental challenges that exist in these areas and thus allow the safe and efficient production of oil and gas reserves from the arctic offshore.

Industry's history in the offshore arctic is one of continuous improvement and development that has allowed safe and successful arctic operations to be completed within all of the major arctic offshore ice environments. Offshore arctic operating capability is a North American success story which is poorly understood and appreciated by many. This is largely due to the fact that it has been ongoing in the background for the last 60 years. The record speaks for itself and industry has shown throughout its arctic journey a consistent ability to meet and exceed the challenges set before it and will continue to do so.

VIII.E Cited References

[1] **http://www.wmo.int/pages/index_en.html**

[2] **http://www.iso.org/iso/home.htm**

IX. FINDINGS DISCUSSION

The following discussion is based on observations noted in the preceding sections, and tabulated relative to the findings in Section III.

The majority of these findings support the contention that a huge resource base in the North American Arctic will not be available in the 2025 to 2050 timeframe if the status quo is maintained.

IX.A Resource Base

The North American Arctic (U.S., Canada and Greenland) has large (world scale) discovered undeveloped (6.4 Billion barrels oil, 0.9 Billion barrels natural gas liquids and 83 TCF gas) [1] and very large undiscovered (80.1 Billion barrels oil, 11.1 Billion barrels natural gas liquids and 595.1 TCF gas) [2] oil, natural gas liquid and gas resources. Development lead times are very long (historically 10 to 20 years from discovery to first production).

IX.A.1 Onshore & Offshore U.S. Resource Base

Field sizes on the North Slope historically have had to be large in order to justify the large expense of mobilization, logistics, and the high cost of transporting the oil to the market via TAPS. Field sizes for the offshore OCS regions will need to be even larger to justify the huge capital expenses required for building ice resistant production platforms, and new pipeline infrastructure (trenching, materials, and construction) for tying into TAPS. Additional oil production from already discovered resources (both onshore and offshore), as well as new discoveries, is essential to keep TAPS in operation both technically and economically. In the absence of any new oilfield development, the existing oil fields could probably produce about another 6.1 Billion barrels of oil.[3] But based on estimated decline rates for oilfield production, flow rates through the trans-Alaska oil pipeline would drop below the 200,000-barrel-per-day mechanical limit for the pipeline by 2039, with that date being extended to 2045 if new oil comes online from fields currently being developed or under evaluation. A shutdown of the pipeline in 2045 would potentially strand about 1 Billion barrels of oil reserves from the known fields that were analyzed.[3]

[1] *Mean, discovered, technically recoverable,* volume estimate. These discovered volumes are remote to existing development and production infrastructure.
[2] *Mean, risked, technically recoverable, undiscovered, yet-to-find volumes*

A report issued in April 2009 by DOE's National Energy Technology Laboratory's Arctic Energy Office produced a comprehensive analysis of the future, potential North Slope production, and the following material discussing Alaska relies heavily upon it.[3] The DOE report concludes that the North Slope is far from a mature oil province and that there remains much oil to be found: For the complete study interval from 2005 to 2050, the forecasts of economically recoverable oil and gas additions, including reserves growth in known fields, is 35 to 36 Billion barrels of oil and 137 TCF of gas. These optimistic estimates assume relatively high oil and natural gas prices, stable fiscal policies, and that all areas open for exploration and development, including ANWR, the Chukchi Sea, the Beaufort Sea, and that a natural gas pipeline from the North Slope will be built. If the ANWR 1002 area is removed from consideration, the estimated economically recoverable oil is 29 to 30 Billion barrels of oil and 135 TCF of gas. Removal of ANWR 1002, Chukchi Sea OCS, and the Beaufort Sea OCS, and failure to build a gas pipeline, reduces the estimate to 9 to 10 Billion barrels of oil, and any natural gas discovered will likely remain stranded. <u>The following is taken directly from that report:</u>

The magnitude and success of future exploration and development will be largely dependent on the degree to which the following assumptions are satisfied:

- Oil (and gas) prices remain high enough to support continued exploration and development.
- Climate change will not be so great, during the next 50 years, to render current exploration methods obsolete or foreclose modifications, such as the use of Rolligons and new drilling platforms.
- All new exploration and development activities will use technologies at least as good as those at Alpine. (Note: At the time of the DOE report, Alpine was the most recent oilfield to be developed, and is considered by many to be the state-of-the-art remote oilfield.)
- Onshore exploration (and probable extraction) will continue to expand both southward into the foothills of the Brooks Range and westward across the NPR-A.
- Offshore exploration (and probable extraction) will continue, but at a cautious pace, along the Beaufort Sea coast/shelf from Point Barrow to Flaxman Island and possibly eastward to the Canadian border. The exploitation of the Chukchi Sea OCS will depend on anticipated success in adjacent portions of NPR-A and the construction of a gas pipeline. Recent lease sale results from the 2008 Chukchi Sea sale suggest this may be an overly conservative position.
- Facility sharing agreements will be in place, which permit reasonable and affordable access for those companies not currently producing and transporting hydrocarbons.
- A gas pipeline will be built and, over time, gas will become a significant if not the dominant component of many exploration and development programs and new explorers will have access to the gas pipeline.
- The number of exploration companies, especially those with gas interests, will expand, competition will increase, and a greater variety of play types and exploration provinces will be evaluated and drilled.

The long lead time of 7 to 10 years (onshore) or 10 – 20 years or more (offshore) that is required for developing frontier areas in the Arctic means that exploration and development needs to continue, or even accelerate, in order to maintain the future of ANS oil production.

It is not generally recognized that once TAPS discontinues its operation, then the pipeline and associated infrastructure must be removed and the right-of-way remediated, forever removing the possibility of refurbishing and restarting the pipeline. Opening of the ANWR 1002 area and the OCS areas could increase the likelihood of major oil discoveries.

Exportable hydrocarbon natural gas reserves (produced gas less carbon dioxide (CO_2) and lease use, local sales, and shrinkage) are estimated at 23.7 TCF for the Prudhoe Bay Unit (PBU) and 8 TCF for the Point Thomson Unit (PTU), for a total of 31.8 TCF. A higher recovery factor for PBU and PTU, or additional amounts from other currently producing fields, will be required to provide the total of 35 TCF frequently referred to in discussions of ANS gas reserves.

Natural gas is not currently exported off the North Slope because there is no gas pipeline or tanker capability to transport the gas to markets. Alternatives such as building a gas-to-liquids plant which could convert the natural gas to a higher density liquid product for transport through the TAPS system has reportedly been studied, but the major oil companies have apparently determined that building a natural gas pipeline is the most economic method for moving the natural gas to market as evidenced by their recent investments. Until an export capability is developed, the majority of the gas is re-injected back into the producing reservoirs to enhance oil production, and used locally for energy and heating.

In the *2011 Annual Energy Outlook,*[4] the U.S. Energy Information Administration (EIA) assumes that the Alaska natural gas pipeline is uneconomical in its reference case and therefore will not be built, and does not contemplate a GTL scenario. Reasons given by EIA for removing Alaska natural gas from their reference case are the increased cost estimates for building the pipeline, and the lower gas prices as a result of more natural gas available from shale development.

Even if the Alaska Natural Gas Pipeline moves forward, it most likely will not be ready for first gas until 2020 at the earliest.[5] Regardless of whether or not the Alaska Natural Gas pipeline is built; near term emphasis on the North Slope will be upon oil-focused development.

Alaska is known to have potentially recoverable methane hydrates in accumulations below the Arctic permafrost. The methane hydrates are still considered an unconventional resource with an estimated 85 TCF potentially recoverable from the North Slope alone.[6] Successful production testing will both move this resource to the conventional category and triple the known inventory of available natural gas in Alaska.[7]

The costs and logistics of working in the Arctic present daunting challenges. Alaska is nearly one-fifth the size of the continental U.S., and the North Slope (about the size of Minnesota) is far from any industrial center and difficult to get to. The North Slope lacks basic infrastructure such as roads, deepwater ports, railroads, airports, water, power, communications, medical facilities, and living accommodations. This means that those choosing to develop onshore or offshore Alaskan Arctic oil and gas resources must add the cost of this infrastructure into their plans, making the minimum size of developing any discovery so large that only world-class oil & gas companies, with deep pockets, are able to develop these world class oil and gas resources.

IX.A.3 Onshore Canada

Field sizes onshore Arctic Canada have to be large to justify development and none of the discovered oil or gas fields north of Norman Wells (0.3 Billion barrels recoverable oil originally in place), in the Northwest Territories (Figures 4.C.1.1 and 4.C.1.2), have been large enough to justify the capital expenditure for pipeline construction thus none have been developed to date. Discoveries in the Canadian North Onshore Basins (Yukon and Mackenzie Valley) as well as the Mackenzie Delta region have been gas prone. More than 5 TCF[8] of gas has been discovered onshore with the largest field on the mainland being the Taglu field (2.3 TCF recoverable) but none has been developed due to lack of infrastructure (pipeline or LNG facilities). The largest discovered onshore oil field north of Norman Wells in Canada is Atkinson Point, which has an estimated 0.04 Billion barrels of recoverable oil. The Tuk Field nearby has a larger volume of dominantly heavy oil.

IX.A.4 Offshore Canada North

Field sizes offshore Canada (Canadian Beaufort and the even more remote Arctic Islands/Sverdrup Basin region, Figure 4.C.1.1) have to be even larger than those onshore and none of the numerous discovered fields have demonstrated enough reserves[8] to warrant the capital expenditure. Two of the more significant discoveries, Paktoa and Amauligak Fields, reside within the shallow part of the Beaufort Sea. Amauligak Field is estimated to contain 0.24 Billion barrels oil and 1.5 TCF gas recoverable,[37] and the recent Paktoa discovery is thought to contain 0.2 Billion barrels oil.[38] The current economic threshold is greater than 0.3 Billion barrels of recoverable oil for the Beaufort Sea area and substantially higher in the more remote Arctic Islands/Sverdrup Basin region where oil fields like Cisco (0.2 Billion barrels recoverable oil) and gas fields like Drake (5.4 TCF recoverable gas) and Hecla (3.7 TCF recoverable gas) have been discovered.[37] Development studies for the Hecla and Drake fields have been done as recently as in 2004 without resulting in a development application.[42]

IX.A.5 Offshore Canada East

Discoveries on the offshore Canadian East region (Labrador/Newfoundland Shelf) have predominantly been gas (~ 4 TCF) with the exception of the Jeanne D' Arc Basin just offshore of Newfoundland (Figures 4.C.2.b.1 and 4.C.2.b.2).[9] No pipelines exist to export the oil and the current production from this region is supported by tankering. It is anticipated that future oil developments in this area will also feature tankering of produced oil. The preferred method of producing and exporting (tankering vs. subsea pipeline construction) of the existing proven gas is yet to be determined.

IX.A.5 Onshore and Offshore Greenland

No significant oil or gas fields have been discovered either onshore or offshore Greenland. Field work onshore and limited exploration wells offshore have demonstrated elements of a working hydrocarbon system. Recent drilling by Cairn Energy LLC[10] in 2010 has validated the occurrence of thermal oil and gas trapped in offshore structures in the West Greenland offshore area. Analysis by the USGS[11, 12, 13] suggests that the offshore basins flanking Greenland offer the greatest potential for encountering large reserves of trapped hydrocarbons (Section IV and Figure 4.D.1). Future discoveries offshore Greenland will need to demonstrate large to giant accumulations of recoverable oil to justify the capitol required for development and export although smaller accumulations may be able to be commercialized the area offshore Southwest Greenland (Disko Bay and south.

IX.B Infrastructure and Technology Challenges

Exploration and development technology, both onshore and offshore, is not expected to be a limiting factor in developing conventional Arctic hydrocarbon resources. Numerous Arctic producing fields exist on land and safe development and production of offshore Arctic reserves has occurred since the late 1960s (i.e. Cook Inlet offshore). Nonetheless, technology and practices to prevent and mitigate environmental risks associated with the Arctic will continue to evolve and be enhanced.

IX.B.1 U.S. Infrastructure and Technology Challenges

Discussion of infrastructure and technology will be limited to those Alaskan regions that have demonstrated the greatest opportunity for significant future production (North Slope Onshore, Beaufort Sea and Chukchi Sea):

Onshore Infrastructure Challenges

- Large discovered, and significant undiscovered, natural gas reserves are stranded by lack of a natural gas pipeline.
- The current facilities on the North Slope are optimized for processing the existing oil production. If additional oil or natural gas exploration also results in additional gas or water production, then technical solutions are required to address flow constraints as the current facilities are operating at capacity.
- TAPS: Mechanical lower operating limit may be reached by 2039, and economic limit may be reached sooner.[3]
- TAPS: Subject to early shutdown if the economic limit is reached due to higher operating costs and lower volume over which to spread those costs. This could strand over 1 billion barrels of known recoverable reserves.[3]
- TAPS: A lower flow rate could cause ice crystals formation on walls and within the oil leading to ice jams. In turn, this could lead to seasonal operation of the line.
- TAPS: A lower flow rate will lead to wax deposition and asphaltene deposition, requiring more frequent pigging.
- TAPS: Heating the oil pipeline, or portions of it, may become required with a lower daily volume.
- Roads (and possibly railroads) into the Brooks Range foothills could encourage exploration in the area, and may even lead to year round operations.
- Retreating Arctic ice may provide a shorter barge and tanker route to serve the East Coast markets. An "Over the Top" route would be much shorter than shipping through the Panama Canal, and could require building a year-round port and an adequate fleet of ice-class tankers.
- Low-cost methods for delineation of permafrost and fault areas using aerial/satellite imagery may speed construction of the natural gas pipeline.
- Elevated platforms on the North Slope may be an alternative to ice pads and allow for year-round drilling.

Onshore Technology Challenges

- Estimates vary widely, but Alaska is generally thought to contain 26 to 45 Billion barrels of viscous or heavy oil contained within the Ugnu, West Sak and Schrader Bluff reservoirs that reside within the existing North Slope infrastructure (greater Prudhoe Bay - Kuparuk Field areas) and is largely untapped due to lack of affordable technology. Current viscous oil production is limited to the "best" reservoirs with API gravity from 14° to 21° API. The largest potential reserves growth will probably occur in the viscous, heavy oil fields.

- The current estimate of *economically* recoverable viscous reserves is between 1.45 and 1.80 Billion barrels oil.[3] Ultimate reserve numbers may be much larger and estimates suggest that one-fifth of the ANS in-place viscous oil could be produced.
- Most heavy oil recovery in the lower-48 is by thermal methods, including steam injection and, to a lesser extent, insitu combustion, and cyclic steam injection. These methods may not the most beneficial for use in Arctic where maintaining the integrity of the permafrost near the well bores is critically important.
- New cold production methods have less capital cost than thermal methods, but also have lower recovery efficiency.
- Use of CO2 from the produced natural gas for heavy oil development to improve viscosity means additional investment to protect against corrosion.
- Heavy Oil upgrading prior to shipment through TAPS (in concert with a Gas to Liquids (GTL) option if the natural gas pipeline is not built) could require building a complex processing plant that will also add expenses.

Offshore Infrastructure/Operational Challenges

- Large historic oil and gas discoveries will require appraisal drilling to validate reserve estimates and demonstrate commercially viability to warrant huge capital costs associated with building offshore production facilities and pipelines to shore.
    - Only one offshore field proximal (~ 6 miles) to the North Slope infrastructure has been developed
- Large additional undrilled opportunities will require exploratory drilling to validate published undiscovered resource potential
- Limited supply globally of Arctic class drilling vessels, ice breakers, anchor handlers, resupply and support vessels, and oil spill response vessels.
- No proximal deep water ports to primary operational regions (Chukchi and Beaufort Seas)
    - Impacts resupply and adds to logistical costs
- Limited “summer’ seasonal “open water” drilling window July through October
    - Possibility of further reduction of “open water” operational window in U.S. Beaufort Sea due to subsistence hunting of mammals (August 25 to mid September)
    - Daily operations that generate noise in the water column may be temporarily suspended if mammals get within a certain radius of the drilling operations
- Harsh winter season, reduced daylight, and pack ice
- Potential restrictions on number of helicopter flights, flight paths, and minimum flight altitude

Offshore Technology Challenges

- Reducing operational footprint to minimize impact on environment
    - Geophysical imaging of prospects to reduce exploration and appraisal drilling risk (minimize number of wells required to determine commercial viability)
        - Modern Seismic Data Acquisition (limit marine mammals exposure to noise)
        - Viable reprocessing of historic 2D seismic data to meet required standards
- Ice resistant production platforms/facilities designed for year round operations

- Advances in offshore pipeline trenching to bury oil and or gas pipelines safely below observed historic ice gouge depths
  - Existing Beaufort Sea opportunities (Figure 4.B.1.1, Sivulliq "Hammerhead" and Kuvlum Prospects) will require relatively short pipelines (less than 20 miles) to tie back into the North Slope pipeline network that ultimately ties into Pump Station 1 of TAPS
  - Future Chukchi discoveries will require a buried pipeline of 60 miles (minimum distance) to shore in water depths ranging from 0 – 165 feet. This will require another ~ 200 mile above ground pipeline to be built across NPR-A and a portion of the North Slope Coastal Plain to allow access to TAPS (Figure 4.B.1).
  - More remote Beaufort Sea Prospects will face challenges that are similar to those described for the Chukchi Sea
- Advances in pipeline design to mitigate the impact on permafrost where present
  - Shallow permafrost has been observed in the subsurface proximal to the Sivulliq and Kuvlum prospects in the Beaufort offshore
  - Shallow permafrost has not been observed in the subsurface at any of the prospects drilled in the Chukchi

IX.B.2 Canada Infrastructure and Technology Challenges

In Canada there are both infrastructure and technology challenges. Discussion in this section will be limited to the Canadian North Region (Canada North Onshore Basins, Mackenzie Delta/Canadian Beaufort, and Arctic Islands/Sverdrup Basin) (Figure 4.C.1.1):

Onshore Infrastructure Challenges

- Large historic oil and gas discoveries will require appraisal drilling to validate reserve estimates and demonstrate commercially viability to warrant huge capital costs associated with building production facilities and pipelines.
  - Only one onshore field (Norman Wells) has been developed (in response to oil demand and energy security for North America during WWII)
- Large additional undrilled opportunities will require exploratory drilling to validate published undiscovered resource potential
- Northernmost extent of small diameter oil pipeline is located at Norman Wells and is remote to proven and unproven accumulations (Figure 4.C.1.1)
- Harsh winter season, reduced daylight, and severe storms
- Permafrost present

Onshore Technology Challenges

- Reduced operational footprint to minimize impact on environment
  - Imaging of prospects to reduce exploration and appraisal drilling risk (minimize number of wells required to determine commercial viability)
    - Seismic Data
      - Reprocessing historic 2D seismic data
      - Focused 3D seismic data acquisition

- Production pads/facilities designed for year round operations
  - Use of extended reach, horizontal and multilateral drilling technology to minimize pad size requirements
  - Engineered to avoid damaging permafrost
  - Facilities in Mackenzie Delta designed to avoid spring floods and river ice floes
  - Pipeline routing through wetlands
- Oil spill avoidance and response capability

Offshore Infrastructure Challenges

- Large historic oil and gas discoveries will require appraisal drilling to validate reserve estimates and demonstrate commercially viability to warrant huge capital costs associated with building offshore production facilities and pipelines to shore.
- Large additional undrilled opportunities will require exploratory drilling to validate published undiscovered resource potential
- Limited supply globally of Arctic class drilling vessels, ice breakers, anchor handlers, resupply and support vessels, and oil spill response vessels.
- No proximal deep water ports to primary operational regions (Canadian Beaufort and Arctic Islands)
  - Impacts resupply and adds to logistical costs
- Limited "summer' seasonal "open water" drilling window July through October
- Harsh winter season, reduced daylight, pack ice and severe storms

Offshore Technology Challenges

- Reducing operational footprint to minimize impact on environment
  - Geophysical imaging of prospects to reduce exploration and appraisal drilling risk (minimize number of wells required to determine commercial viability)
    - Modern Seismic Data Acquisition (limit marine mammals exposure to noise)
    - Viable reprocessing of historic 2D seismic data to meet required standards
- Ice resistant production platforms/facilities designed for year round operations in highly variable water depths (10 feet to greater than 4500 feet) (Table 8.C.1)
  - Use of extended reach, horizontal and multilateral drilling technology to minimize platform size
- Advances in offshore pipeline trenching to bury oil and or gas pipelines safely below observed historic ice gouge depths
  - Existing and future discoveries will require an offshore pipeline network of 50 miles (minimum) before tying in to a yet to be built pipeline system back to Norman Wells (Figure 4.C.1.1)
  - More remote Canadian Beaufort Sea Prospects will face challenging water depths in which to lay pipeline (> 600 feet) given the limited "summer open water season"
- Advances in pipeline design to mitigate the impact on permafrost and or hydrate where present

  - Shallow permafrost and hydrates have been observed in the subsurface of the Canadian Beaufort Continental Shelf
    - Reduce possibility of subsea seafloor instability
- Oil spill avoidance and same season response capability

IX.B.3 Greenland Infrastructure and Technology Challenges

Offshore Infrastructure Challenges

- Large undrilled opportunities will require exploratory drilling to validate published undiscovered resource potential
- Appraisal wells will be required to validate future discoveries before determining if this unproven region can warrant the significant capital costs associated with the building of the development and infrastructure network
- Limited supply globally of Arctic class drilling vessels, ice breakers, anchor handlers, resupply and support vessels, and oil spill response vessels.
- Deep water ports available adjacent to primary operational regions (West Greenland) but still remote from the closest oil production (Jeanne D' Arc Basin off of Newfoundland)
  - May impact resupply and adds to logistical costs
- Variable "open water" conditions, icebergs present all year
- Deep water conditions (10's of feet to 3,300 feet)
- Harsh winter season, reduced daylight, pack ice and icebergs, and severe storms

Offshore Technology Challenges

- Reducing operational footprint to minimize impact on environment
  - Geophysical imaging of prospects to reduce exploration and appraisal drilling risk (minimize number of wells required to determine commercial viability)
    - Modern Seismic Data Acquisition (limit marine mammals exposure to noise)
    - Viable reprocessing of historic 2D seismic data to meet required standards
- Ice resistant "floating" production platforms/facilities designed for year round operations in highly variable water depths (10 feet to greater than 3,300 feet) (Table 8.C.1) or possible subsea completions with protected well heads and buried pipeline networks to protect against significant force and ice gouges produced by omnipresent icebergs
  - Subsea pipeline networks tied back to "floating" production facilities or to onshore production gathering facility
  - Use of extended reach, horizontal and multilateral drilling technology to minimize platform size
- Advances in pipeline design to mitigate the impact on permafrost and or hydrate where present
  - Shallow permafrost and hydrates have been observed in the subsurface of the Canadian Beaufort Continental Shelf
    - Reduce possibility of subsea seafloor instability

- Oil spill avoidance and same season response capability

IX.C Lease Terms

Existing 10-year lease terms are not long enough to ensure sustained exploration and appraisal of material oil and gas resources in the U.S. Arctic onshore and offshore basins. Infrequent lease sales, lengthy multifaceted permitting procedures, and high incidence of litigation coupled with short drilling windows (onshore winter and offshore summer) reduce the ability to identify, appraise and develop economic volumes in this short time span. It can easily take four to five years from first permit application until the initial exploration well can be spudded if there are no litigation delays. Current regulatory practices and policies make it extremely difficult to perform more than one of the required sequential activities (acquire seismic data, acquire shallow hazards data, drill a well) in a single year.

- 10-year leases in the U.S. Arctic would be barely adequate if:
    - A coordinated regulatory process was in place between Federal and State agencies, for the complex overlapping permits required to conduct an effective exploration program
        - seismic acquisition (3D and shallow hazards)
        - exploration and appraisal drilling program
    - Regulatory bodies were adequately staffed to evaluate and process the permit applications in a timely fashion
        - enable cost effective business planning for both the industry and the regulators
    - Litigation injunctions were limited to reasonable complaints
    - If simultaneous exploration activities such as seismic acquisition, shallow hazard acquisition and drilling planned by several operators (in the same OCS area) to be conducted by more than one operator were supported by the permitting agencies
        - Regulations can potentially constrain any operator's activity because of similar activities planned by another operator in the same OCS area in the same season
    - Post-discovery unitization rules and procedures recognized the limited drilling windows and thus the slower pace of appraisal
    - If a sufficient supply of ice class drilling and marine equipment were readily available

- Fortunately unitization rules may extend the duration of the lease if the leasee can demonstrate that producible hydrocarbons discovered in the exploration well(s) might be commercialized and make a good faith effort to mature development plans
    - A significant issue is that marginal discoveries (sub economic) may not justify the capital required to develop and then must be dropped. Thus there is no option to hang on to those leases beyond 10 years, unlike the Significant Discover License (SDL) process utilized by Canada, even though significant investment was made to bring the lease to the point of discovery.

  - The lease term on multiple leases within a prospect should be extended based upon a single successful exploration well. Given the long lead time required to permit and drill an exploration well, industry will be reluctant to drill on large prospects late in the lease term because of risk that much of the discovered volumes may be subsequently lost before appraisal drilling can be conducted to extend the term of the adjoining leases.

- Canada's SDL process enables the companies to hold onto the acreage covering the marginal discovery until infrastructure is in place, whereas in U.S. unit extensions must be negotiated and renewed periodically. This level of effort to protect a lease for a marginal find may serve to discourage new entrants into the Alaska Arctic.

IX.C.1 Onshore U.S. Longer Lease Terms Required

On Alaska's North Slope, off-road travel is limited to the winter months, and only then allowed when the ground is sufficiently frozen and there is adequate snow cover to protect the flora. Snow packing and ice road building across the tundra are necessary and required for work activities such as seismic shoots, pipeline maintenance and to move drilling rigs in and out for exploration activity. During summer months the existence of marshy tundra precludes exploration related construction activity. The winter only work season leads to drilling and appraisal programs spread out over multiple years because of the limited number of work days available for on-site work during the winter months. Moreover, the number of available work days in a given winter season fluctuates from year to year. In 1970, the winter exploration season lasted for over 200 days. More recently the number of days available for winter exploration and off-road travel has reduced to just over 100 days. Using the best available methods and assuming no permitting challenges, exploration in remote Arctic areas can take to five to seven years to identify and prove up a commercial discovery, and then years more to plan and build the infrastructure to develop and produce that resource (Table 9.C.1).

Onshore and State Waters Development Time			
Fields	**Discovery**	**Sanction**	**First Oil**

Nikaitchuq (State Waters)	2004	2008	2011
Oooguruk (State Waters)	2003	2006	2008
Liberty (Federal Offshore)	1982	2008	2013??
Seal/Northstar (State/Federal Offshore)	1984	1996	2001
Alpine (Onshore)	1994	1996	2000
Alpine West (Onshore)	2001	???	???

Table 9.C.1 Time from discovery to first oil for several Onshore and State Waters Fields.

Accomplishing this prior to the expiration of a typical 10-year lease term is a challenge for even the most efficient and technically competent companies. In addition to having a limited number of days available to work each year of the 10-year lease term, there is also the very real possibility, or even expectation, that permitting and litigation delays will occur, further slowing the progression towards an online producing developed discovery. The combination of winter only arctic work windows with significant litigation and delay risk creates a serious disincentive to conducting exploration and development activity, which, in turn, could jeopardize the medium to long term development of the U.S. Arctic, a major U.S. based oil and gas prone province.

IX.C.2 Offshore U.S. Longer Lease Terms Required

The current lease terms in the Arctic are identical to that in the Gulf of Mexico (GOM) OCS despite the significant differences in operating season length and regulatory restrictions on activity. Broadly speaking, the lease requires the Operator to be in the position, at the end of 10 years, to negotiate with the BOEMRE and define an exploration or production unit that accurately defines the potentially productive area for their discovery. Failure to capture a unit designation from the BOEMRE could result in the loss of the leases that cover the potential field. Once the unit designation is granted the Operator is required to make a good faith effort to mature development plans.

Some of the major inconsistencies with the GOM policy as applied to the current duration and retention terms for U.S. Arctic leases are as follows:

- In the GOM one has access to a 365 day operating season (excluding occasional hurricanes) whereas in the U.S. Chukchi and Beaufort Sea you would be fortunate to have access to 30 – 40% of those days for drilling, and less for seismic acquisition
- In the GOM, one has access to a wide variety of available drilling equipment, both locally and on a worldwide basis. In the Arctic such drilling equipment is rare and may require either a new build or significant modifications to make it suitable for service in the Arctic environment. No allowance is made for this "non-productive" time involved in securing and preparing such drilling systems for work in the Arctic environment

- As previously mentioned, the seismic acquisition season is also similarly limited thus taking a longer time to develop targets to the drilling stage than would be common in the GOM
- Unlike the GOM simultaneous operator or industry activities are constrained in the U.S. Arctic by regulatory policies and practices. Such constraints may result in an operator being unable to progress a project in a given year despite a desire and willingness to do so.
- With all of these impediments, the Operator needs to acquire sufficient seismic, analyze and define objective targets, acquire site-specific shallow hazards data, access a limited supply of specialized drilling and ice management equipment, and drill and discover a possible large hydrocarbon accumulation. This discovery will need to be further defined by appraisal drilling (several appraisal wells to define the trap, demonstrate adequate reservoir capable of production and sufficient in place volumes of oil and or gas) before the Operator can consider commercial development scenarios and potentially be ready to commit the capital required to move forward with production plan. If one were fortunate enough to make a discovery and complete all of these steps only to find that the field was sub-economic (not uncommon in a new Arctic basin with no limited offshore infrastructure) then the net result would be that the termination of the lease after the 10 years had expired. These restrictive conditions do not encourage exploration and appear contrary to what should be the goal of any leasing system policy; exploring for and producing hydrocarbons in a safe and environmentally responsible manner.

All of the above issues when considered together represent a significant disincentive to exploration in the U.S. Arctic offshore and, to a large extent, places the U.S. out of step with other Circum-Arctic countries (Canada, Greenland, Norway and Russia).

There is considerable scope for the development of new U.S. government policies in this area which would provide a level playing field for Arctic explorers while, in no way, compromising the high standards of safety and environmental protection that will be required in this area.

Adopting some form of the Canadian Significant Discovery License (SDL) concept for use in Alaska's Arctic province could help mitigate these disincentives.

IX.C.4 Onshore and Offshore Canada Longer License Terms Required

In the case of Canada, the original exploration license terms of 9 years were originally conceived for the Continental Shelf (0 – 100 m water depth) where the targets were relatively shallow and straightforward. If an exploration well found trapped oil or gas during the nine year term, the operator would then be granted a SDL and would be able to hold on to the license till sufficient export infrastructure in place to support development. Exploration focus in the Canadian North (Beaufort Sea) is now moving further offshore into deeper water (>100m water depth) with a more challenging ice regime (Table 8.C.1), targeting giant and potentially more complex prospects. Here a new generation of arctic drilling and marine equipment is required to maintain a +120 day operating season. These new exploration challenges (water depth and ice regime) environment will require new build drilling systems (drillship and ice management fleet) which will necessitate a 3 – 5 year design and construction period. This new fleet has yet to be commissioned and the clock is ticking on the relatively "new" 9 year licenses that were first awarded in 2007.

The exploration license term is the same for the Canadian East offshore margin, where year round operations may be possible depending on the area (Table 8.C.1).

Although the Canadian Exploration License Term may be adequate for now, extending the duration of the exploration license terms might be warranted for those regions with reduce operating windows due to harsher environmental conditions.

IX.C.5 Onshore and Offshore Greenland Longer License Terms Required

The Greenland Regulatory and Lease Terms and Conditions are continuing to evolve however they have been receptive to the key issues surrounding License Duration and Retention. As such, they currently have offshore drilling activity and just completed a highly successful lease sale for NW Greenland with a further licensing round for NE Greenland to take place in 2012. The pending NE Greenland licensing round will feature a term of 16 years given the harsh operating climate (Table 8.C.1).

Greenland has worked closely with Canada on addressing any cross border issue and it is expected that this dialogue will continue.

IX.D Regulatory Uncertainty

IX.D.1 Onshore and Offshore U.S. Regulatory Uncertainty

There is no clear, dependable, regulatory path for gaining approval of submitted exploration or development permit applications. This is due to a multitude of U.S. Government agencies/regulatory bodies (BOEMRE, EPA, NMFS, NOAA, BLM, USCG, USFWS, etc.) which have overlapping authority, and each have their own independent permit review and approval schedule.

The Alaskan region (onshore and offshore) holds about a quarter of America's remaining proved oil reserves and about one-eighth of its proved natural gas reserves. Alaska's potential energy resources are world class in scale. Converting these potential resources into actual producing reserves requires a clear and dependable regulatory path to exploration and development approval.

- Lead times required for permitting, and the uncertainty of obtaining the required permits leads to project schedule uncertainty, wasted capital (human and fiscal resources), and significant investment risk.
- Agencies increasingly require oil companies to collect and report scientific baseline data over multiple years prior to any decisions to allow exploration and appraisal drilling,

shifting costs that should be part of the agency's management mandate, from the public to the private sector, with no promise of granting permission to move forward with development. This practice also reduces the effective duration of the leases for exploration activities and will lead to industry being unable to drill many leases prior to lease expiry.

- The national focus on preserving the perceived pristine nature and wildlife of the Alaskan and North Canadian Arctic region frequently leads to court challenges.
- The need to mitigate impact on subsistence lifestyle frequently requires operations to be interrupted. For example, coastal and near-coastal exploration and development activities may need to be suspended locally during migration periods and subsistence activities such as whaling.
- The EPA has had little to no experience issuing offshore air quality permits for offshore exploration drilling programs, especially in the Arctic. This has led to extensive delays and permits with conditions which are more applicable to on-shore stationary sources. Unfortunately, often the premise for procedures in receiving air permits is based more on administrative requirements than actual protection of air quality. Further, industry has constructed multiple air monitoring stations in remote locations in the Arctic to gather necessary data for input into the air models to support both PSD major source, and minor source permits.
- Dismantlement and removal of infrastructure, including gravel pads and road, when no longer needed for operation. (The alternative is not to remove them, rather leave them to provide insect relief for animals, or for potential building sites in the future.)
- Marshy tundra precludes summer exploration and construction. The limited work season, generally not more than five months out of the year, leads to multi-year drilling programs because of limited time available for on-site work.
- Need to develop new technologies for ice road building, especially in foothills of the Brooks Range. For example, how do you build an ice road that needs a 5% grade and then safely move heavy machinery up or down it?

Blocked access, both onshore and offshore, can occur for a variety of reasons such as permitting delays, court challenges, and uncertainty over which agency or level of government has primacy with respect to a specific permitting issue (overlapping jurisdiction and rules). Access challenges thwart exploration or development and discourage investment in developing Alaska's vast energy potential.

Operator's increasingly find themselves in the difficult position of having conducted costly data acquisition in accordance with the terms and conditions of the mineral lease granted by the leasing authority, often having invested tens of millions of dollars early on in the history of a lease, only to find that exploration or development of a commercial discovery is stymied by any one of the multiple agencies involved in the permit approval process. Agencies involved in on-shore permitting decisions can represent overlapping, and at times conflicting, Local, State and Federal jurisdictions. Local permit stipulations may contradict or violate Federal requirements, or vice versa, leading to difficult catch-22 situations which effectively block exploration and development. Access to the highest potential areas ends up blocked (in the case of ANWR 1002 area), or subject to significant permitting uncertainty and delay (in the case of NPR-A). Attempts by Conoco-Phillips to expand development of its Alpine area into the easternmost part of NPR-A have been delayed by permitting issues for approximately 3-4 years despite robust support from the Local and State agencies involved, including the Governor of the State of Alaska and the local indigenous subsistence population.

In the offshore Chukchi and Beaufort Sea OCS areas the regulatory environment is very complex and subject to frequent changes from new regulations from the Department of Interior. Concurrent permits are required for most planed lease activities and must be sought from several Federal and State of Alaska agencies. Attempts by Shell to conduct exploration well operations in the Beaufort and Chukchi have been held up since 2007 due to permit delays, litigation against the BOEMRE and Presidential moratoriums (2010 post Deepwater Horizon incident in Gulf of Mexico). Currently all future lease sales in the Chukchi Sea and Beaufort Seas under the 2007-2012 Five Year Program have been cancelled. Leases awarded by the BOEMRE in the Chukchi Sea (OCS Sale 193) are still being challenged in court.

Permitting uncertainty and risk degrades venture (exploration and development project) economics and can turn an otherwise economic project into a money losing proposition. Unpredictable permitting processes create schedule delays and investment uncertainty, ultimately leading to poorly allocated financial and human resources and the redeployment of capital into more favorable regions, leaving even areas with world class potential such as Alaska, untapped and undeveloped. Potential Alaska exploration and development projects must be able to compete on a global stage (Arctic or sub-Arctic) with other investment opportunities. A clear and dependable regulatory path to permit approval must be available in order to realize the enormous resource potential of the North Slope and surrounding offshore areas and allow Alaska to compete on the global stage.

IX.D.2 Onshore Canada Regulatory Uncertainty

The regulatory system in Canada is relatively complex and opaque because of the 3 levels of government (Federal, Provincial/Territorial and Aboriginal) and the ongoing devolution process (Figure 9.D.2.1). [14] One example is the recent Joint Review Panel (JRP) hearing for the Mackenzie Gas project; The Proponents' Environmental Impact Statement (EIS) was submitted to the JRP on October 7, 2004. On July 18, 2005, the Panel issued a Sufficiency Determination in which it concluded that there was sufficient information to proceed to the hearings phase of its review, subject to certain further information being filed within a time frame prescribed by the Panel. The Panel's public hearings began in Inuvik on February 14, 2006 and concluded in Inuvik on November 29, 2007. The Panel held 115 days of hearings in 26 centers and northern communities. The Panel heard directly from 558 presenters, as either individuals or as representatives of groups or organizations. The JRP final report was issued in the end of December 2009. The report included 176 recommendations intended to mitigate the potential adverse impacts of the project on the environment and the people living in the project area (Foundation for a Sustainable Northern Future) that the various governments, regulators and proponents evaluated and commented on before the NEB issued its "Reason for Decision" 16-Dec-2010.[15] The NEB decision was then handed to the Federal cabinet for approval before it came back to the NEB who then issued a Certificate of Public Convenience and Necessity for the Mackenzie Valley Pipeline 10-Mar-2011. The next step is the various permits required; the MGP proponents estimate that they will have to apply for over 6,000 permits before the construction can begin.[16]

The various government bodies are well aware of the challenges and INAC commissioned a report called 'The Road to Improvement' by Mr. Neil McCrank[17] the Federal Minister of Indian Affairs and Northern Development's Special Representative for the Northern Regulatory Improvement Initiative, which highlights the challenges and suggests a path forward.

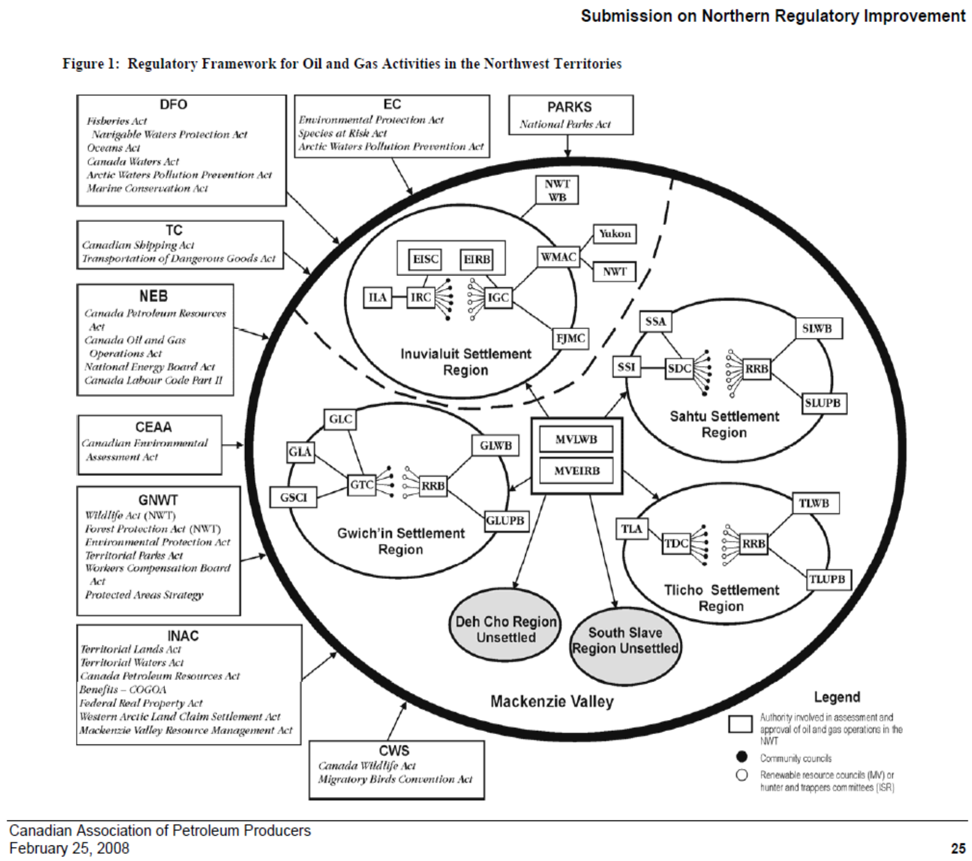


Figure 9.D.2.1 - Overview of regulatory framework from CAPP's submission to Mr. McCrank's study group. [14]

<u>IX.D.3 Offshore Canada Regulatory Uncertainty</u>

While the Canadian approval system can often be lengthy it is more in need of a tune-up than a major overhaul. A good working relationship exists between the Regulator and Industry and numerous offshore wells have been successfully permitted over the years. One important difference between the Canada and the U.S. is that it is the responsibility of the Operator to obtain the Environmental approvals. At first sight this may seem more onerous but, in reality, it allows any issues to be addressed up front between the local stakeholders and both the Operator and the Regulator and, generally, has been reasonably effective. Ongoing efforts are being made to streamline the approval system and this will continue to be an evolutionary process

Not unlike in the U.S., due to Regulator imposed drilling safety hearings we essentially have a cessation to the processing of any drilling program approvals. As mentioned previously, Industry is effectively in a "Force Majeure" situation but with no recourse to "stop the lease clock". Currently, it would appear that seismic operations may still be permitted but in face of the associated regulatory uncertainty this is a disincentive to activity at this time. There is a great need, in both the U.S. and Canada, to address this issue in a fair, reasonable and timely manner.

IX.E Impact of Merchant Marine Act of 1920 (Jones Act)

This section applies only to the U.S. as it refers to U.S. Federal law

The Merchant Marine Act of 1920, codified in 2006, and is better known as the Jones Act. The Act requires all goods transported by water between U.S. ports be carried in U.S. flagged, constructed, owned and operated vessels. No commercially available U.S. flagged ice-classed vessels are available for U.S. Arctic.[18] Thus the potential cost to operate in the U.S. Arctic is noticeably higher, impacts project economics and makes it difficult to compete in a global market. Either exemptions are required to use foreign flagged vessels or excessive costs can be expected to comply with this statute.

It is already well documented that the Jones Act has added a real, direct cost to consumers, particularly those in Alaska and Hawaii.[19] Since 1970, 19% of the merchant ships built in U.S. shipyards have been built for the Alaska trade, 97% of which is south bound crude oil. These higher costs translate to large minimum field size required to obtain a return for the larger investment and risk of Arctic exploration and development. Prospects would necessarily need to be at least 360 million barrels to breakeven and the odds of finding such a giant are 1 in 20 versus a 1 in 7 chance if the minimum size required was 100 million barrels.[20] Only part of the cost of Arctic oil and gas development is carried by tankers, yet a 52% reduction in transportation cost could be realized if foreign-flagged tankers were not barred by the Act.[21]

Tankers are just part of the impact. In 2007, Shell Oil used foreign flagged anchor handlers for its exploration activities in the Arctic OCS. As no U.S. anchor handlers existed at the time, Shell was granted a temporary waiver. The temporary exemption was extended in October of 2010 until 2017 if the oil companies agreed build an American boat.[22] The 342 foot boat is being built at a cost of 150 million dollars and will be doubled hulled and able to break first year ice.[23]

The future development of offshore U.S. Arctic resources could also be impacted by this legislation due to the lack of modern U.S. ice breakers. The U.S. currently only has three ice breakers all of which are operated by the U.S. Coast Guard (USCG); the Polar Sea and Polar Star both of which were built in the 1970's are currently out of service, and the Healy which was commissioned in 1999 and does not possess the icebreaking capacity of the other two vessels.[24] These older U.S. icebreakers use an old technology of using contoured bows to allow the ship to ride up on the ice and crush the sheet ice with the vessel's bulk weight.[24] By contrast, the other Arctic nations have a more modern and substantial fleet of ice breakers at their disposal and they are continuing to add to their inventory: Russia 18, Finland 7, and Canada 6. Modern innovations in non-U.S. flagged ice breaker design include: 1) diesel-electric drive technology; 2) the installation of electric drive propellers (an azimuthal propulsion system) on the stern allowing the vessel to carve through ice (Figure 9.E.1); and 3) the capacity to store oil and also serve as a tanker.[25, 26] The result is that non U.S. ships with ice breaking capability now have the capacity double as a tanker and transport oil, and in the future similar vessels may be able to tanker LNG.

Figure 9.E.1 – Image of Aker Arctic Technology double acting ice breaking tankering vessel.[26] Stern of vessel is actively transiting through ice towards viewer.

The Jones Act is believed to stand in the way of shipping Alaska's North Slope gas from Valdez to America's West Coast. Sempra LNG, one of the company that for a time was proposing to build a gas pipeline from the North Slope to Valdez, briefed the Alaska Legislative Budget and Audit Committee that the U.S. has lost the ability to globally compete in the building and shipping of LNG, as the cost of a LNG carrier is 3 times the cost for the same vessel on the open market.[27] Currently there are 125 LNG carriers on order or being built globally none of which are being constructed in the U.S.[28] Further, the status of the 16 U.S. flagged LNG tankers are as follows: 12 are available, 1 is out of service indefinitely, and 3 have been scrapped.[28] Sempra estimates the shipping cost of LNG to be 35 cents per million BTU with a Jones Act waiver as compared with and Jones Act compliant cost of $1.30 per million BTU.[28]

Most recently, Alaska's senators are again looking for a waiver of the Jones Act to bring a drilling rig to the Cook Inlet region of Alaska.[29, 30] The high cost associated with bringing a Jones Act compliant rig to explore in this mature basin, for the benefit of the greater Anchorage consumer market, is not economical.

It should be noted that no similar legislation exists in Canada, thus operators have the ability, with modest duty payments, to utilize foreign flagged vessels that meet current regulatory standards. If a Canadian vessel of similar capability be available, then preference may be given to utilization of that vessel.

IX.F Year Round Tanker Transportation

Year round tanker transportation of crude oil from the Russian Arctic to market is presently viable and will become increasingly used as the ice pack recedes.[31] Tankering offers greater flexibility of evacuating crude oil from multiple onshore or offshore development facilities than new pipelines. Possible lower transport costs will in turn increase the economic viability of projects and therefore will enable the potential for future increased production. This form of transportation could be equally viable for the export of proven, undeveloped "stranded" reserves and undiscovered potential reserves from the North American Arctic (U.S., Canada and Greenland).

Satellites recorded the opening of the Northwest Passage in September of 2007 (Figure 9.F.1),[32, 33] a short cut between Europe and Asia via the North American Arctic, that had been sought since European explorers started seeking the discovery of new trade routes in the 15th century. The importance for the Arctic oil and gas resources is that tanker transportation may now take crude oil to market and will more likely be a viable and cost competitive alternative to pipeline transport. This is not a new idea as in August 1969 Exxon tested the concept in hopes of proving tankers viable for transportation of the Prudhoe Bay crude oil.[25] After modifications, the S.S. Manhattan, a U.S. tanker, was escorted by a Canadian icebreaker on a round trip voyage which successfully passed through the Arctic waters (Figure 9.F.2).[34] The idea was shelved when the subsequent winter voyage proved unsuccessful.

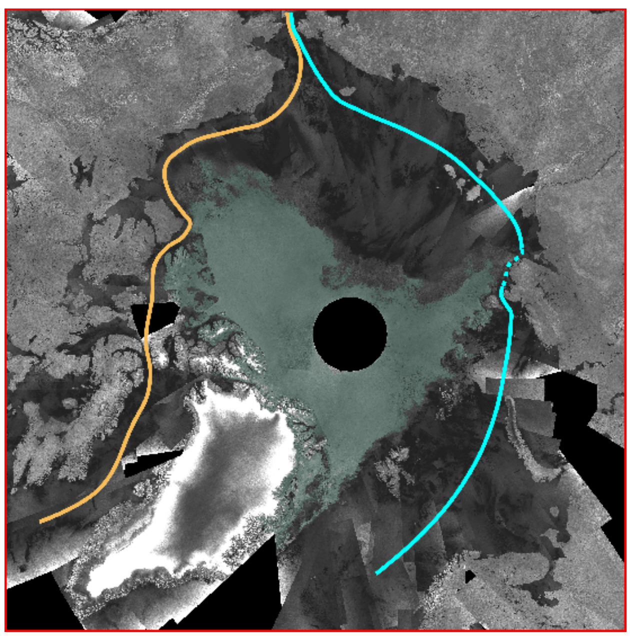


Figure 9.F.1 - Envisat mosaic of Arctic Ocean circa 2007. The yellow line shows the fully navigable passage through the Northwest Passage (between the gray colored Northern Canada and the greenish ice pack), while the aqua line shows the partially blocked route along the Siberian Coast.[32]

Figure 9.F.2 - Canadian icebreaker and the Esso S.S. Manhattan carrying a symbolic barrel of Alaska North Slope crude oil to the U.S. East coast.[34]

Analysis shows that transport by tanker is lower cost and more flexible than new pipelines to evacuate crude from multiple onshore and offshore locations in the Arctic.[35] The TAPS tariff is about $4.50 per barrel transported overland approximately 1000 pipeline miles in the 48" pipeline. The same barrel transported from the pipeline terminus at Valdez to America's West coast is believed to incur only ½ the cost despite being 2 to 3 times the distance depending on the landing destination. This is consistent with crude oil transportation prices from the Persian Gulf or West Africa to the Gulf of Mexico which averages $2.16 per barrel.[35] Lower transport costs increases the economic viability of projects and therefore increases production potential.

Currently there are the discovered oil fields in the Beaufort Sea, which according to the BOEMRE, are undeveloped in part due to the distance to established infrastructure. The Sivulliq field with 200 million barrels, the Kulvum field with 400 million barrels and the 150 million barrel Sandpiper field are current examples of stranded oil due to economic viability.[3, 36] At present, any discovery in the adjacent Chukchi Sea would likely require a new 75 mile subsea pipeline followed by a new 200 mile pipeline onshore across the NPR-A. In addition to a multi-billion dollar infrastructure addition, the timeline is estimated to add 10-15 years to the delivery of any oil and gas found.

In the Russian Arctic, reinforced ice-breaking oil tankers are being loaded for export to North American and European markets via an offshore fixed ice resistant floating storage tank about as far north of the Arctic Circle as Prudhoe Bay. The sea export system transports Russian Arctic Crude oil at minimum cost and in quantities expected to be as much as 240,000 barrels of crude oil per day.[31] The tankers possess a 70,000 ton deadweight capacity and have been specially built for Arctic transportation of oil to Murmansk. The oil is then is transferred to tankers at Murmansk and these in turn transport the oil to the U.S. east coast market. These facilities are handling the Yuzhno Khylchuyu field producing 150,000 barrels of crude oil per day which in turn is expected to become an important contributor for increased oil production in Russia.[37] Plans are also in the works for two oil tankers, accompanied by ice breakers, to head east from the same Russian facility, to test a commercial voyage to Southeast Asia.[38] If successful the voyage will demonstrate Russia's potential ability to deliver oil and gas from its Arctic fields to the western U.S. markets and further increase their market share.[39] Russian oil imports to the U.S. went from zero to 100,000 barrels per day in 2010 and they are expected to increase their current 4% share of the U.S. market, as Alaska production continues on decline.[40]

Similar tankering capability is currently employed in the Norwegian Barents Sea and the Norwegian Barents Secretariat predicts that oil tanker traffic in this arctic region could increase to 2 Million barrels oil per day within the next 5 years.[41]

Enabling this tankering capability in the North American Arctic may help unlock the commercial potential of region and should be seriously considered as a viable hydrocarbon transportation option in the near future.

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X. PRODUCTION FORECAST SENARIOS SUMMARY

X.A Arctic Supply Cases

Given that no overall N. America Arctic supply outlooks could be found in the public domain (although there are a few basin specific analyses for portion of Alaska and Canadian Arctic), [1,2,3,4,5,6,7,8,9] the Arctic Subgroup developed three (3) consensus cases - Reasonably Constrained, Most Likely and Reasonably Unconstrained. The adjective "Reasonably" is used with care; it does not imply that all constraints are either turned on or turned off. It represents the Subgroup's informed view of what may happen to Arctic development through 2050 given economic, regulatory and environmental constraints that either are less, or are more, favorable to such development.

The 3 cases each outline a different oil and gas production scenario for major current or future developments (Figure 10.1.A). Large, remote severely-stranded resources (e.g. Canadian Arctic Islands, NE Greenland Rift Basin, etc.) and unconventional resources (e.g. CBM, methane hydrates, etc.) have not been included, as the Subgroup considers their supply impact to be relatively small prior to 2050.

Reasonably Constrained Case	Most Likely Case	Reasonably Unconstrained Case
No AK gas pipeline	AK gas pipeline 4.5 BCFD, 2025	AK gas pipeline expansion 5.9 BCFD, 2035
No Mackenzie gas pipeline	Mackenzie gas pipeline 1.2 BCFD, 2025	Mackenzie gas pipeline expansion 1.8 BCFD, 2035
No Chukchi, Beaufort OCS or Canadian Beaufort Production	N. Alaska Onshore, Chukchi & Beaufort OCS and Canadian Beaufort Production 15% resource developed by 2050	N. Alaska Onshore, Chukchi & Beaufort OCS and Canadian Beaufort Production 25% resource developed by 2050
TAPS offline 2030$^{+/-}$	TAPS ~300 KBD	TAPS ~500 KBD
Grand Banks oil current decline only Hebron developed	Grand Banks oil slow decline few satellites developed	Grand Banks flat oil production
No Sverdrup/Arctic Islands, Labrador or Grand Banks gas	No Sverdrup/Arctic Islands, Labrador or Grand Banks gas	Labrador and Grand Banks gas 10% resource developed by 2050
No E Canada “Baffin Bay” or W Greenland oil	No E Canada “Baffin Bay” or W Greenland oil	E Canada “Baffin Bay” and W Greenland oil10% resource developed by 2050

Figure 10.A.1. - The Three (3) Hypothesized N. America Arctic Supply Case Scenarios.

A description of the Relatively Constrained, Most Likely and Relatively Unconstrained scenarios for each major development follows.

X.A.1 Alaska and Mackenzie Gas Pipelines

The EIA's AEO2011 (Annual Energy Outlook 2011) [7] excludes an Alaska or Canadian Mackenzie gas pipeline for the first time in recent Annual Outlooks. This is largely due to the EIA's substantially increased forecast of U.S. L48 unconventional gas (shale gas) supply (Figure 10.A.2).[8,9] However, the Subgroup considers that of the three proposed gas pipeline projects (Denali, TransCanada and or Mackenzie Valley systems) [10,11,12] that an Alaskan and a Canadian gas pipeline network (or some variation) will be built and will deliver gas from North Alaska and the Mackenzie Delta/Canadian Beaufort into Western Canada and the lower U.S. by 2025 at capacities proposed by their project sponsors in the Most Likely Case (Figures 10.A.3, 10.A.4 and 10.A.5). It should be noted that the proposed Denali Gas Pipeline was terminated on May 17, 2011 due to lack of customer support (see Section V.B for further discussion).[10]

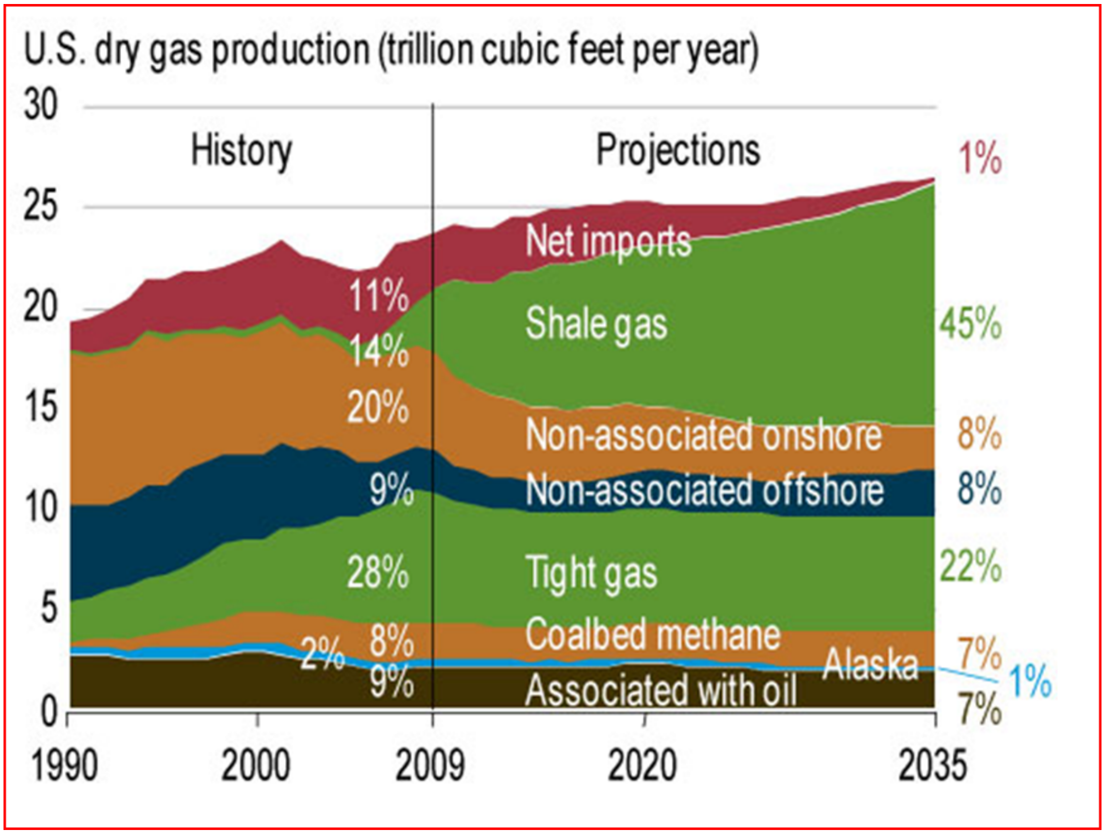


Figure 10.A.2 - Historic vs. projected U.S. gas production (note expanding shale gas wedge).[9] **Depicted Alaska gas production most likely for Cook Inlet.**

Figure 10.A.3 - Denali Gas Pipeline that was championed by ConocoPhillips and British Petroleum.[10]

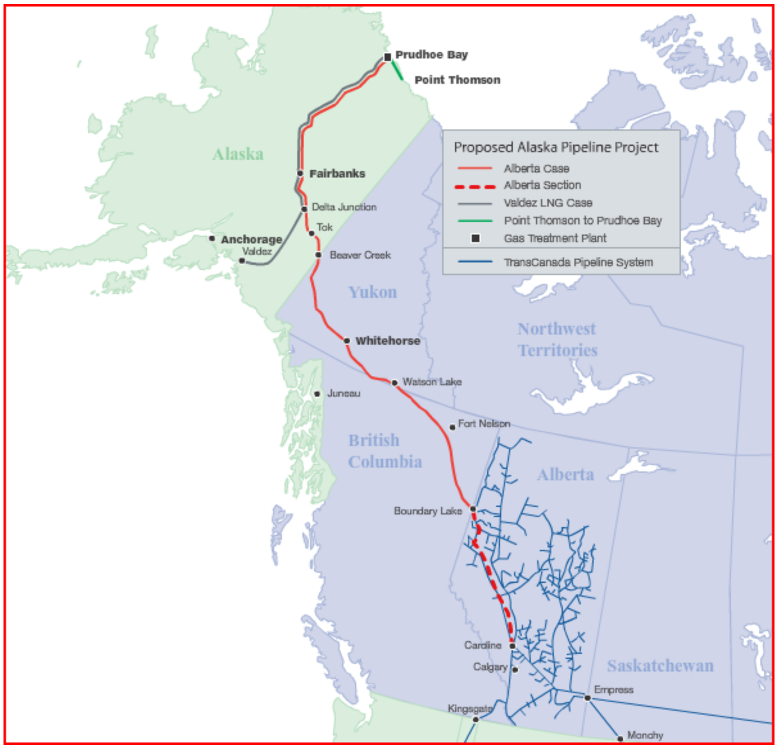


Figure 10.A.4 - TransCanada Gas Pipeline still championed by Trans-Canadian and ExxonMobil.[11]

Figure 10.A.5 - Mackenzie Valley Gas Pipeline championed by Imperial Oil, ExxonMobil Canada, Shell Canada, ConocoPhillips Canada and The Aboriginal Pipeline Group. [12]

In the Reasonably Constrained Case, these pipeline systems and their associated field developments will not be built, thereby stranding approximately 73 TCF of discovered gas (N. Alaska onshore & offshore, Canadian Beaufort/Mackenzie Delta and Canada North Onshore Basin) in the Arctic.

In the Most Likely Case, these pipeline systems will have been built to access both the North Alaska and Canadian Beaufort/Mackenzie Delta gas at capacities proposed by their project sponsors thereby providing a collective production potential of 5.5 BCF/day (~ 2 TCF/year) in 2035. On the Alaska side this would amount to 1.6 TCF/year with a further 0.4 TCF/year from the Canadian Mackenzie Delta/Beaufort region. Gas production from this region is assumed to be flat through 2050.

In the Reasonably Unconstrained Case, the pipeline systems will have been built to access both the North Alaska and Canadian Beaufort/Mackenzie Delta gas, as in the Most Likely Case, and expansions completed by 2035 at capacities proposed by their project sponsors. This scenario would provide a collective potential production of 7.7 BCF/day (~ 2.9 TCF/year) in 2035. On the Alaska side this would amount to 2.2 TCF/year with a further 0.7 TCF/year from the Canadian Mackenzie Delta/Beaufort region. Gas production from this region is assumed to be flat through 2050.

X.A.2Labrador and Grand Banks Offshore Gas

Although there is approximately 66 TCF of discovered, undeveloped, and risked, undiscovered gas resource offshore the Labrador and Grand Banks region (as described in Sections IV.C.2.b and VI.C) the Most Likely Case assumes no material volumes can be competitively brought to market competitively by 2035. This does not imply that the substantial gas resource in this region will never be developed, only that it will start to be developed sometime prior to 2050.

Because there is no development in the Most Likely Case, it follows that there will be no supply in the Reasonably Constrained Case by 2035.

However, for the Reasonably Unconstrained Case, the Subgroup used a Delphi approach to suggest that approximately 10% of the gas resource (~7 TCF of cumulative production) by 2050. The Arctic Subgroup assumed that this production would begin sometime post 2035 at a rate of 1.4 BCF/day (~0.5 TCF/year).

X.A.3 Existing TAPS Infrastructure Discussion, TAPS Assumptions, and the Resultant Chukchi, Beaufort OCS, North Slope Alaska and Mackenzie Delta/Canadian Beaufort Development/Production Forecast Scenarios

There has been much conjecture about the minimum oil throughput for the 800 mile TAPS based on engineering and commercial reasoning. TAPS was designed to transport ~ 2,100,000 barrels oil per day and is currently averaging ~ 650,000 barrels a day in throughput.

In their 2008 analysis the EIA[13] forecast that *"In the AEO2008 reference case, Alaska crude oil production (without ANWR) declines from 714,000 barrels per day in 2006 to about 520,000 barrels oil per day in 2014. After 2014, Alaska oil production increases due to the discovery and development of new offshore oil fields that are expected to be found off the North Slope. These new fields raise Alaska oil production to about 700,000 barrels per day in 2020. After 2020, Alaska oil production declines to about 300,000 barrels per day in 2030".* The EIA also stated their opinion that *TAPS "is believed to be uneconomic to operate once the oil throughput falls below 200,000 barrels per day"* [13] and made the case that production from the ANWR 1002 area would potentially extend the lifetime operation of TAPS well beyond 2030.

The EIA[13] concludes that TAPS will be offline sometime after 2030 if production from the ANWR 1002 area is not permitted and the Arctic Subgroup has used this for the Reasonably Constrained Case. This scenario would strand significant discovered and undiscovered reserves (~ 1 – 2 Billion barrels oil) and significantly alter the economy of the State of Alaska.

In contrast to the EIA's assumption, Alyeska's Pipeline Service Company President Tom Barrett[14] told the Alaska House Resources Committee *"that the trans-Alaska oil pipeline system, known as TAPS, had come close to the brink of a major outage when forced into a winter shutdown following an oil leak in January at pump station one, at the northern terminus of the line."* and later in Juneau *"was…talking to the House Finance Committee, reiterating his concerns about declining oil flow through the line and saying that the pipeline is already at a point where cooling of the slowly flowing oil as it travels from Prudhoe Bay to Valdez could lead to a major disruption in pipeline operation.* He was further quoted as saying *"A lot of people have asked me, at what point will the declining flow of crude oil become a problem for TAPS, for Alyeska,…And the response is simple — the problem exists out there now. This is not something facing us down the road; it's not theoretical; it's an issue we confront at TAPS daily, today. And without increased throughput in the line, our challenges of operating the line safely will increase over time…* our *bottom line is pretty simple and straightforward: We need more oil in the pipeline … TAPS viability, in all honesty, depends on the political will for oil development; it depends on it in Washington and it depends on it in Alaska. And so we need help to get safe and responsible production in Alaska; it's urgent and it's critical."* This assertion is supported by a major recent study on TAPS operational issues and challenges.[15]

In spite of the preceding discussion, the Arctic Subgroup assumed that TAPS will still be operating with a flow rate of approximately 0.3 Million barrels/day in the Most Likely Case, based on the development of additional accessible onshore and offshore resources as described in Sections IV - VII and IX. In the Reasonably Unconstrained Case, TAPS throughput is increased to approximately 0.5 Million barrels/day.

X.A.3.a Chukchi, Beaufort OCS, North Slope Alaska and Mackenzie Delta/Canadian Beaufort Development/Production Forecast Scenarios

In the Most Likely Case, the Subgroup considers that there will be inevitable development of these hydrocarbon prone areas, even though there are some currently unfavorable circumstances. Using a simplified Delphi approach, it was agreed that approximately 15% of the potential risked resource, both discovered and undiscovered, from these collective areas (excluding the ANWR 1002 area), or approximately 11.4 Billion barrels oil equivalent would be developed through 2050. Based on this premise, the most likely production for the North Alaska region in 2035 would be ~0.6 Million barrels/day (~211 Million barrels/year). This includes a normal decline of current Alaska North Slope production to 0.28 Million barrels/day, augmented by new discoveries totaling 0.3 Million barrels/day from the North Slope, North Alaska State waters, and the Beaufort and Chukchi OCS regions. This case assumes new feeder pipelines into TAPS and also assumes that TAPS can continue to be functional at a minimum daily rate of 0.6 Million barrels/day (see subsequent discussion in Section X.A.3, as well as Sections II, III, V.B, IX.A.1, and IX.B.1). Another 0.13 Million barrels/day (~47 Million barrels/year) of new production from the Mackenzie Delta/Canadian Beaufort area, would be supplied to the marketplace via a new dedicated oil pipeline, or a new feeder pipeline into TAPS, or possibly tankering. The Subgroup foresees a, long-term, slow decline in the collective total production for this region to ~0.6 Million barrels/day (211 Million barrels/year) by 2050. A portion of the collective remaining risked resource of 64.6 Billion barrels oil equivalent for these specific regions, as described in Sections IV, V and VI, would be developed post-2050.

A further deterioration of the current barriers to development described throughout this Topic paper and highlighted in Sections II, III and VIII lead to the Reasonably Constrained Case where there is no development of these rich oil and gas resources other than the existing producing fields within the Alaskan North Slope, as TAPS is offline in the $2030^{+/-}$ timeframe. Based on this premise the most likely production would amount to ~0.28 Million barrels/day (~100 Million barrels/year) in 2035, if TAPS is still in operation. No production is forecast from the Mackenzie Delta/Canadian Beaufort in either the 2035 or 2050 timeframe this scenario. Consequently, there will be no production from North Alaska fields in 2050. Issues and concerns addressing TAPS operational issues and its future existence are discussed further in Sections II, III, V.B, IX.A.1, and IX.B.1.

In the Relatively Unconstrained Case, the Subgroup consensus was that approximately 25% of the undifferentiated risked resource for these areas, or ~20 Billion barrels oil equivalent would be developed through 2050. Based on this premise, the most likely production for the North Alaska region in 2035 would be ~0.8 Million barrels/day (~282 Million barrels/year). This includes a normal decline of current Alaska North Slope production to 0.28 Million barrels/day, augmented by new discoveries totaling 0.5 Million barrels/day from the North Slope, North Alaska State waters, and the Beaufort and Chukchi OCS regions. Another ~0.2 Million barrels/day (~77 Million barrels/year) of new production from the Mackenzie Delta/Canadian Beaufort area, would be supplied to the marketplace via a new dedicated oil pipeline, or perhaps a new feeder pipeline into TAPS, or possibly tankering. The Subgroup foresees a, long-term, slow decline in the collective total production for this region to ~0.9 Million barrels/day (~327 Million barrels/year) by 2050. A portion of the collective remaining risked resource of 56 Billion barrels oil equivalent for these specific regions, as described in Sections IV, V and VI, would be developed post-2050.

It should be noted that the Arctic Subgroup's oil production forecast may be conservative for Alaska, as compared to a published analyses by Northern Economics[1] that suggests that the U.S. Beaufort and Chukchi OCS regions are capable of significant production collectively exceeding 1.0 Million barrels/day (~399 Million barrels/year) in 2035 (Figures 10.A.6, 10.A.7 and 10.A.8), if the undiscovered hydrocarbon resource assessment reported by the BOEMRE[16], is validated by future exploration and appraisal drilling.

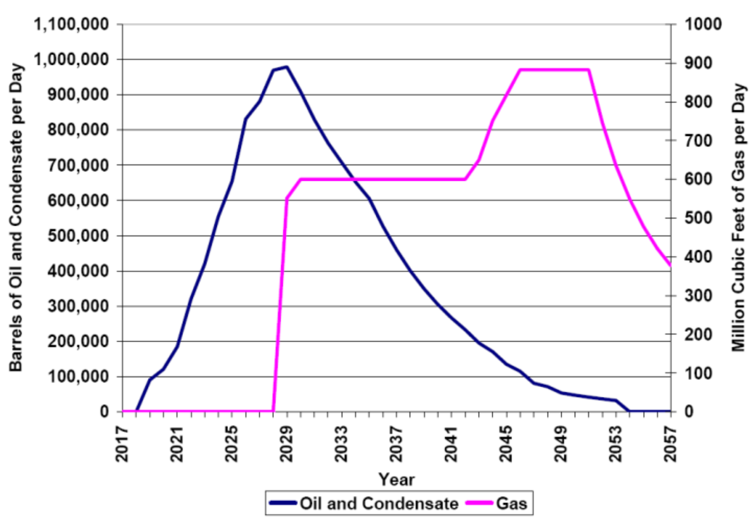
Table 2. Summary of OCS Development Scenarios

	Beaufort	Chukchi	North Aleutian	Total
Resource Size (Mean)				
Oil and condensates (billion barrels)	5.97	8.38	0.71	15.06
Gas (trillion cubic feet)	15.94	34.43	7.65	58.02
Exploration				
Exploration/Delineation Wells	47	43	10	100
Exploration Rig Seasons	31	27	8	66
Development				
No. of offshore production platforms	7	4	2	13
Offshore/Onshore pipelines (miles)	235	680	300	1,215
Shore bases / facilities				
Marine terminal	*yes*	*yes*	*yes*	
Liquefied Natural Gas (LNG) facility	*no*	*no*	*yes*	
Production facility	*yes*	*yes*	*yes*	
Support base	*yes*	*yes*	*yes*	
Production				
Year 1st oil flows	2019	2022	2021	
Year 1st gas flows	2029	2036	2022	
No. of producing fields	7	4	2	13
Total cumulative volume produced (through 2057)				
Oil & gas (billion barrels of oil equivalent)	6.34	6.16	1.29	13.69
Oil & condensates (billion barrels)	5.10	4.79	0.39	10.18
Gas (trillion cubic feet)	6.96	7.78	5.08	19.82
Daily peak production				
Oil & condensates (barrels per day)	1,165,707	565,472	105,074	
Gas (million cubic feet per day)	883	1,421	661	

Note: The resource size estimates are from the 2006 MMS Resource Assessment. The numbers shown in the table are the mean undiscovered economically recoverable resource estimates (UERR) assuming resource commodity prices of $60 per barrel of oil and $9.07 per thousand cubic feet of natural gas.

Figure 10.A.6 - Table 2: Alaska OCS Production Forecasts based on published 2009 Northern Economics study.[1]

Figure 6. Projected Daily Oil and Gas Production in the Beaufort Sea OCS



Source: Northern Economics, Inc. estimates based in part on MMS scenarios in *Beaufort Sea Planning Area Oil and Gas Lease Sales 186, 195, and 202 Final Environmental Impact Statement.* OCS EIS/EA MMS 2003-01. February 2003.

Figure 10.A.7 - U.S. Beaufort Sea OCS Production Forecasts based on published 2009 Northern Economics study.[1]

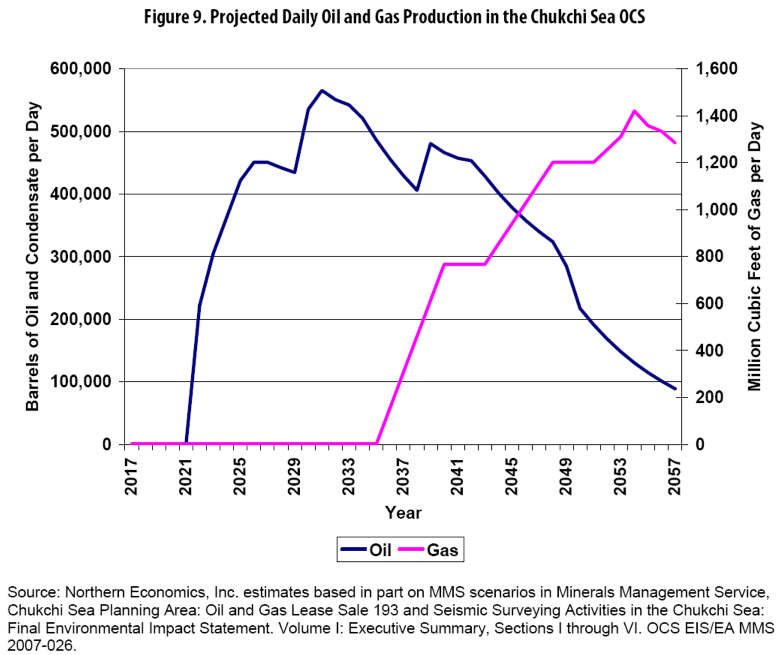


Figure 10.A.8 - U.S. Chukchi Sea OCS Production Forecasts based on published 2009 Northern Economics study.[1]

X.A.4 Offshore East Canada-Grand Banks Oil

The Most Likely Case assumes that Hebron (0.7 – 1.1 Billion barrels oil recoverable) will be developed within the next few years[17], and that a number of satellites to this and the currently producing fields (Hibernia, Terra Nova and White Rose fields) will be subsequently developed. The tankering of oil will still be utilized to commercialize these offshore fields, as no pipeline exists to the marketplace. Based on this premise, the most likely production for this region in 2035 would be ~0.07 Million barrels/day (~26 Million barrels/year). The Subgroup foresees a slow, long-term, average decline in total production to 2.4 Million barrels/year (~0.007 Million barrels/day) by 2050, as the existing discoveries are developed and depleted.

In the Reasonably Constrained Case, only Hebron is developed, and no satellites are brought on to mitigate decline. Based on this premise, the production for this region in 2035 would be ~0.06 Million barrels/day (~21 Million barrels/year). Consequently, the existing Grand Banks oil fields (currently producing and planned) will be exhausted prior to 2050.

In the Reasonably Unconstrained Case, enough new, but unspecified, fields and satellites will be put on production by 2035. Based on this premise, the production for this region in 2035 would be ~0.11 Million barrels/day (~39 Million barrels/year). There is ample resource on the Grand Banks for this to be feasible (see Sections IV.C.2.b and VI.D.1). The Subgroup foresees a slow, long-term, average decline in total production to ~0.07 Million barrels/day (~26 Million barrels/year) by 2050, as the existing and new discoveries are developed and depleted.

X.A.5 East Canada and West Greenland Oil (Baffin Bay region)

Finally, for both the Most Likely and Reasonably Constrained Cases, the Arctic Subgroup has assumed that the East Canada and West Greenland "Baffin Bay" region, will not contribute oil production prior 2035.

Development of a portion of the approximately 10.7 Billion barrels oil (mean, risked, undiscovered, technically recoverable resource), as described in Section IV.D.1. is foreseen in the Reasonably Unconstrained Case. Again, the Subgroup used a Delphi approach to suggest that approximately 10% of the oil resource, or 1.1 Billion barrels oil, would be developed by 2050. Based on this premise, the production for this region would begin sometime post 2035 and would yield production of ~0.22 Million barrels/day (~79 Million barrels/year) by 2050.

X.A.7 Arctic Production Forecast Summary

The reader should again be reminded that the three (3) supply cases developed by the Arctic Subgroup are judgments, not facts, about the Most Likely outlook and its two end members - Reasonably Constrained and Reasonably Unconstrained and these production forecasts may be conservative. The purpose of these forecast scenarios is to demonstrate the supply upside if the constraints outlined in Sections II, III and IX are reasonably ameliorated. Conversely, the Most Likely supply outlook will be adversely impacted if the same, or similar, constraints are allowed to continue. The collective 2035 forecast volumes for oil and gas immediately follow.

X.A.7.a 2035 Oil Forecast Summary

The most likely production outlook for the Arctic indicated 2035 production potential of 0.77 Million barrels/day (282.5 Million barrels/year). This includes a normal decline of current Alaska North Slope production to 0.28 Million barrels/day, augmented by new discoveries on the North Slope, in the Chukchi and Beaufort Seas and in Alaska state waters totaling 0.3 Million barrels/day. Arctic Canada would provide a further 0.2 Million barrels/day, split between Grand Banks production and new discoveries in the Canadian Beaufort and Mackenzie Delta areas.

In the constrained case outlook, it is assumed that new exploration activity would not occur because of a variety of restrictions on access and permitting, such that the only remaining production would be from currently producing fields which will be in decline over this period. Total remaining production in 2035 would be just 0.33 Million barrels/day (121 Million barrels/year), split between the Alaska North Slope (if TAPS is still in operation) and the Grand Banks area of Canada. Further declines post 2035 would ultimately lead to the closure of the TAPS as available North Alaska supply falls below operational minimum volumes of about 200,000 barrels/day. It is estimated that this could occur as late as 2045, making any subsequent development and production reliant on new infrastructure.

In the upside case, with a higher level of resource development in the new offshore areas of the Arctic, particularly offshore the Alaska North Slope, total production by 2035 could be as high as 0.88 million b/d (322 million barrels per year) and 0.5 million b/d of this could come from potential significant developments from the offshore Beaufort and Chukchi OCS and North Slope areas (excluding the ANWR 1002 area).

X.A.7.b 2035 Gas Forecast Summary

The most likely case is expected to lead to Arctic production of 2 Tcf/year (5.5 bcf/d), based on pipelines being developed in Alaska, including new offshore areas, and the Mackenzie Delta/Canadian Beaufort region, to take gas to market by around the middle of the decade of the 2020s. On the Alaska side this would amount to 1.6 TCF/year, with a further 0.4 TCF from the Mackenzie Delta/Canadian Beaufort.

In the constrained case, these sources of gas would remain stranded as it is assumed that the required infrastructure development would not occur with continuing economic and regulatory challenges acting as a disincentive to the project proponents.

In the unconstrained case, it is assumed that a higher pace of resource development activity in Alaska including new offshore areas and the Mackenzie Delta/Canadian Beaufort, would justify expansions of the two pipeline systems by 2025, allowing increases in production to a total of 2.9 Tcf/year (almost 8 bcf/day), of which about 2.2 TCF would be from Alaska and the remainder from the Mackenzie Delta/Canadian Beaufort.

X.A.6 Cited Literature

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XI. SUMMARY AND CONCLUSIONS

This study supports the idea that action by the U.S. Federal Government is warranted, if these critical resources are to be validated and safely developed in a prudent manner for America's benefit.

The North American Arctic contains significant, discovered oil and gas accumulations both onshore and offshore. These discoveries have yet to be produced due to lack of development and production infrastructure, including pipelines, because they have been unable to compete economically with alternate oil and gas sources. It should be noted that essentially all of the offshore discoveries north of the Arctic Circle, were safely drilled in an earlier era (1960s – 1995).

This same region is also estimated to contain globally significant undiscovered oil and gas resources primarily in the offshore basins, as per USGS, BOEMRE, and the NEB assessments. Evidence of this undiscovered offshore potential, is supported by industry's recent significant capital investment since 2005 in acquiring exploration leases and licenses, limited but modern seismic data, and extensive environmental baseline data offshore Alaska, Canada and Greenland. Since 2007, several companies have submitted or are in the process of filing the necessary permits to drill exploration wells to test whether or not these giant offshore accumulations exist. So far only Greenland has allowed contemporary drilling to occur in the offshore north of the Arctic Circle, enabling Cairn Energy to drill three (3) exploration wells in 2010 and issuing permits for another four (4) to be drilled in 2011.

Dwindling production from the North Slope of Alaska (~ 650,000 barrels oil per day) and excess ullage (~ 1,450,000 barrels excess capacity) in TAPS are beginning to challenge the pipeline's lower volume mechanical operational limit. There are some concerns, as to whether or not the pipeline could quickly reestablish oil throughput to Valdez, if the pipeline were to experience a lengthy operation downtime during a future harsh winter. Such a shutdown could potentially impact and disrupt the supply of crude oil to the West Coast of the U.S. Further, TAPS is expected to become mechanically and economically obsolete, once the flow of oil falls below ~ 200,000 barrels oil per day. This scenario is forecast to occur by 2039 by the EIA, but could in fact be a reality prior to that date, further stranding significant resources. One way to mitigate this future issue is for the U.S. Federal Government to coordinate its numerous Agencies, which have overlapping permitting authorities, and challenge these agencies to encourage a timely evaluation and issuance of the numerous permits required for the exploration and appraisal drilling of the offshore prospects. If these opportunities are successful, then the Federal Government should enable industry to facilitate the safe development of these National Resources. This process will need to begin in earnest, due to: 1) the limited yearly exploration operational window (~70 - 150 days); 2) the limited number of years remaining on the existing exploration leases (3 – 6 years); and 3) the long lead times to move from exploration to production (10 – 20 years). A successful effort on the part of government (leasing and regulatory) and industry (a safe exploration, development and ultimately production program) could significantly impact future production throughput via TAPS as early as 2025.

Technology challenges are not the main issue in the U.S. Arctic. The main challenge to safely unlocking this region's potential, is the significantly high supply costs associated with the entire economic life cycle (long lead time costs associated with exploration, development and production infrastructure including the construction of new pipelines), as compared to other non-Arctic arenas in the Western Hemisphere.

Other issues, beyond the regulatory morass, that should be addressed by the U.S. Government to enable the safe and economic extraction of these U.S. resources are:

1) Modify the leasing process by either extending the initial exploration lease terms beyond the current 10-year limit, or perhaps consider a licensing system similar to Canada that allows the acreage containing the discovered hydrocarbon reserves to be held by the operator until they can be economically developed;

2) Reinstate regular lease sales in the Alaska OCS areas;

3) Continue to grant exemptions to the Jones Act for the use of non U.S. flagged ice-class vessels for offshore Arctic operations;

4) Consider a Federal revenue sharing program for the Alaska State and local coastal governments of potentially impacted communities, similar to GOMESA; and

5) Stay abreast and open to the concept and option of tanker transportation of crude oil out of the arctic in the future. It is already a reality in the Eastern Arctic Hemisphere and may provide a viable and economic option for exporting oil from the Western Arctic Hemisphere in the near future.

Other issues that have not been addressed in this paper but might be considered for further investigation are:

1) The exploration and extraction of the unconventional resources of the Arctic region
    a. Tight sand and shale plays
    b. Coal bed methane
    c. Hydrates
2) Liquefied natural gas; and
3) Gas to Liquids technology.