BEAUFORT REGIONAL
ENVIRONMENTAL ASSESSMENT

UPDATED

Oil and Gas Exploration & Development Activity Forecast

Canadian Beaufort Sea 2013 – 2028

Prepared for

Aboriginal Affairs and Northern Development Canada

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March 2013

Canada

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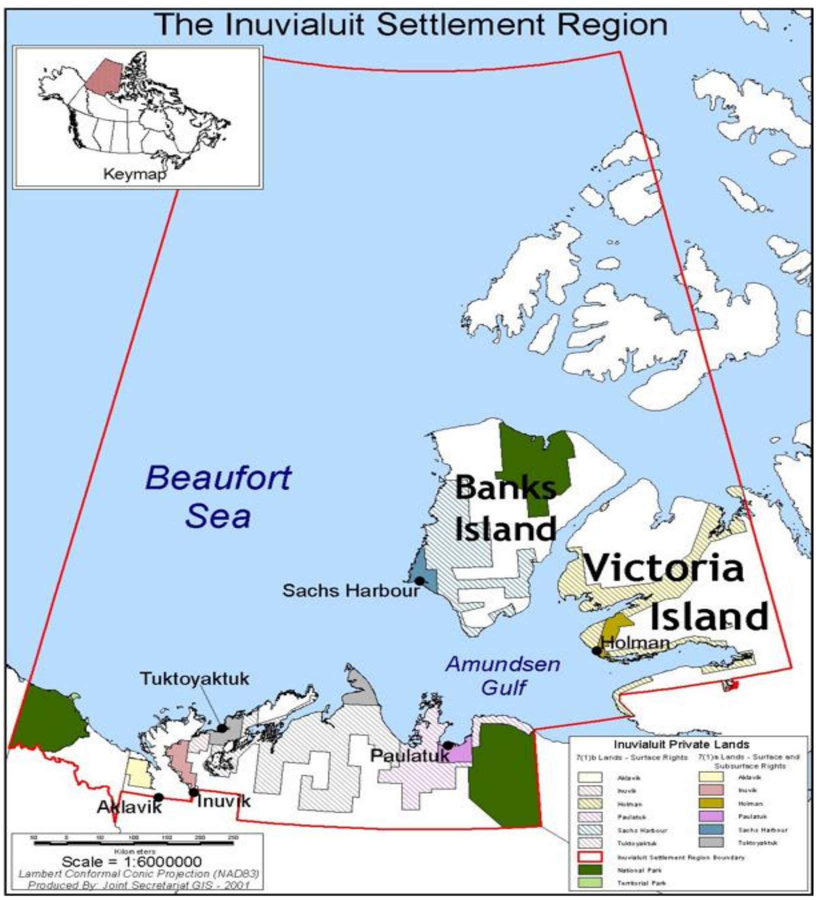
1. INTRODUCTION

The Beaufort Regional Environmental Assessment (BREA) is a multi-stakeholder regional research initiative that will make historical information available and gather new information vital to the future management of oil and gas activity in the Beaufort Sea. BREA will help ensure the Inuvialuit, governments, regulators, industry, and all Canadians are better prepared for oil and gas exploration and development in the Beaufort Sea by:

1. filling regional information and data gaps related to offshore oil and gas activities; and
2. supporting effective and efficient regulatory decision-making by providing the necessary data and information to all stakeholders.

BREA is supporting targeted research projects that will improve the management of oil and gas activities in the Beaufort Sea. The BREA area of study is the Canadian Beaufort Sea within the Inuvialuit Settlement Region (ISR), with an emphasis on the deeper waters offshore, but also including the broader northern area covered within the ISR boundaries.

Figure 1. BREA Study Area (source Joint Secretariat 2001)



A number of factors affecting potential oil and gas exploration and development activities in the Beaufort Sea have changed since the 2012 BREA Activity Forecast was prepared. This report is intended to provide an updated general description of potential oil and gas exploration and development activities in the Beaufort Sea over the next fifteen years (2013 to 2028). It is to provide the BREA Steering Committee, its working groups and arctic researchers with a current forecast of industry activity they can use when assessing the priorities, scope, and timing of Beaufort Sea research. It is also intended to help with understanding the implications of BREA research findings.

The forecasts and opinions expressed in this report are the responsibility of LTLC Consulting and Salmo Consulting Inc. and do not represent the official position or views of Aboriginal Affairs and Northern Development Canada.

2. HISTORY OF THE OIL AND GAS INDUSTRY IN THE MACKENZIE BEAUFORT REGION

This section builds on the 2009 report "Beaufort Regional Environmental Reports Summary" prepared by LTLC Consulting and Salmo Consulting Inc. for the Canadian Association of Petroleum Producers (CAPP). Where recent information has been added it is referenced.

Oil and gas development in the Mackenzie Valley began with the discovery of oil at Norman Wells by Imperial Oil Limited (Imperial) in 1919 and the subsequent construction of a topping plant in 1921. Hydrocarbon development continued to be focused on Norman Wells until the 1950s.

Exploration activity in the Mackenzie Delta/Beaufort Sea region began onshore in 1957 with early reconnaissance-level ground and air studies by the British American Oil Company (BA), Chevron Canada Limited (Chevron), Dome Petroleum Limited (Dome), Imperial, Shell Canada Limited (Shell) and others.

In 1961, the British American Oil Company Limited (BA), which later became Gulf Canada Limited (Gulf) completed the first exploratory drilling in the Mackenzie Delta. This was followed by onshore drilling for oil and gas at the Reindeer site on Richards Island by a consortium comprised of BA, Shell and Imperial. With the discovery of oil and gas at Prudhoe Bay Alaska in 1968, exploration activity intensified throughout the Western Arctic, particularly in the Mackenzie Delta and Canadian Beaufort Sea. In 1970, Imperial reported the first discovery of oil in the Mackenzie Delta at Atkinson Point. The discovery of major gas fields by Imperial at Taglu (1971), Gulf at Parsons Lake (1972) and Shell at Niglintgak (1973) resulted in the first proposed Mackenzie Valley Pipeline in 1974 and increased exploration and investment offshore.

The settlement of native land claims had a major influence on hydrocarbon development in the Canadian Beaufort Region during the 1970s and 1980s. Through the actions of the Committee on Original Peoples Entitlement (COPE), the Inuvialuit Land Rights Settlement Agreement in Principle was signed in 1978. This agreement led to completion of the Western Arctic Claim Settlement and the Report of the Task Force on Northern Conservation in 1984. These agreements culminated in the signing of the Inuvialuit Final Agreement (IFA) in 1984. The IFA set aside a 906,430 square kilometre area, including much of the Canadian Beaufort Sea, referred to as the Inuvialuit Settlement Region (ISR), which would be managed under the terms of the IFA.

Canadian offshore drilling in the Beaufort Sea began in the early 1970s. The National Energy Board (NEB) records show 142 Canadian Arctic offshore wells have been drilled, with 92 of these wells drilled in the Beaufort Sea region. Historical well records show that the industry operated in an extremely harsh environment, where drillships were often forced off station by heavy ice. Records also show that numerous well kicks and wellhead gas and water flows were encountered and controlled. Yet there have been no significant oil spill incidents and the industry has a track record of technical innovation (CAPP 2011). Numerous innovative drilling platforms and techniques were developed and proven to operate successfully in the Canadian Beaufort Sea. Table 1 summarizes the Beaufort Sea offshore drilling activity since 1972, it was developed using data provide by the NEB and by reviewing historical Well Reports downloaded from the North West Territories Geoscience Office database.

Table 1. Drilling Activity in the Beaufort Sea

WELL NAME	WELL OPERATOR	WELL SPUD DATE	RIG RELEASE	DRILLING PLATFORM	WATER DEPTH (M)
NUKTAK C-22	Imperial	16-Dec-1972	8-Mar-1973	Land on Hooper Is	NA
IMMERK B-48	Imperial	17-Sep-1973	22-Dec-1973	Sacrificial Beach Is	3
ADGO F-28	Imperial	28-Dec-1973	19-Mar-1974	Sandbag Retained Is	2
PULLEN E-17	Imperial	21-Apr-1974	11-Jul-1974	Sandbag Retained Is	2
UNARK L-24	Sun	26-Sep-1974	24-May1975	Hauled Island	2
PELLY B-35	Sun	5-Oct-1974	14-Feb-1975	Hauled Island	2
ADGO P-25	Imperial	2-Jan-1975	28-Mar-1975	Sandbag Retained Is	2
NETSERK B-44	Imperial	6-Jan-1975	8-Jun-1975	Sandbag Retained Is	5
ADGO C-15	Imperial	21-Apr-1975	25-Jul-1975	Sandbag Retained Is	2
IKATTOK J-17	Imperial	10-Jul-1975	28-Feb-1976	Sandbag Retained Is	2
NETSERK F-40	Imperial	8-Nov-1975	9-May-1976	Sandbag Retained Is	8
SARPIK B-35	Imperial	2-Apr-1976	4-Sep-1976	Sandbag Retained Is	4
KOPANOAR D-14	Dome	8-Aug-1976	26-Sep-1976	Canmar Explorer 3	60
TINGMIARK K-91	Dome	11-Aug-1976	18-Oct-1977	Canmar Explorer 1/3	28
NEKTORALIK K-59	Dome	23-Sep-1976	17-Oct-1977	Canmar Explorer 2/3	64
KOPANOAR M-13	Dome	27-Sep-1976	10-Sep-1979	Canmar Explorer 3	57
KUGMALLIT H-59	Imperial	30-Sep-1976	10-Nov-1976	Sandbag Retained Is	5
ARNAK L-30	Imperial	5-Oct-1976	16-Mar-1977	Sacrificial Beach Is	9
UNARK 2L-24	Sun	19-Oct-1976	8-May-1977	Hauled Island	2
KANNERK G-42	Imperial	30-Mar-1977	14-May1977	Sacrificial Beach Is	8
UKALERK C-50	Dome	18-Jul-1977	3-Oct-1977	Canmar Explorer 1	42
KAGLULIK A-75	Dome	19-Jul-1977	6-Aug-1978	Canmar Explorer 3	39
NERLERK M-98	Dome	4-Oct-1977	28-Aug-1982	Canmar Explorer 1/3	52
ISSERK E-27	Imperial	4-Dec-1977	5-May-1978	Sacrificial Beach Is	13
NATSEK E-56	Dome	10-Jul-1978	8-Oct-1979	Canmar Explorer 2-4	34
UKALERK 2C-50	Dome	10-Aug-1978	11-Oct-1979	Canmar Explorer 1	42
TARSIUT A-25	Dome	18-Oct-1978	28-Jul-1980	Canmar Explorer 3	20
KAGLULIK M-64	Dome	3-Nov-1978	10-Jul-1979	Canmar Explorer 2	27
ADGO J-27	Esso	5-Apr-1979	7-Aug-1979	Sandbag Retained Is	2
KENALOOAK J-94	Dome	20-Sep-1979	1-Nov-1982	Canmar Explorer 2-4	68
KOPANOAR L-34	Dome	11-Oct-1979	26-Nov-1979	Canmar Explorer 2	58
KOAKOAK O-22	Dome	5-Nov-1979	31-Oct-1981	Canmar Explorer 1/2	49
KOPANOAR 2L-34	Dome	26-Nov-1979	28-Nov-1979	Canmar Explorer 4	56
ISSUNGNAK O-61	Imperial	6-Feb-1980	8-Jul-1980	Sacrificial Beach Is	37
KILANNAK A-77	Dome	23-Jun-1980	4-Sep-1981	Canmar Explorer 3	38
ORVILRUK O-03	Dome	9-Jul-1980	16-Sep-1980	Canmar Explorer 1	60
KOPANOAR I-44	Dome	10-Jul-1980	1-Aug-1980	Canmar Explorer 4	59
KOPANOAR 2I-44	Dome	2-Aug-1980	28-Oct-1981	Canmar Explorer 2	58
ISSUNGNAK 2O-61	Imperial	2-Oct-1980	13-Aug-1981	Sacrificial Beach Is	19
N. ISSUNGNAK L-86	Gulf	17-Jul-1981	17-Oct-1981	Canmar Explorer 2	26
ALERK P-23	Imperial	21-Sep-1981	24-Dec-1981	Sacrificial Beach Is	12
IRKALUK B-35	Dome	27-Sep-1981	4-Oct-1982	Canmar Explorer 4/2	58
E. TARSIUT N-44	Gulf	10-Dec-1981	7-Jun-1982	Concrete Caisson	19
W. ATKINSON L-17	Imperial	1-May-1982	25-Jun-1982	Sandbag Retained Is	7
E. TARSIUT N-44A	Gulf	8-Jun-1982	19-Sep-1982	Concrete Caisson	19
KIGGAVIK A-43	Gulf	21-Jul-1982	17-Oct-1982	Canmar Explorer 1	18

Table 1. Drilling Activity in the Beaufort Sea (cont.)

WELL NAME	WELL OPERATOR	WELL SPUD DATE	RIG RELEASE	DRILLING PLATFORM	WATER DEPTH (M)
AIVERK I-45	Dome	5-Oct-1982	23-Oct-1982	Canmar Explorer 2	62
AIVERK 2I-45	Dome	3-Nov-1982	11-Oct-1984	Canmar Explorer 4/1	61
ITIYOK I-27	Imperial	5-Nov-1982	2-May-1983	Sacrificial Beach Is	14
UVILUK P-66	Dome	10-Nov-1982	21-May1983	SSDC	30
NATIAK O-44	Dome	16-Jul-1983	25-Sep-1984	Canmar Explorer 2	44
HAVIK B-41	Dome	17-Jul-1983	24-Aug-1986	Canmar Explorer 1	35
SIULIK I-05	Dome	25-Jul-1983	18-Oct-1984	Canmar Explorer 4	52
ARLUK E-90	Dome	30-Jul-1983	13-Oct-1985	Canmar Explorer 3	57
PITSIULAK A-05	Gulf	22-Aug-1983	26-Jul-1984	Kulluk	27
KADLUK O-07	Imperial	25-Sep-1983	24-Apr-1984	CRI	14
AMAULIGAK I-44	Gulf	7-Oct-1983	15-Nov-1983	Kulluk	20
KOGYUK N-67	Gulf	28-Oct-1983	30-Jan-1984	SSDC	28
AMAULIGAK J-44	Gulf	16-Nov-1983	23-Sep-1984	Kulluk	31
AMERK O-09	Imperial	22-Aug-1984	3-Mar-1985	CRI	26
W. TARSIUT P-45	Gulf	25-Sep-1984	24-Dec-1984	Molikpaq	22
NERLERK J-67	Dome	26-Sep-1984	24-Oct-1985	Kulluk	45
ADGO H-29	Imperial	27-Sep-1984	12-Jan-1985	Sandbag Retained Is	3
NIPTERK L-19	Imperial	3-Oct-1984	23-Mar-1985	Sacrificial Beach Is	11
AKPAK P-35	Gulf	17-Oct-1984	8-Nov-1985	Kulluk	41
NIPTERK L-19A	Imperial	21-Apr-1985	15-Jul-1985	Sacrificial Beach Is	11
AKPAK 2P-35	Gulf	8-Jul-1985	14-Aug-1985	Kulluk	41
ADLARTOK P-09	Dome	8-Aug-1985	17-Oct-1985	Canmar Explorer 3	68
EDLOK M-56	Dome	10-Aug-1985	18-Sep-1985	Canmar Explorer 4	32
AMAULIGAK I-65	Gulf	24-Sep-1985	21-Jan-1986	Molikpaq	23
ADGO G-24	Imperial	7-Oct-1985	7-Jan-1986	Sandbag Retained Is	2
AAGNERK E-56	Gulf	28-Oct-1985	26-Jun-1986	Kulluk	20
MINUK I-53	Imperial	27-Nov-1985	2-May-1986	Sacrificial Beach Is	15
NORTH ELLICE L-39	Chevron	25-Jan-1986	20-Apr-1986	Sandbag Retained Is	2
AMAULIGAK I-65A	Gulf	28-Jan-1986	20-Mar-1986	Molikpaq	23
AMAULIGAK I-65B	Gulf	20-Mar-1986	19-Sep-1986	Molikpaq	23
ARNAK K-06	Imperial	27-Apr-1986	12-Aug-1986	Sacrificial Beach Is	8
KAUBVIK I-43	Imperial	22-Oct-1986	10-Jan-1987	CRI	18
ANGASAK L-03	Trillium	24-Feb-1987	12-Apr-1987	Spray Ice Island	5
AMAULIGAK F-24	Gulf	1-Oct-1987	12-Aug-1988	Molikpaq	32
AMAULIGAK 2F-24	Gulf	22-Dec-1987	29-Jan-1988	Molikpaq	32
AMAULIGAK 2F-24A	Gulf	30-Jan-1988	17-Feb-1988	Molikpaq	32
AMAULIGAK 2F-24B	Gulf	15-Apr-1988	7-Aug-1988	Molikpaq	32
AMAULIGAK O-86	Gulf	30-Jun-1988	26-Aug-1988	Kulluk	20
AMAULIGAK CH NO.1	Gulf	12-Aug-1988	7-Sep-1988	Molikpaq	32
AMAULIGAK 2F-24BST	Gulf	27-Jun-1988	7-Aug-1988	Molikpaq	32
NIPTERK P-32	Esso	21-Feb-1989	20-Apr-1989	Spray Ice Island	7
IMMIUGAK N-05	Gulf	1-Jun-1989	10-Jun-1989	Kulluk	32
IMMIUGAK A-06	Gulf	16-Jun-1989	22-Sep-1989	Kulluk	53
KINGARK J-54	Amoco	18-Jul-1989	10-Oct-1989	Canmar Explorer 1	59
ISSERK I-15	Imperial	11-Nov-1989	8-Jan-1990	Molikpaq	12
PAKTOA C-60	Devon	5-Dec-2005	19-Mar-2006	SDC	13

2.1 DRILLING PLATFORMS

The following information on the various types of drilling platforms used in the Canadian Beaufort Sea is summarized from Timco et al. (2009).

2.1.1 Artificial Islands

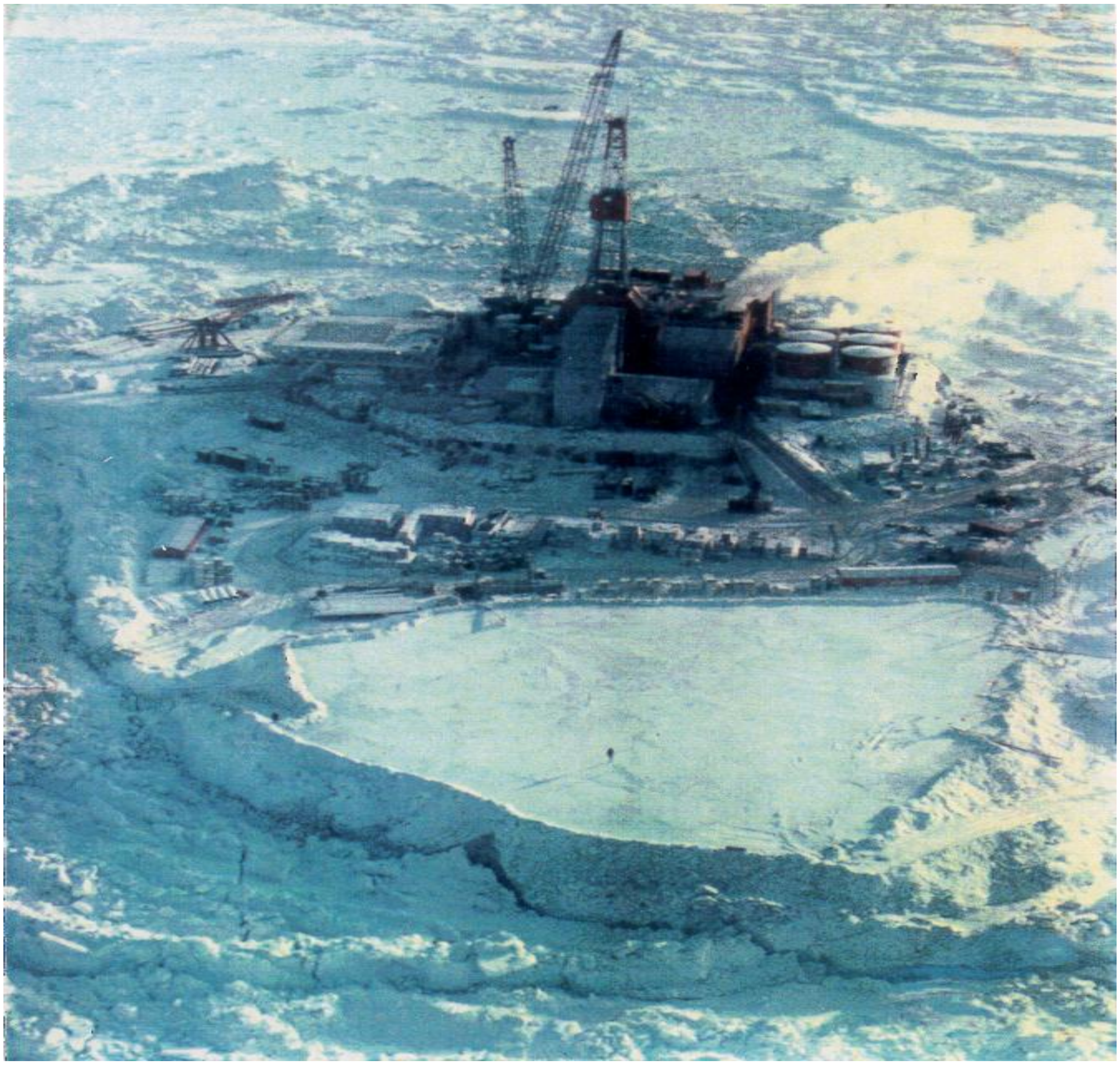
The first offshore man-made drilling island was constructed in 1973 by Imperial for the Immerk B-48 well. Although, Imperial drilled the Nuktak C-22 well in the Beaufort Sea region a year earlier, records show that it was a conventionally drilled well on Hooper Island. Artificial offshore islands were constructed by either dredging the local sea bottom and building-up an island (referred to as a sacrificial beach or sandbag-retained island, or by trucking gravel from the shore and depositing it to form an island (referred to as a hauled island. The latter approach was carried out during winter months across ice roads. Table 1 shows that these artificial islands were constructed in shallow water. Most were located in the landfast ice zone, where first-year ice has little movement during the winter months. Although, artificial islands allowed for year round drilling, they were subject to wave action and in 1985 a rig on the Minuk I-53 sacrificial beach island was lost during a severe storm (Dixit pers. comm. 2012).

2.1.2 Caisson Structures

In the early 1980's, special caisson structures were designed and built to allow year-round drilling and exploration of regions further offshore in deeper water and harsher ice conditions. The following four types of caisson retained drilling platforms were used in the Canadian Beaufort:

- Concrete Caisson (Tarsuit Caisson)
- Single-Steel Drilling Caisson (SSDC/SDC)
- Caisson-Retained Island (CRI)
- Molikpak Mobile Arctic Caisson (MAC)

Figure 2. Concrete Caisson (Tarsuit Caisson)(source G.W. Timco)



The concrete caisson island was developed by Gulf and deployed at Tarsuit N-44 in 1981. The structure consisted of four concrete caissons that were floated to the drilling site and ballasted down with sand to form a square over an underwater berm that was within 6m of the water surface. The inner core was filled with dredged sand. This structure was not considered a "mobile" structure due to the difficulty of resetting and connecting the four caissons. It had no issues with wave loads, but wave action undercut the footings of the caissons necessitating remedial action. Wave splash was also a problem, due to its low freeboard and flat sides. Later caisson structures were designed with wave deflection collars. The concrete (Tarsuit) caisson structure was only used for drilling at the Tarsuit N-44 location.

Figure 3. Single Steel Drilling Caisson (SSDC/SDC)(source G.W. Timco)

The Single-Steel Drilling Caisson (SSDC) was operated by Canadian Marine Drilling Limited (Canmar) a subsidiary of Dome. It was constructed from a former tanker and brought to the Beaufort Sea in 1982. In the winters of 1982/83 and 1983/84, it drilled at two different locations in approximately 30m of water. In 1985/86, a new steel base, the MAT, was designed, built and deployed. This removed a limitation of the SSDC that had required construction of a subsurface sand berm for locations deeper than 9m. The SSDC combined with the MAT was capable of operating year round in water depths of 7 to 24m without a berm, in a wide variety of bottom conditions. It was renamed the SDC and used in the winter of 2005/06 by Devon Canada Corporation (Devon) to drill the Paktoa C-60 well in 13m of water.

Figure 4. Caisson-Retained Island (CRI)(source A. Barker)

The Caisson Retained Island (CRI) was originally built by Imperial. It was developed in 1977, as a means of reducing dredge quantities, needed for the construction of traditional sand islands. It was first deployed in the Canadian Beaufort Sea in the summer of 1983. The CRI consisted of 8 individual caissons forming a ring held together with two pre-stressed bands of steel wire cable. It was therefore named the stressed Caisson Retained Island and overall it had an octagonal-shape with an inclined outer face. The central core was filled with sand.

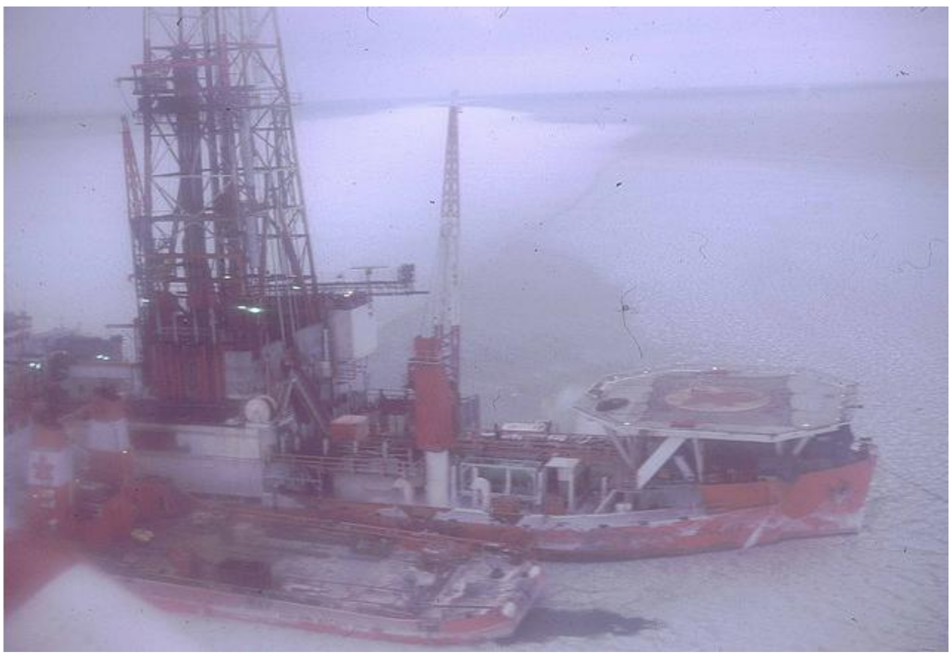
Figure 5. Mobile Arctic Caisson (MAC)(source Gulf Canada Resources)

The Molikpaq a Mobile Arctic Caisson (MAC) was deployed in the Canadian Beaufort Sea in 1984. It was developed by Gulf and consisted of a continuous steel annulus sitting on a self-contained deck structure. The outer face of the Molikpaq was designed for extreme ice features. The structure was able to operate without a berm in water depths ranging from 9 to 21m. In greater water depths, the structure was designed to sit on a submerged berm. The core of the annulus was filled with sand, which provided over 80 percent of the design horizontal resistance. To achieve the full design horizontal resistance under dynamic load, densification of the hydraulically placed core was required. Like many offshore vessels the Molikpag used water for ballast.

2.1.3 Floating Drillships

In 1976 Dome, through its subsidiary Canmar, brought a fleet of three ice reinforced drillships and accompanying icebreakers to the Beaufort Sea to support its oil and gas exploration program. The floating drillships (Explorers 1, 2 and 3) were employed during the summer months in waters, up to 68m deep along the edge of the shear ice zone. They were moored on station during the summer (essentially open water) months. It often took at least two years to drill and test a well (Table 1). These drillships required the support of ice management icebreakers. Icebreakers would break any oncoming ice and reduce the size of the floe that could impact the vessel. Drilling usually started in late June and some years extended into November. In 1979 Dome sent a fourth drillship the Explorer 4 to the Canadian Beaufort Sea.

Figure 6. Canmar Explorer 1 with an Icebreaker Being Forced off Station by Ice October 1978 (source Gulf Canada Resources)



2.1.4 Conical Floating Drilling Platform

In 1983 Gulf built an inverted-cone shaped floating drillship, the Kulluk, which could be used throughout the summer and early autumn months. The vessel was towed to the drill site and moored with a twelve-point anchor system capable of resisting ice forces from any direction. Ice management was usually necessary to break the ice locally around the Kulluk. This technique extended the drilling season by allowing operation earlier and later in the year. The Kulluk began operations as early as late May and continued working until late December. Activities were usually suspended because of relief well drilling restrictions, rather than limitations in the in-ice station-keeping capabilities of the Kulluk itself (Wright & Associates 2000). Table 1 indicates the Kulluk drilled in the Beaufort Sea at water depths up to 45m.

Figure 7. Conical Floating Drilling Platform (Kulluk)(source Gulf Canada Resources)

2.2 SPRAY ICE ISLANDS

In the late 1980s, spray ice islands were used as pads for drilling a couple of wells in the Canadian Beaufort Sea. These were deployed in the landfast ice zone, in water depths of less than 8m. The ice pads were built by spraying seawater using large pumps and nozzles to locally increase the ice thickness. This spraying normally continued until the pad rested on the seabed with sufficient freeboard and enough weight to resist the ice loads that it would incur during the drilling season. The cost of spray islands was reported to be approximately one-half the cost of gravel islands.

2.3 EXPLORATION RESULTS

By the mid 1980s, a number of oil and gas discoveries had been made in the Beaufort Sea. The most significant discovery was that of the Amauligak oil and gas field by Gulf. The oil and gas discoveries made in the region are described in more detail in Section 5 of this report. Despite these discoveries, by this time it had become apparent that the high expectations for the region had not been met. Unlike the Alaskan North Slope, where a small number of large prolific fields exist, the Mackenzie Delta/Beaufort Sea region was characterized by a large number of smaller widely scattered reserves, due to highly structured and fractured sedimentary strata.

2.4 ARCTIC EXPLORATION AND WORLD EVENTS

In the mid 1980s, world oil prices and oil demand began to decline rapidly, thereby affecting the impetus and available financing to undertake hydrocarbon exploration in the Canadian Arctic. In March 1989, the Exxon Valdez ran aground in Prince William Sound, Alaska. Worldwide publicity of the spill's impacts had repercussions for hydrocarbon exploration, development and transportation throughout North America, particularly in the Beaufort Sea region.

In 1989, Imperial was granted approval to drill the Isserk I-15 well. However, in 1990 the Environmental Impact Review Board (EIRB), created under the IFA, found a lack of preparedness of the government and Gulf to deal with a major oil blowout in the Beaufort Sea. The EIRB recommended the Minister of Indian and Northern Affairs not approve Gulf’s proposed Kulluk drilling program. Following the denial of the Kulluk drilling program, there was little exploration activity in the Mackenzie Delta or Beaufort Sea for the next decade. In 1999-2000 increasing North American gas prices led to a renewal of seismic exploration in the Mackenzie Valley/Beaufort Sea and the drilling of several exploration wells in the Mackenzie Delta. However, Devon’s Paktoa C-60 well drilled in 2005-06, which targeted natural gas and discovered a reported 240 million barrels (mmbbl)(38 $10^6 m^3$) of recoverable oil, has been the only Beaufort Sea offshore well drilled in the last 22 years.

2.5 ARCTIC OIL AND GAS PRODUCTION

Despite the billions invested in oil and gas exploration in the Canadian High Arctic, there has been no significant commercial production. In 1985 Panarctic Arctic Oils Limited (Panarctic) began to tanker oil from the Bent Horn oil field (discovered in 1974 at Bent Horn N-72 on Cameron Island) to Montreal. One to three tankers of oil were shipped every summer from 1985 to 1996, with a total production from the field of 2.8mmbbl (Drummond 2005). The only oil production from the Mackenzie Delta and Beaufort Sea occurred in 1986, when Gulf shipped a demonstration tanker load of 317,000 barrels (bbl)(50 10^3m^3) of oil from the Amauligak field to Japan (Drummond 2005). The first natural gas production from the Mackenzie Delta was in July 1999 from the Ikhil gas field (discovered by Gulf), which provides local production to the town of Inuvik. The small Ikhil gas reserves were expected to provide a community gas supply for a few years and were to be replaced by gas from MGP. Unfortunately, production from the Ikhil field is currently declining and since MGP is not economic, the town is now faced with having to find a new fuel supply. It appears that this new fuel will initially be more expensive propane trucked from Alberta.

3. THE CYCLE OF OFFSHORE INDUSTRY ACTIVITY

The search for hydrocarbons in the Beaufort Sea is highly complex and costly due to the extreme environment, a multi-jurisdictional regulatory system and multiple technical challenges. The extreme climate, ice conditions, long periods of darkness, and remoteness each contribute to the complexity of planning and costs of exploring for hydrocarbons in the Beaufort offshore (Erlandson et al. 2002). Stories have recently appeared in the press predicting increases in oil and gas activity in the Canadian Arctic due to the influence of Climate Change. Although, Climate Change now allows for routine vessel transit of the Northwest Passage and appears likely to extend summer drilling seasons and reduce drilling risks from multi year ice flows, it may also increase the frequency and severity of storms. On balance, it appears unlikely that Climate Change will significantly reduce industry operating costs in the Beaufort Sea during the timeframe of this forecast.

The document titled "*Oil and Gas Approvals in the Beaufort Sea*" by Erlandson et al. (2002) is part of the regulatory road map series of documents prepared for Indian Affairs and Northern Development Canada and CAPP. The road map provides a detailed outline of the regulatory framework for reviewing and authorizing oil and gas activities in the Beaufort Sea at the time of its publication.

The life cycle of an offshore project begins with a Call for Nominations followed by a Call for Bids issued by the Northern Oil and Gas Branch (NOGB) of Aboriginal Affairs and Northern Development Canada (AANDC). The successful bidders are issued ELs, which provide the exclusive right to explore for and develop hydrocarbons from a specified parcel of land during the 9-year term of the licence. Figure 8 reflects the 2009 NEB update to the Canadian Oil and Gas Drilling and Production Regulations (COGDPR) and illustrates the general approval phases of the cycle of offshore industry activities. Figure 9 from the NOGB on the AANDC website, also reflects the 2009

COGDPR update and illustrates the steps in the Northern Oil and Gas Rights Management Process.

Figure 8. National Energy Board Exploration and Production Approval Phases (revised from Dixit 2009)

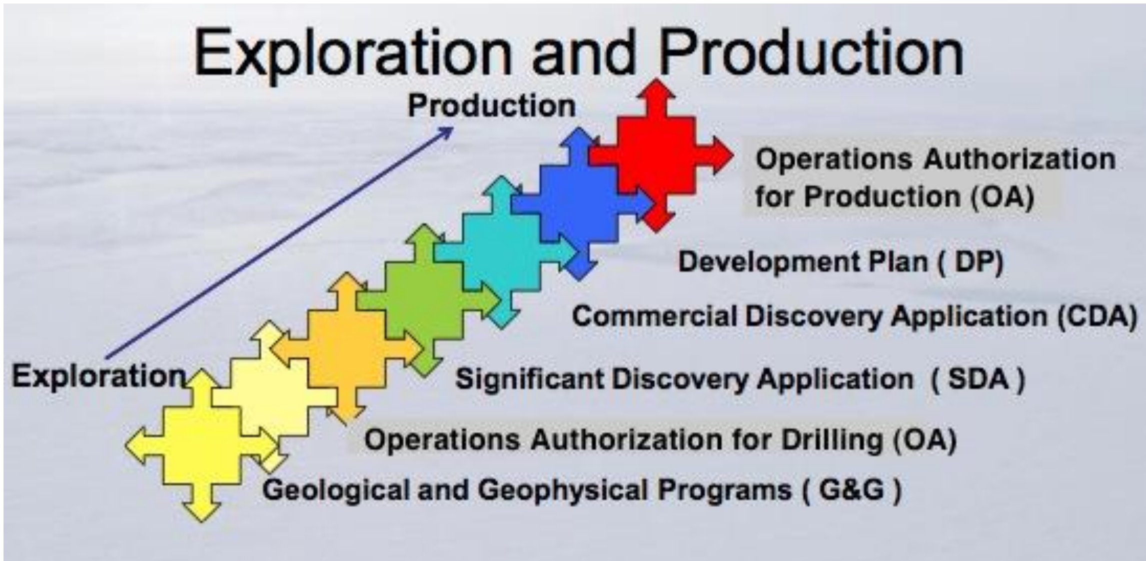
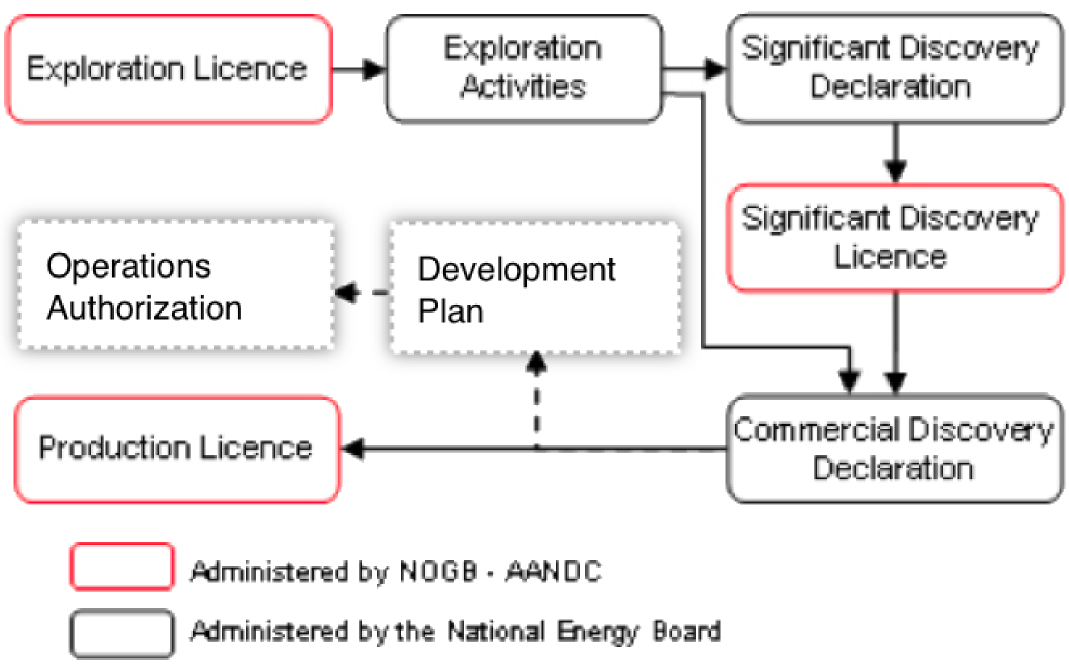


Figure 9. Northern Oil and Gas Rights Management Process (revised from NOGB of AANDC 2012)



3.1 GEOLOGICAL AND GEOPHYSICAL PROGRAMS

Seismic surveys are generally the first active exploration activity undertaken on new EL areas. They are used to gain an understanding of the regional geologic structure and to identify drilling targets. Companies wishing to conduct seismic programs must apply to the NEB for Geological/Geophysical Operation Authorizations (GOA). Consultation with local communities and other agencies having regulatory authority is critical to the approval process for all types of seismic programs. In the past several different types of seismic surveys have been conducted in the near shore areas of the Beaufort Sea. These include the use of vibroseis vehicles on the ice, drilled shotholes, airguns, geophones drilled through or placed on the ice, and ocean bottom cables with mini airguns used in open water.

In the deep-water areas of the Beaufort Sea Two Dimensional (2D) and Three Dimensional (3D) surveys are conducted by seismic vessels in generally open water conditions. The following description of deep-water seismic surveys is summarized from the report "*Marine Seismic Operations*" by the International Association of Geophysical Contractors (IAGC) 2002. In 2D seismic surveying, a single seismic cable or streamer is towed behind the seismic vessel, together with a single source. The reflections from the subsurface are assumed to lie directly below the 'sail line' that the seismic vessel traverses, hence the name 2D. The processing of 2D data is less sophisticated than that employed for 3D surveys. 2D lines are typically acquired several kilometers apart, on a broad grid of lines, over a large area. The method is generally used in frontier exploration areas (before 3D seismic or drilling is undertaken), to produce a general understanding of the regional geological structure. The size of a 2D survey is usually expressed in kilometres of line surveyed.

A 3D survey covers a specific area, generally with known geological targets generated by previous 2D exploration, and is usually undertaken in an EL area to better identify potential reservoirs and drilling locations. Prior to the survey, careful planning is undertaken to ensure the survey area is precisely defined. The result of the detailed planning is a map defining the survey boundaries and the direction of the survey lines. Specific acquisition parameters such as energy source, firing and receiver station intervals, together with seismic listening time, are also defined. In 3D surveying, groups of sail lines (or swathes) are acquired with the same orientation.

3D seismic sail line separation is normally on the order of 200 to 400m. By utilizing more than one source and many parallel streamers towed by the seismic vessel, the acquisition of many closely spaced sub-surface 2D lines, typically between 25 and 50m apart, can be achieved by a single sail line. A 3D survey is therefore much more efficient in that many times more data is generated than in a 2D survey. The size of a 3D survey is usually referred to in square kilometers. With the number of sail line kilometers involved, 3D surveys can take several months to complete.

High resolution seismic site surveys are carried out before a well is drilled, as there is a legal and operational need to have detailed information on the area immediately surrounding the well location and the geological layers immediately below the subsurface. The information on the nature of the seabed is needed to identify any physical hazards on the surface of the seabed and the information on the shallow subsurface is used to identify other unforeseen hazards, such as buried channels, shallow gas pockets, gas hydrates and permafrost that could cause problems if penetrated by the drill.

KAVIK-AXYS (2008) provided a hypothetical shortest duration Beaufort Sea offshore development timeline based on a review of regulatory approval processes, hypothetical development scenarios, and input from industry experts. They estimate the licencing and seismic exploration phase of an offshore development to take a minimum of 3 years.

3.2 DRILLING PROGRAMS

While seismic surveys can identify targets of interest, drilling is required to confirm the presence or absence of hydrocarbons. An NEB Operations Authorization (OA) is required to undertake drilling operations for petroleum resources in the offshore area as required by the Canada Oil and Gas Operations Act (COGOA). In addition, individual well approvals from the NEB are required to drill a well (ADW) or to alter the condition of a well (ACW). Prior to the NEB issuing an OA, environmental screening must be completed under the IFA, and the requirements of the *Canadian Environmental Assessment Act, 2012* (CEAA 2012) and COGOA must be met. Further, the Applicant would need to demonstrate financial responsibility to the satisfaction of the NEB, and the NEB needs to have notification that a Benefits Plan prepared by the Applicant has been approved by AANDC or the requirement for it waived.

KAVIK-AXYS (2008) estimated the exploration and delineation-drilling phase of a Beaufort Sea offshore development to take a minimum of 3 years. However, since a single offshore deep-water well may take 3 years to drill, this phase of an offshore development may be considerably longer.

3.3 SIGNIFICANT DISCOVERY AND COMMERCIAL DISCOVERY APPLICATIONS

If an exploration well results in the discovery of hydrocarbons the Operator can make an application to the NEB for a Significant Discovery Declaration (SDD). The NEB may, by order, make a SDD in relation to those frontier lands in respect of which, there are reasonable grounds to believe the Significant Discovery may extend.

The Applicant can then seek a Significant Discovery Licence (SDL) from the NOGB of AANDC, which would extend the Applicant’s rights to areas identified in the SDD without any time limit.

Additional delineation wells and 3D seismic may be needed to determine if a discovered hydrocarbon resource is sufficiently large to warrant production. An Operator that can demonstrate to the NEB that the sought area contains petroleum reserves that justify the investment of capital and effort to bring the discovery to production can submit an application for a Commercial Discovery Declaration (CDD). The NEB may, by order, make a CDD in relation to those frontier lands in respect of which there are reasonable grounds to believe the Commercial Discovery may extend.

3.4 DEVELOPMENT PLANS AND OPERATION AUTHORIZATIONS

An SDL does not expire, it can be held for many years, before conditions are favorable enough to justify the costs and risks involved in attempting to produce hydrocarbons. To date, other than the three limited examples described in Section 2.5 there has been no commercial production of hydrocarbons from the Mackenzie Delta, Beaufort Sea and/or Canada's Arctic Islands. It is difficult to predict the timing and amount of work involved in progressing a project through to production. Although, the specific timing of each activity will vary depending on the type and scale of individual projects, it is expected that at a minimum the activities listed in Table 2 would be required in order for the NEB to consider a Development Plan Approval (DPA) application and issue a DPA. The DPA is subject to Governor-in-Council consent, and Operations Authorizations (OA) for activities included in the DPA. Finally, once a CDD has been made by the NEB, the NOGB of AANDC may issue a Production Licence that would enable the Operator to sell the produced oil and gas, make royalty payments, and profits.

3.5 COMMERCIAL DISCOVERY DEVELOPMENT TIMELINE

The timeline for an offshore development project is controlled by the time required to work through each stage of the development process and complete the types of activities illustrated in Table 2. The larger and more complex the development project, the longer the timelines will be extended. Please note that the time lines illustrated in Table 2 are estimated by the author and are not endorsed by AANDC or any other Regulatory Authority (RA).

It is normal practice for the Operator to reduce the overall development schedule by undertaking activities concurrently, however, some activities such as regulatory hearings and authorizations or approvals must be completed prior to undertaking physical works. Since activities like detailed engineering and procurement are not normally initiated prior to receiving regulatory approvals Table 2 only assumes, in the author's estimation, a 30% reduction in the median development timeframe resulting from work activities being conducted concurrently.

Table 2. Activities and Estimated Time Schedule for a Generalized Beaufort Sea Offshore Development Project

Activity	Estimated Timing
Reserves Assessment Market Assessment Conceptual Engineering Economic Modeling Budgeting Assessment of Regulatory Environment Feasibility Study	0.5 - 1.5 years
Reservoir Engineering Drilling and Completions Engineering Cost and Schedule Engineering Public and Regulatory Consultation	0.5 - 1.5 years
Environmental Fieldwork Engineering Fieldwork	1 - 3 years
Construction Engineering Design Business and Economics Analysis Development Plan Environmental Impact Assessment Socio-economic Impact Assessment Decommissioning and Abandonment Plan	1 - 2 years
Public Regulatory Review Processes Regulatory Approvals Permitting	2 - 5 years
Detailed Design Procurement and Construction of Infrastructure Development Drilling Procurement and Construction of Facilities Facility Start-up/Commissioning	5 - 7 years
TOTAL Median Estimated Development Timeframe	**14 years**
TOTAL Estimated Development Timeframe Reduced 30% for Concurrent Work	**10 years**

3.6 OPERATIONS AUTHORIZATIONS FOR DECOMMISSIONING AND ABANDONMENT

The final phase of the project life cycle is decommissioning and abandonment. As indicated in Table 2, an initial Decommissioning and Abandonment Plan is required before regulatory approvals to construct are issued. This plan includes decommissioning of installations, abandonment of fields and abandonment of wells. Specific facility and well abandonments may be undertaken several times during the operating life of an oil or gas development. At the end of a project life cycle, once the requirements of all other Regulatory Authorities (RAs) have been met, an Operator can apply to the NEB for a final OA for decommissioning and abandonment. However, the Operator continues to be accountable and responsible for a well, even after abandonment, and may be required to carry out remediation work should a well later be discovered to be leaking or require other maintenance.

3.7 POTENTIAL FUTURE OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES

Table 3 was prepared by CAPP, for the Beaufort Sea Strategic Regional Plan of Action (BSStRPA) 2008 report; it identifies potential future oil and gas exploration and development activities in the Canadian Beaufort Sea. It is the most recent comprehensive description of potential oil and gas activities available. However, in December 2012 Imperial Oil Resources Ventures Limited (IORVL) filed a Preliminary Information Package (PIP) on behalf of the Beaufort Sea Exploration Joint Venture. The PIP contains information on the range of exploration activities that IORVL is considering for EL 476 (Ajurak) and EL 477 (Pokak). The PIP states these ELs are in the Canadian Beaufort Sea about 125 km north-northwest of Tuktoyaktuk in water depths ranging from 60 to 1500m. IORVL indicates that a typical well drilled on these leases might be drilled over 3 or more summer drilling seasons.

The PIP indicates that the major components of the drilling operation may include:

- a drilling rig and related equipment similar to the drillings system described in section 4.2.2 of this report.
- marine support vessels, including ice-class supply vessels, icebreaking support vessels, and ice escort vessels
- a shore-based facility and a warebarge or ware ship
- emergency and spill response vessels and equipment
- some fuel supply will be loaded onboard the drilling rig and marine vessels during the spring transit into the Beaufort Sea. To meet fuel requirements for the entire drilling season, a double hulled ice-class fuel tanker is expected to be necessary. The fuel tanker may make refueling trips from a western port to the drill site during the summer drilling seasons

An example of the types and numbers of drilling and support vessels that may be used is also provided in the PIP. The example provided is largely consistent with the following list provided in the 2012 version of this report:

- 2 or 3 icebreakers would stay on location at the drillsite
- 2 or 3 supply vessels would make trips back and forth to a shore base,
- 1 possible wareship would stay on location, replacing 1 supply vessel
- 1 fuel tanker would be on location during the drilling operation

The PIP states that various facilities and services are being considered to support the offshore operation, including:

- a shore-based facility possibly at Tuktoyaktuk
- an onshore camp for upwards of 200 people (PIP estimate of 125 now believed to be low)
- staging sites and storage areas
- a docking area which may require some dredging
- land transportation services primarily between the shore-base and airstrip, but some materials and supplies could be transported over land or ice roads to Tuktoyaktuk
- air transportation services including two or more helicopters averaging one flight per day to the drill site
- storage of emergency equipment such as oil spill response equipment and other emergency equipment would likely be at the shore-based facility
- potable water supply would be required at the shore-based facility and the onshore camp
- waste management services would include transporting wastes on the supply vessels back to the shore-based facility, for disposal onshore or for storage prior to shipment out of the region

Figure 1-3 in the PIP provides an example of a possible exploration program schedule. The schedule indicates that a “Screening – Project Description and Environmental Impact Statement” might be filed later in 2013. These documents are expected to provide further details on the exploration equipment and activities required for drilling a deep water exploration well in the Beaufort Sea.

BREA researchers should consider the drilling system described above along with the industry activities described in Table 3, when attempting to identify and fill regional information and data gaps related to offshore oil and gas exploration and development activities.

Table 3. Potential Future Oil and Gas Exploration and Development Activities (from BSStRPA 2008)

Activity	Details
2D and 3D Seismic – near shore	• Vibroseis vehicles on ice which must be frozen to the bottom • Airguns and geophones drilled through the ice in <20m water depth, one airgun or receiver per hole • Shot holes drilled through the ice in <20m water depth with charge size limited by Department of Fisheries and Oceans pressure restrictions • Ocean bottom cables with mini airguns used during open water season in <70m water depths
2D and 3D offshore seismic - deep water	• Seismic vessels using airgun arrays and streamers during the open water season in >20m water depths
Wellsite surveys	• High resolution seismic and geotechnical surveys
Exploration drilling - landfast ice zone	• Drilling from spray ice pads grounded in <15m water depths • Drilling from spray ice pads floating in >15m water depth within the land fast ice zone • Construction of ice roads to shore
Offshore exploration drilling - shallow water zone (including land fast ice zone)	• Drilling from gravel or sand islands in <20m water depth with a surface blowout preventer (BOP) and up to 12 month season • Drilling from gravity based structures (GBS) like the Caisson Retained Island (CRI), or the Concrete Island Drilling System (CIDS) in <20m water depth with a surface BOP and a 12 month season
Offshore exploration drilling - deep water zone	• Drilling from GBS like the Steel Drilling Caisson (SDC) or the Molikpaq in >10m to <40m water depths, with a surface BOP and up to 12 month season • Drilling from floating drill ships like the Kulluk in >15m water depths with a subsea BOP and a 3-6 month season
Offshore drilling support	• Small and heavy lift helicopters • Supply vessels and barges • Ice breakers for towing, anchor handling, and ice management • Spill response vessels and equipment • Marine maintenance facilities (i.e. floating drydocks)
Offshore development - shallow water zone	• Gravel islands in <20m water depths • Causeways or subsea pipelines to shore
Offshore development - shallow water zone	• A GBS in <60m water depths • The GBS may need an ocean bottom excavation and sand or gravel foundation • Directionally drilled production wells from GBS • Subsea pipelines to shore

Table 3. Potential Future Oil and Gas Exploration and Development Activities (from BSStRPA 2008)(cont.)

Activity	Details
Offshore development - deep water zone	• floating development drilling • subsea wells and satellite well clusters in >60m water depths with subsea gathering lines • subsea pipelines to onshore processing facilities
Offshore development - deep water zone	• floating development drilling • subsea wells and satellite well clusters in >60m water depths with subsea gathering pipelines to the GBS which is located in <60m water depths **and** • subsea pipelines to shore **or** • crude oil storage on the GBS, with ice breaking crude oil tanker off take
Offshore development - deep water zone	• floating development drilling • subsea wells and satellite well clusters in >60m water depths with subsea gathering pipelines to the GBS which is located in <60m water depths and • subsea pipelines to shore with; • Liquified Natural Gas (LNG) facility onshore, and ice breaking LNG tanker off take
Subsea oil, gas and Natural Gas Liquids gathering and transportation pipelines	• Dredging, pipe laying, hydro testing, backfilling of trenches • Pipeline landfalls either trenched onto shore or directionally drilled from shore
Offshore production support	• Small and heavy lift helicopters • Icebreakers for ice management • Supply vessels, with oil spill response capability and barges • Marine Maintenance Facilities (i.e. floating dry docks) and other repair shops • Floating well workover, wireline and other well servicing equipment • Marine and logistics bases, including diesel storage and storage for oil spill equipment • Helicopter support bases • Camps with offices, control room and medical facilities • Multiple storage and warehousing facilities for companies providing drilling and production support services
Inspections	• Subsea Remote Operated Vehicle (ROV) inspections of pipelines, the GBS and subsea satellites • Subsea multi-beam and side scanning sonar inspections of pipelines, the GBS and subsea satellites • Diver inspections of pipelines, GBS and subsea satellites
Abandonment activities	• This area is uncertain at this time. Abandonment and reclamation are regulated and industry will work with regulators to develop appropriate plans

4. PREDICTED BEAUFORT SEA OIL AND GAS ACTIVITY

Several attempts have been made historically to predict the type, scale and timing of future Beaufort Sea oil and gas exploration and development. These include: Beaufort Environmental Monitoring Project (1988); Beaufort Region Environmental Assessment and Monitoring Program (1995); Gilbert, Laustsen, Jung Associated Ltd. (2004); the Mackenzie Gas Project (2005); and the Breakwater Group (2006) which all provide hypothetical development scenarios. In addition, the Beaufort Sea Strategic Regional Plan of Action (BSStRPA 2008) appendices contain a potential oil and gas development scenario largely drawn from the work by Morrell (2005, 2007). The INAC (2007) submission to the Joint Review Panel for the Mackenzie Gas Project (MGP) titled "*Towards a View of Future Oil and Gas Development in the Mackenzie Valley, Delta and the Beaufort Sea*" expands on Morrell's earlier work. Finally, CAPP provided a presentation titled *"Potential Oil and Gas Activities in the Beaufort Sea to the National Energy Board Offshore Drilling Review"*, Inuvik Roundtable Sept. 12-16, 2011. This report is an update to the "Oil and Gas Exploration & Development Activity Forecast, Canadian Beaufort Sea 2012-2013", prepared by the author in April 2012.

Peterson et al. 2003 describes forecasts as a "best estimate of future conditions from a particular model, method, or individual." He goes on to state the "public and decision makers generally understand that a forecast may or may not turn out to be true." Given that changing future conditions are a near certainty, this oil and gas activity forecast, is intended to describe a plausible future based on current assumptions. However, it is important to recognize that there are numerous ever-changing factors, which may significantly alter the forecast at any time.

In an attempt to try and develop plausible current forecasts of potential oil and gas activity in the Beaufort Sea, company representatives working on exploration and development projects in the area were interviewed in 2012 and again in 2013. Those companies known to be considering or currently undertaking exploration and/or development planning in the Beaufort Sea were asked to describe their current plans for activity. The author used this information to develop an industry-wide overview of potential oil and gas exploration and development activities for the 15 years. The report also provides a description of the oil and gas exploration and development activity cycle, which will apply to industry activities expected to occur over the long term. That is, the expected life cycle of those activities initiated during the next 15 years, is described to provide an indication of how these developments may build out to full scale and eventually be decommissioned. Any prediction of oil and gas exploration and development activities in Beaufort Sea over a 15 years period, will necessarily have a large margin for error. Therefore, the longer-term project life cycle predictions included in the report are only general and based on industry experience.

4.1 ASSUMPTIONS

4.1.1 Factors in Development of Assumptions

There are numerous regulatory, technical and economic factors, which may have a significant impact on the type and level of oil and gas activities that will occur in the Canadian Beaufort Sea over the next 15 years. BREA industry committee members identified the following key factors:

- The NEB report and filing requirements, resulting from the Public Review of Arctic Offshore Drilling have the potential to affect the type and level of oil and gas industry activity in the Beaufort Sea. Industry representatives expressed concern that the NEB Same Season Relief Well Policy could significantly impair exploration of the deeper waters of the Beaufort Sea. The same-season relief well capability requirements have been in place since the 1970s and the NEB in re-affirming the policy, provided the context and intent of the policy, and articulated the policy in its report and companion Filing Requirements. However, the NEB's requirement that any company applying for an offshore drilling authorization, "demonstrate how they would meet or exceed the intended outcome of our policy" (NEB 2011a,b), is expected to create regulatory and financial uncertainty as industry attempts to address the policy. IORVL in the PIP states, "A decision to proceed with an exploration drilling operation in the Beaufort Sea would require a significant financial commitment by the joint venture partners. Many factors would have to be considered in making a decision, including regulatory approvals and resolution of issues such as the NEB's equivalency to same season relief well capability".

- EL holders delayed filing offshore drilling applications, while they participated in the NEB Public Review of Arctic Offshore Drilling, and awaited guidance to be issued by the Board pursuant to its review. Such delays were expected in the 2012 forecast to result in current offshore EL holders seeking extensions to the timelines for their exploration work commitments. In September 2012 replacement ELs were issued to current EL holders in the Beaufort Sea to equitably restore the license term which was adversely affected due the NEB Arctic Offshore Drilling Review, during which operations were effectively suspended. The new ELs were issued in relation to the same frontier lands and all other terms and conditions of the new licences remain the same as the original licences.

- Industry representatives indicate that one or more built-for-purpose or retrofitted Arctic class drillships will need to be commissioned for drilling offshore in the Beaufort Sea deep slope areas. IORVL in its submission to the NEB titled "*Submission Regarding the Relief Well Policy for Offshore Drilling in the Arctic, March 2010*" states that existing floating drilling rigs are unsuitable for operating in the deep ice-infested waters of the Beaufort Sea. Their preliminary plans included the construction of a new purpose built Det Norske Veritas Polar Class 4 drillship. The PIP states that, "The unique conditions of the Arctic environment might require the construction of new and specialized equipment." The ordering of an Arctic class drillship is unlikely to occur until the NEB has issued an OA for drilling. Based on industry experience, the actual design, construction and commissioning of a purpose built drillship will take 3 to 4 years, which is consistent with the timing in Figure 1-3 in the PIP for design and construction of a new-build deepwater drilling rig and new-build icebreakers. The Stena Drill-Max Ice reported to be the world's first Arctic ice class, dual mast, ultra deepwater drillship was ordered in 2008 and commissioned in 2012.

- Increases in North American shale gas production have caused natural gas unit prices to tumble from more than US $8 per mcf in 2008 to about US $4 in 2011, with current spot prices even lower at between US $2 and $3. The 2012 forecast recognized that natural gas prices remaining at current levels would likely render Arctic gas production uneconomic. The MGP update presented at the June 2012 Inuvik Petroleum Show confirmed that the project is "not a commercial opportunity at this time" because the "natural gas market has changed significantly". The MGP update contained a North American supply/demand forecast indicating that a market for Mackenzie Delta gas may develop around 2023 and project activities could ramp up should market conditions improve. The 2012 forecast recognized that in the absence of MGP, industry exploration and development activities in the Beaufort Sea will focus more on oil than natural gas.
- The 2012 forecast indicated that existing offshore significant discoveries, located in less than 100m water depths, represent the best near term development opportunities in the Beaufort Sea. ConocoPhillips which is currently in the second year of a three year study of the Amauligak development concept feasibility, is the only company known to be actively evaluating a Beaufort Sea development.
- Although, current oil prices remain near historical highs, global economic instability is resulting in significant swings in world oil prices. This combined with high costs and industry uncertainty, as to how equivalency to the NEB Same Season Relief Well Policy can be achieved, may result in shifts in corporate exploration and development expenditures away from the Beaufort Sea. However, a sustained global economic recovery with accompanying increases in oil prices would encourage exploration and development.

Although the above list of factors is not exhaustive, in the author's opinion it does appear that negative factors continue to dominate positive factors for natural gas exploration and development activity in the Beaufort Sea. The outlook for oil exploration and development is somewhat more positive at this time, with Franklin planning seismic, IORVL filing the PIP and ConocoPhillips continuing to pursue the Amauligak feasibility study. However, history has clearly shown that factors affecting the outlook for oil and gas activity in the Beaufort Sea can change dramatically over relatively short timeframes. Therefore, if this forecast is to be relied upon for future planning, it should be revisited on a regular basis to ensure the underlying assumptions remain valid.

4.1.2 Base Assumptions

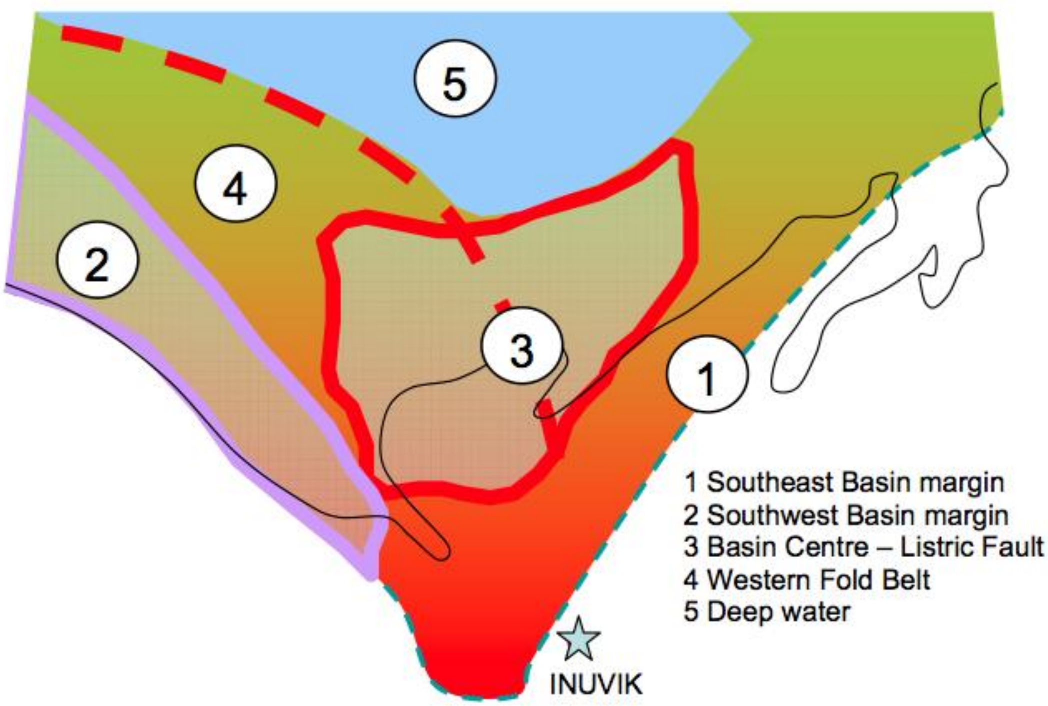
Regarding the above factors identified as potentially affecting oil and gas activity in the Beaufort Sea, this report assumes the following:

- Holders of existing deepwater Exploration Licences have indicated their intention to pursue drilling applications based on pre-engineered drilling systems with demonstrated equivalency to the NEB Same Season Relief Well Policy. It now appears that IORVL is likely to be the first Applicant to attempt to demonstrate equivalency to this policy. The possible program schedule contained in the PIP shows the filing of a Project Description and Environmental Impact Statement for screening in the third quarter of this year. IORVL indicates their "target" timeline for obtaining key regulatory approvals for drilling on EL's 476/477 is over the next 3 years, after which a decision on drilling will be made. The PIP shows a possible NEB Well Approval in 2019, which is one year later than the author predicted in the previous forecast of industry activity.
- One or more purpose-built or retrofitted Arctic class drillships are expected to be commissioned to drill deep shelf and deep slope wells in the Beaufort Sea. The possible program schedule in the PIP is consistent with the 2012 forecast assumption that it will take 3 to 4 years to design and construct a purpose built drillship. The timeline for retrofitting an existing drillship to meet Arctic drilling requirements is still unknown, and assumed to be similar to that for constructing a new drillship.
- MGP will not proceed as scheduled, however; if the North American supply/demand forecast MGP present at the 2012 Inuvik Petroleum Show proves to be accurate the project could ramp up to begin production around 2023.
- The Amauligak field is now assumed to provide the most likely near term development opportunity in the Beaufort Sea, as it is the only potential Beaufort Sea development known to be under evaluation. ConocoPhillips and the other Amauligak interest owners are currently in the second year of a three year study to identify a potentially feasible development concept for the field. .
- The 2012 forecast predicted that low natural gas prices, and regulatory uncertainty would reduce the number of industry nominations and bids for Beaufort Sea ELs over the 15-year timeframe of the forecast. However, Franklin Petroleum a newcomer to the Canadian Beaufort Sea took advantage of the recent lack of interest by other petroleum operators in Beaufort Sea and acquired 8 ELs covering 1,117,095 hectares for a total work bid of only $9,506,528. Franklin is proposing to conduct 3D seismic in the summer of 2013 or in subsequent years, with the hope of identifying one or more drilling locations. Since the timing, complexity and cost of drilling increases with water depth and they cannot predict the water depth of any prospective drilling location, they are unable to forecast when drilling might occur. They company has indicated, however, that it does not expect to be drilling prior to 2015.

4.2 PREDICTED INDUSTRY ACTIVITY

Previous predictions of oil and gas activity in the Beaufort Sea by GLJ (2004), MGP (2005), Morrell (2005, 2007), and the Headwater Group (2006) have generally taken the view that induced natural gas development from the MGP, will dominate early exploration and development in the Beaufort Sea. This early activity was expected to focus on the Listric Fault play illustrated in Figure 10 from BSStRPA (2008) and include the Issungnak-Amauligak and Netserk-Kadluk-Minuk significant discovery areas with new exploration focused on expanding the discovered gas resource near these discoveries.

Figure 10. Mackenzie Delta and Beaufort Sea Basin Geology



Amauligak is the largest oil and gas discovery in the offshore with an estimated 350 million barrels (mmbbl)(56 $10^6 m^3$) of oil and 1.6 trillion cubic feet (tcf)(48 $10^9 m^3$) of gas (Drummond 2009); its size and proximity to shore suggest that it would likely be part of any initial offshore development proposal. As Morrell (2007) notes, offshore oil production does not necessarily require the offshore expansion of a gas pipeline network from onshore. He also notes that high oil prices could encourage oil exploration and possibly development in the Beaufort Sea continental margin. North American gas prices have declined during the last few years, and oil prices have risen dramatically. These price changes have shifted the focus of offshore activity in the Beaufort Sea from MGP-induced gas exploration and development to oil exploration and development.

Morrell (2007) also recognized that there are large offshore areas of the Beaufort, which are sparsely explored and have the potential for major oil and gas discoveries. Since most of the large near shore structures have experienced some exploration, any new major discoveries will likely be in deeper water offshore. Morrell also foresaw the possibility that large international companies could become interested in exploring the deeper offshore Beaufort Sea, through their continual evaluation of opportunities in their worldwide portfolios. The awarding of high value ELs for deep slope areas of the Beaufort Sea has proven Morrell's predictions to be accurate.

One indicator of future exploration activity in the Beaufort Sea is the number of current ELs and the financial and well drilling commitments they contain. Figure 11 from AANDC (2011), shows the locations of ELs, SDLs and other features in the Mackenzie Delta and Beaufort Sea. Table 4 shows the effective dates of the current Beaufort Sea ELs, the work bid amounts, the dates wells are to be drilling, and the year each EL expires, if a well is not drilled and work commitments not met.

Figure 11. Current Exploration Licences and Significant Discovery Areas Map (from AANDC November 2012)

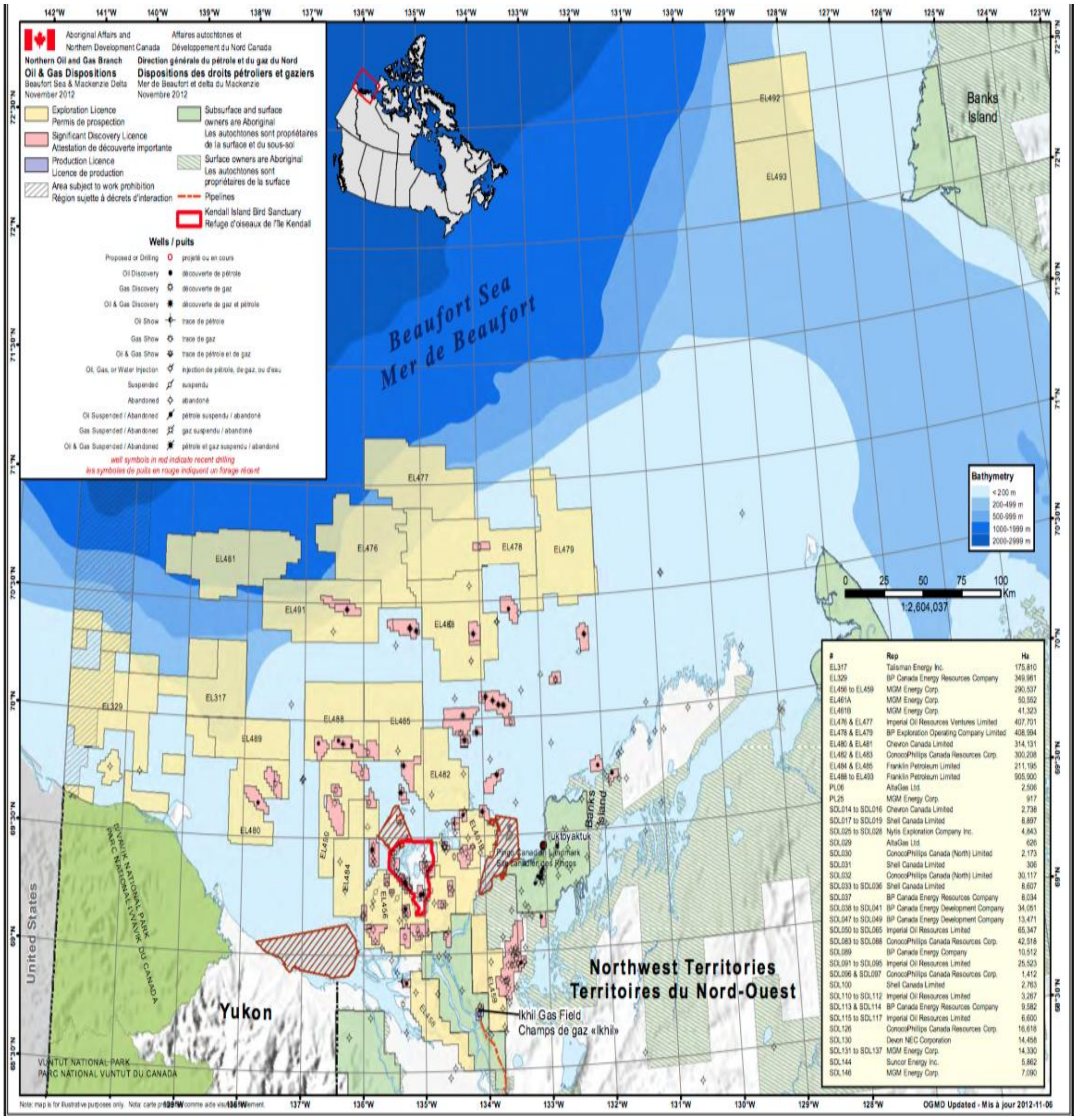


Table 4. Current Beaufort Sea Exploration Licences

Licence	Area (ha)	Representative[1]	Effective Date	Well to be Drilling[2]	Expiry Date	Work Bid Amount ($)
EL476 was 446	205,321	Imperial Oil Resources Ventures Limited	01-Sept-2012	2015 was 2012	31-July-2019 was 2016	585,000,000
EL477 was 449	202,380	Imperial Oil Resources Ventures Limited	01-Sept-2012	2016 was 2013	30-Sept-2020 was 2017	1,180,100,000
EL478 was 451	205,359	BP Exploration Company Ltd.	01-Sept-2012	2015 was 2013	31-Aug-2019 was 2017	15,100,000
EL479 was 453	203,635	BP Exploration Company Ltd.	01-Sept-2012	2016 was 2013	30-Sept-2020 was 2017	1,100,000
EL480 was 448	108,185	Chevron Canada Limited	01-Sept-2012	2015 was 2012	31-Oct-2019 was 2016	1,010,100
EL481 was 460	205,946	Chevron Canada Limited	01-Sept-2012	2017 was 2016	31-Aug-2021 was 2020	103,300,000
EL482 was 447	103,711	ConocoPhillips Canada Resources Corp.	29-Aug-2012	2015 was 2012	28-June-2019 was 2016	12,084,131
EL483 was 452	196,497	ConocoPhillips Canada Resources Corp.	01-Sept-2012	2016 was 2013	20-Sept-2020 was 2017	2,543,896
EL484 was 464	90,381	Franklin Petroleum	01-Sept-2012	2017 was 2016	31-Aug-2021 was 2020	1,000,000
EL485 was 465	120,314	Franklin Petroleum	01-Sept-2012	2017 was 2016	31-Aug-2021 was 2020	1,000,000
EL488	134,142	Franklin Petroleum	06-Mar-2013	2018	05-Mar-2022	1,251,088
EL489	93,483	Franklin Petroleum	06-Mar-2013	2018	05-Mar-2022	1,251,088
EL490	99,324	Franklin Petroleum	06-Mar-2013	2018	05-Mar-2022	1,251,088
EL491	201,101	Franklin Petroleum	06-Mar-2013	2018	05-Mar-2022	1,251,088
EL492	187,200	Franklin Petroleum	06-Mar-2013	2018	05-Mar-2022	1,251,088
EL493	190,650	Franklin Petroleum	06-Mar-2013	2018	05-Mar-2022	1,251,088

Notes:

1. Representative as prepared by AANDC as of July 11, 2012.
2. Per the original licence, Period 1 may be extended using drilling deposits or through amendment to the licence. The drilling of one exploratory or delineation well prior to the end of Period 1 of the term is a condition precedent to obtaining tenure to Period 2.

4.2.1 Seismic Surveys

Since 2006, one or two large 2D seismic surveys have been conducted each year in the Beaufort Sea. Third party seismic companies that conduct both speculative and contracted seismic surveys normally carry out these large surveys. Recent surveys have focused on the Beaufort deep slope areas, the central Beaufort Sea, the areas West of Banks Island, and the Tuktoyaktuk Peninsula, and to a lesser extent the Western Beaufort Sea. In addition, 3D seismic surveys were carried out in 2008 by IORVL on EL446, in 2009 by BP on EL449 and in 2012 by Chevron Canada on ELs 480 and 481.

Industry geologists evaluate the prospectivity of new exploration regions and decide where to carry out seismic surveys using, a combination of available information, analogues from similar basins, geological models and professional judgment. Without having access to these confidential industry assessments of regions in the Beaufort Sea, future seismic exploration is very difficult to predict. Since several large 2D surveys have been conducted in the Beaufort Sea in the last few years, the size and frequency of these surveys over the next 15 years is likely to decrease. History has shown that in any specific year one or two 2D seismic surveys of varying sizes may be conducted in the Beaufort Sea.

Franklin indicates they are applying to conduct a marine 3D and contingent 2D seismic program in the Canadian Beaufort Sea during the open-water period of 2013 or subsequent years of Franklin Petroleum’s lease term. The primary objective of their program is to acquire 3D seismic data over ELs 485 and 488-491. However, if environmental conditions prohibit the acquisition of these data, Franklin Petroleum is proposing to acquire contingent 2D seismic data in ELs 492 and 493 offshore Banks Island. Their program entails the acquisition of up to 4000km^2 of 3D seismic data and potentially up to 1000km of 2D data. The 3D survey area is located between 50 and 100km northeast of Herschel Island and is bounded by 139°W on the west, 135°W on the east, and extends northward to 70°40’N. Water depths range from 15-1000m within the proposed 3D survey area. The 2D survey area is located 80km west of Banks Island, in water depths of 100-400m.

Additional 2D seismic surveys are likely to be conducted in other unexplored areas as well. The number of future 3D surveys can be expected to closely track the number of offshore wells drilled. Due to the high cost of offshore wells, 3D surveys are now routinely conducted on each EL a few years prior to drilling. High-resolution wellsite seismic surveys will also be conducted to map the sea bottom surface and near subsurface prior to spudding all offshore wells.

4.2.2 Deep Shelf and Slope Beaufort Sea Wells

As predicted in the 2012 forecast replacement ELs were issued in 2012 to compensate operators for the time they spent participating in the NEB Public Review of Arctic Offshore Drilling. The current ELs call for 8 wells to be drilled in the deeper offshore Beaufort Sea between 2015 and 2018, which is unlikely.

As indicated earlier, industry expects that only one or two built-for-purpose or retrofitted Arctic class drillships will be acquired to drill deep slope wells (>100m water depth) in the Beaufort Sea. It now appears that IORVL is likely to be the first Applicant to apply for an Operations Authorization to drill a deep water Beaufort Sea well. The possible program schedule contained in the PIP indicates drilling to start in 2020, which is consistent with the 2012 forecast, that it would be unlikely for the first deep water well to be spudded before 2018.

Given the extremely high cost for new Arctic class drilling systems, industry representatives indicate that only 1 or 2 such drilling systems are likely to be acquired for use in the Beaufort Sea over the next 15 years. The Stena Drill-Max Ice which was commissioned in 2012 cost $1,065 Billion USD and is the most expensive drillship ever built. The extremely high cost of similar drillships and their accompanying icebreakers, makes it unlikely that two companies would concurrently decide to acquire such vessels for use in the Beaufort Sea. A more likely scenario is that the first drilling system would be acquired and a successful deep-water well drilled, before a second drillship and its icebreakers are acquired.

Figure 12. Stena Drill-Max Ice Drillship (source Det Norske Veritas)

The PIP indicates that it will likely take 3 drilling seasons to drill and test a deep-water well on EL447. Therefore, if as the possible program schedule in the PIP indicates, the first deep slope Beaufort Sea well is completed in 2022, a second drillship and its icebreakers may be acquired and ready to start deep-water drilling by about 2025. However, the timeframe for a second deep-water drillship to start drilling in the Beaufort may be significantly extended should the first well fail to discover significant oil reserves.

Arctic exploration in deep water is technically challenging and extremely expensive. Crooks D. et. al. (2012) in an article titled "*Energy: Drills, chills and spills*" described several deep water Arctic developments which have in recent years been delayed or abandoned in Alaska, Norway and Russia due to high costs. The article pointed out that even the development of one of the worlds largest Arctic offshore gas fields, the Shtokman field with an estimated 130 trillion cubic feet (tcf)(3.8 $10^{12}m^3$) of gas, 600 km north of Russia was put on hold in August 2012 for an indefinite time due to high costs and low gas prices. In the same article a senior Arctic consultant for ExxonMobil stated that the company expects to spend three summers drilling a single exploration well in the Canadian Beaufort Sea, making it potentially "the most expensive well ever drilled". He went on to state that due to a lack of infrastructure and logistic challenges an offshore Arctic reservoir would have to contain 500 million to 1 billion barrels (bbl)(80 10^6m^3) to 160 10^6m^3) of recoverable oil to be economically viable.

Royal Dutch Shell plc (Shell plc) recently encountered extreme offshore weather conditions in Alaska, which resulted in the grounding of the Kulluk while it was being towed south at the end of the 2012 drilling season. This incident resulted in Shell plc pausing its Alaska drilling program for 2013, and towing the Kulluk and a second drill rig, the Nobile Discoverer, to Asia for maintenance and repairs.

Further, on April 10, 2013 ConocoPhillips Alaska announced that it had cancelled its plans to drill in the deep waters of the Chukchi Sea off Alaska's northwest shore in 2014. ConocoPhillips pointed to uncertainties in the evolving federal regulatory requirements as the reason and stated that it would not be prudent to commit the financial resources at this time. The company cited a recent Interior Department report, which said industry and government should work together to create an Arctic-specific model for petroleum exploration. Following the ConocoPhillips announcement Alaskan senator L. Murkowski issued a statement saying, "Companies can't be expected to invest billions of dollars without some assurance that federal regulators are not going to change the rules on them almost continuously". She went on to state that; "The administration has created an unacceptable level of uncertainty when it comes to the rules for offshore exploration".

4.2.3 Shallow Beaufort Shelf Wells

Table 4 indicates that ELs 480, 482, 483, 484, 485, 488, 489, 490, and 491, which have water depths less than 100m, are to have wells drilled between 2015 and 2018. This timeline also appears unlikely.

There are currently no suitable drilling platforms for these shallow wells located in the Canadian Beaufort Sea. Thus either an existing Arctic drilling platform will have to be brought into the Beaufort Sea from another jurisdiction, or a new shallow water Arctic drilling platform will have to be commissioned. Due to the scarcity and high cost of such Arctic drilling platforms, it is again expected that only 1 or 2 will be used in the Beaufort Sea during the timeframe of this report. If a suitable Arctic drilling platform can be located and transported to the Beaufort Sea, this could be accomplished faster than commissioning a new one. Therefore, it is predicted that the first shallow water drilling platform will commence operations by 2016, with a second commencing drilling a couple of years later. A first well date of 2016 is consistent with the 3D seismic schedule proposed by Franklin, which holds the largest number of Beaufort Sea ELs in shallow water.

As history has shown, shallow water Beaufort Sea wells could be drilled from artificial islands, caisson structures or spray ice islands. However, the timeframe for drilling a well using one of these drilling platforms, is unlikely to be much before 2016 as industry indicates that no AO applications to do so are currently being considered.

Historical forecasts expected the impetus for drilling shallow water wells in the Beaufort would be induced natural gas exploration due to MGP, which has been found to be uneconomic at this time. Figures 13 and 14 from the MGP *"Environmental Impact Statement Additional Information Report, March 2005"* show a possible sequence of tie-ins for Mackenzie Delta/Beaufort Sea existing significant discoveries and potential new discoveries. Although this is a simplistic scenario, it indicates that 11 onshore and 10 offshore existing significant discoveries could potentially be tied in, before any new offshore discoveries are added to the system. Figure 14 shows the first new offshore discovery being tied in approximately 17 years after MGP start-up. Therefore, allowing 3 years for drilling and tie-ins, there will be no incentive for MGP induced gas exploration to occur during the timeframe of this forecast. This simply reflects the lack of economic incentives to increase gas reserves in the vicinity of existing discovered fields.

One potential driver for shallow Beaufort Sea exploration is ongoing high oil prices, which may provide sufficient incentive for oil exploration and possibly production drilling during the next 15 years. This drilling would rely on the same types of shallow water (<100m) arctic drilling platforms discussed earlier. Therefore, even though little incentive to drill Listric Fault or Basin Margin gas wells is anticipated during the report period, the potential exists for shallow water oil exploration to begin when appropriate drilling platforms become available. As indicated earlier suitable drilling platforms could be available in the Canadian Beaufort Sea by 2016. Therefore, it is reasonable to assume that 1 or 2 shallow water drilling platforms will be operational in the Beaufort Sea from 2016 on.

As discussed earlier, the Amauligak development is assumed to provide the most likely near term development opportunity in the Beaufort Sea. If the project proceeds successfully through the project planning process and all required regulatory processes, ConocoPhillips has indicated construction and development drilling could begin sometime around 2020, with first production potentially around 2025.

Figure 13. Scenario Assumptions for Years of Production per Field for the Mackenzie Delta (from MGP 2005)

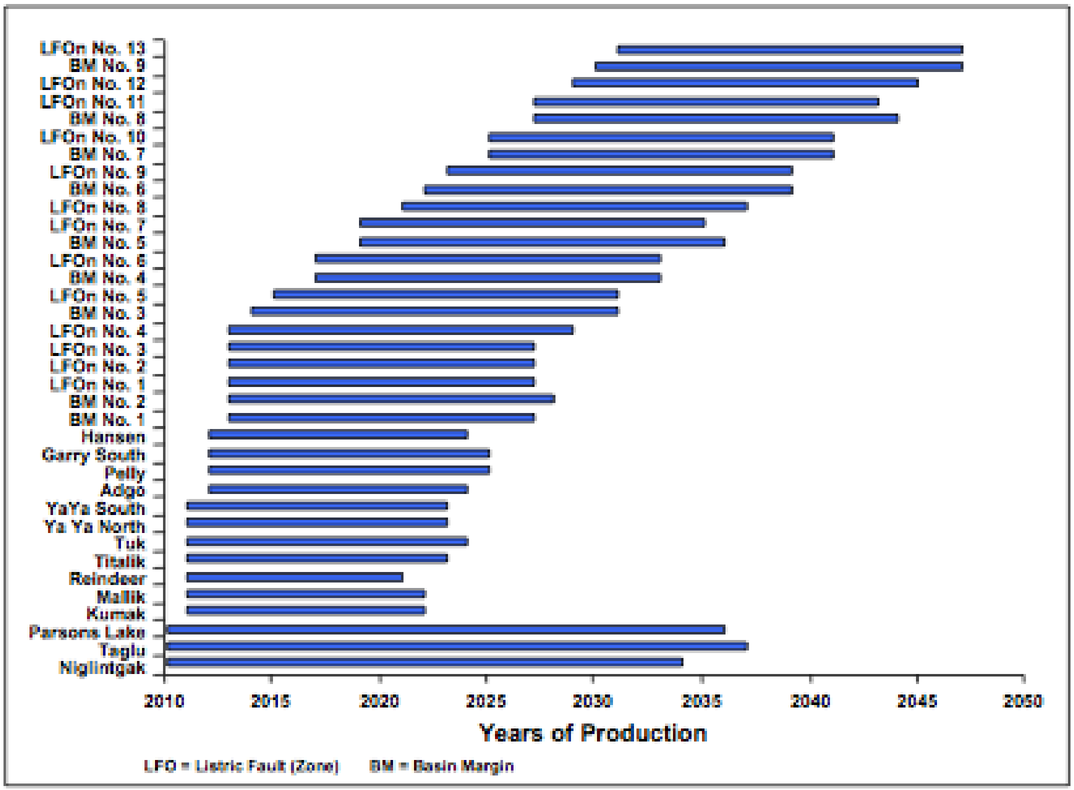
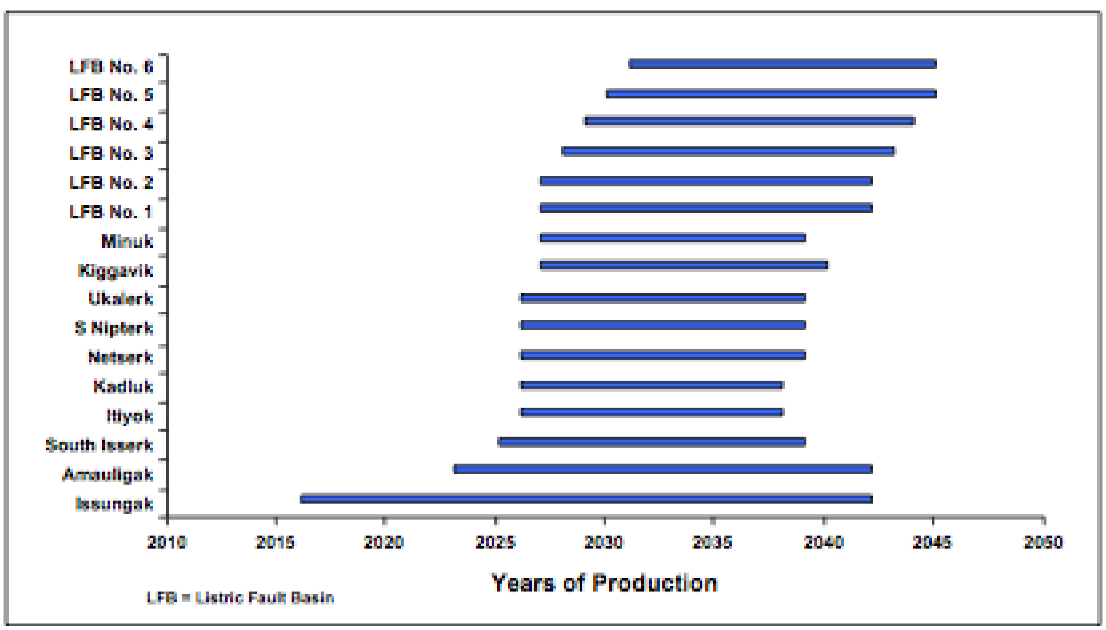


Figure 14. Scenario Assumptions for Years of Production per Field for Beaufort Sea (from MGP 2005)



4.2.4 Short- to Medium-Term Oil and Gas Activity Forecast

Table 5 provides a summary of the oil and gas activity predicted to occur in the Beaufort Sea over the next 15 years. This table should be used in conjunction with Section 3.7, which provides descriptions of these activities and the facilities, vessels and infrastructure needed to carry them out.

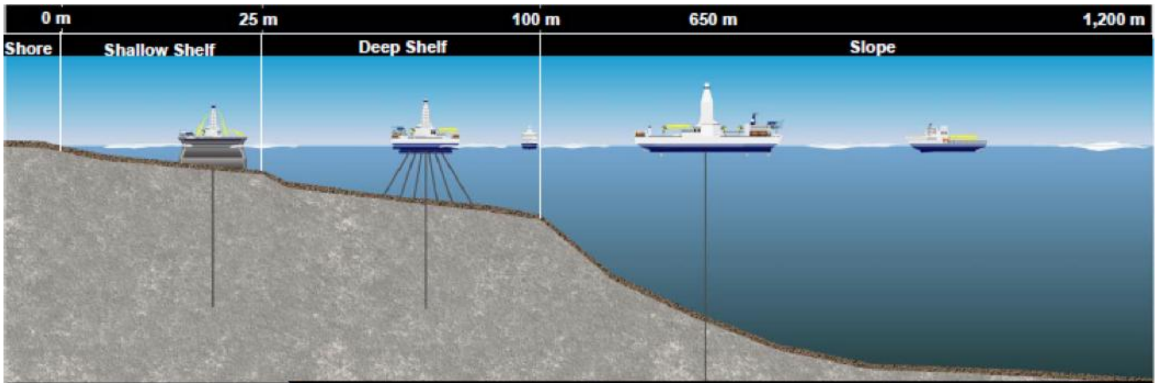
Table 5. Summary of Offshore Oil and Gas Activity 2013-2028

Activity	Predicted Timing or Intensity
2D Seismic Surveys	- sporadic 1 or 2 per year
3D Seismic Surveys	- on each EL a few years prior to drilling
Wellsite Seismic Surveys	- prior to spudding each well
Mackenzie Gas Project	- possible start-up delayed beyond 2023
Discovered Offshore Gas tie-ins to MGP	- none during the next 15 years
Shallow Shelf Exploration Wells	- one or two per year starting in 2016
Deep Shelf and Slope Exploration Wells	- first well 2020, 2 or 3 more wells by 2028
Shallow Shelf Oil Production	- first potential drilling/construction in 2020
Oil Production from the Beaufort Sea	- first possible production in 2025

4.2.5 Longer Term Oil and Gas Activity

The predicted short- to medium-term oil and gas exploration and development activities over the next 15 years in the Beaufort Sea, have a large margin for error. Therefore, longer-term project life cycle predictions can only be general and based on industry experience. Table 3 from BSStRPA(2008) provides the most current industry description of potential future oil and gas exploration and development activities for the Canadian Beaufort Sea, while Figure 15 illustrates the types of drilling platforms predicted to be used in exploring and developing the shallow slope, deep shelf and slope areas of the Beaufort Sea.

Figure 15. Typical Drilling Platforms in the Beaufort Sea (from Imperial Oil in CAPP 2011)

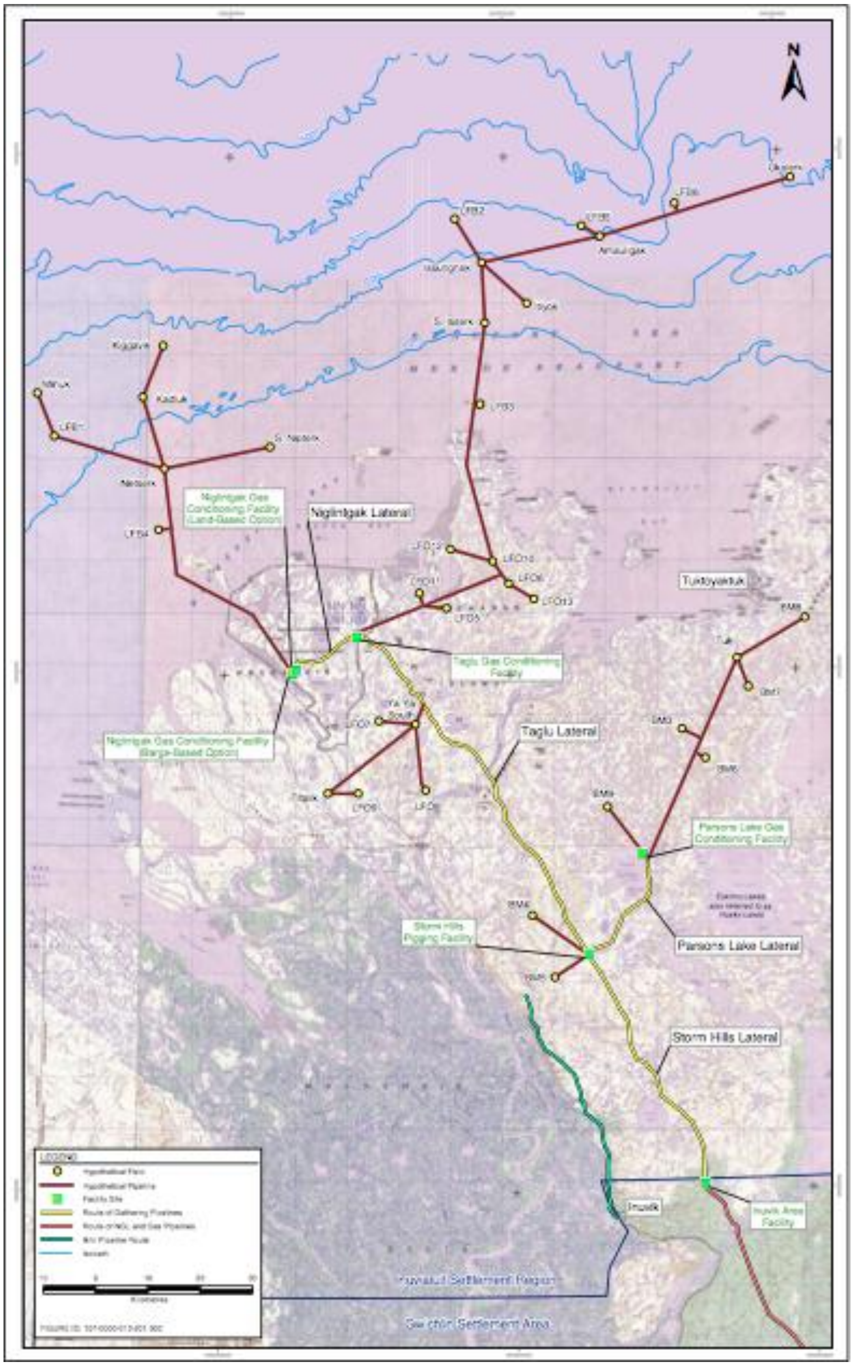


Factors	Shallow Shelf	Deep Shelf	Slope
Water Depth	▪ 0 m–25 m	▪ 25 m–100 m	▪ 100 m–1,200 m
Ice	▪ land-fast, first-year ice ▪ limited multi-year ice	▪ multi-year ice intrusions	▪ multi-year ice present
Type of Offshore Drilling Rig	▪ bottom-founded and moored drilling	▪ moored drilling	▪ dynamically positioned drilling
Open Water Season	▪ 85 days	▪ 70 days	▪ 50 days
Winter Season	▪ 120 days	▪ None	▪ none

As indicated, historical predictions of oil and gas activity in the Beaufort Sea have generally taken the view that induced natural gas development from MGP will dominate early exploration and development in the Beaufort Sea. Figure 16 is a simplistic depiction of how this pattern of development may proceed in the long term. However, since MGP has been determined to be uneconomic at this time, the focus of industry development activities in the Beaufort Sea have shifted to oil rather than natural gas.

If oil development does proceed in the Beaufort Sea, it will not necessarily require the offshore expansion of a pipeline network from the onshore. Offshore oil production could occur using subsea pipelines to shore, Gravity Based Structures (GBS) or Floating Production Storage and Offloading (FPSO) facilities. Since industry planning for possible offshore oil production from the Beaufort Sea is at a very early stage it is not possible to predict, which if any, of these oil production systems may be used.

Figure 16. Hypothetical Development Scenario Year 2030 (from MGP 2005)



5. MACKENZIE DELTA - BEAUFORT SEA HYDROCARBON RESOURCE POTENTIAL

The literature contains a number of estimates of discovered and potential oil and gas resources in the Mackenzie Delta and the Beaufort Sea. These include:

- NEB (1998) a probabilistic estimate of discovered recoverable oil and marketable gas for each field in the Mackenzie Delta/Beaufort Sea
- Canadian Gas Potential Committee (CGPC) (2005) an estimate of discovered and undiscovered gas resources in the combined Beaufort Sea/Mackenzie Delta
- Chen et al. (2007) an estimate of future oil discovery potential of the Mackenzie/Beaufort Geological Province
- Drummond (2009) an estimate of distribution of ultimate oil and gas resources in the onshore and offshore areas of the Mackenzie/Beaufort Basin.

The discovered recoverable oil resource in the combined Mackenzie Delta/Beaufort Sea is between 1bbl (159 $10^6 m^3$)(NEB 1998) and 1.2bbl (183 $10^6 m^3$)(Chen et al. 2007) and the total recoverable oil resource may be as high as 10.6bbl (1691 $10^6 m^3$)(Chen et al. 2007). The majority of the discovered oil reserves are located in the Beaufort Sea offshore.

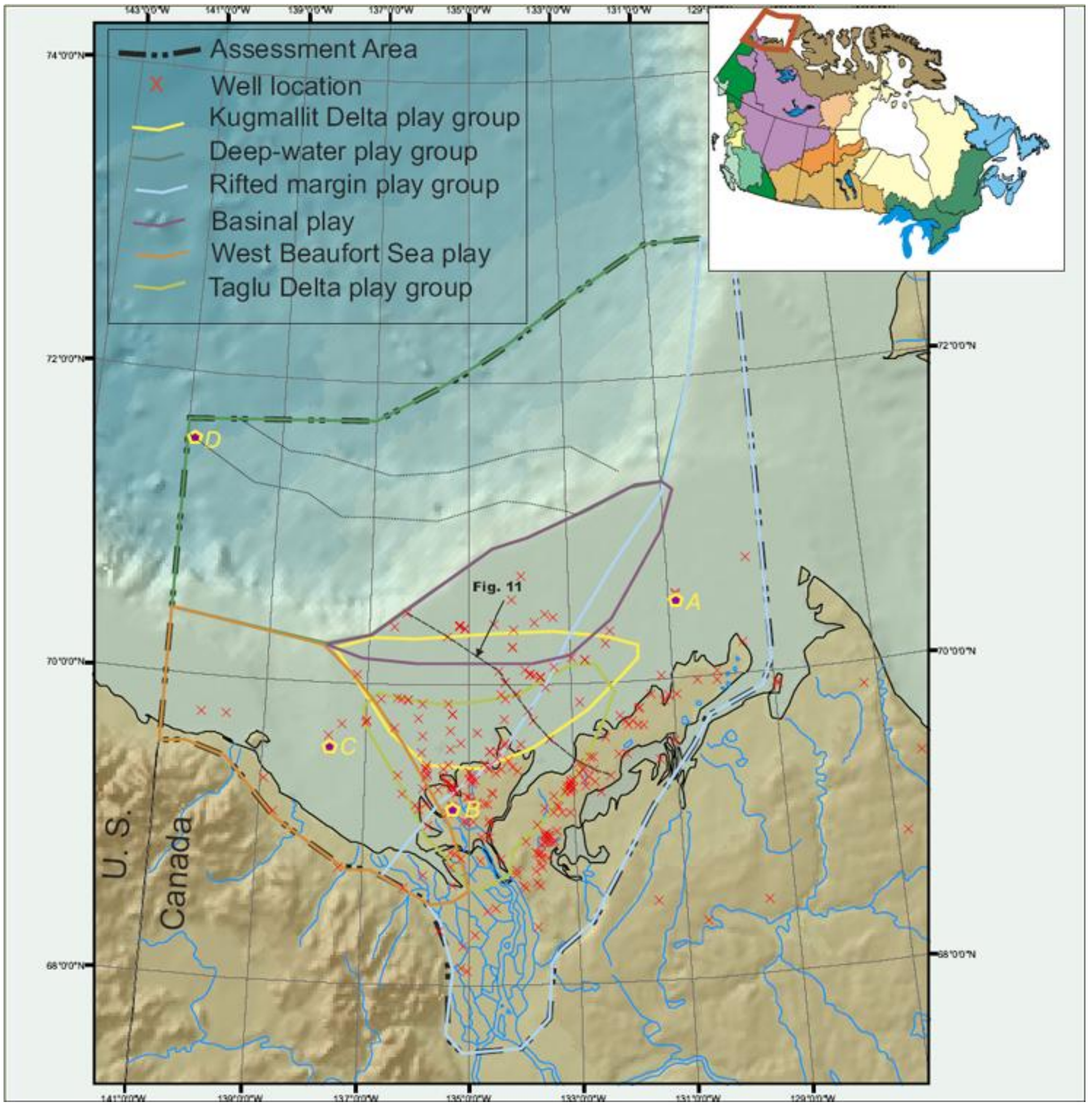
The estimated discovered marketable gas resource in the Mackenzie Delta and Beaufort Sea is between 9tcf (254.8 $10^9 m^3$)(CPGC 2005) and 10.4tcf (294.5 $10^9 m^3$)(Drummond 2009) and the ultimate marketable gas resource may be as high as 56.9tcf (1611.2 $10^9 m^3$)(Drummond 2009). Discovered gas reserves are relatively evenly distributed between the Mackenzie Delta and the Beaufort Sea. Table 6 provides a summary of the regions currently estimated oil and gas potential.

Table 4. Mackenzie Delta and Beaufort Sea Oil and Gas Resource Potential

Resource	Current Estimate
Discovered Recoverable Oil Resource	- 1 to 1.2bbl (159 to 183 $10^6 m^3$)
Total Recoverable Oil Resource	- 10.6bbl (1691 $10^6 m^3$)
Discovered Marketable Gas Resource	- 9 to 10.4tcf (254.8 to 294.5 $10^9 m^3$)
Ultimate Marketable Gas Resource	- 56.9tcf (1611.2 $10^9 m^3$)

It is important to note that the Mackenzie Delta/Beaufort Sea Geological Province is still in an early stage of exploration. Chen et al. (2007) states, “It is expected that there will be both increased data and understanding that will lead to new large discoveries in the more remote areas and deeper parts of the sedimentary succession as the scope of exploration expands both geographically and technologically”. As can be seen in Figure 17 the deep slope region of the Beaufort Sea has not been explored or assessed. The issuance of ELs with high value work commitments there (Figure 11 and Table 4) is a strong indication that industry believes this area has the potential to hold large accumulations of hydrocarbons.

Figure 17. Location Map Showing Study Area, Play Group Boundaries and Exploratory Wells in the Mackenzie/Beaufort Geological Province (from Chen et al. 2007)



In addition, to the above quantitative resource estimates, AANDC on its website, provides an interactive Petroleum and Environmental Management Tool (PEMT). The PEMT displays generalized environmental and socio-economic information for selected Arctic regions to help inform decisions about oil and gas exploration and land management. The PEMT tool is used to identify and overlay potential environmental and socio-economic sensitivities, with map layers showing petroleum potential and geologic uncertainty. The user can view and print maps of specific grid areas of the Beaufort Sea, illustrating ratings for known environmental sensitivities, petroleum potential and geologic uncertainty.

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