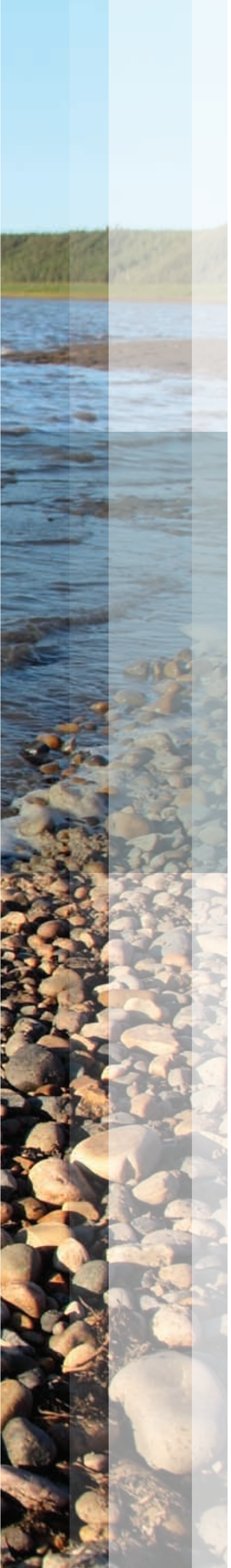


Technical considerations: Implementing the decision

List of Figures

List of Tables

Chapter 1 Introduction

1.1 The project

The Mackenzie Gas Project is a proposal to produce and transport natural gas and natural gas liquids from the three largest discovered onshore natural gas fields in the Mackenzie Delta area. Natural gas from the Niglintgak, Taglu and Parsons Lake fields would travel via the Mackenzie Valley Pipeline from Inuvik, Northwest Territories, to northwestern Alberta and on to southern markets. Natural gas liquids would be separated from the natural gas at a gas processing facility near Inuvik (Inuvik Area Facility) and transported via a smaller pipeline to Norman Wells, Northwest Territories, where it would connect to the existing Enbridge Pipelines (NW) Inc. Norman Wells Pipeline (see Figure 1-1).

In October 2004 the National Energy Board received the following applications for the construction and operation of the Mackenzie Gas Project:

- the development of three natural gas fields—Niglintgak, Taglu and Parsons Lake development fields—applied for under section 5.1 of the *Canada Oil and Gas Operations Act*;
- the Mackenzie Gathering System, including 189.2 kilometres of upstream gathering pipelines, the Inuvik Area Facility, and a 457.2 kilometre natural gas liquids pipeline from the Inuvik Area Facility to Norman Wells, all applied for under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act*;
- the 1195.8 kilometre long Mackenzie Valley Pipeline, including three compressor stations, a heater station and associated pipeline facilities to transport natural gas from the Inuvik Area Facility to northwestern Alberta, applied for under section 52 of the *National Energy Board Act*. This pipeline would connect with the existing NOVA Gas Transmission Ltd. system in Alberta; and
- an order, pursuant to Part IV of the *National Energy Board Act*, approving the toll and tariff principles that are to apply to service on the Mackenzie Valley Pipeline.

Did you know?

Pipelines in the North

If the Mackenzie Gas Project proceeds it would be by far the largest pipeline system to be constructed and operated in Canada's North, although it would not be the first. The Canol Pipeline, built during World War II, moved crude oil from Norman Wells to Whitehorse, and in the mid-1980s, Enbridge Pipelines (NW) Inc. built the Norman Wells Pipeline from Norman Wells to Zama, Alberta. Several natural gas pipelines have been built from southern Yukon and the Northwest Territories into British Columbia and Alberta in the last half century and, in the late 1990s, the Ikhil Pipeline was built to supply Inuvik with natural gas.

The Mackenzie Valley Pipeline is designed to transport approximately 34.3 Mm³/d (1.2 Bcf/d) of natural gas with three compressor stations in operation.

The proponents of the Mackenzie Gas Project are Imperial Oil Resources Ventures Limited, Mackenzie Valley Aboriginal Pipeline Limited Partnership, Imperial Oil Resources Limited, ConocoPhillips Canada (North) Limited, Conoco Phillips Northern Partnership, ExxonMobil Canada Properties and Shell Canada Limited as managing partner of Shell Canada Energy, (collectively, the Proponents).

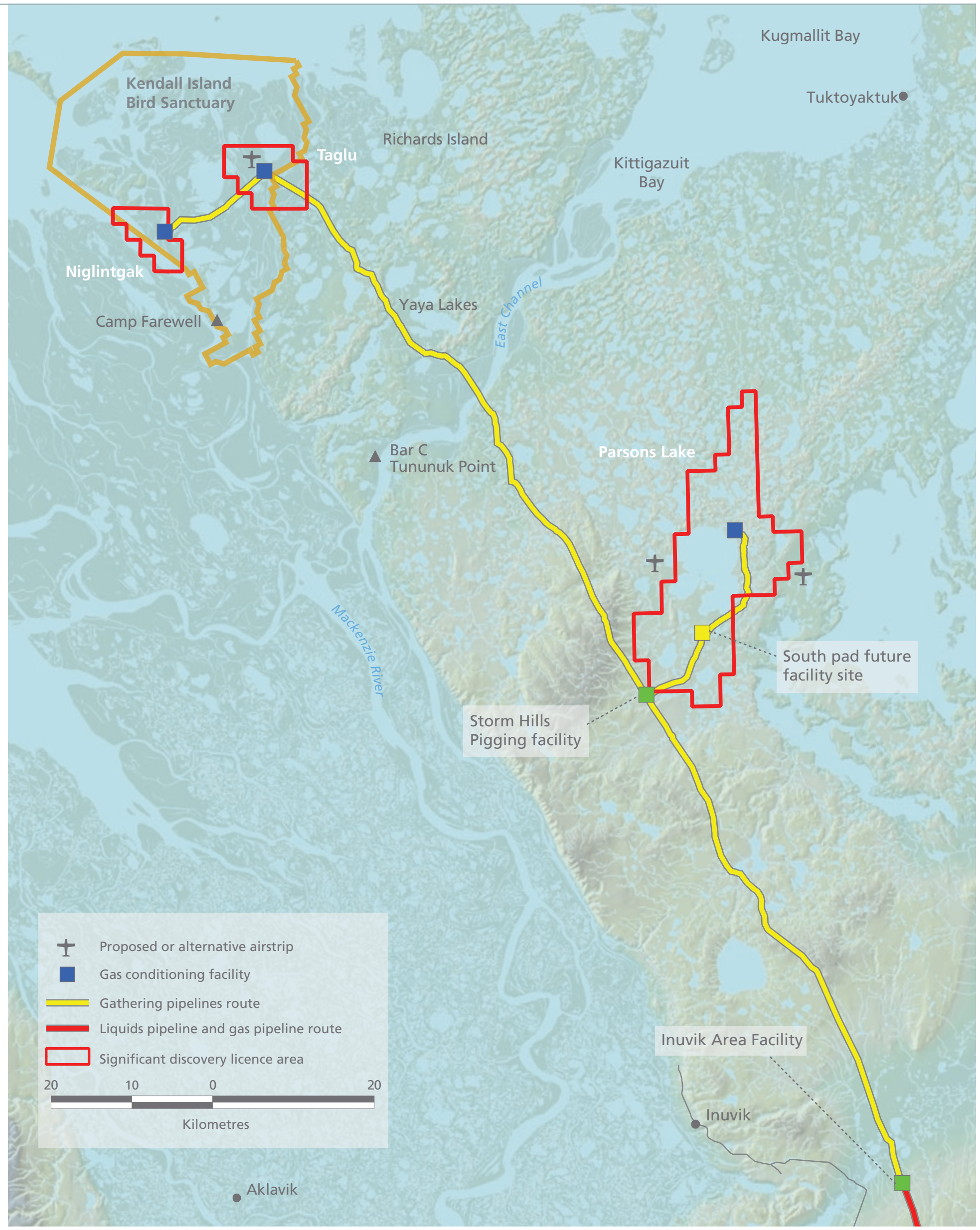
The capital cost of the Mackenzie Gas Project is estimated at $16.2 billion (2006$). It is planned to be in operation by the end of 2018, based on the start of construction in late 2014.

Figure 1-1

Overall project map

Figure 1-2

Development fields and upstream gathering pipeline



1.2 Project description

1.2.1 Niglintgak field

Shell Canada Limited (Shell) applied for approval of a Development Plan under section 5.1 of the *Canada Oil and Gas Operations Act* for the Niglintgak field on 20 October 2004.

The Niglintgak Significant Discovery Licence SDL019 is located about 120 kilometres northwest of Inuvik and 85 kilometres west of Tuktoyaktuk and lies within Kendall Island Bird Sanctuary in the Mackenzie Delta (see Figure 1-2).

The proposed production facilities include:

- six to twelve production wells located on three well pads;
- a system of above-ground flow lines;
- a gas conditioning facility located in the Kumak Channel;
- a disposal well; and
- infrastructure including an emergency shelter and helipads.

Construction is planned over four winter seasons from 2014 to 2018 with operations to commence in 2018 and continue for about 25 years. The initial capital expenditure for drilling and facilities is expected to be $800 million (2006$).

1.2.2 Taglu field

Imperial Oil Resources Limited applied for approval of a Development Plan under section 5.1 of the *Canada Oil and Gas Operations Act* for the Taglu field on 7 October 2004.

The Taglu Significant Discovery Licence SDL063 is located about 120 kilometres northwest of Inuvik and 70 kilometres west of Tuktoyaktuk in the Mackenzie Delta (see Figure 1-2).

The proposed production facilities include:

- up to 15 production wells drilled from a single pad;
- one or two disposal wells;
- a gas conditioning facility;
- associated infrastructure including pads and foundations;
- a barge landing site;
- an airstrip and helicopter pad;
- buildings; and
- a water treatment system.

Did you know?

Nominal pipes size (NPS)

Nominal pipe size (NPS) is a set of standard pipe diameters used for pressure piping in North America measured in inches.

Approximate conversions to SI (metric) for the pipes in this project are as follows:

Nominal pipe size	Approximate pipe diameter
NPS 10	250 mm
NPS 16	400 mm
NPS 18	450 mm
NPS 26	650 mm
NPS 30	750 mm
NPS 32	800 mm

Construction is planned to take place from 2014 to 2018 with operations commencing in 2018. The estimated initial capital expenditure for developing the field is $1,750 million (2006$) with an additional $800 million for future compression and infill wells.

1.2.3 Parsons Lake field

ConocoPhillips Canada (North) Limited applied on behalf of itself and ExxonMobil Canada Properties for approval of a Development Plan pursuant to section 5.1 of the *Canada Oil and Gas Operations Act* for the Parsons Lake field on 7 October 2004.

The Parsons Lake Significant Discovery Licences SDL032 and SDL030 are located about 70 kilometres north of Inuvik and 55 kilometres southwest of Tuktoyaktuk, to the east of the Mackenzie Delta on Tuktoyaktuk Peninsula (see Figure 1-2).

The proposed production facilities include:

- a north pad with 9 to 19 production wells;
- disposal wells and a gas conditioning facility;
- a south pad with three to seven production wells;
- flow lines; and
- support infrastructure including an all-weather airstrip.

Construction is planned to take place from 2014 to 2018 with operations commencing in 2018 and expected to continue for 25 or 30 years. The estimated initial cost for developing the field is $1,200 million (2006$) with an additional $350 million for future compression and infill wells.

1.2.4 Mackenzie Gathering System

Imperial Oil Resources Ventures Limited applied on behalf of itself, Shell Canada Limited, ConocoPhillips Canada (North) Limited, and ExxonMobil Canada Properties for authorization under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* for the Mackenzie Gathering System on 7 October 2006.

The Mackenzie Gathering System includes:

- approximately 190 kilometres of NPS 16, NPS 18, NPS 26 and NPS 32 gathering pipelines to transport production from the Niglintgak, Taglu and Parsons Lake natural gas fields to the Inuvik Area Facility;
- the Inuvik Area Facility, which would process production from the three development fields;
- an approximately 457 kilometre long NPS 10 natural gas liquids pipeline from the Inuvik Area Facility to Norman Wells; and
- block valves, pigging facilities, and meter stations for the upstream gathering pipelines and the natural gas liquids pipeline.

On 12 October 2007 MGM Energy Corp. executed a Capacity Request Agreement indicating its intent to become either an owner in the Mackenzie gas gathering and processing facilities or to contract for firm capacity in the facilities for an identified volume of 5.66 Mm^3/d (200 MMcf/d). A supply of 2.83 Mm^3/d (100 MMcf/d) from a field known as MGM East would be delivered to a receipt point located at Taglu, and a supply of 2.83 Mm^3/d (100 MMcf/d) from a field known as MGM West would be delivered to a receipt point located at Niglintgak.

MGM Energy Corp. was the only third-party shipper to make a volume commitment to the Mackenzie Gas Project during the course of the proceedings. MGM Energy Corp. did not make a capacity request for space on the Mackenzie Valley Pipeline.

The Mackenzie Gathering System would have the capacity to deliver about 30.9 Mm^3/d (1.1 Bcf/d) of gas to the Mackenzie Valley Pipeline and to transport about 4000 m^3/d (25,200 Bbl/d) of natural gas liquids from the Inuvik Area Facility to Norman Wells. The approximate capital cost of the Mackenzie Gathering System is $3,500 million (2006$). It is scheduled to be in service in 2018.

1.2.5 Mackenzie Valley Pipeline

Imperial Oil Resources Ventures Limited applied on behalf of itself, Mackenzie Valley Aboriginal Pipeline Limited Partnership, Shell Canada Limited, ConocoPhillips Canada (North) Limited, and ExxonMobil Canada Properties for a certificate of public convenience and necessity pursuant to section 52 of the *National Energy Board Act* and an order pursuant to Part IV of the *National Energy Board Act* approving the toll and tariff principles that would apply to the Mackenzie Valley Pipeline (see Figure 1-3). Subsequently, ConocoPhillips Canada (North) Limited’s interests in the Mackenzie Valley Pipeline were transferred to ConocoPhillips Northern Partnership.

The Mackenzie Valley Pipeline includes:

- approximately 1196 kilometres of buried NPS 30 pipeline from the Inuvik Area Facility to a point of interconnection with the NOVA Gas Transmission Ltd. system just south of the Alberta-Northwest Territories boundary;
- three compressor stations, one at Great Bear River to be installed initially and two others at Loon River North and River Between Two Mountains to be installed when additional shipping commitments are received;
- the Trout Lake heater station to be installed when additional shipping commitments are received;
- a meter station located at the Inuvik Area Facility; and
- a pig receiver and block valve just south of the Alberta-Northwest Territories boundary.

As applied for, the Mackenzie Valley Pipeline has a design capacity of 27.3 Mm^3/d (964 MMcf/d) with one compressor station and 34.3 Mm^3/d (1.2 Bcf/d) with three compressors and one heater station in operation. The design capacity is expandable to 49.8 Mm^3/d (1.8 Bcf/d) with a total of 14 compressor stations in operation. The Proponents propose initially to construct a single compressor station and no heater station. The approximate capital cost of the Mackenzie Valley Pipeline is $7,050 million (2006$) with one compressor station at the Great Bear River. The Loon River North and River Between Two Mountains compressor stations and the Trout Lake heater station would add approximately $800 million to the capital cost. The Mackenzie Valley Pipeline is scheduled to be in service in 2018.

1.2.6 Construction schedule

The Proponents indicated that the earliest they would make their final decision on whether or not to proceed with the Mackenzie Gas Project would be at the end of 2013, subject to regulatory approval and receipt of required permits. Should the project proceed as proposed, the detailed design and construction phases of the pipeline and related facilities would commence by 2014 and would be expected to continue into 2018. It would be during this phase that the project activities would have the greatest interaction with the northern communities and the natural environment. The Proponents submitted that this phase of the project would also see the completion of the following activities in the project area:

- field investigation and testing programs to provide data for detailed design;
- procuring and mobilizing materials, equipment, goods and services;
- ongoing consultation with the northern communities;
- developing and constructing infrastructure support, such as borrow sites;
- drilling and completing wells at the development fields; and
- constructing production facilities and flow lines at the development fields.

Figure 1-3

Mackenzie Valley Pipeline and natural gas liquids pipeline

The winter months (mid-October to late April) would be the primary time for pipeline construction activities. The summer months (May to October) would be used for mobilizing equipment, materials and fuel to the sites to support the winter construction. Infrastructure development and facility fabrication and construction are anticipated to proceed year round. A schedule proposed by the Proponents is provided in Figure 1-4.

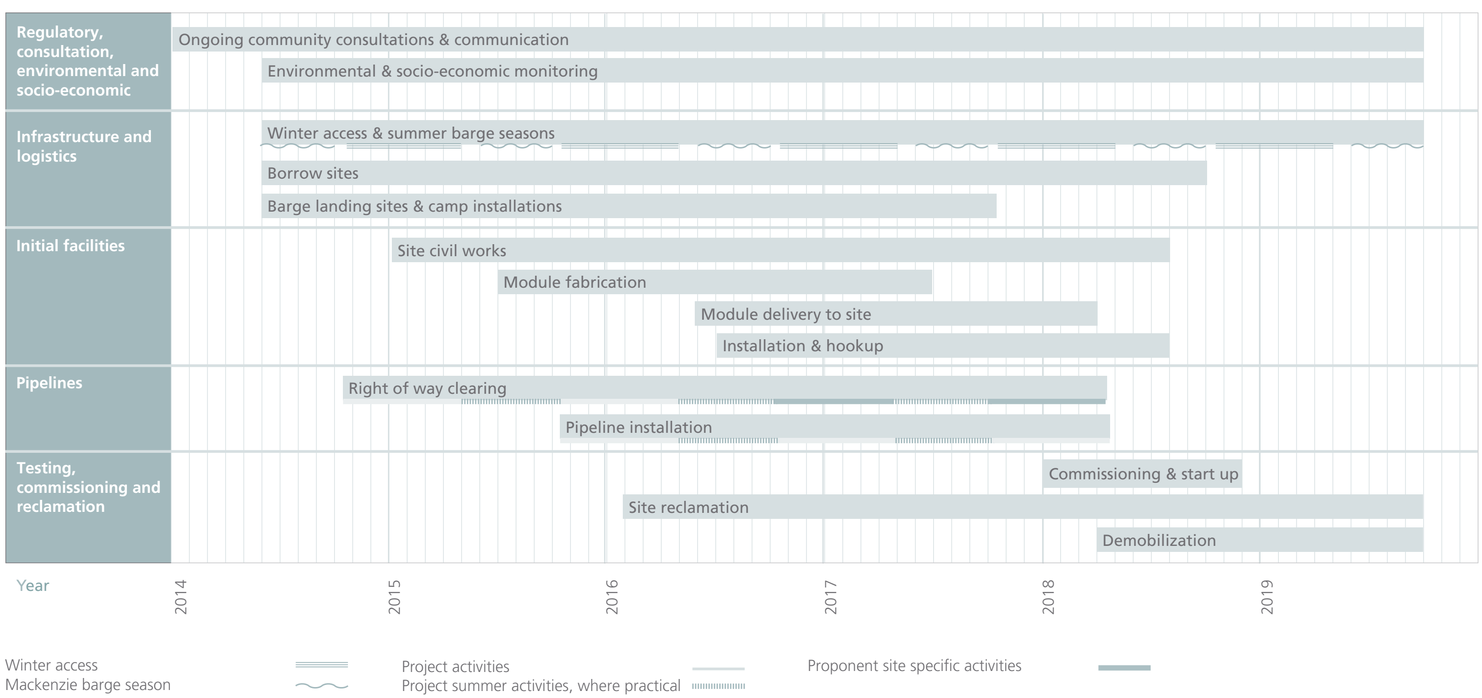
Onsite activities are proposed to commence in early summer 2014 with site preparation and initial development of some construction support infrastructure (barge landing facilities, small construction camps, borrow sites, material staging and fuel storage sites). The winter of 2014 -2015 would see the first sections of the pipeline right of way surveyed, cleared and graded and further development of borrow sites, staging and tank sites, barge landing sites and the main construction camps. The Proponents expect these activities to extend into the summer of 2015. During the summer of 2015, pipeline materials, equipment, camps and fuel would be mobilized to site for the first pipe laying season in the winter of 2015-2016.

The Proponents propose to divide construction of the pipeline into 12 construction spreads (see Figure 1-5). Each spread is expected to require an initial winter season for site preparation, a subsequent winter season for construction of the pipeline and a third winter season for final clean-up. Work would occur sequentially (clearing crews would be followed by pipeline installation and clean-up crews) proceeding in one direction along the spread with minor exceptions at some locations due to weather, construction camp locations or watercourse crossings.

Clearing activities and horizontal directionally drilled water course crossings are expected to be completed on all spreads in the first two winter construction seasons. Commissioning and start-up activities would be scheduled to commence in 2018 after the final

Figure 1-4

Proposed construction schedule for Mackenzie Gathering System and Mackenzie Valley Pipeline



season of pipeline installation. Reclamation and demobilization of camps, equipment and materials are expected to extend into the fall of 2019.

Construction of the station facilities (Inuvik Area Facility, metering facility and Great Bear River Compressor Station) is proposed to commence in the winter of 2014-2015 with survey, clearing and grading of the facility sites. Gravel pads would be installed the following summer. The Proponents submitted that the pile foundations for the facilities would be drilled and installed during the winter and summer of 2016. Construction of the facility modules would occur off site and the Proponents anticipate mobilizing the modules to the facility sites to finalize assembly in the winter of 2017-2018. The Proponents anticipate concluding facility construction in the summer of 2018.

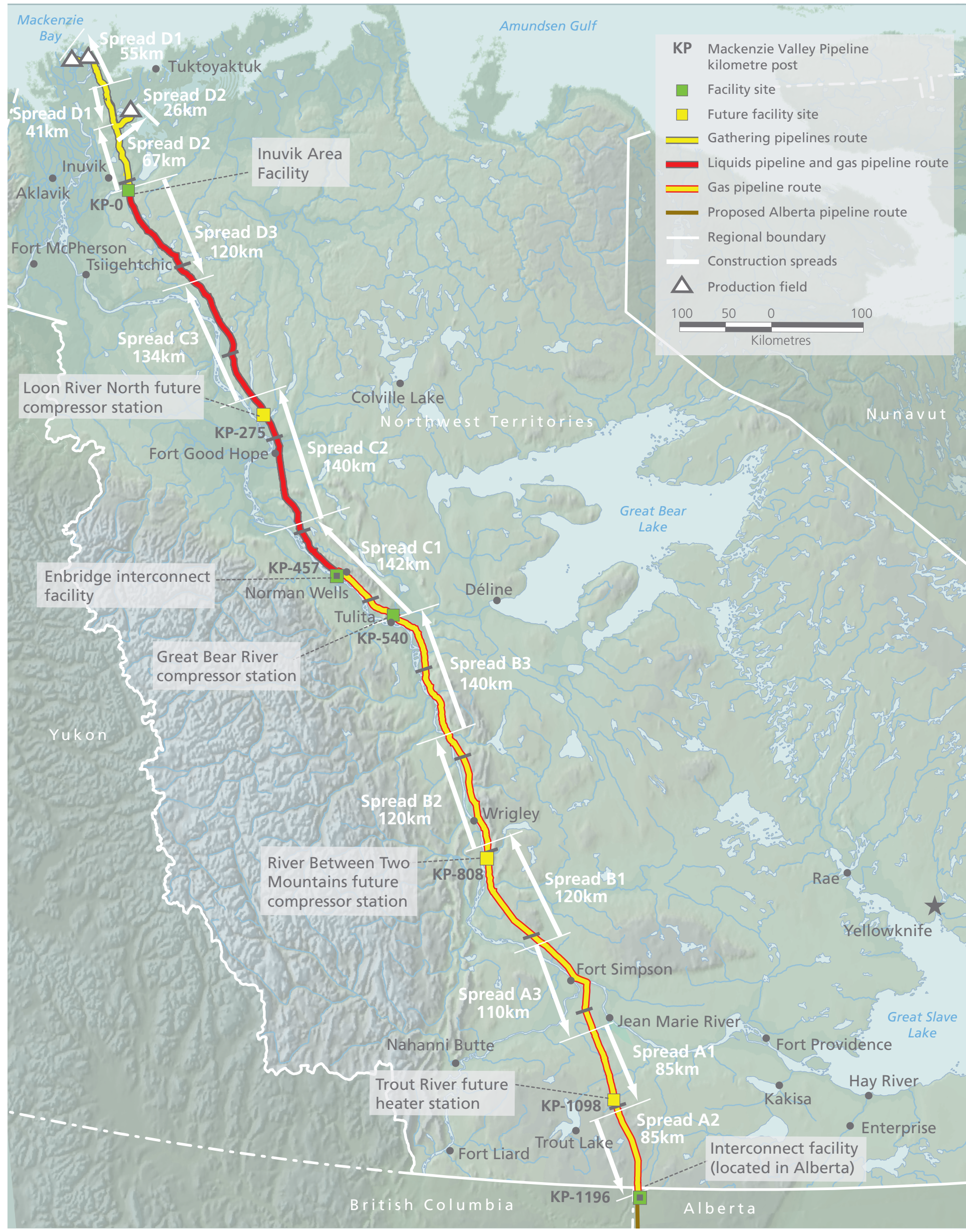


Figure 1-5

Proposed construction spreads

Did you know?

Definitions

Permafrost – soil or rock that remains at or below 0ºC for at least two consecutive years.

Continuous permafrost – permafrost occurs beneath more than 90 percent of land area. Taliks may exist beneath river channels, lakes and in other localized areas.

Extensive discontinuous permafrost – permafrost occurs beneath 65 to 90 percent of land area.

Intermediate discontinuous permafrost – permafrost occurs beneath 35 to 65 percent of land area.

Sporadic discontinuous permafrost – permafrost occurs beneath 10 to 35 percent of land area.

Isolated patches of permafrost – permafrost occurs beneath less than 10 percent of land area.

Talik – a pocket of unfrozen ground in a permafrost area, often beneath a lake or river.

Muskeg – a bog or peatland typically containing Sphagnum moss, willows and stunted black spruce trees. Muskeg can reach depths of 30 metres or more and is a significant impediment to transportation and construction during the summer.

1.3 Project setting

1.3.1 Project environment

The Mackenzie Delta is located above the Arctic Circle and is approximately 14 250 square kilometres in area; more than twice the size of Prince Edward Island. The Mackenzie Delta is the outlet of the Mackenzie River, which flows for approximately 1800 kilometres from Great Slave Lake in the Northwest Territories to the Beaufort Sea. The Mackenzie River is Canada's longest, and one of the world's largest, river systems. Along its route, the Mackenzie River picks up and carries a large amount of silt that settles out in the Mackenzie Delta, forming an extensive network of channels, islands, lakes and ponds. The Canadian North has more lakes than the rest of the world combined and more than 25,000 of them are in the Mackenzie Delta.

The proposed Mackenzie Gas Project stretches over 1000 kilometres from the Mackenzie Delta to northwestern Alberta and generally follows the Mackenzie Valley. The rivers and lakes of the region, including the Mackenzie Delta, support 41 species of fish, including Arctic grayling, northern pike, longnose sucker, slimy sculpin and lake chub. Wildlife populations found in the project area include grizzly bear, polar bear, barren-ground and woodland caribou, moose, marten, lynx, beaver, beluga whale, bowhead whale, ringed seal, and many bird species. On the northeast tip of the Mackenzie Delta, still more than 2000 kilometres from the North Pole, lies Kendall Island Bird Sanctuary. The Sanctuary is home to more than 90 species of birds, including the lesser snow geese, the tundra swan and other migratory birds.

Permafrost lies beneath much of the project area. The Niglintgak and Taglu fields are located in areas of discontinuous permafrost in the Mackenzie Delta (see Figure 1-6). The Parsons Lake field is located on higher ground to the east of the Mackenzie Delta, where the permafrost is continuous. North of the Inuvik Area Facility, the upstream gathering pipelines would be buried for the most part in continuous permafrost. South of the Inuvik Area Facility, the Mackenzie Valley Pipeline and natural gas liquids pipeline would leave the continuous permafrost zone and enter the discontinuous permafrost zone. South of Fort Simpson the Mackenzie Valley Pipeline would enter the sporadic permafrost zone.

The soil in the Mackenzie Delta region is thinly layered and formed from river deposits of silt, sand and gravel. The delta's low-lying geography exposes both the Niglintgak and Taglu fields to regular flooding and occasional storm surges from the Beaufort Sea.

Most of the land along the pipeline route is flat and covered with muskeg, except for a few areas with rolling hills and other features. The Mackenzie Gas Project would cross more than 600 watercourses that vary from small, seasonal streams to large rivers. The vegetation along the route changes from the treeless tundra in the Mackenzie Delta to the boreal forest in Alberta. Large areas of forest in the Mackenzie Valley have burned in recent years. Rare plants and uncommon vegetation types are found throughout the region. Some plants are used for traditional purposes, such as food, medicine, ceremonies or materials.

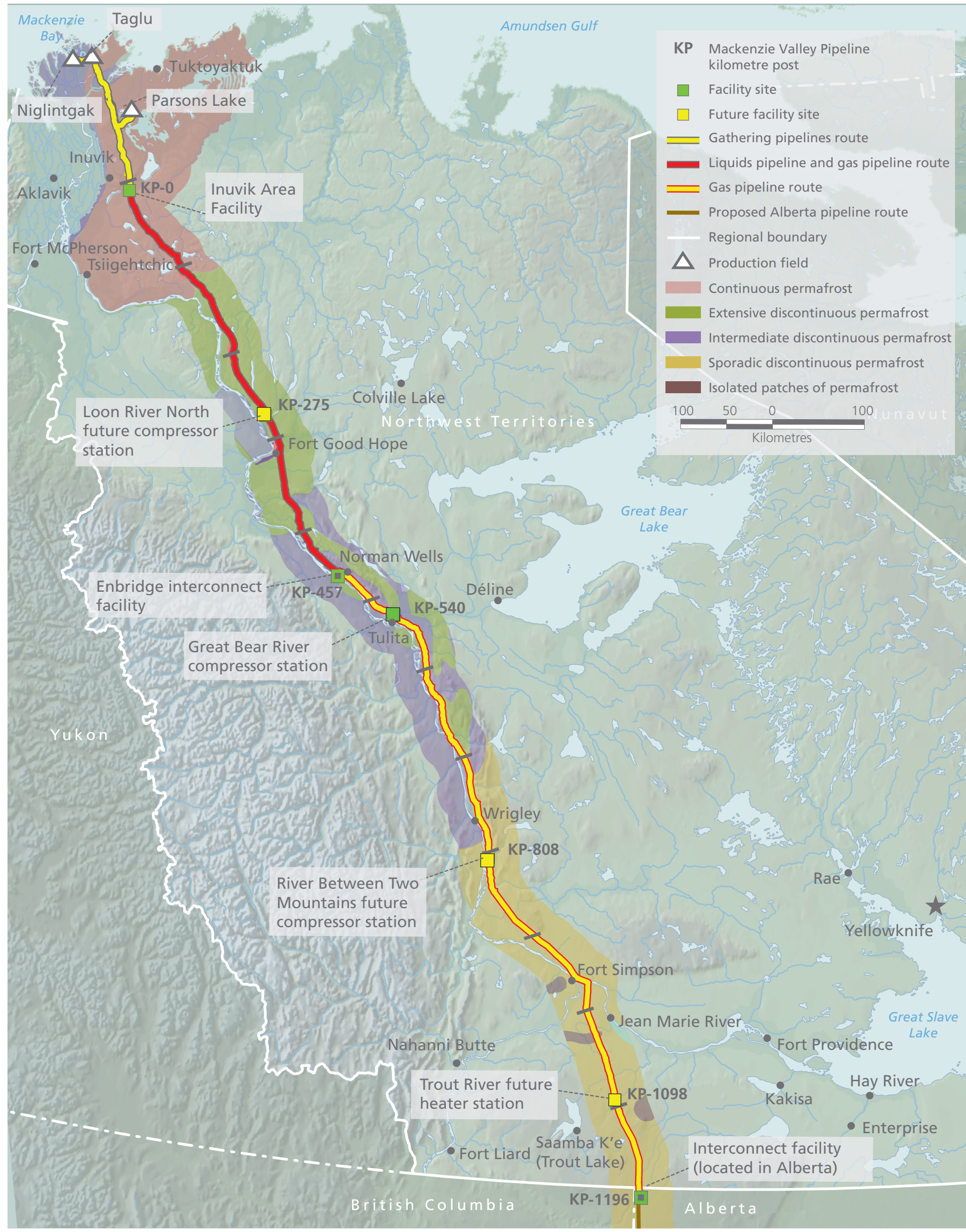


Figure 1-6

Permafrost regions

Figure 1-7

Land claim regions of the Mackenzie Valley

1.3.2 Social, cultural and economic setting

The Proponents identified up to 32 communities in the Northwest Territories and in northwestern Alberta that could be affected by the Mackenzie Gas Project (see Table 1-1). The 26 communities in the Northwest Territories are home to about 35,000 residents and are found in four regions—Inuvialuit Settlement Region, Gwich'in Settlement Area, Sahtu Settlement Area, and the Dehcho Region. The six communities in northwestern Alberta are home to about 7,000 residents and are located in the Dene Tha' First Nation region.

The population in the four regions of the Northwest Territories in the Mackenzie Delta and along the Mackenzie Valley where the Mackenzie Gas Project would be built is about 12,000. More than 75 percent of these people are Aboriginal. Most live in communities smaller than 1,000 people. About half of the total Northwest Territories population and about 40 percent of the northwestern Alberta population is Aboriginal.

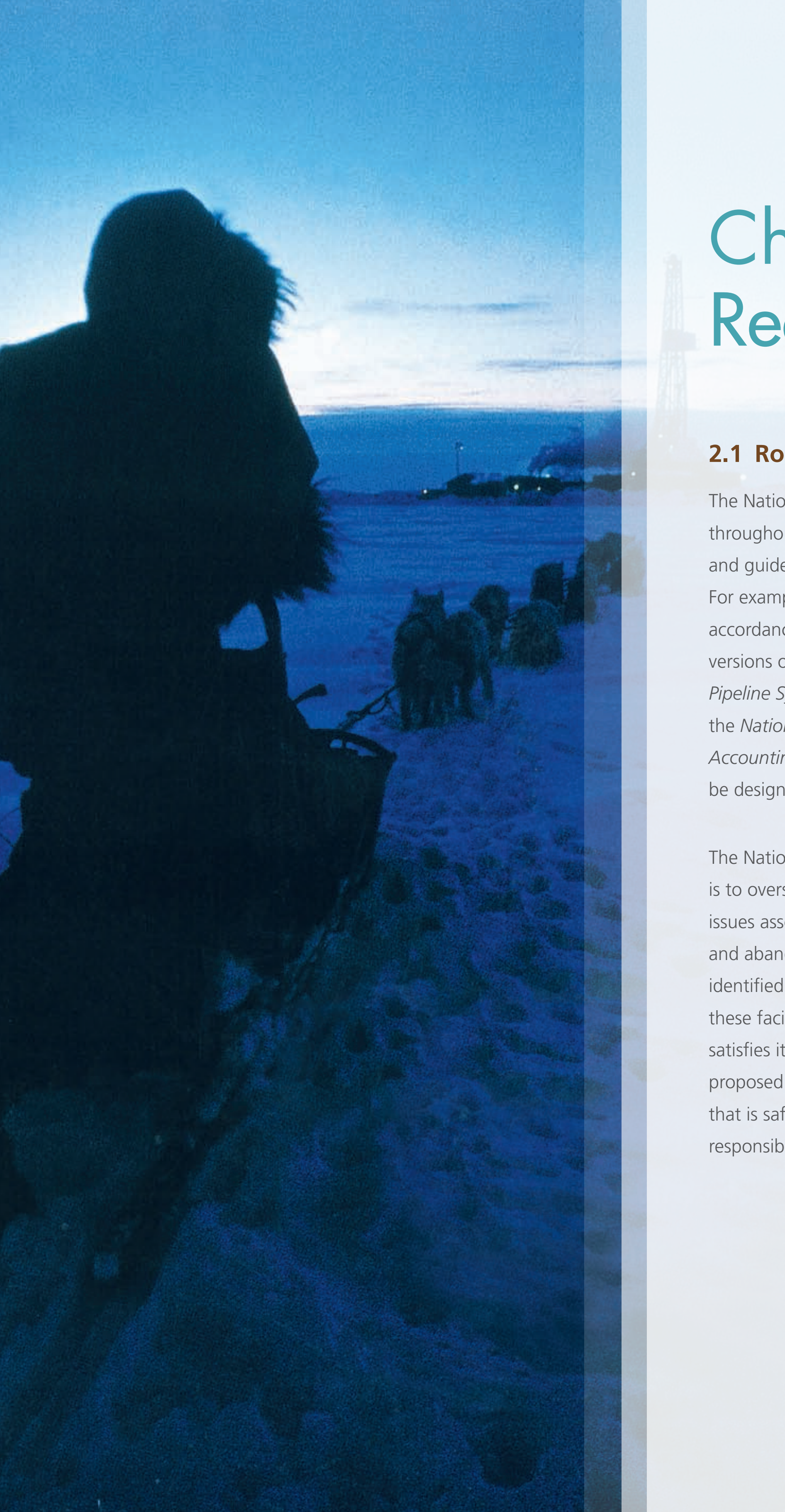
In the project area, some land claims have been settled. The first was the *Inuvialuit Final Agreement* in 1984. In 1992, the Gwich'in signed an agreement that established the Gwich'in Settlement Area. In 1994 the *Sahtu Dene and Metis Land Claim Settlement Act* came into effect. There are ongoing negotiations with the Dehcho (see Figure 1-7).

The cost of living is higher in more northern communities due to their distance from the source of supply for basic goods. Based on a 2000 survey, the cost of living in the Mackenzie Delta was 25 percent to 115 percent higher than in Edmonton, Alberta, depending on the remoteness of the community. Country foods such as caribou and moose are a large part of the diet for many Aboriginal people. Traditional gathering and harvesting supplement earned incomes and help offset the high cost of living. In most communities, government-related employment is the largest and most stable economic influence.

Table 1-1

Potentially affected communities

Area	Region	Community
Northwest Territories	Inuvialuit Settlement Region	Aklavik Tuktoyaktuk Holman Paulatuk Sachs Harbour
	Gwich'in Settlement	Inuvik Fort McPherson Tsiigehtchic
	Sahtu Settlement Area	Norman Wells Fort Good Hope Deline Tulita Colville Lake
	Dehcho Region	Fort Simpson Fort Providence Fort Liard Wrigley Nahanni Butte Trout Lake Jean Marie River Kakisa Hay River Reserve West Point Reserve
	Industrial and commercial centres	Yellowknife Hay River Enterprise
Northwestern Alberta	Dene Tha' First Nation	Chateh Meander River Bushe River
	Industrial and commercial centres	High Level Rainbow Lake Zama City



Chapter 2 Regulatory review process

2.1 Role of the National Energy Board

The National Energy Board regulates safety, security, environmental and economic matters throughout a pipeline project's lifespan. The National Energy Board has developed regulations and guidelines for the safety, security and protection of people, the environment and property. For example, pipelines regulated under the *National Energy Board Act* must be designed in accordance with the National Energy Board's *Onshore Pipeline Regulations, 1999* and the latest versions of relevant design codes, including the *Canadian Standards Association Z662, Oil and Gas Pipeline Systems*. Pipelines must also be operated in accordance with all other regulations under the *National Energy Board Act*, such as the *Toll Information Regulations* and *Gas Pipeline Uniform Accounting Regulations*. Facilities regulated under the *Canada Oil and Gas Operations Act* must be designed and operated in accordance with their own set of regulations.

The National Energy Board's role as regulator is to oversee that safety and environmental issues associated with construction, operation and abandonment of regulated facilities are identified and managed by the owners of these facilities. The National Energy Board satisfies itself that a facility's design and proposed operations would result in a project that is safe, reliable and environmentally responsible before it is approved.

As well as regulating the physical facilities, the National Energy Board oversees the economic aspects of a proposed project. Pipeline development in Canada may occur in a competitive market but often occurs in a monopoly or near-monopoly situation. The National Energy Board's authority for economic regulation of pipelines is intended to ensure that the prices set for transporting the gas, the costs that are incurred by the pipeline proponents and the returns to the pipeline owners are similar to those that would occur if the market were competitive.

Before submitting an application to the National Energy Board, companies must ensure that the proposed project would comply with existing statutory and regulatory requirements.

Once an application is received, the National Energy Board typically reviews the proposed project to:

- assess the application from economic, engineering, safety, environment and lands perspectives;
- ensure that regulated companies have notified and consulted with landowners, Aboriginal peoples, and other affected parties;
- determine how best to provide opportunities for affected people and other stakeholders to provide their input on the proposed project; and
- determine whether, with specific mitigation measures and other conditions, the project would be in the public interest.

2.2 The "public interest"

We must decide whether Canadian society would be better or worse off if the project is approved. The *National Energy Board Act* requires us to consider any public interest that may be affected by granting or refusing the application. To determine if a project is in the public interest, we consider the potential benefits it could bring to Canadians and the burdens it could place on Canadians.

In doing so, we examine engineering, economic, environmental and socio-economic factors. In particular, we assessed:

- the proposed engineering design—whether or not the facilities will be safe;
- the economics of the proposed project—is there sufficient supply and demand, will other parties have access to the facilities; are the tolls and tariffs reasonable;
- the effect the proposed project will have on the environment, as well as the effect the environment will have on the project—the environment includes the physical, social and cultural setting where the facilities would be built; and
- the effect the proposed project would have on individuals, groups, communities and societies.

To ensure that we heard a wide range of views from an informed and engaged public, we carried out activities to encourage meaningful participation in the review process for the Mackenzie Gas Project by all potentially affected people. These activities were designed with the following objectives:

- to share information in a timely manner with the public about the National Energy Board's process;
- to design a process that generally reflects the public's needs and expectations;
- to design a process that takes into account Northerners' experiences and expectations; and
- to ensure that the hearing process provides an opportunity to people from all walks of life to participate fully and in a manner in which they felt comfortable.

If the National Energy Board determines that a project is in the public interest, its role as a regulator would continue through the construction, operation and abandonment phases of the project.

Did you know?

Contributing partners to the Cooperation Plan

Boards and agencies with mandatory public hearing processes:

- Mackenzie Valley Land and Water Board;
- Mackenzie Valley Environmental Impact Review Board;
- Gwich'in Land and Water Board;
- Sahtu Land and Water Board;
- Northwest Territories Water Board;
- Canadian Environmental Assessment Agency;
- National Energy Board; and
- Environmental Impact Review Board for the Inuvialuit Settlement Region.

Other agencies with a direct interest in Environmental Impact Statement and regulatory matters:

- Joint Secretariat for the Inuvialuit Settlement Region;
- Environmental Impact Screening Committee for the Inuvialuit Settlement Region;
- Inuvialuit Game Council;
- Inuvialuit Land Administration;
- Inuvialuit Land Administration Commission; and
- Indian and Northern Affairs Canada.

Observers:

- Nominee of the Dehcho First Nation to the Mackenzie Valley Land and Water Board;
- Government of the Northwest Territories; and
- Government of Yukon.

2.3 Coordination of review process

A renewed interest in developing northern gas resources emerged in 2000. The many agencies that would be affected by a pipeline proposal realized that there would be substantial duplication and overlap of public review processes if each agency worked alone. Beginning in the fall of 2000 the heads of these agencies met to explore means of working cooperatively to minimize duplication and overlap. In June 2002, the agencies signed the *Cooperation Plan for the Environmental Impact Assessment and Regulatory Review of a Northern Gas Pipeline Project through the Northwest Territories* (Cooperation Plan). The Cooperation Plan provided a framework for a joint environmental impact assessment process that met the requirements of the *Inuvialuit Final Agreement*, the *Mackenzie Valley Resource Management Act* and the *Canadian Environmental Assessment Act*. Mr. Rowland J. Harrison, Q.C. of the National Energy Board was appointed as a member of the Joint Review Panel for the Mackenzie Gas Project (Joint Review Panel). To assist the National Energy Board in meeting its environmental requirements, the National Energy Board authorized Mr. Harrison under subsection 15(1) of the *National Energy Board Act* to report and make recommendations on social, cultural, economic and environmental matters pertaining to the Mackenzie Gas Project.

As contemplated in the Cooperation Plan our hearing process was coordinated with the Environmental Impact Review of the Mackenzie Gas Project by the Joint Review Panel. The Joint Review Panel Report and Mr. Harrison's subsection 15(1) report were taken into account in our public interest determination.

The filings made with the National Energy Board and the Mackenzie Valley Land and Water Board initiated the regulatory and environmental review processes (see Table 2-1). The Agreement issued on 22 April 2004 set out details for the environmental impact assessment by a Joint Review Panel, the coordination of hearings between regulatory agencies and the maintenance of a public registry. It also set out the role of the Northern Gas Project Secretariat, which provided logistical, communications, information management, administrative and technical support throughout the review process.

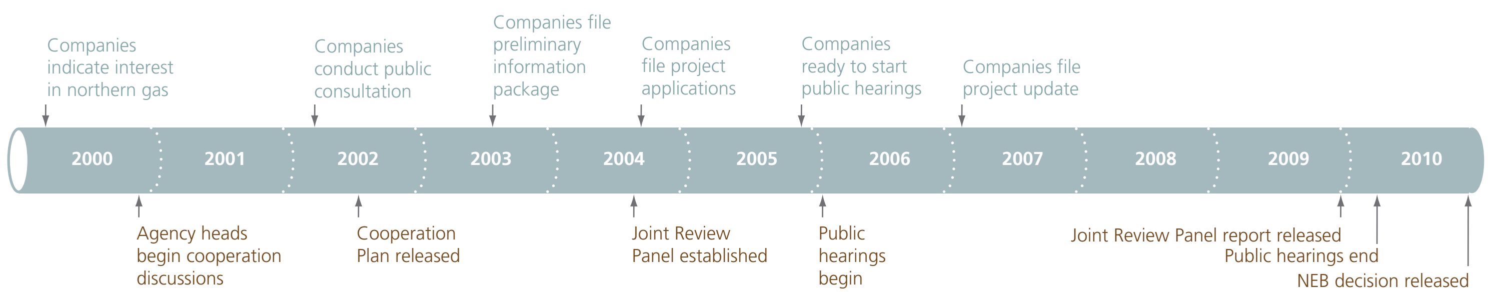
Table 2-1

Initial events in the coordinated review process

Date	Event
18 June 2003	Preliminary information package filed by the Proponents of the Mackenzie Gas Project with the National Energy Board.
21 July 2003	An application for a Type A Land Use Permit and Type B Water Licence for the Camsell Bend Development filed with the Mackenzie Valley Land and Water Board. This triggered the environmental review process.
21 August 2003	Mackenzie Gas Project referred by the Minister of the Environment to a Joint Review Panel under the *Canadian Environmental Assessment Act*.
22 April 2004	Agreement for the Coordination of the Regulatory Review of the Mackenzie Gas Project signed by the parties.
July/August 2004	Agreement for an Environmental Review of the Mackenzie Gas Project signed by the Chair of the Mackenzie Valley Environmental Impact Review Board, Chair of the Inuvialuit Game Council, and Federal Minister of the Environment.

Figure 2-1

Process timeline for review of Mackenzie Gas Project



2.4 National Energy Board hearing process

2.4.1 Overview

The National Energy Board received the applications for the Mackenzie Gas Project in October 2004. Following an initial review we decided to hold a hearing and issued Hearing Order GH-1-2004 on 24 November 2004. Our hearing sessions were coordinated with the Joint Review Panel's hearing sessions (see Figure 2-2).

Hearing Order GH-1-2004 initially contained a list of 12 issues for discussion in the hearing related to the National Energy Board's mandate pursuant to the *National Energy Board Act* and the *Canada Oil and Gas Operations Act*. We focused on engineering, safety and economic matters in our hearing, whereas the Joint Review Panel focused on environmental, cultural, and socio-economic matters. Following the receipt of comments from intervenors, Issue 13 was added to the list of issues (Appendix A – List of issues) by way of Order AO-1-GH-1-2004, dated 23 November 2005, to address concerns about tolls, access, tariff provisions and dispute mechanisms related to the Mackenzie Gathering System. Key events in our hearing process are shown in Table 2-2 and Appendix C – Summary of events.

2.4.2 Events leading up to the oral hearing

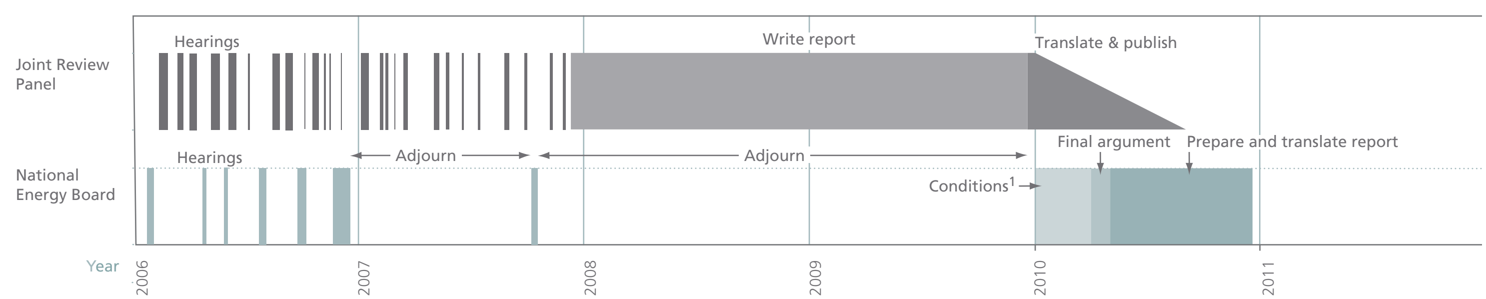
Throughout 2005, we continued our examination of the applications, which included the exchange of several rounds of information requests and the submission of evidence by participants. Also throughout 2005, the National Energy Board, the Joint Review Panel and the Northern Gas Project Secretariat held information sessions in northern communities near the pipeline route to explain their roles and to provide information on the National Energy Board and Joint Review Panel hearing processes. We held a pre-hearing planning conference between 5 and 13 December 2005 in Inuvik, Yellowknife, Fort Good Hope and Fort Simpson. The purpose of the conference was two-fold: to provide information on our hearing process and the National Energy Board's role throughout the lifespan of a pipeline; and to hear participants' views on shaping certain parts of the hearing process to meet their needs.

2.4.3 Oral hearing

By letter of 23 November 2005 the Proponents indicated that they were ready to start the public hearings. We released our hearing schedule on 20 December 2005. The scheduled evidentiary portion of the oral hearing started in Inuvik on 25 January 2006 and ended back in Inuvik on 14 December 2006. The evidentiary hearing involved the questioning of witnesses for the Proponents and intervenors on their filed evidence and the presentation of oral statements by members of the communities. We held hearing sessions on 47 days in 15 communities in the Northwest Territories and Northern Alberta throughout 2006.

Figure 2-2

National Energy Board and Joint Review Panel coordinated hearing schedule



1. Written comment process on NEB response to Joint Review Panel recommendations, including proposed conditions. Addresses NEB role with respect to "consult to modify" aspect of *Mackenzie Valley Resource Management Act*.

On 7 April 2006 Mackenzie Explorer Group filed a motion with us for an order that, when constructed and placed into service, the Mackenzie Gathering System and the Mackenzie Valley Pipeline will be a single pipeline subject to regulation under Part IV of the *National Energy Board Act* and that the Proponents prepare, file and serve the toll principles and the tariff(s) for this single pipeline for approval under Part IV of the *National Energy Board Act*. An oral hearing was held in Yellowknife on 2 June 2006. On 10 July 2006 we denied Mackenzie Explorer Group's motion.

Mackenzie Explorer Group subsequently appealed our decision. The appeal was heard by the Federal Court of Appeal on 23 October 2007 and dismissed on 22 April 2008.

In early 2007, the Proponents filed updates to the applications and on 10 and 11 October 2007 we held an oral hearing session in Yellowknife to examine the updated evidence.

In March 2010 we provided an opportunity for parties to file updated evidence and on 28 March 2010 a hearing session was held in Yellowknife to allow parties the opportunity to examine the updated evidence that was filed by the Proponents, the Government of Canada Crown Consultation Unit and other intervenors. This brought the evidentiary portion of the hearing to a total of 50 days.

Table 2-2

Key events in the National Energy Board hearing process

Date	Event
November 2004 to December 2005	Information sessions and technical review
5 to 13 December 2005	Pre-hearing Planning Conference in Inuvik, Yellowknife, Fort Good Hope, and Fort Simpson
25 January 2006 to 14 December 2006	National Energy Board hearing sessions in 15 Northern communities
2 June 2006	Mackenzie Explorers Group motion heard in Yellowknife
10 July 2006	Ruling on Mackenzie Explorers Group motion
5 February 2007	Proposed conditions initially issued for comment
10 and 11 October 2007	Hearing in Yellowknife to examine updated evidence
14 December 2007	Federal government enacted changes to the *Canada Oil and Gas Operations Act*, granting the National Energy Board the power to regulate tolls, tariffs and access on COGOA pipelines.
22 April 2008	Federal Court of Appeal dismissed Mackenzie Explorer Group's appeal, noting but not basing their decision on the fact that changes to the *Canada Oil and Gas Operations Act* had resolved Mackenzie Explorer Group's concerns.
30 December 2009	Joint Review Panel Report issued
30 December 2009	Mr. Harrison's subsection 15(1) Report issued
Jan. to Mar. 2010	Consult to modify process
28 March 2010	Hearing in Yellowknife to examine updated evidence
12 to 22 April 2010	Final argument in Yellowknife and Inuvik

2.4.4 *National Energy Board Act* subsection 15(1) Member's report

Mr. Rowland J. Harrison, Q.C., the National Energy Board Member appointed to the Joint Review Panel, was authorized under subsection 15(1) of the *National Energy Board Act* to report and make recommendations to the National Energy Board on matters identified in the Environmental Impact Statement Terms of Reference for the Mackenzie Gas Project under Authorization MO-13-2004 dated 15 October 2004 (see *Appendix F – Authorization MO-13-2004*).

Mr. Harrison's subsection 15(1) report was issued on 30 December 2009. In it he adopted the Joint Review Panel Report for the purposes of fulfilling the requirements of his National Energy Board obligation (see *Appendix G – Mr. Rowland J. Harrison's Subsection 15(1) Report*).

2.4.5 Consult to modify process and final argument

The Joint Review Panel Report was issued on 30 December 2009, following which we conducted a "consult to modify" process under section 137 and subsection 141(6) of the *Mackenzie Valley Resource Management Act*. By letter dated 9 March 2010, parties to both the National Energy Board hearing and the Joint Review Panel hearing were invited to comment on Joint Review Panel's

Figure 2-3

Communities where our information sessions and public hearings were held

recommended measures that were directed to the National Energy Board. We received comments from 30 parties, and then made proposed modifications to the recommended measures in the form of proposed conditions, which were cross-referenced to the Joint Review Panel's recommended measures by way of a concordance table. These were presented to the Joint Review Panel for its comment and for the comment of parties in the final argument phase of our hearing (see Section 3.2, Consult to modify process). We received a letter from the Joint Review Panel on 31 March 2010 responding to our proposed conditions.

We resumed our hearing 12 April 2010 in Yellowknife to hear final argument. Our hearing ended on 22 April 2010 in Inuvik after a total of 58 hearing days.

In addition to the evidence obtained through our hearing process, we also considered the Joint Review Panel Report, Mr. Harrison's subsection 15(1) report, the comments received in the consult to modify process, the *Governments of Canada & of the Northwest Territories Final Response to the Joint Review Panel Report for the Proposed Mackenzie Gas Project* and the comments on that response before making our regulatory decisions with respect to the Mackenzie Gas Project. We have adopted the Joint Review Panel's recommendations directed to us, as modified, and they have been included in the conditions to the approvals granted for the Mackenzie Gas Project. The National Energy Board will monitor and enforce the implementation of the conditions in the approvals.

Did you know?

Northern Gas Project Secretariat

The parties responsible for the environmental impact assessment and regulatory review of the Mackenzie Gas Project agreed through the Cooperation Plan to coordinate and harmonize their review and public hearing processes for the Mackenzie Gas Project. The parties determined that their review could most effectively be implemented through the services of a secretariat to support and coordinate the public hearing processes, including all aspects related to public involvement.

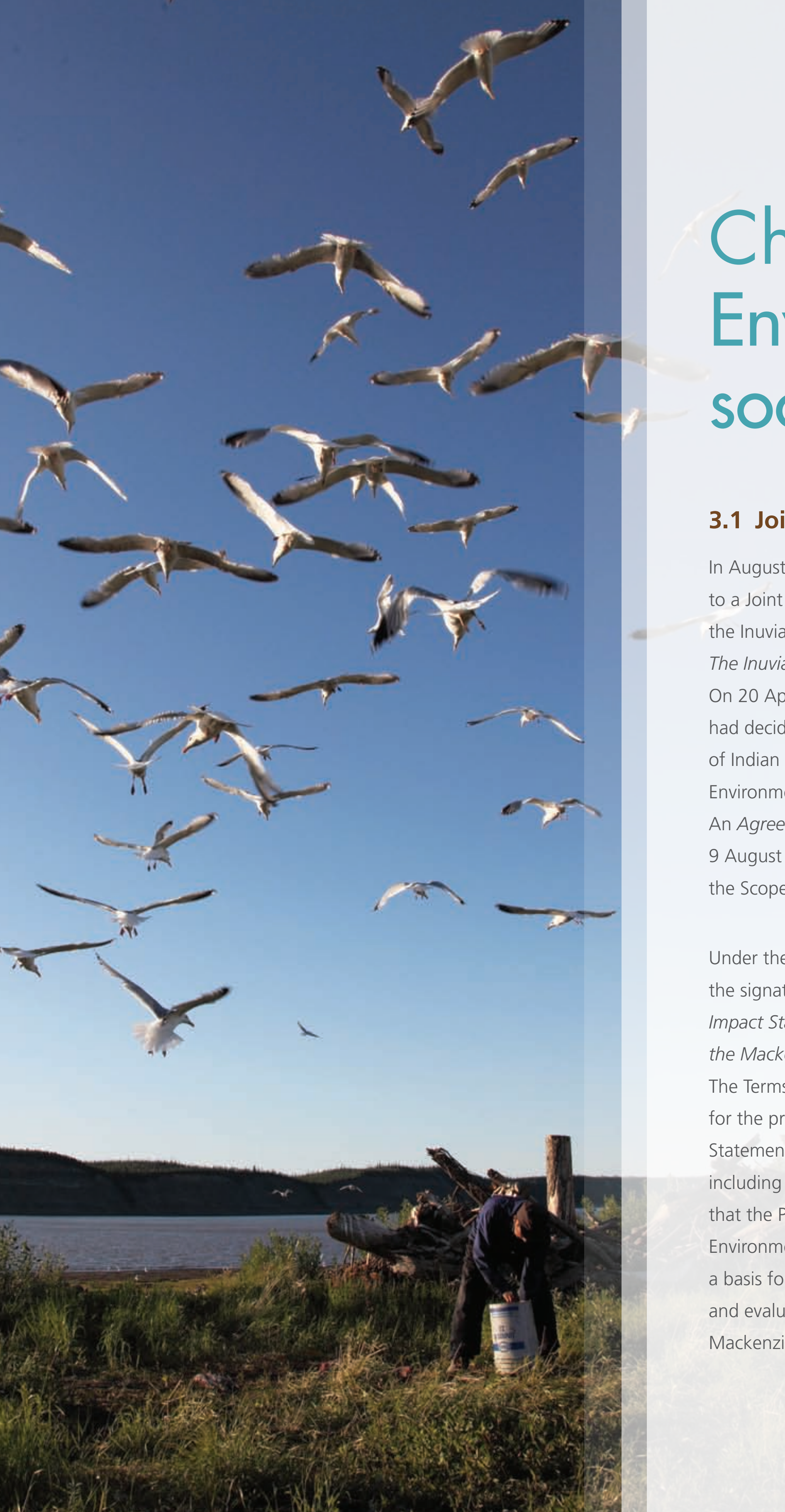
The Northern Gas Project Secretariat was established in 2003 to assist in coordinating the regulatory review and environmental assessment of the Mackenzie Gas Project. An Executive Committee of Chairs, supported by the Northern Gas Project Secretariat, provided the forum through which all involved parties could present their positions and requirements and where cooperative and harmonized approaches would be developed while respecting the need for the review processes to be conducted independently. The committee comprised the Sitting Chairs of the Joint Review Panel, the NEB Panel, the Mackenzie Land and Water Board and the Northwest Territories Water Board.

Leading up to the beginning of public hearings in late January 2006, the Northern Gas Project Secretariat coordinated information sessions with the National Energy Board and Joint Review Panel to explain the review process and to present up-to-date information about how the public could participate. In addition to organizing formal public information sessions, the Northern Gas Project Secretariat conducted several informal visits to the communities along the project route to assist community leaders in their preparations for the public hearing process.

The Northern Gas Project Secretariat published an electronic monthly newsletter in English plain language: The Review – your link to the review of the Mackenzie Gas Project. The goal of the newsletter was to bring the most up-to-date information on the project to community decision-makers and leadership in an easy-to-understand, electronic format. Throughout the hearing process the Northern Gas Project Secretariat maintained offices in Yellowknife, Inuvik, Norman Wells and Fort Simpson.

A list of public information sessions held by the Northern Gas Project Secretariat, the Joint Review Panel and the National Energy Board follows.

2004	Inuvik, NT (Nov. 15) Norman Wells, NT (Nov. 16) Yellowknife, NT (Nov. 17) Fort Simpson, NT (Nov. 23) High Level, AB (Dec. 13) Enterprise, NT (Dec. 14)
2005	Hay River, NT (Jan. 13) Tulita, NT (Feb. 8) Fort Good Hope, NT (Feb. 9) Inuvik, NT (Feb. 28) Norman Wells, NT (Mar. 1) Yellowknife, NT (Mar. 3) Meander River, AB (Mar. 9) Fort Simpson, NT (Mar. 10) Aklavik, NT (Mar. 15) Wrigley, NT (Mar. 16) Tuktoyaktuk, NT (Mar. 23) Saamba K'e (Trout Lake), NT (Oct. 12) Jean Marie River, NT (Oct. 13) Colville Lake, NT (Oct. 19) Tsiigehtchic, NT (Oct. 20) Inuvik, NT (Elders' session) (Oct 20) West Point First Nation, NT (Nov. 2) Ft. Liard, NT (Nov. 14) Nahanni Butte, NT (Nov. 15) Fort Providence, NT (Nov. 21) Kakisa, NT (Nov. 24) Déline, NT (Nov. 25) Fort McPherson, NT (Nov. 29) Tsiigehtchic, NT (Nov. 30)
2006	K'atlodeeche First Nation (Hay River Reserve), NT (Jan. 19)



Chapter 3 Environmental and socio-economic matters

3.1 Joint Review Panel process

In August 2003, the federal Minister of the Environment referred the Mackenzie Gas Project to a Joint Review Panel under the *Canadian Environmental Assessment Act*. In January 2004, the Inuvialuit Environmental Impact Screening Committee, under the *Western Arctic Claim: The Inuvialuit Final Agreement,* made the decision to refer the project to the review panel process. On 20 April 2004, the Mackenzie Valley Environmental Impact Review Board announced that it had decided to refer the project to an environmental impact review. In May 2004, the Minister of Indian Affairs and Northern Development Canada gave his approval for the Mackenzie Valley Environmental Impact Review Board to enter into an agreement to establish a joint review panel. An *Agreement for an Environmental Impact Review of the Mackenzie Gas Project* was released on 9 August 2004. This agreement created the Joint Review Panel, set out its mandate and established the Scope of the Environmental Impact Review, including the factors to be considered in the review.

Under the Joint Review Panel Agreement, the signatory agencies issued the *Environmental Impact Statement Terms of Reference for the Mackenzie Gas Project* in August 2004. The Terms of Reference contained guidelines for the preparation of an Environmental Impact Statement for the Mackenzie Gas Project, including the nature and scope of the issues that the Proponents needed to address. The Environmental Impact Statement served as a basis for the Joint Review Panel's review and evaluation of the potential impacts of the Mackenzie Gas Project on the environment.

As set out in the Joint Review Panel Agreement, the Joint Review Panel was also required to have regard to "the protection of the existing and future social, cultural and economic well-being of residents and communities", in addition to its consideration of environmental matters. The social, cultural and economic concerns that were raised with the Joint Review Panel included:

- resource harvesting;
- land use;
- cultural heritage;
- infrastructure and services; and
- economic, social and cultural impacts.

Our hearing focused on safety, engineering and economic issues, but comments received during the consult to modify process and final argument also included a number of social, cultural and economic issues and concerns.

On 2 September 2004 the federal Minister of Environment appointed Mr. Rowland J. Harrison, Q.C., a member of the National Energy Board, as one of the seven members comprising the Joint Review Panel. On 15 October 2004, the National Energy Board authorized Mr. Harrison to report and make recommendations to us in our consideration of the Mackenzie Gas Project.

On 30 December 2009 the Joint Review Panel issued its report and Mr. Harrison adopted it as his report to us. The report contained 176 recommendations, 85 of which were addressed to us. The remainder required action by various federal and territorial governments and agencies.

3.2 Consult to modify process

Subsection 141(6) and section 137 of the *Mackenzie Valley Resource Management Act* require the National Energy Board as a designated regulatory agency to adopt the recommendations of the Joint Review Panel or, after consulting with the Joint Review Panel, adopt the recommendations with modifications or reject them.

On 6 January 2010, we established a process to consult on the Joint Review Panel recommendations. Parties to both our hearing and the Joint Review Panel hearing were invited to provide comments on recommendations within the National Energy Board's mandate according to the following schedule:

28 January 2010	The Proponents sent comments to us and parties to both hearings
11 February 2010	Parties to both hearings sent comments to us, the Proponents and other parties
18 February 2010	The Proponents sent reply comments to us and parties to both hearings
9 March 2010	We drafted proposed modifications and provided them to the Joint Review Panel for written response
29 March 2010	The Joint Review Panel responded to our proposed modifications

For recommendations that fell outside of the National Energy Board's mandate, we provided a separate administrative process to gather comments for use by other federal and territorial government departments and agencies.

In a letter dated 9 March 2010, attached as Appendix H, we proposed modifications to the Joint Review Panel recommendations that were directed to us and listed our proposed conditions, many of which were designed to address the Joint Review Panel recommendations as modified. We indicated that the proposed modifications preserved the intent of the recommendations and were made to clarify desired end results and timing for implementation. We also stated that some recommendations were not included as conditions because they were duplicative of the requirements of statutes and regulations or of the mandate of other regulatory authorities; required the National Energy Board to delegate its authority to others; related to internal operational matters; or fell outside the scope of the present applications.

The Joint Review Panel responded to the proposed modifications on 29 March 2010. The Joint Review Panel concluded that:

> the NEB Proposed Conditions have not rejected any of the Panel's recommendations that are directed to the NEB and that the modifications proposed by the NEB are primarily for the purpose of ensuring that the implementation of those recommendations conforms to established NEB protocols and procedures, operational requirements and other statutes and regulations.

A copy of the letter is included in Appendix J.

The summary of the Joint Review Panel's recommendations directed to the National Energy Board and references to our associated conditions can be found in the Concordance Table in Appendix I.

3.3 Environmental matters discussed in final argument

In keeping with the purposes of establishing the Joint Review Process, we relied on the Joint Review Panel Report for the environmental and socio-economic assessment of the Mackenzie Gas Project. Matters arising from the Joint Review Panel Report were raised in final argument. These matters were:

- cumulative effects and upstream impacts;
- end use of gas and downstream impacts;
- air quality issues and greenhouse gas emissions;
- impacts of climate change on the project;
- wildlife and species at risk;
- environmental protection plans; and,
- National Energy Board's role in enforcing recommendations directed at others.

3.3.1 Cumulative effects and upstream impacts

To address the potential effects of the project as filed and the potential cumulative effects of future developments, the Joint Review Panel directed recommendations to us, governments, and regulatory agencies and authorities. The Joint Review Panel concluded that, subject to the full implementation of its recommendations, the project is not likely to have significant adverse environmental effects. The Proponents submitted that this conclusion is unsustainable because it was inappropriate for the Joint Review Panel to tie its recommendations related to speculative or hypothetical future developments to the environmental assessment decision for the Mackenzie Gas Project. The Proponents stated that:

> from an environmental assessment perspective, the issue in any event isn't whether the Proponents believe that the addition of future facilities is reasonably foreseeable. The issue is whether there is sufficient detail about future facilities to allow for a meaningful assessment of their effects to be made, which in this case there clearly is not.

The Proponents submitted that future induced development should not be included in the cumulative effects assessment in the first place because it is contrary to the law and contrary to environmental assessment guidance. For this same reason, the National Energy Board should not include conditions about such developments in the Mackenzie Gas Project decision. The Proponents then concluded that the National Energy Board must not include those Joint Review Panel recommendations related to future facilities in the environmental assessment decision for the Mackenzie Gas Project, and that the National Energy Board:

> should make a decision to permit the Mackenzie Gas Project to proceed, subject to the implementation of the mitigative and remedial measures and follow-up programs as proposed in the NEB letters dated March 9 2010, on the basis that the Mackenzie Gas Project is not likely to cause significant adverse environmental effects.

The Sierra Club of Canada countered this by reaffirming what was heard before the Joint Review Panel: that there is a typical sequence of development that follows a pipeline going into a frontier area and that the commonality between the Sproule Associates Limited and Gilbert Laustsen Jung Associates Ltd. supply studies shows likely locations of future development, therefore future development is neither hypothetical nor fanciful. World Wildlife Fund Canada submitted that the Joint Review Panel appropriately exercised its discretion as to what it regards as reasonably foreseeable projects. Both the Sierra Club of Canada and World Wildlife Fund Canada submitted that we should not revisit the Joint Review Panel's conclusion on the importance of induced development for sustainability, but rely on the Joint Review Panel's conclusions and recommendations in light of the delegation of the social and environmental review to it.

Related views were presented on the linkage between future induced developments and sustainability and its relevance to our decision. The Proponents submitted that the basis for the Joint Review Panel's sustainability conclusion on page 585 of the Joint Review Panel Report is flawed because the Joint Review Panel actually assessed future development for which little is known, instead of assessing the Mackenzie Gas Project itself. The Sierra Club of Canada submitted that specialist advisors to the Joint Review Panel emphasized the importance of considering induced development before being able to determine sustainability. The Sierra Club of Canada also proposed that it is incumbent on the National Energy Board to take on the idea of sustainability as part of its own processes.

Parties also stated their concerns to us about how cumulative effects of future development would be managed. The Joint Review Panel Report presented a number of recommendations related to future development directed to us and to government authorities. Alternatives North submitted that Northerners do not want to see the same pattern of hydrocarbon development that happened in Alberta, and that it is unacceptable that each development be assessed separately at different times without adequate up-front consideration of cumulative effects. World Wildlife Fund Canada supported the principle of Conservation First, submitting that this means anticipating cumulative effects and induced development and sequencing up front certain conservation accomplishments while Northerners still have a chance to do so. The Sierra Club of Canada expressed the need for up-front controls on the pace and scale of upstream-induced development. The Sierra Club of Canada supported the Joint Review Panel's position that mitigation must occur up front, in a proactive manner, not as each individual development project is proposed. It suggested that we consider a number of up-front strategies proposed by the Joint Review Panel, such as the federal government's completion of species recovery strategies, interim withdrawals to support a network of protected areas, and land use planning to incorporate thresholds and limits of acceptable change. The Sierra Club of Canada urged us to make sure that the recommendations from the Joint Review Panel to control cumulative impacts from induced development are put in place before the project goes ahead.

The Inuvialuit Regional Corporation submitted that:

> While we do not support the extent to which the Joint Review Panel report recommends additional assessment procedures throughout this expansion process, we nevertheless appreciate, in principle, the need to ensure the future development of our region's hydrocarbon resources does not occur at a scale and pace that will endanger our natural environment and overwhelm the social fabric of our communities.

The Inuvialuit Regional Corporation stated that the Inuvialuit have worked in close partnership with government departments and agencies, with co-management boards, and with other Aboriginal groups to identify both the anticipated impact of these developments and the measures that should be taken to either mitigate or to manage them. The Inuvialuit Regional Corporation would like to see us direct the government to provide the necessary financial resources to allow initiatives such as the Beaufort Sea Strategic Regional Plan of Action, the Beaufort Regional Environmental Assessment process and the impact planning in advance of the Mackenzie Gas Project impact fund to take place. The Mackenzie Valley Aboriginal Pipeline Limited Partnership (Aboriginal Pipeline Group), representing members of the Inuvialuit, Gwich'in and Sahtu, submitted that care must be taken so that the project is not burdened with unreasonable expectations. It objected to the Joint Review Panel's recommendations which would freeze future development, and did not believe that was their mandate in the first place. The Aboriginal Pipeline Group added that:

> We have protected our land for thousands of years. We are proud of this land given to us by the Creator to provide for us. We will continue to use our land wisely.

The Sierra Club of Canada submitted that imposing conditions related to future projects does not fetter the discretion of future panels. The Sierra Club of Canada submitted that, under the *Canadian Environmental Assessment Act* and *Mackenzie Valley Resource Management Act*, mitigation measures relied upon to conclude that a project can go ahead must actually be implemented. Dehcho First Nations submitted their concerns that we did not understand the spirit and intent of many recommendations such as those involving future projects that are not currently before us. Dehcho First Nations suggested adjusting the timing of Joint Review Panel recommendations related to future projects so they apply to this project instead. The Proponents submitted that future development, be it new gas fields or a pipeline expansion, would be subject to the intense scrutiny of the regulatory process, including scrutiny by the National Energy Board.

The Joint Review Panel's response to our proposed modifications to the recommendations stated that, where we noted that a relevant Joint Review Panel recommendation is:

> [o]utside the scope of the Mackenzie Gas Project (MGP) applications as it involves future application(s), [t]he Joint Review Panel does not understand this notation to be a rejection by the NEB of the relevant recommendation. The relevant Joint Review Panel recommendations stand and the Panel expects that they would, accordingly, be considered by the NEB in the specific context of any future applications.

The Sierra Club of Canada held the position that it is relevant that the National Energy Board has jurisdiction over approving future induced developments, but that does not take away from the Joint Review Panel's assertions that this work needs to be done up front. According to the Sierra Club of Canada, rights issuances and exploration in the area will increase, and this is not within the National Energy Board's purview. The Sierra Club of Canada submitted that they would agree with the Joint Review Panel's response interpreted as the Joint Review Panel agrees that once preparatory work is done, then future applications can be dealt with one at a time because the necessary preparatory work is complete.

Views of the Board

The matter of cumulative effects and upstream impacts was heard in full before the Joint Review Panel. We rely on their methodology and conclusions.

In response to the concerns raised regarding the need for up-front planning and the National Energy Board's jurisdiction over future projects, we continue to rely on the Joint Review Panel's assessment to identify mitigation measures appropriate for addressing cumulative effects of future development. We believe that our approach to implementing mitigation measures related to future development at the time of application for that development maintains the spirit and intent of the Joint Review Panel recommendations while adhering to the principles of natural justice and procedural fairness for future projects. The National Energy Board will consider all relevant evidence at the time of future applications, including cumulative impacts on the environment, and will make decisions in the public interest. The Joint Review Panel agrees that this procedural modification does not mean that we are rejecting the Joint Review Panel's recommendations directed at future projects. The Joint Review Panel stated that they expect that [cumulative effects] would be considered by the National Energy Board in the specific context of any future applications. The National Energy Board will continue to play its role in decision-making and project oversight in order to minimize environmental impacts now and in the future.

People at the hearing were concerned about the future. While views differed in the details, common threads included the integration of the land, the economy and the people; the importance of future generations; and community self-reliance. We listened to these views and incorporated them into our public interest determination. We heard from the Inuvialuit Regional Corporation:

> We ask that you consider not only the need to ensure the protection of our environment, but also the provision of economic opportunity to our residents and the social integrity of our communities.

We also heard from the Dehcho Elders and Harvesters:

> We're talking about the future of our children and we need to make sure that things are going to be better for our children in the long future and we don't want anything sitting wrong for our children in the future.

The Aboriginal Pipeline Group stated that they "need to regain socio-economic self-sufficiency for our people today and for our future generations."

The National Energy Board will continue to listen to Northerners through its lifespan regulatory oversight and accompany them in the pursuit of a sustainable energy future. Achieving sustainable outcomes will be a product of many parties including government authorities, communities, industry, and the Canadian public, that all support different pieces of the picture.

3.3.2 End use of gas and downstream impacts

Parties brought forward concerns in final argument related to the downstream impacts of the project and the end use of Mackenzie gas. The Sierra Club of Canada and France Benoît expressed concern that the gas from the Mackenzie Gas Project was intended for use in the oil sands where it would significantly increase greenhouse gas emissions. The Sierra Club of Canada submitted that, short of carbon neutrality, the Mackenzie Gas Project could contribute to a sustainable energy future if the gas is used wisely by displacing more carbon-intensive fuels. The Sierra Club of Canada proposed a National Energy Board certificate condition which would delay 'leave to open' for the pipeline until satisfactory implementation of Joint Review Panel recommendations 8-8 and 8-9. These recommendations were directed at the federal government to implement initiatives to manage greenhouse gas emissions (8-8) and to direct natural gas to 'wise' end-use applications (8-9). Ecology North also recommended the National Energy Board support these Joint Review Panel recommendations.

According to the Proponents, the Mackenzie Gas Project would deliver gas into the Alberta pipeline system where it would be commingled with other gas supplies and sold into markets throughout Canada and the United States. The Proponents submitted that there is no direct connection between the Mackenzie Gas Project facilities and a specific facility where gas will be burned, thus it is not relevant to our decision for us to consider the environmental effects of the combustion of Mackenzie gas at all facilities across North America where the gas could be burned. The Sierra Club of Canada countered that since the location of greenhouse gas emissions is irrelevant to their impacts, it is not logical to ignore end use impacts for the reason that the location of end use is unknown.

Views of the Board

Mackenzie gas would enter the North American market, where it would augment other supplies of natural gas. The end use of this gas would be determined by competitive markets operating within a public policy framework. The Joint Review Panel Report concluded that:

> mandating carbon neutrality and intervening in the market to specify preferred end uses for natural gas cannot be resolved on a project-by-project basis through the environmental assessment process, but must be addressed by governments through comprehensive climate change strategies.

When the National Energy Board is asked to consider the impacts of downstream facilities, it looks for a direct connection between these downstream facilities and the project under consideration. It is not possible to identify any particular downstream facility that would use the gas transported by the Mackenzie Gas Project. The gas would be transported through the TransCanada Alberta System to markets in southern Canada and elsewhere in North America. Where that gas would be delivered depends on future gas sales contracts and it is not possible at this time to determine what portion, if any, would be consumed in Alberta or in which sectors of the North America economy over the life of the pipeline. No specific markets or consumers can be directly linked to the Mackenzie Valley Pipeline and the operation of downstream facilities is not contingent upon receiving Mackenzie gas. Because there is no direct connection between the Mackenzie Valley Pipeline and any particular downstream facility, the environmental effects arising from the operation of downstream facilities do not appear to us to be relevant to the applications before us.

Nevertheless, we believe that augmenting the Canadian supply of natural gas, a relatively clean-burning and efficient fuel source, is of benefit to the Canadian public. Greater gas supply in the market increases the potential that fuels with higher greenhouse gas outputs would be preferentially displaced. Global energy demand is independent of whether Mackenzie gas comes on stream or not. Since natural gas is relatively low in greenhouse gas output per unit of energy produced, overall emissions would tend to be lower than the alternative where other carbon-based energy sources would be used.

3.3.3 Air quality issues and greenhouse gas emissions

Air quality issues

Air quality in the North is considered to be of high quality and Northerners are very concerned that it remains that way. Both Environment Canada and the Proponents agreed that existing air quality in the proposed project area is good and, along with other government regulators, emphasized the need to "keep clean areas clean." This principle requires new industrial development to be "planned, constructed and operated in a manner that minimizes the degradation of air quality in these areas."

Air quality issues for the project included project emissions for the pipeline and development fields, monitoring, and greenhouse gases in the context of monitoring climate change. These are aligned with the issues identified in the Joint Review Panel report. In its view the key air quality issues included:

- the project would be a long-term source of new air emissions in a generally pristine environment, and while impacts are not predicted to exceed relevant standards and guidelines, participants invoked the "keep clean areas clean" principle;
- Environment Canada and the Government of the Northwest Territories recommended the use of best available technology to minimize emissions, while the Proponents countered that they would use best practical technology, which is "technology that considers safety, engineering requirements, cost and environment, to reduce operational emissions"; and
- the project's air emissions would require appropriate monitoring during the construction and operation phases.

The Joint Review Panel noted that the National Energy Board would be the prime regulator of air emissions from the project and that Environment Canada and the Government of the Northwest Territories would play advisory roles. The Joint Review Panel recognized the National Energy Board's expertise and experience in regulating interprovincial aspects of the oil, gas and electric utility industries, including environmental matters. The Joint Review Panel also recognized the extensive environmental and local knowledge that Environment Canada and the Government of the Northwest Territories can provide.

Air emissions can be related to the project-specific effects of construction, operations, and waste incineration. Specific components of air emissions for the project might include: sulphur dioxide; nitrous oxides; ozone; carbon monoxide; carbon dioxide; volatile organic compounds; particulate matter; and compounds that include sulphates and nitrates, together called potential acid input. Carbon dioxide, methane and nitrous oxides are compounds that have the potential to collect in the atmosphere and influence global temperatures (greenhouse gases). Air quality impacts can be local to regional in the case of particulate matter and sulphur dioxide, or global in the case of greenhouse gases.

Specific discussion regarding air quality issues including emissions for the three gas fields is included in Chapter 4, Development fields. Further specific discussion on air emissions pertaining to facility design is found in Chapter 6, Facilities.

The Joint Review Panel report indicated that the Proponents' baseline information was compiled from historical data and results of air quality monitoring that was carried out over one year near the communities of Inuvik and Norman Wells, and periodically at the Parsons Lake and Taglu gas fields. The Proponents' monitoring data and other sources indicated that background concentrations of air contaminants are generally below detection levels or applicable guidelines. The one exception that is not below detection levels is ozone; relatively high background levels were monitored in Inuvik and Norman Wells. The Proponents indicated that elevated ozone levels at high latitudes in the northern hemisphere are thought to result from the intrusion of stratospheric ozone. The Proponents stated that all ground-level concentrations of compounds released by the project during operations at the gas fields, the Inuvik Area Facility, and compressor and heater station sites would increase, but would be below those outlined in applicable federal and territorial guidelines at all locations in the production area and along the pipeline corridor.

Environment Canada recommended that the Proponents design and implement suitable air quality monitoring programs with its help. Environment Canada focused its recommendations on pollution prevention and the use of best available technology and best management practices to minimize the degradation of air quality. Further discussion around application of these principles may be found in Chapter 6, Facilities.

The Dehcho Elders and Harvesters indicated that the project needs to be designed to minimize air quality impacts, with monitoring plans in place to verify the predicted emissions and impacts. Corrective action needs to be taken quickly to avoid impacts upon the land and wildlife from degraded air quality.

Greenhouse gas emissions

Parties were concerned about the impacts of the project on climate change, especially in light of Canada's international efforts under the United Nations Framework Convention on Climate Change and the *Kyoto Protocol*.

Greenhouse gas emissions arising from the project include carbon dioxide, methane and nitrous oxides with each compound having a different climate change potential. During operation, the project would emit greenhouse gases from burning natural gas at combustion related sources such as compressors and methane gas released through normal venting procedures and minor leaks (fugitive emissions). Further specific discussion on air emissions pertaining to facility design is found in Chapter 6, Facilities.

In the Joint Review Panel's view, Environment Canada is responsible for the design and implementation of ongoing climate monitoring in the region, the analysis of the data and the assessment of potential impacts. The Proponents' responsibility should be limited to providing relevant site-specific monitoring information to Environment Canada and ensuring that their operations and maintenance program takes into account any changes beyond that currently predicted.

Alternatives North submitted that the National Energy Board and the Government of Canada have a public interest mandate that requires consideration of greenhouse gas emissions.

Ecology North deemed that high project-specific standards for greenhouse gas emissions, based on a robust and strong definition of best available technology and accompanied by penalties in the cases where they do not meet those project standards or targets, would provide the best possible protection in terms of minimizing upstream greenhouse gas emissions associated with the project.

Sierra Club of Canada submitted that we need to specify an actual target and it is not enough to just leave it up to the Proponents. Sierra Club of Canada indicated that the target should at least match the general recommended target in Joint Review Panel recommendation 8-8.

Views of the Board

We understand the importance of clean air in the North and that air quality must be considered in a cumulative manner. We also recognize the need to minimize greenhouse gas emissions resulting from the project. The Joint Review Panel directed several recommendations to us relating to air quality and air emissions. We have addressed air issues through several conditions for the Mackenzie Gas Project. These conditions are focused on the Proponents taking appropriate measures to minimize air emissions and address air quality. We are committed to working collaboratively with Environment Canada and the Government of the Northwest Territories to protect air quality in the North, recognizing the extensive environmental and local knowledge that these agencies can provide.

Conditions 11, 12 and 13 address technologies for reducing emissions, incorporation of best management practices and best available technologies, and facility design. Condition 12 requires the submission of a report evaluating incinerator emissions from camps and station facilities. Technologies and practices must be reflected in the waste management plans required by Conditions 16 and 59. Condition 67 requires the Proponents to minimize and reduce emissions from flaring. Further specific discussion for these conditions regarding air emissions pertaining to facility design is found in Chapter 6, Facilities.

Air quality monitoring is part of comprehensive environmental monitoring under an environmental management system. Through environmental management, systems are established to address the effects of the project on the environment and of the environment on the project, with the overall goal of minimizing negative impacts. Adaptive management is a systematic process for continually improving management practices by learning from their outcomes.

Environmental monitoring is an important part of environmental management that directly supports adaptive management by observing and evaluating the effects that occur, then changing or adding mitigative measures, as appropriate, to limit or reverse the environmental effects. Environmental monitoring can include:

- compliance monitoring, to verify that all environmental mitigation is implemented as presented in the Environmental Protection Plan (EPP) and environmental alignment sheets and that work is in compliance with environmental regulations; and
- effects monitoring, to assess the effects resulting from project-environment interactions and evaluate the effectiveness of approved mitigation measures. This is further discussed in section 3.3.6, Environmental Protection Plans.

The National Energy Board promotes goal-oriented environmental management and monitoring. This means the National Energy Board tends to require a desired end result and the proponent may choose the means of achieving that result provided the means are acceptable to the National Energy Board. A proponent is expected to implement Environmental Protection and Monitoring and Surveillance Programs which include protection of the environment as one of the main goals.

The *Onshore Pipeline Regulations, 1999* require the proponent to implement an Environmental Protection Program which must include monitoring and adaptive management. (Section 48: "A company shall develop and implement an environmental protection program to anticipate, prevent, mitigate and manage conditions which have a potential to adversely affect the environment.")

Monitoring is required by the National Energy Board under Section 39 of the *Onshore Pipeline Regulations, 1999*. ("A company shall develop a monitoring and surveillance program for the protection of the pipeline, the public and the environment.") A monitoring program may:

- identify any issues or potential concerns that may compromise the protection of the environment;
- include methods for developing measures to prevent or mitigate the impact of the identified issues;
- provide for continued monitoring of sites to evaluate success of mitigative measures undertaken;
- provide a system for implementing additional mitigative measures as necessary; and
- provide a feedback system that allows for adaptation of successful mitigation to future pipeline projects.

Monitoring programs may have specific goals and targets and could include methods for evaluating and interpreting collected data such as air quality or emissions data. Monitoring may include any relevant environmental practices (e.g., vegetation establishment, water quality sampling, waste disposal).

Responsibilities of the National Energy Board regarding monitoring include:

- conducting environmental inspections of facilities, verifying compliance with

terms and conditions, and assessing the effectiveness of mitigation;
- monitoring ongoing operation and verifying reclamation and maintenance of the project site to acceptable standards; and
- conducting environmental audits, evaluating environmental management systems and environmental programs.

The National Energy Board generally requires the filing of environmental post-construction monitoring reports as a condition of an authorization. The Filing Manual provides guidance for companies on the content of environmental post-construction monitoring reports. The information in monitoring reports should include:

- confirmation of proper implementation of mitigation and reclamation measures used;
- identification of the outstanding environmental issues; and
- discussion of the company's plans for how outstanding issues will be resolved.

We have addressed the monitoring of air emissions through several conditions. Condition 3 requires the Proponents to submit for approval an Environmental Protection Plan prior to pre-construction activities which includes monitoring of activities for this stage of the project. Condition 15 outlines expectations for an Air Quality Monitoring Program and includes the requirement for consultation with other government agencies, location and selection methods of monitoring sites, and complaint response. Condition 16 includes the requirement for monitoring incinerator emissions.

A commitment to continuous improvement, outlined in Joint Review Panel recommendation 8-6, is expected to be a component of the Air Quality Monitoring Program required by Condition 15. We are of the view that the commitment to continuous improvement is not limited to greenhouse gas emissions but should apply to all discharges to the environment, which in this case is the atmosphere. Condition 15 also covers the requirements for methods and locations of monitoring.

Condition 13 requires the Proponents to file a report outlining the use of best available technology for station facility construction. Selection of best available technology is the most significant factor in determining achievable air emissions targets. Condition 59 outlines the requirements for an Environmental Protection Program. The condition requires the Proponents to submit policies, practices and procedures for management of air emissions including maximum proposed greenhouse gas targets and reduction strategies for air emissions including particulate matter, NOx and greenhouse gases. Condition 59 also addresses other matters from the Joint Review Panel recommendations including employee training, monitoring, public communication, waste management and required consultation with Environment Canada and the Government of the Northwest Territories. With these conditions, we find it acceptable for the Proponents to develop greenhouse gas targets for the project consistent with the use of best management practices and in consultation with appropriate government agencies.

3.3.4 Impacts of climate change on the project

Warming of the global and regional climate could raise sea levels and affect weather patterns. The Niglintgak and Taglu fields are located in the low-lying Mackenzie Delta near the Beaufort Sea. We heard concerns that seasonal flooding and storm surges could affect these facilities during the life of the project. The companies provided evidence that the facilities would be high enough to protect them from storm surges and flooding even if sea levels were to rise. Parsons Lake is located on higher ground and further from the sea, so its facilities would be less exposed to possible effects of climate change.

The Sierra Club of Canada was concerned about the lack of peer-reviewed research publications on the effects of climate change, specifically for the Mackenzie Delta over the 30 year lifespan that was used by Shell in the design of the Niglintgak facilities. The Sierra Club of Canada stated that from a design perspective, there is uncertainty regarding the effects of climate change on the permafrost, the rise in sea level and the degree of flooding. The Sierra Club of Canada referred to the Arctic Climate Impact Assessment prepared by the International Arctic Science Committee. The Arctic Climate Impact Assessment states that the Arctic is experiencing the most rapid and severe climate change on earth, including the disappearance of Arctic sea ice which allows higher waves and storm surges.

The Proponents said that climate change would be considered further in detailed engineering design, where required, such as for well pads, pipelines, facilities, and the right of way. Other possible impacts of climate change, such as landform changes and groundwater flows, would be handled through monitoring and mitigation. Overall, the Proponents indicated that their designs were sufficiently conservative to address potential climate change and variability.

Environment Canada indicated that interactions of climate variability and climate change would likely be a more significant environmental stressor on Project components over the anticipated lifespan of the project of about 25 years than currently acknowledged by the Proponents. Therefore, appropriate assessment, monitoring and mitigation approaches must be incorporated into the project's design, maintenance, contingency plans and decommissioning plans. Environment Canada also recommended that, prior to construction:

> climate change modeling employed by the Proponents properly incorporate the upper limit temperature scenarios to ensure that the safety margin built into the project design is adequate to cover the range of future temperature conditions including their variability extremes.

The Joint Review Panel was generally satisfied that the Proponents had taken climate change into account in their design. Nevertheless the Joint Review Panel recommended that the National Energy Board add a condition which would require the Proponents to file final design plans that incorporated further analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that this analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

Indian and Northern Affairs Canada suggested in final argument that the Proponents should demonstrate how upper limit temperature scenarios have been considered in their design. Further specific discussion on climate change regarding project design is found in Chapter 4, Development fields and Chapter 6, Facilities.

Views of the Board

We are satisfied with the Proponents' climate change estimates used in the design. Given the uncertainty regarding climate change predictions, a prudent step would be to assess the design using upper limit temperature scenarios as suggested by the Joint Review Panel. As the name implies, upper limit temperature scenarios would be less likely to occur than what has been used by the Proponents for the design of the project. Condition 6 requires the Proponents to submit a report which includes an analysis of the impacts of climate change and variability on permafrost and terrain stability for a series of representative locations and conditions using potential upper limit temperature scenarios which may occur along the pipeline. The analysis is to include potential impact on slope and water course crossing design. We have not specified how the study should be structured. We are of the view that, as part of this study, government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise.

Conditions N8, T7 and P8 require the Proponents to provide final detailed design information which incorporates an analysis of the impacts of climate change and variability on permafrost and terrain stability for each facility using potential upper limit temperature scenarios which may occur during the operational life of the project. The Proponents will also provide information about how upper limit temperature scenarios may impact precipitation, rise in sea level, storm surges, ice floes and flood levels, and watercourse crossing designs. We are of the view that government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise for the field design.

3.3.5 Wildlife and species at risk

Throughout final argument, parties reaffirmed the importance of wildlife to the people of the North and to Canada as a whole. The Dehcho stated:

> We have depended on the wildlife and plants to provide for our physical, emotional, and spiritual health, as well as providing our economic base for long before the last ice age.

The Sierra Club of Canada submitted that species at risk are of national interest and that biodiversity loss is a pressing global problem.

Parties presented three outstanding concerns with respect to wildlife and species at risk:

- habitat disruption and sensory disturbance;
- woodland caribou; and
- conditions regarding species at risk.

Habitat disruption and sensory disturbance

Parties to our hearing restated in final argument their concerns about habitat disruption and sensory disturbance to wildlife.

The Dehcho Elders and Harvesters were concerned about the disruption to wildlife that would occur from work on the pipeline. They submitted that disturbance of wildlife and wildlife habitat must be minimized as much as possible for all animals, including those that hibernate and live underground. They stated:

> the destruction of winter feeding, breeding and birthing areas and migration routes of all animals in the clearing of the land for the right of way, facilities and activities must be minimized and, in some cases, avoided by choosing an alternative pipeline route or facility location.

They also confirmed that the pipeline corridor must not be a barrier to wildlife movement.

Sensory disturbance such as noise and vibration were of concern to the Dehcho Elders and Harvesters. They submitted that noise and vibration pollution from the Enbridge pipeline affected animal migration and fish runs and that proper studies need to be undertaken to determine the sensitivities of all fish and wildlife to the sounds and vibrations generated by pipeline operation and how these affect their behaviour patterns, migrations and other activities. The project design should then be changed as required to ensure that its operation has no effect on wildlife behaviour.

Views of the Board

We heard that the Proponents have already committed to some mitigation measures to reduce wildlife disturbance and habitat disruption. These include:

- use of insulation and sound-suppression equipment;
- minimizing the use of flares and lighting;
- preventative maintenance to minimize unplanned activities; and
- altered design of laterals to allow for passage by caribou and harvesters.

It is our view that with the Proponents' commitments and with the additional requirements specified in Conditions 29 through 36 and similar Conditions on the approvals for the three development plans, disturbance to wildlife and their habitats will be minimized. We require the Proponents to submit for approval Wildlife Protection and Management Plans that include pre-construction wildlife surveys, detailed descriptions of mitigation measures and how these will be implemented, and protocols for monitoring and adaptive management. Among the mitigation measures the Proponents must submit are the scheduling of activities to minimize wildlife disturbance, procedures to avoid denning areas, measures to avoid sensory disturbance, and measures to minimize impacts of vehicle and air traffic on wildlife. Annual den surveys and mitigation measures to avoid dens must also be completed and filed with the Government of the Northwest Territories and wildlife management boards.

We require the Proponents to submit Wildlife Protection and Management Plans prior to filing the detailed route. Any adjustments to the detailed route that would minimize impacts to wildlife populations or their habitat will be evaluated and completed at the design stage. The National Energy Board will assess the effectiveness of Wildlife Protection and Management Plans and will monitor their implementation. The National Energy Board will conduct compliance monitoring throughout the lifespan of the project and will require all commitments to be satisfied.

We also require that the Wildlife Protection and Management Plans be developed in consultation with wildlife management boards, the territorial government and Environment Canada. We ask for evidence of this consultation to be provided with the Proponents' submission. Through this, we are satisfied that agencies with expert knowledge on wildlife management in the North will have input into the Plans. We believe that Condition 28 regarding the hiring of local residents as monitors will also assist local residents to identify any areas where mitigation measures are not working. The National Energy Board can direct the Proponents to take appropriate action to adaptively manage the situation. We heard from the Dehcho Elders and Harvesters that, "we need to work together and closely and to make sure that everything is safe". We plan to do so.

Woodland caribou

Canada's *Species at Risk Act* requires the Minister of the Environment to put in place a recovery strategy and action plan for listed wildlife species, which includes boreal woodland caribou. This has not yet been completed. The Sierra Club of Canada submitted that since legal obligations under the *Species at Risk Act* have not been fulfilled, the environmental assessment is not complete because the Joint Review Panel has accordingly been unable to determine the significance of impacts on species at risk such as woodland caribou.

The Proponents submitted that the Joint Review Panel made recommendations to address the uncertainty about the significance of the impacts the project might have on woodland caribou, including recommendation 10-4. Recommendation 10-4 states that a further assessment of the impacts that the project is predicted to have on species listed on Schedule 1 of the *Species at Risk Act* (listed species) should take place once the Proponents have greater certainty about the location of project facilities. It also states that surveys and impact assessments for listed species must be carried out after recovery strategies and action plans have been completed. The Sambaa K'e Dene Band submitted that we had not taken full consideration of Joint Review Panel recommendation 10-4 in our proposed conditions.

The Sierra Club of Canada, Alternatives North, Jean Marie River First Nation and the Sambaa K'e Dene Band submitted that the woodland caribou recovery strategy and action plan must be finalized and approved under the *Species at Risk Act* as a prerequisite to the development of a Wildlife Protection and Management Plan for woodland caribou and in advance of National Energy Board final authorizations. Jean Marie River First Nation also submitted that required mitigation measures include avoidance of critical overwintering habitat for woodland caribou. The proposed Mackenzie Valley Pipeline corridor is home to over-wintering woodland caribou, traditionally harvested by the Sambaa K'e Dene Band members. The Sambaa K'e Dene Band field and literature research carried out over a period of three years, consistent with other woodland caribou research, indicates that these animals are most vulnerable to industrial development during the late winter months — January through March — which is precisely when Mackenzie Gas Project activities will be occurring. The Sierra Club of Canada argued that consideration of the impacts on these key species at risk was meant to be conducted in public hearings, either before the Joint Review Panel or before the National Energy Board, and that this public process was being omitted from the proposed National Energy Board conditions.

Views of the Board

We acknowledge the importance of woodland caribou to the people of the North and of species at risk to Canadian biodiversity. We believe that our Conditions 29 and 30 capture the intent of the Joint Review Panel recommendations related to woodland caribou protection and management, and are within the National Energy Board's abilities to effectively assess, manage, and enforce.

Mitigation measures must be developed by the Proponents in consultation with Environment Canada — the same agency responsible for completing the woodland caribou recovery strategy and action plans under the *Species at Risk Act*. We expect that through this consultation, the Protection and Management Plan for woodland caribou will be informed by the same research that is going into the development of the recovery strategy and action plans.

Conditions 29 and 30 require the Proponents to conduct pre-construction surveys and submit, for National Energy Board approval, updated impact assessments, specific mitigation measures, protocols for monitoring and adaptive management, and provisions for updating the Wildlife Protection and Management Plan for woodland caribou as recovery strategies and action plans are effected and additional knowledge becomes available. Mitigation measures to be described by the Proponents include:

- the timing and dates of project activities to avoid conflict with caribou movement or sensitive feeding and calving time;
- measures to limit predator travel along right of ways;
- access management; and
- measures to avoid or minimize linear disturbance, effects of habitat fragmentation, and barriers to movement.

These mitigation requirements were derived directly from Joint Review Panel recommendations 10-1, 10-4 and 10-16, which had been recommended to the Joint Review Panel by the Government of the Northwest Territories who are involved in the preparation of woodland caribou recovery strategies. We have also stipulated that the Wildlife Protection and Management plans be developed in consultation with Environment Canada, the Government of the Northwest Territories, and wildlife management boards. Based on comments received by parties on the Joint Review Panel recommendations, we also included specific consultation requirements with the Dehcho Boreal Caribou Working Group. Between the combined efforts of the Proponents and these authorities we believe that potential adverse impacts of the project on woodland caribou will be minimized. When the recovery strategies and action plans are finalized, the Proponents are required to update their Wildlife Protection and Management Plans accordingly. However, we expect that such modifications to plans will be minimal since consultation with the parties responsible for developing the recovery strategy and action plan is required throughout.

We recognize that without a recovery strategy for woodland caribou in effect at this time, critical habitat has not yet been established as defined under the *Species at Risk Act* although research is in progress. However, Condition 29 requires Wildlife Protection and Management Plans to be filed for approval by the National Energy Board prior to decisions being made on the detailed route. In the case that the recovery strategy and action plan for woodland caribou remain incomplete at this time, we expect that additional science-based and traditional knowledge will be available to inform the detailed route in avoiding critical habitat to the extent possible. The knowledge of the Dehcho Boreal Caribou Working Group should be a valuable tool for the Proponents in identifying and protecting critical habitat.

We are of the mind that, with the application of the mitigation measures proposed in Conditions 29 and 30, developed in consultation with federal, territorial and Aboriginal government authorities and approved by the National Energy Board prior to filing of the detailed pipeline route, impacts of the project on woodland caribou can be minimized.

Species at risk

Environment Canada submitted that the draft conditions circulated by the National Energy Board may unduly impose survey requirements for those species at risk where the Minister of Environment has determined that its recovery is not feasible at this time, such as the Eskimo curlew. Environment Canada also clarified that the requirements for listed species described in Conditions 29, N22, T21 and P21 should apply to all species at risk added to Schedule 1 of the *Species at Risk Act* at the time the Proponents file their Wildlife Protection and Management Plans with the National Energy Board, not only to those listed species assessed during the Joint Review Panel hearings.

Environment Canada submitted that Condition 34 be amended so that the survey area for yellow rail and western toad be based on the latest information on the species. Environment Canada stated that in some cases, the Committee on the Status of Endangered Species in Canada reports may not include the most up-to-date information, and management authorities for the species may have more current information on species range.

Views of the Board

We agree that pre-construction surveys are not required for species at risk for which recovery is not feasible at this time, and modified our Conditions 29, N22, T21 and P21 accordingly. We expect that any incidental observations of individuals will still be reported as per part (a) of these Conditions. We also agree with Environment Canada's clarification regarding newly listed species at risk. We expect that the Wildlife Protection and Management Plans will address all known species at risk current at the time of Plan submission.

With respect to the survey area for yellow rail and western toad, it is our view that Condition 34 as proposed addresses Environment Canada's concern. Condition 34 requires evidence of consultation with Environment Canada and the Government of the Northwest Territories when preparing the surveys and proposing mitigation and monitoring measures specific to those species. Any discrepancies regarding survey area may be addressed by the Proponents and the appropriate management authorities through this consultation.

3.3.6 Environmental Protection Plans

Concerns regarding protection of the land were raised during final argument. These concerns included impacts to the environment such as air quality, aesthetic impacts, and noise. The Dehcho raised specific concerns regarding project specific environmental monitoring requirements, protection of water resources, and minimizing invasive plant introduction.

The National Energy Board adds a requirement to facility approval documents for a company to develop and file for approval an Environmental Protection Plan. The Environmental Protection Plan is a document that guides environmental oversight for the duration of a project and typically includes elements such as environmental mitigation measures, reclamation and re-vegetation. The Environmental Protection Plans are an important element of our regulatory approach to environmental protection.

The Environmental Protection Plan is an important tool that is used to communicate the environmental procedures and mitigation measures to the Proponent's field personnel and construction or operation contractors. The purpose of the Environmental Protection Plan is to document and communicate all the project-specific environmental protection measures or mitigation committed to by the Proponent in a clear and user-friendly document. It is a way to ensure the Proponent will honour all the environmental commitments that were made during the hearing process. It also helps to outline clear lines of responsibility and accountability for the company.

During review of the Environmental Protection Plan, the National Energy Board verifies that all relevant mitigation and environmental commitments are included. The Proponents use the Environmental Protection Plan to communicate environmental commitments to its contractors and mandatory language is used to facilitate compliance. There is flexibility for the Proponent in developing the overall content of the Environmental Protection Plan. Other plans such as the Waste Management Plan, Wildlife Protection and Management Plan, and Heritage Resources Plan may be incorporated into the Environmental Protection Plan as specific chapters to make it more encompassing for field staff.

The Environmental Protection Plan typically addresses the following:

- specific goals for protecting environmental and socio-economic elements identified as important (air, vegetation, soils, permafrost, native plants, access management, wetlands, water resources, mitigating noise and aesthetic impacts, preventing weeds and invasive species, and reclamation);
- practices and procedures that can be implemented to meet these goals;
- criteria for evaluating the success of practices and procedures, particularly for reclamation and any new mitigation measures;
- incorporation of flexibility by covering options for environmental practices and procedures that may be used;
- criteria by which decisions will be made regarding which practices and procedures to implement and under what circumstances;
- assignment of accountabilities and responsibilities for carrying out environmental practices and procedures, making criteria-based decisions, and how to confirm compliance;
- requirements of permits by other regulators with regulatory responsibilities for the project;
- evidence of consultation with other regulatory agencies that confirms satisfaction of proposed environmental mitigation;
- frequency and scheduling of monitoring activities;
- schedule of expected reporting to the National Energy Board on the progress and success of the mitigation measures implemented;
- inclusion for adaptive management, which allows for appropriate means to evaluate and amend issues that may arise during project operations; and
- effective means of reporting issues that may arise and reporting structures.

The Environmental Protection Plan incorporates the environmental alignment sheets. References to the Environmental Protection Plan are also incorporated into these alignment sheets. The Environmental Protection Plan is a comprehensive document that includes requirements of all regulatory agencies.

The requirement for an Environmental Protection Plan is consistent with National Energy Board goal-oriented regulation. An Environmental Protection Plan must be submitted to the National Energy Board for approval prior to pre-construction activities and pipe-laying operations for the Mackenzie Valley Pipeline and Mackenzie Gathering System. As the project begins the operational phase the Environmental Protection Program (Section 48 of the *Onshore Pipeline Regulations, 1999*) will apply. Prior to any drilling or construction activity relating to a Development Plan Application, authorizations under paragraph 5(1)(b) of the *Canada Oil and Gas Operations Act* would be required. Section 6 of the *Canada Oil and Gas Drilling and Production Regulations* states that an operator shall provide an Environmental Protection Plan for an authorization under paragraph 5(1)(b). Each of the Proponents will submit their own specific Environmental Protection Plan for the applications and may file several plans depending on timing of construction, the type of activity, and site specific considerations.

Alternatives North requested that the Conditions N11, T10, and P10 which deal with Environmental Protection Plans for Kendall Island Bird Sanctuary and Fish Island be filed with the National Energy Board for approval.

Views of the Board

We listened to the issues raised about the land, water resources, invasive species and other biophysical components. Through appropriate environmental management and planning we believe that these matters can be appropriately addressed during all stages of the project. We are committed to protection of the environment and will ensure measures are in place to address potential environmental impacts. A key component of this includes adherence to our conditions and Environmental Protection Plans required by Conditions 3, 38, N11, T10 and P10.

We will ensure that Environmental Protection Plans for the project are enforceable; that commitments made during the hearing are included; that appropriate field practices are incorporated; and that routine field amendments are addressed. The Environmental Protection Plans will facilitate environmental regulatory oversight for the project because they will incorporate all the environmental protection requirements in one document for each portion of the project. The Environmental Protection Plans provide a basis for working collaboratively with other Northern agencies. We will monitor and inspect all aspects of the project and the Environmental Protection Plans will be utilized as a document to verify compliance.

Required Environmental Protection Plans also address Joint Review Panel recommendation 6-4, *Construction and Operation Plan for the Kendall Island Bird Sanctuary and Fish Island*.

Conditions N11, T10, and P10 address Environmental Protection Plan requirements regarding the Development Plan Applications. The National Energy Board will assess future applications for authorizations for work or activity at the anchor fields along with the accompanying Environmental Protection Plan. Environmental mitigation during construction and operation for Fish Island will be addressed through Section 39 and 48 of the *Onshore Pipeline Regulations* and will also be addressed in the specific Environmental Protection Plans.

3.3.7 National Energy Board's role in enforcing recommendations directed to others

During final argument, parties submitted that the National Energy Board has a responsibility as "key gatekeeper" on this file to ensure that all Joint Review Panel recommendations are fulfilled. World Wildlife Fund Canada submitted that the National Energy Board must address the broader roster of Joint Review Panel recommendations, including those directed to government authorities, because they fall within the National Energy Board's fundamental mandate to recommend a project if and only if it is in the public interest. They added that the Joint Review Panel felt compelled to underline that the full suite of recommendations were needed to make the project sustainable. The Sierra Club of Canada submitted that we are leaving critical sustainability issues to others such as governments because almost all those recommendations intended to control the pace and scale of upstream development and those intended to ensure sustainability in relation to the end use of gas are not reflected in the National Energy Board's proposed conditions. Alternatively, the Gwich'in Tribal Council submitted that not all of the Panel's recommendations need to be accepted before the project can proceed; that matters best left to government policy should not be addressed by the recommendations; and that the completion of third-party actions should not be a pre-condition to project advancement.

Some parties had confidence in the ability of Northern agencies to protect the land. The Inuvialuit Regional Corporation stated:

> Much of the responsibility for the health of our environment is held collectively by the organizations and co-management bodies established under our land claim agreement and by the residents of every Inuvialuit community.
>
> Over the past 25 years, the Inuvialuit have gained a high level of confidence in the ability of these organizations and individuals to collectively provide for the

> ongoing health of the environment and wildlife across the Inuvialuit Settlement Region while allowing the orderly conduct of development and other commercial activities.
>
> As we look forward to the future development of the resource within our region, we do so in the comfort that our organizational structures have both the skills and the experience to maintain a responsible and objective balance between the health of our environment and the provisions of economic opportunity to the residents of our communities.

Other parties expressed concern that Joint Review Panel recommendations directed to other authorities would not be met. The Sierra Club of Canada submitted that we must set conditions that provide reasonable assurance that all of the Joint Review Panel's recommendations will be implemented, or say no to the project at this time. The Canadian Parks and Wilderness Society submitted that we should consider conditions that provide a greater level of certainty that recommendations outside the National Energy Board's mandate are fulfilled. The Sierra Club of Canada and Canadian Parks and Wilderness Society gave examples of ways in which we could ensure compliance. The Sierra Club of Canada suggested a two-part approach in which we first weigh the government response to evaluate whether the response commits to substantial implementation of the Joint Review Panel's recommendations, then we add a condition that the certificate does not take effect until the National Energy Board has determined in a public process that governments have met their commitments. Canadian Parks and Wilderness Society suggested other assurances such as timelines, land withdrawals, funding requirements, or checklist tracking. World Wildlife Fund Canada requested we state that this project is only in the public interest if all the Joint Review Panel's recommendations are implemented. World Wildlife Fund Canada cited an example in which another regulator, the Natural Resources Conservation Board, chose to make an approval come into effect upon the completion by government of a statutory order creating a wildland recreation area. World Wildlife Fund Canada suggested that we could, if we chose, take on a similar sequencing consideration and stipulate the order in which things happened, even where those things are not immediately within the National Energy Board's purview. Parties were afforded a further opportunity to comment on these and related matters upon receipt of the government response. In general, parties were concerned about the adequacy of the government response and either proposed strengthened conditions or took the view that, given this response, the project is not in the public interest.

Views of the Board

The National Energy Board has considerable responsibility with respect to the Mackenzie Gas Project. Fourteen federal and territorial agencies, departments and regulatory boards also have a role in managing environmental aspects of the project.

After making its regulatory decisions, the National Energy Board collaborates with others to protect wildlife, water, air and vegetation from potential negative impacts resulting from project development.

Our responsibility begins with making the public interest determination. The question central to our public interest determination is whether Northerners and other Canadians would be better or worse off if the Mackenzie Gas Project is approved. This question is answered in *Volume 1, Respecting all voices: Our journey to a decision*.

The public interest determination takes into account benefits and impacts of the project on the land, the people, the economy, and safety and technical concerns. The review and hearing of environmental and socio-economic impacts was conducted by the Joint Review Panel, whose assessment helped inform our determination. In order to make a decision that the project is in the public interest, we had to be assured that environmental impacts could be minimized and that high standards for environmental protection will be maintained throughout the project life. The National Energy Board has within its abilities three important regulatory tools to achieve this. The National Energy Board's authority allows us to condition, enforce and conduct compliance monitoring for a number of requirements related to environmental protection, which include many recommendations of the Joint Review

Panel. The National Energy Board is responsible for lifespan regulation of the project. The National Energy Board also has jurisdiction over the assessment of new applications for future developments. In addition, northern agencies and federal authorities have responsibilities related to monitoring the project and managing the effects. We regard these responsibilities as complementary to the National Energy Board's responsibilities, and the National Energy Board is committed to working in collaboration with others to support an effective and efficient regulatory scheme.

It is our view that conditions contingent upon third-party actions would unduly leave both Northerners and the Proponents in a state of uncertainty about whether and when the project could proceed. We heard that people need certainty and time to make appropriate preparations for development. These preparations include training workers, resolving outstanding land issues, developing job and business opportunities, and conducting detailed permitting by land and water boards, among others. Since we feel that a high standard of environmental protection will be met through the National Energy Board's regulatory authority to enforce those Joint Review Panel recommendations directed to us, to enforce those commitments made by the Proponents during our hearing and the Joint Review Panel hearing over the project's lifespan, and to assess the impacts of future related developments, we believe that a clear public interest determination can be made at this stage without the ultimate reliance on third-party action. We remain committed to collaboration with other authorities to protect wildlife, water, air and vegetation.

3.4 Socio-economic matters discussed in final argument

3.4.1 Socio-Economic Agreement

The Government of the Northwest Territories stated that the Mackenzie Gas Project is crucial to the socio-economic future of the Northwest Territories, and has the potential to:

> transform the Territories from a region dependent on the support and contributions from the rest of Canada to a self-sufficient Territory.

The Government of the Northwest Territories also noted that the Mackenzie Gas Project is expected to impact the well-being of residents and communities in the Northwest Territories, and that a socio-economic agreement for the Mackenzie Gas Project was therefore a critical component of the project.

To address concerns of mutual interest, the Proponents and the Government of the Northwest Territories signed the Socio-Economic Agreement for the Mackenzie Gas Project in 2007. The Agreement outlines commitments that are intended to optimize beneficial opportunities and mitigate negative impacts arising from the Mackenzie Gas Project for Northwest Territories residents. The Socio-Economic Agreement includes measures to address employment and training, social and cultural well-being, business, net effects on government, monitoring, reporting and adaptive management.

The Government of the Northwest Territories requested that we ensure compliance by the Proponents with the terms outlined in the Socio-Economic Agreement by requiring adherence to the Socio-Economic Agreement as a condition of approval.

Views of the Board

The commitments set out in the Socio-Economic Agreement provide important measures for addressing the socio-economic impacts and optimizing the benefits of the Mackenzie Gas Project. Enforcement is best left to the parties to the agreement and we see no value in attaching a condition to the Certificate requiring the implementation of the agreement.

3.4.2 Employment and training

The Dehcho Elders and Harvesters Councils stated that the Proponents and government should provide Dehcho communities with educational and training opportunities, to help mitigate impacts and enhance benefits of the project. The Dehcho Elders and Harvesters Councils stated this should include educational upgrading, safety courses, survival training, as well as information and scholarships for careers as forest rangers, fisheries officers, game wardens, and park rangers. The Dehcho Elders and Harvesters Councils and the Liidlii Kue First Nation also stated that Canada needs to fulfill the original terms of the Mackenzie Gas Project Impacts Fund by limiting it to the Aboriginal communities and regions along the pipeline corridor, and to make the first phase of funding immediately available. The Dehcho Elders and Harvesters Councils and the Liidlii Kue First Nation also suggested that some of the Mackenzie Gas Project Impacts Fund be used for wilderness, language and cultural programs.

The Dehcho Elders and Harvesters Councils also stated ongoing training, information sessions and workshops in Dehcho communities for follow-up and monitoring programs are needed. The Dehcho Elders and Harvesters Councils further stated that Dehcho communities should be provided with financial and logistical support to allow them to hire their own dedicated Mackenzie Gas Project environmental monitors, who would report directly to the Dehcho communities. The Dehcho Elders and Harvesters Councils stated that management, monitoring and follow-up programs for the project must include the direct involvement of the Dehcho, to ensure that the needs and interests of Dehcho communities are represented and protected, and that such programs must fully incorporate Dene knowledge.

To achieve this, the Dehcho Elders and Harvesters Councils recommended the establishment of a Dehcho Mackenzie Gas Project monitoring agency to oversee, observe and protect land, wildlife and habitat during the planning, construction and reclamation of the project. The Sambaa K'e Dene Band also requested that the Proponents or Canada provide funding to the Sambaa K'e Dene Band for an independent environmental monitoring program during and for a period following construction.

Concerns were also raised about training for Mackenzie Gas Project personnel, which the Dehcho Elders and Harvesters Councils stated should include cultural awareness training, seminars and workshops, as well as participation in on-land activities with Dehcho Elders and harvesters.

The Government of Yukon requested that we adopt Joint Review Panel recommendations 15-7 and 15-8, relating to the inclusion of the Yukon in the Proponents' Human Resources and Employment Database for the Mackenzie Gas Project, and designating Whitehorse as a point-of-hire. Alternatives North requested that the requirement for a communications plan as part of the Proponents' diversity plan originally included in recommendation 15-9 of the Joint Review Panel be included in our conditions. Northern Pipeline Projects Ltd. recommended that contact between closed camp worker populations and local people should be planned and minimal.

Views of the Board

We recognize the potential benefits, as well as the potentially undesired effects, that employment generated by the Mackenzie Gas Project can bring to communities. A number of our conditions and the Proponents' commitments address these effects. Condition 28 requires the Proponents to provide information to the National Energy Board related to the hiring of local residents as monitors to carry out compliance and environmental impact monitoring for the Mackenzie Gas Project. In addition, Condition 29 requires the Proponents to prepare and submit to the National Energy Board a number of Wildlife Protection and Management Plans that will address general wildlife and species-specific protection, and will include details on protocols for monitoring and adaptive management, in addition to Conditions 3 and 38 which require Environmental Protection Plans for the Mackenzie Gas Project.

The Socio-Economic Agreement for the Mackenzie Gas Project details the measures and commitments that are intended to minimize the socio-economic impacts of the project and enhance benefits. Section 2 of the Socio-Economic Agreement outlines the employment, training and hiring commitments made by the Proponents, including hiring priorities, points of hire for the Mackenzie Gas

Project, employment requirements and policies, human resources development, and the services and support for employment, education and training that will be provided by the Government of the Northwest Territories. Section 3 of the Socio-Economic Agreement outlines the commitments of the Proponents for promoting cultural preservation and understanding. These include the provision of cultural sensitivity and cross-cultural awareness training for all project workers, and supporting cultural activities such as community-based traditional lifestyle initiatives, traditional harvesting and the promotion of traditional culture and positive relationships with communities.

We believe these measures, commitments and programs will adequately address employment and training needs, and concerns relating to monitoring and cultural protection.

Regarding the recommendation by Northern Pipeline Projects Ltd. related to work camps, we believe the requirements for closed work camps and the preparation by the Proponents of plans to monitor and minimize adverse effects of worker-community interactions as contained in Conditions 24, 25 and 26 will provide for planned and limited interactions between the Mackenzie Gas Project workforce and local communities, and will minimize potential negative interactions.

With respect to the Government of Yukon's request for us to adopt Joint Review Panel recommendations 15-7 and 15-8, we note the Government of Yukon confirmed that these recommendations were consistent with, if not specifically contemplated by, the Proponents' written commitments to the Government of Yukon, and we are therefore confident these issues will be addressed. We are similarly confident that the existing requirements for monitoring and reporting systems contained in Conditions 23, N28, T27 and P27 will sufficiently address communications needs related to the Proponents' diversity plans, and no additional requirements to these conditions are needed.

3.4.3 Impacts to harvesters, land and resources

The Dehcho Elders and Harvesters Councils, the Sambaa K'e Dene Band and the Liidlii Kue First Nation raised a number of concerns regarding potential impacts on harvesters, land and resources in the Dehcho Region. The Sambaa K'e Dene Band stated its opposition to the development of borrow pits within the K'eotsee (Trainor Lake) watershed.

The Sambaa K'e Dene Band also requested that harvester compensation be addressed through a consultation agreement with Canada and the Proponents, through the conclusion of the Dehcho Process, or through the conclusion of an Impact Benefits Agreement.

To address compensation concerns, the Liidlii Kue First Nation requested that we require the Proponents to enter into a benefits agreement with the Liidlii Kue First Nation and the Dehcho First Nations as a condition of approval. The Liidlii Kue First Nation further requested that the agreement include funds to allow the Liidlii Kue First Nation to establish and maintain a monitoring program throughout the life of the project in their territory.

The Dehcho Elders and Harvesters Councils stated that research is required on the traditional Dehcho economy and the impact the project will have on physical, cultural and spiritual health and well-being. The Dehcho Elders and Harvesters Councils also requested that routing and siting of all project facilities avoid burial and sacred sites, and that work along water courses be conducted in a ceremonial manner with the involvement of the Dehcho. To address concerns regarding compensation for resources, the Dehcho Elders and Harvesters Councils requested that Dehcho harvesters be covered by a Harvesters Compensation Agreement before the project is allowed to proceed, and that compensation be provided for the value of all timber stands cleared on the right of way.

Finally, the Dehcho Elders and Harvesters Councils requested that the project be designed and built in a manner that minimizes the aesthetic impacts upon people and wildlife, and that Dehcho communities be involved in the development of a granular management plan for the project. The Dehcho Elders and Harvesters Councils expressed the desire of Dehcho communities to work with the Proponents to identify alternative sources of granular material, and that Dehcho communities, not Canada, be the recipients of any granular royalties.

Views of the Board

We recognize the importance of harvesting to the economy of the Northwest Territories, as well as its socio-economic and cultural importance for Aboriginal communities. In response to the concerns of the Dehcho Elders and Harvesters Councils regarding timber resources, Condition 75 for the Mackenzie Valley Pipeline will require the Proponents to notify and consult with Aboriginal and municipal authorities regarding community use of merchantable timber cleared along the right of way. With respect to harvester compensation, the report of the Joint Review Panel summarized the commitments made by the Proponents to provide compensation to harvesters. The Proponents committed to providing compensation to harvesters in accordance with the terms of the Inuvialuit Final Agreement, and the Comprehensive Land Claim Agreements for the Gwich'in and Sahtu Settlement Areas. They also committed to providing compensation to Dehcho harvesters on terms similar to these final agreements. We are satisfied with the commitments the Proponents have made to address harvester compensation.

For matters relating to granular resources, we will continue to rely on the authority of northern regulatory bodies and federal departments. For concerns over borrow pits and participation in management plans raised by the Sambaa K'e Dene Band and the Dehcho First Nations, the Mackenzie Valley Land and Water Board has regulatory oversight for permitting activities related to granular resource extraction in the Mackenzie Valley. In response to concerns over impacts to burial or sacred sites and aesthetic impacts raised by the Dehcho Elders and Harvesters Councils, Condition 21 requires the Proponents to submit to the National Energy Board their Heritage Resources Management Plan, as reviewed by the Prince of Wales Northern Heritage Centre. The mitigation measures committed to by the Proponents, as detailed in their Environmental Impact Statement, will adequately address aesthetic and visual impacts.

3.4.4 Project reporting

Alternatives North requested that we commit to a full public registry for all Mackenzie Gas Project applications and follow-up to ensure transparency and accountability. They further suggested the public registries of the Mackenzie Valley Environmental Impact Review Board and the Mackenzie Valley Land and Water Board could serve as models.

Views of the Board

We are committed to the open, transparent sharing of information with all those who have an interest in the Mackenzie Gas Project, including the northern institutions and federal departments with whom we will continue to work cooperatively as the project proceeds. Subject to statutory limitations, we will continue to make information about the project publicly available on our repository. For all projects regulated by the National Energy Board that have proceeded to construction, our public repository includes submissions made by proponents relating to their compliance with certificate conditions, as well as responses to these submissions by the National Energy Board.

Chapter 4
Development fields

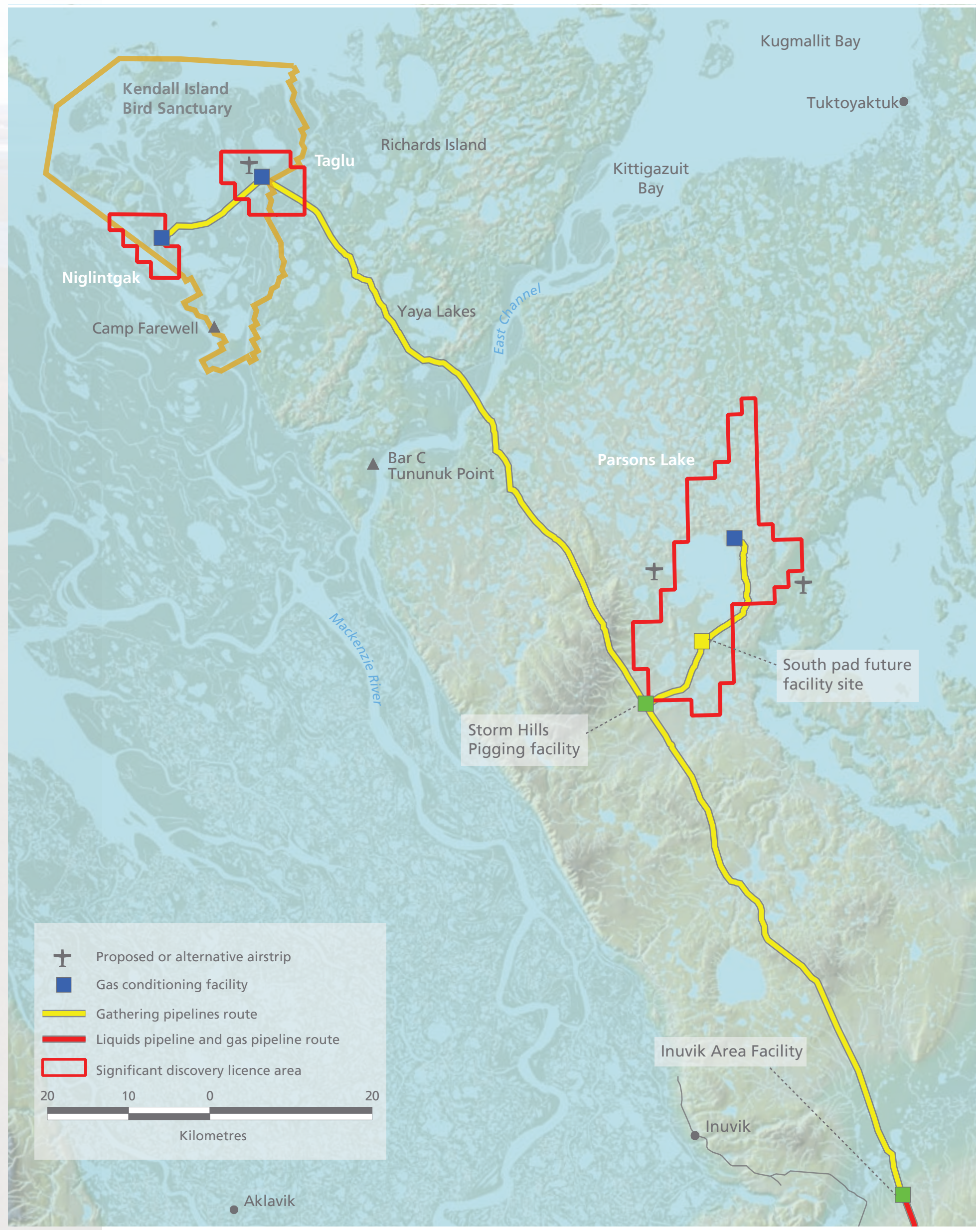


Figure 4-1 Development fields

4.1 The reservoirs

The Mackenzie Gas Project is anchored on the production of natural gas from three development fields near the edge of the Mackenzie Delta. These three fields—Niglintgak, Taglu and Parsons Lake—would produce about 172 Gm^3 (6.1 Tcf) of sweet natural gas (see Table 4-1). This is enough gas to heat one million average Canadian homes for almost fifty years.

Each field consists of reservoirs of trapped natural gas. Typically, oil and gas reservoirs are found and the boundaries identified through activities such as two dimensional and three dimensional seismic surveys and drilling and testing of exploratory wells and delineation wells. Results from surveys and tests provide technical information on the sub-surface rock and the trapped gas. Computer models use this information to predict the best locations to put production wells for the most efficient method of extracting the gas. *Appendix D – Development Field Reservoirs: Characteristics and Exploration History* provides additional information on the field reservoirs and exploration history.

Total supply from the anchor fields is projected to be about 24 Mm^3/d (0.850 Bcf/d) of sales gas, with level production for 12 years, following which production would decline until the reservoirs are depleted (see Figure 4-2).

Natural gas liquids production would begin at 1756 m^3/d (11,050 Bbl/d) and would immediately decline (see Figure 4-3).

Table 4-1

Recoverable volumes of natural gas in the development fields

Field	Recoverable volumes of natural gas
Niglintgak	27 Gm^3 (0.95 Tcf)
Taglu	81 Gm^3 (2.8 Tcf)
Parsons Lake	64 Gm^3 (2.3 Tcf)

Figure 4-2

Natural gas supply

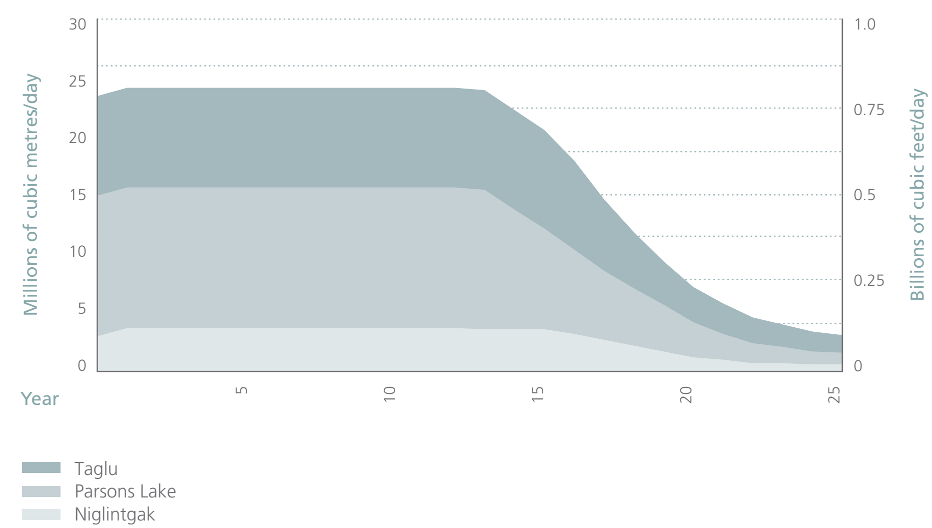
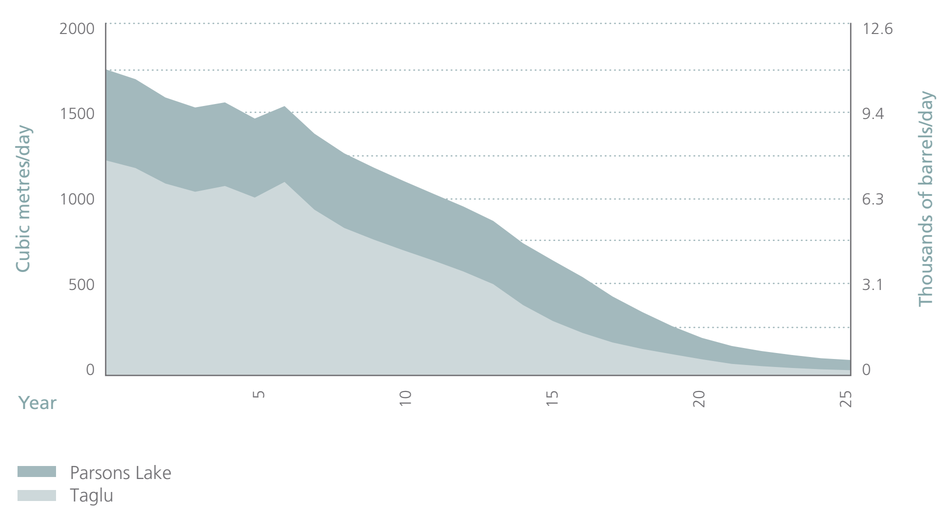


Figure 4-3

Natural gas liquids supply



Niglintgak production is negligible on this scale, i.e., 7 m^3/d

4.2 Niglintgak

4.2.1 Design of the Niglintgak facilities

Niglintgak is the westernmost of three natural gas fields associated with the project and is the starting point of the proposed Mackenzie Gathering System. Located entirely within Kendall Island Bird Sanctuary, Niglintgak is approximately 120 kilometres northwest of Inuvik and 85 kilometres west of Tuktoyaktuk.

Shell Canada Limited (Shell) is the Proponent for a Development Plan for the Niglintgak field under the *Canada Oil and Gas Operations Act*. Development of the field is estimated to cost $800 million with an estimated annual average operations and maintenance expenditure of $10 million per year for the period 2019 to 2023. Construction is planned over four winter seasons from 2014 to 2018 with production operations to commence in 2018 and continue for about 25 years.

The proposed production facilities include:

- six to twelve production wells located on three well pads;
- a system of above-ground flow lines;
- a gas conditioning facility located in the Kumak Channel;
- a disposal well; and
- infrastructure including an emergency shelter and helipads.

Shell proposes to start construction by barging supplies and equipment to Camp Farewell (refer to Figure 4-1) during late summer 2014 in preparation for winter work. Production is scheduled to start in the summer of 2018. Highlights of the proposed construction and drilling activities are shown in Table 4-2.

Table 4-2

Niglintgak construction highlights schedule

Activity	Season and year
Barge supplies and equipment into Camp Farewell	Late summer 2014
Start constructing well pad pilings, flow line pilings and well pad decking	Winter 2014/15
Option to commence drilling at south well pad	Winter 2014/15
Dredge gas conditioning facility transportation route, if required	Summer 2015
Construct flow lines including horizontal directional drill	Winter 2015/16
Excavate gas conditioning facility set-down site and prepare foundation	Winter 2016/17
Transport gas conditioning facility to set-down location	Summer 2017
Complete drilling and completion program and demobilize	Winter 2017/18
Start up operations and production	Summer 2018

Wells and well pads

All drilling would be conducted from three well pads (north, central and south) which would lie along the shoreline of the Mackenzie River's Middle Channel (see Figure 4-5). Each well pad would be built of steel decking and elevated on steel piles.

From these pads, Shell plans to initially drill six production wells. Once production begins and more is learned about the reservoir, as many as six contingent wells may be needed to optimize natural gas recovery. Shell also indicated that some wells may require commingled production in order to recover gas with a minimal well count. Commingled production is production of oil and gas from more than one pool or zone through a common well-bore without separate measurement of the production from each pool or zone.

Flow lines and water disposal well

After the natural gas is extracted from the reservoir, it would be transported along 10 kilometres of insulated above-ground flow lines to a gas conditioning facility, where the gas would be separated from any liquid hydrocarbons and water. Water that has been removed would be sent to a disposal well on the south well pad. The flow lines would be elevated at least 2.2 metres above ground on vertical supports.

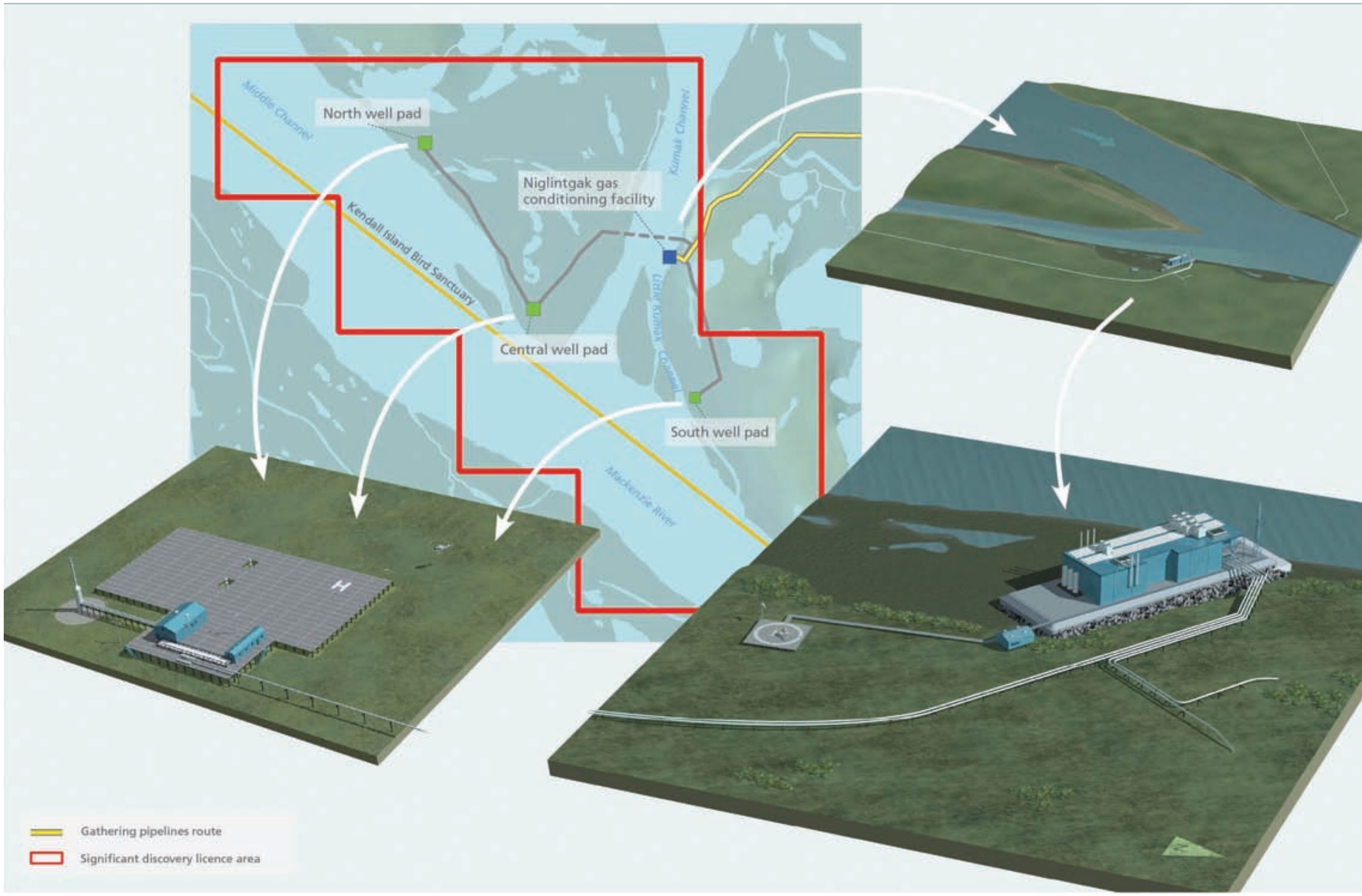


Figure 4-4

Niglintgak production facilities

Gas conditioning facility

Shell's proposed gas conditioning facility would be prefabricated and housed on a lightweight, ice-strengthened steel barge. The gas conditioning facility, designed for a maximum capacity of 4.3 Mm^3/d (150 MMcf/d) consists of several production modules designed to:

- separate the gas from free water and hydrocarbon liquids;
- inject produced water into a disposal well;
- compress and dehydrate the gas;
- inject hydrocarbon liquids into the sales gas line; and
- chill and meter the sales gas before it is pumped into the buried lateral pipeline which connects to the Mackenzie Gathering System.

Shell plans to tow the gas conditioning facility barge through the Beaufort Sea and into Little Kumak Channel in the Mackenzie Delta, where it would be set down on the Kumak Channel flood plain at a location north of the Little Kumak Channel. The current design calls for a barge with a 1.5 metre draft that stretches 50 metres across and 150 metres in length, which is slightly larger than a soccer field. Once the barge reaches its final location, it would be installed onto steel-pile foundations.

Barging

The gas conditioning facility would be transported by barge through the Beaufort Sea and up the Mackenzie River. In summer, beluga whales, bowhead whales and ringed seals all make the southeast Beaufort Sea home. There is the possibility that personnel would encounter groups of marine mammals; however, encounters are anticipated to be short term. Measures such as reducing vessel speeds, using an onboard mammal monitor to watch for aggregations of bowheads, and redirecting vessels to avoid whales could be used to mitigate these concerns. Impacts on water quality during transportation are not expected to be significant as no dredging is anticipated.

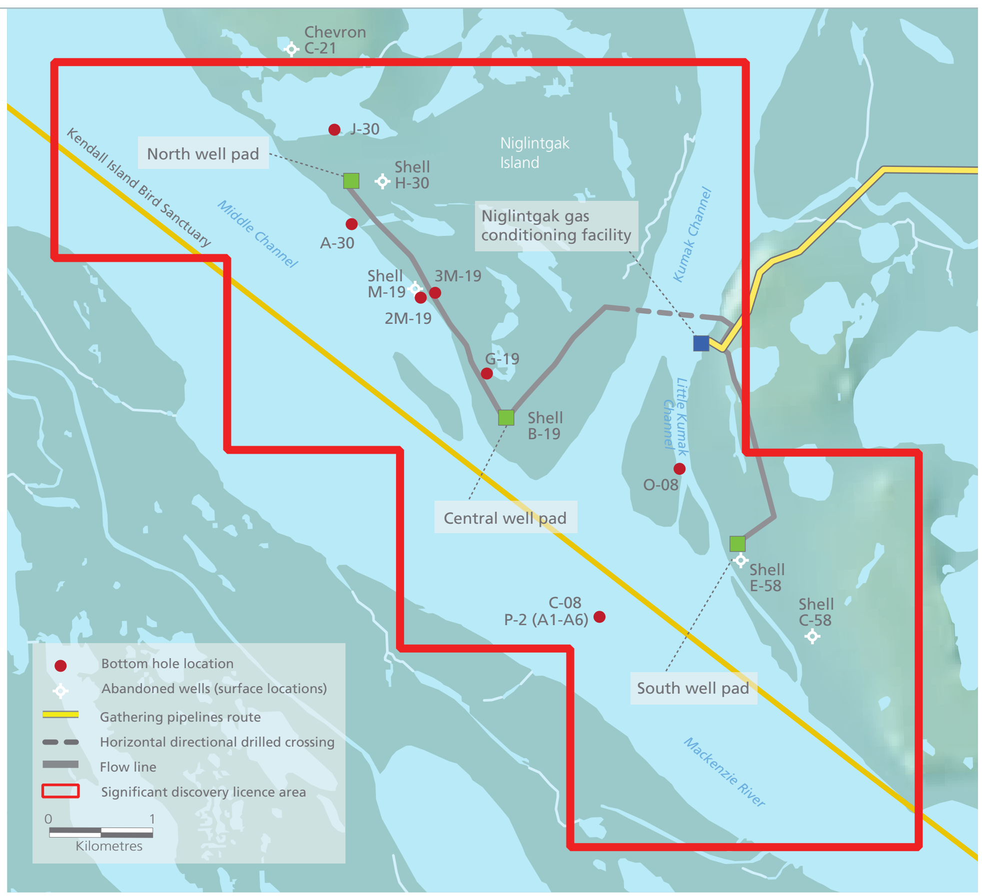
Shell's preferred route to the set-down location runs through the previously dredged Kittigazuit Bay (location shown on Figure 4-1), which is part of an existing shipping lane. This would eliminate the need to dredge the shallow waters at the mouth of the Mackenzie River. Shell plans to perform bathymetry and if required, conduct additional dredging on the transportation route. Proposed production facilities for the Niglintgak field (see Figure 4-4) are described opposite.

Camp Farewell

Camp Farewell, which includes an airstrip, an equipment laydown area, a barge landing site and fuel storage facilities, would be used to support drilling and construction activities at Niglintgak. The camp is Shell's staging and storage facility within Kendall Island Bird Sanctuary and has operated to support northern exploration and drilling activities since the late 1960s. It is located 15 kilometres southeast of the Niglintgak field and provides accommodation for 35 workers and support staff.

Figure 4-5

Niglintgak field map



Views of the Board

We are satisfied with the general approach, conceptual design and plan proposed by Shell for the Niglintgak field. We note that when Shell drills and produces gas from its wells, new geological and reservoir data will be acquired that will determine if additional faulting and compartmentalization exists and whether any contingent wells would be required. Condition N18 requires Shell to submit to the National Energy Board an updated resource management plan within 18 months after production commences or prior to the drilling of contingent wells.

We consider Shell's conceptual plan requiring commingled production in some wells in order to optimize gas recovery with a minimal well count to be acceptable. The National Energy Board will consider commingled production on an individual well basis during drilling and production operations in accordance with section 66 of the *Canada Oil and Gas Drilling and Production Regulations.*

Condition N31 stipulates that the approval of the Development Plan for the Niglintgak field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that Shell has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

4.2.2 Development plan issues

During the hearing, we heard the following related to the development of the Niglintgak field:

- matters raised by adjacent rights holders;
- geographic and design issues related to permafrost, subsidence, flood protection and climate change;
- air quality issues and greenhouse gas emissions;
- activity and facility noise levels and environmental footprint in Kendall Island Bird Sanctuary; and
- management of spoils from dredging operations.

Matters raised by adjacent rights holders

On 3 November 2004, the National Energy Board issued a declaration of Commercial Discovery (CDD) for the Niglintgak field, which includes land held and operated by several different parties. Shell is the sole interest holder of Significant Discovery Licence SDL019, which encompasses most of the field (see Figure 4-6). A Significant Discovery Licence interest holder has the right to drill wells and, in the future, obtain production rights for subsurface oil and gas resources.

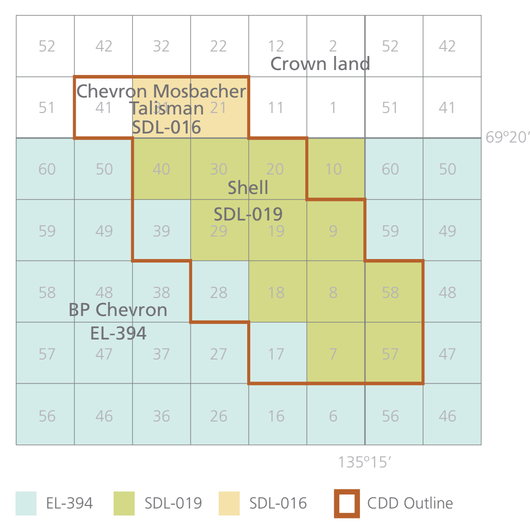
Shell's plans for developing the field are based on the results of reservoir modeling. Shell's models show a reservoir that is smaller and relatively shallow in comparison to the other two fields—the gas reserves lie only about 1000 metres below the surface—and much of the reserves lie underneath the Mackenzie River and its tributaries.

The reservoir is in the poorly consolidated Reindeer Sands geological formation and consists of several separate zones resulting from subsurface faulting. To fully recover the gas in the reservoir, Shell proposes a total of six to twelve wells on the three well pads. These sites were selected because the land has been disturbed by previous drilling activity.

Most of the activity would take place on the north pad where Shell plans to initially drill four gas wells. Initially, one gas well would be drilled on the central pad, and the south pad would contain both a gas well and a water disposal well. To reach the gas reserves, Shell plans to directionally drill under the Mackenzie River. The shallow depth of the reservoir will limit the length of these directionally drilled wells.

Figure 4-6

Commercial discovery declaration area and significant discovery licences for Niglintgak as of 2006



To the north of Significant Discovery Licence SDL019 lies the Significant Discovery Licence SDL016 land held by Mosbacher Operating Ltd. (Mosbacher), Talisman Energy Inc., and Chevron Canada Resources (Chevron) which is also the operator for these lands. To the south, east and west of Shell's land, is Exploration Licence EL394[1] held by Chevron and BP Canada Energy Company with Chevron being the operator.

Chevron and Mosbacher, as interest holders for lands adjacent to the Niglintgak field are concerned that Shell's proposed development would drain their gas resources. Mosbacher and Chevron would prefer to develop the Niglintgak field in collaboration with Shell, either by unitization or by providing third-party access to common facilities.

A unitization agreement would allow parties to jointly develop the field in exchange for a predetermined share of the end product. Shell is opposed to a unitization agreement. Shell also stated that no order for unitization to prevent waste under section 38 of the *Canada Oil and Gas Operations Act* is required as there would be no waste. Shell argued that Chevron and Mosbacher, like Shell, have rights to drill wells and develop their lands, but unlike Shell, Chevron and Mosbacher have chosen not to exercise those rights. In Shell's opinion, the Chevron and Mosbacher lands lie on the outer fringes of the reservoir and there is not enough information about Chevron's and Mosbacher's potential gas reserves to conduct meaningful discussion around unitization. Shell believes the only way Mosbacher and Chevron can prove the extent of gas reserves under their land is by drilling their own wells. This could be assisted by allowing Chevron and Mosbacher access to Shell's well pads so that they may directionally drill wells onto their lands. According to Shell, their proposed well pads could be adjusted to accommodate additional drilling activities, provided all parties could reach a mutually agreeable financial arrangement. If Chevron and Mosbacher choose to drill wells from Shell's well pads, the pads could be extended by 15 metres for each additional well.

According to Shell's estimates, the maximum horizontal reach for wells in the Niglintgak Field is approximately 1.3 to 1.5 kilometres. Chevron and Mosbacher could potentially drill a well from Shell's north and central well pads into their adjacent lands. If an arrangement is reached during the design phase, Shell would consider modifying its facilities, including installing additional river crossings and enlarging flow line structural supports for future expansion and meeting additional fuel gas and power supply requirements for well pads.

Typically when gas fields are developed, wells are positioned according to an established grid of "spacing units", such as that set out in the National Energy Board's *2009 Draft Spacing Requirements*[2]. The *2009 Draft Spacing Requirements* establish a 250 metre off-target area[3] intended to provide adjacent interest holders the opportunity to develop wells on their lands. Shell indicated that the 250 metre off-target area is appropriate, but requested a variance in accordance with the *2009 Draft Spacing Requirements* in order to allow for the optimum location of some wells.

In final argument, both Chevron and Mosbacher indicated that the proposed Niglintgak Development Plan was sub-optimal with respect to minimizing waste and referenced sections 18 and 19 of the *Canada Oil and Gas Operations Act*. In the absence of joint development, both Chevron and Mosbacher submitted to us that Shell should not be granted a variance in accordance with the *2009 Draft Spacing Requirements* for Significant Discovery Licence SDL019 as this would exacerbate drainage of gas from their lands.

Chevron asked us to consider a condition that would require field development to take into consideration the area needs when designing and sizing facilities. Chevron also asked for a condition restricting well density to no more than one well per spacing unit for all Shell lands. The third condition requested by Chevron would require Shell to provide a one grid unit set-back between Significant Discovery Licence SDL019 and lands of differing ownership.

Mosbacher suggested a condition that would direct Shell to include all land in Significant Discovery Licence SDL016 within the commercial

[1] Exploration Licence EL394 has expired and Production Licence PL25 was issued on 17 September 2008 for sections 17, 28 and 39. The current representative interest holder of Production Licence PL25 is MGM Energy Corp.

[2] The *2009 Draft Spacing Requirements* were issued on 31 December 2009 and replaced the *Draft Spacing Unit Regulations*.

[3] The 250 metre off-target area replaces the one grid unit set-back outlined in the *Draft Spacing Unit Regulations*.

discovery declaration area as part of the Niglintgak Development Plan. Secondly, Mosbacher asked for a condition requiring Shell to fully explore joint production arrangements with other interested parties. The third condition requested by Mosbacher would have Shell make available drilling pad space on reasonable commercial terms to allow Mosbacher and other interested parties the opportunity to drill additional wells on a timely basis.

Views of the Board

We are of the view that if the interest holders of the adjacent lands wish to develop their lands a joint and collaborative approach to the development of the Niglintgak field would be advantageous to all parties involved. The benefits would include a minimal duplication of facilities and a minimal environmental footprint within Kendall Island Bird Sanctuary. It is also our view that joint development is best obtained through voluntarily commercial negotiations and agreements between the parties involved. We note that the compulsory unitization[4] provisions in the *Canada Oil and Gas Operations Act* require participation from Shell as it holds a large portion of the lands comprising the Niglintgak commercial discovery declaration area. Shell has stated that it requires that Chevon and Mosbacher drill wells on their lands to demonstrate productivity before serious discussions could occur on joint development or unitization of the Niglintgak field. In this regard, Condition N2 requires the Niglintgak north, central and south well pads to be designed so each may be expanded to allow for the drilling of at least one well by third parties. If the parties involved are able to work out commercial terms including timing, the condition would provide Chevron and Mosbacher the opportunity to drill directional wells to delineate the field on their lands with a minimal environmental footprint in Kendall Island Bird Sanctuary.

As there currently is no joint production arrangement between the interest holders of Significant Discovery Licence SDL016 and Shell, we are of the view that there is no basis for Mosbacher's condition directing Shell to include all sections of land in Significant Discovery Licence SDL016 within the commercial discovery declaration area as part of the Niglintgak Development Plan. As noted, the first step that needs to be taken to commence meaningful discussions on joint production arrangements is the drilling of wells by Chevron and Mosbacher. Without wells on their lands, adjacent interest holders cannot make volume commitments with respect to third party access to Shell's facilities. Therefore, we are not persuaded to include the Mosbacher condition requiring Shell to fully explore joint production arrangements with other interested parties or the Chevron condition requiring field development to take into consideration the area needs when designing and sizing facilities.

In the absence of joint development arrangements, we are of the view that the *2009 Draft Spacing Requirements* are appropriate and provide an approach that balances the optimization of gas recovery with the protection of the correlative rights of adjacent land interest holders. Condition N19 requires Shell to comply with the *2009 Draft Spacing Requirements*. We are not persuaded by Chevron to require a one grid unit set-back between Significant Discovery Licence SDL019 and lands of differing ownership. We consider the 250 metre off-target area for gas wells to be appropriate noting that it is consistent with set-backs used in Alberta, British Columbia, Saskatchewan and Yukon.

The *2009 Draft Spacing Requirements* set a limit of one producing well in spacing units adjacent to lands of differing ownership, but for spacing units not adjacent to lands of differing ownership, there is no off-target area and more than one producing well is permitted[5]. Therefore, we are not persuaded by Chevron to restrict well density to no more than one well per spacing unit for all Shell lands.

[4] Compulsory unitization, sections 39 to 47 of the *Canada Oil and Gas Operations Act* came into force on 31 July 2010. Compulsory unitization requires one or more working interest owners who are parties to a unit agreement and a unit operating agreement and own in the aggregate sixty-five percent or more of the working interests in a unit area to apply for a unitization order with respect to the agreements.

[5] Part IV of the *2009 Draft Spacing Requirements.*

According to the *2009 Draft Spacing Requirements*, Shell would not need a variance for the proposed preliminary well locations. Any future application for a variance would be considered by the National Energy Board at that time and would be assessed in accordance with the *2009 Draft Spacing Requirements*, or any orders dealing with spacing that may supersede it.

We are of the view that the proposed production scheme is appropriate for a conventional gas field such as Niglintgak. With Condition N19 in place requiring compliance with the *2009 Draft Spacing Requirements*, interest holders of Significant Discovery Licence SDL016[6] and Production Licence PL25 have the opportunity to drill wells and develop their lands. We do not consider there to be sufficient grounds to find that the Niglintgak Development Plan is suboptimal in terms of minimizing waste[7], as suggested by Chevron and Mosbacher.

Geographic and design issues

Permafrost

The Niglintgak field is located within a zone of intermediate discontinuous permafrost. Well operations could produce not only warm natural gas, but also circulate other warm liquids, such as reservoir and drilling fluids, which could thaw the permafrost. Thawing of the permafrost may alter the landscape.

To reduce disturbance to the permafrost, Shell proposes to space the wells a minimum of 15 metres apart, and implement a number of other mitigative measures to reduce thawing of the permafrost by warm fluids from well operations. In addition, the well pads would be constructed on a raised steel deck, and the flow lines would be insulated and elevated.

One reason Shell chose the proposed set-down location for the gas conditioning facility is that the site is underlain by permafrost, which provides several options for excavation of the area. Shell's preferred approach is a combination of winter mechanical excavation and summer dredging. Once the gas conditioning facility is in place, the site would be dammed off and drained to isolate it from the channel to allow the permafrost layer to re-establish naturally.

Did you know?

Horizontal directional drill

A method for installing pipelines or other utilities beneath rivers, streams, channels, roads and other obstacles without requiring a trench and with minimal disruption to the surface. A drill rig is used to bore an underground passage for the pipeline or utility with a directionally controlled drill head. The passage is reamed out to an appropriate size and the pipe or utility is then pulled through.

The location of the gas conditioning facility requires the flow lines from the north and central pads to cross the Kumak Channel, a distance of approximately one kilometre. A feasibility assessment for a horizontal directional drill indicated that ice-rich, thaw-unstable permafrost effectively surrounds the Kumak Channel, but concluded the crossing may be successfully constructed with the application of mitigative measures, such as using chilled drilling fluids, to prevent permafrost thaw.

Shell's alternative to the horizontal directional drill would be a trenched flow line crossing about 900 metres downstream of the proposed horizontal directional drill crossing bordering the Little Kumak Channel.

[6] The lands comprising Significant Discovery Licence SDL016 are eligible for a production licence as those lands were included in the NEB's commercial discovery declaration dated 16 September 2004.

[7] Waste as defined in section 18 of the *Canada Oil and Gas Operations Act*.

Views of the Board

We are satisfied with Shell's general approach to addressing permafrost integrity for the Niglintgak development. We note that because warm fluids get circulated up and down the wellbore during drilling and production operations, it is important for safety and environmental protection reasons that the permafrost thaw bulbs around wellbores do not coalesce. Condition N3 requires the interwell spacing on Niglintgak well pads to be no less than 15 metres unless Shell utilizes mitigation measures approved by the National Energy Board.

We are of the view that Shell's preliminary horizontal directional drill design is satisfactory. We note that horizontal directional drill design has been used only once in permafrost areas and that this increases the potential for unforeseen issues during installation. We agree with the use of temperature controlled drilling muds for the horizontal directional drill crossing. When this is not possible, the alternative use of freezing temperature depressants has potential undesirable long term impacts on slope stability and their use as an option in horizontal directional drill must be carefully considered before implementation. Condition N7 requires Shell to provide: a hazard analysis and contingency plan for the proposed horizontal directional drill crossing; detailed final design drawings for the proposed horizontal directional drill crossing and the contingent open cut crossing; a monitoring program of slope stability, scour, drainage impedance and erosion issues for the crossing; and evidence of consultation with other appropriate regulators and government departments.

Subsidence

The reservoir for the Niglintgak field is located in the Reindeer Sands Formation, formed 60 million years ago in the Early Tertiary Period. When natural gas from the Niglintgak field is extracted from the poorly consolidated Reindeer Sands Formation, the sands may become more tightly packed and the surface could settle. This phenomenon is called subsidence. With this subsidence, the Niglintgak field, which is located within the active Mackenzie Delta floodplain, may be more prone to flooding. The low lying terrain of Niglintgak Island presently experiences annual spring floods as snow melt raises water levels in lakes, rivers and their tributaries throughout the Mackenzie Delta.

Shell predicts a maximum subsidence of 0.45 metres at the surface over the centre of the reservoir, which correlates with the centre of the Middle Channel, and predicts subsidence of 0.15 metres at the set-down location of the gas conditioning facility. Shell has indicated that it is considering using global positioning system targets on each of the well sites, the gas conditioning facility, on flow lines and at a number of benchmark locations to monitor subsidence.

Joint Review Panel Report recommendation 6-10 asked us to require Shell to file with the National Energy Board a program to monitor subsidence and flooding due to hydrocarbon extraction for the Niglintgak field. In a letter dated 28 January 2010 responding to the Joint Review Panel Report recommendations the Proponents submitted to us that recommendation 6-10 be rejected as our proposed Condition 7 (dated 5 February 2007) for the Niglintgak field was sufficient. In the Proponents' view, it was unlikely to be technically feasible to monitor flooding due to hydrocarbon extraction since it would be very difficult to differentiate flooding due to hydrocarbon extraction from natural flooding. The Proponents said that flooding at Niglintgak is a natural and annual occurrence.

In argument, Environment Canada suggested the following revisions to the condition:

- clarify and enhance consultation;
- include the monitoring of flooding due to subsidence in order to determine the loss of nesting habitat;
- include monitoring of reservoir compaction in order to differentiate project-induced subsidence from natural changes in ground elevation; and
- allow the use of the most appropriate technology at the time including airborne and remote sensing techniques.

Shell responded in argument by proposing the condition include the terms "best management practices" and "best available technology" in regards to monitoring.

Views of the Board

We are of the view that it will be important to monitor and confirm Shell's estimates of subsidence due to hydrocarbon extraction because the Niglintgak field is located inside Kendall Island Bird Sanctuary and is one of the first proposed developments in the Mackenzie Delta where subsidence due to gas extraction is predicted to occur. Condition N4 requires Shell to submit a program to measure and monitor accumulated subsidence and to monitor flooding for the life of the field.

Environment Canada indicated monitoring of reservoir compaction was needed to differentiate project-induced subsidence from natural changes in ground elevation. Condition N4 requires that elevation benchmarks be located outside of the projected gas-extraction-subsidence-area. We believe that these elevation benchmarks will act as control or reference points to provide data to estimate natural subsidence. We are not persuaded that monitoring of reservoir compaction is necessary.

We agree with Environment Canada that the condition should allow for the use of the most appropriate technology at the time. This is similar to Shell's suggestion to use the terms "best management practices" and "best available technology" in the condition. Condition N4 has been amended to reflect this.

We agree with Environment Canada's suggestion to clarify and enhance consultation and Condition N4 has been revised in this regard.

Flood protection and climate change

Shell's approach to flood protection was to estimate a maximum value for subsidence due to gas extraction and add factors such as the maximum predicted flood level, rising sea levels due to climate change, an increased severity of storm surges, permafrost thaw, and maximum wave height. These factors were all taken into consideration when developing the preliminary design for the well pads, flow lines and the barge-based gas conditioning facilities. Shell determined that permafrost thaw subsidence on areas vulnerable to flooding was much smaller, by an order of magnitude, than subsidence from gas extraction and, therefore, permafrost thaw subsidence was not significant.

Subsidence at the original set-down location of the gas conditioning facility was predicted to be 0.15 metres. A substructure design height of 5.75 metres was determined for the gas conditioning facility, which included consideration of subsidence, foundation settlement, maximum flood level, rise in sea level, storm surge, wave crest and a freeboard of 0.3 metres as additional protection (see Figure 4-7). The well pads would be set between 3 and 4 metres above grade and the flow lines would be elevated a minimum of 2.2 metres above grade.

Shell believes that it has used a conservative approach to estimate the effect of thawing permafrost in its determination of the design height of its facilities. Should the waters of the Mackenzie River ever threaten the facilities, some modification to the facilities and flow lines would be considered. This could include:

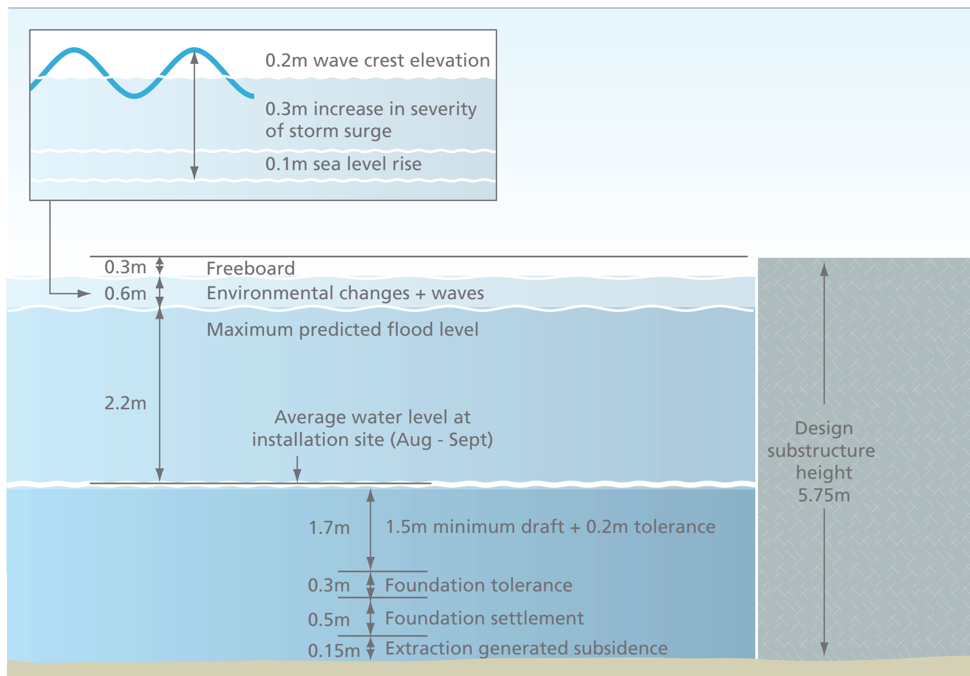
- increasing the height of the equipment platforms and flow lines;
- increasing the number of restraint points on flow lines and certain well site equipment, such as tanks;
- installing a flood barrier around the plant perimeter at deck level;
- increasing the depth of the substructure and raising the elevation of the plant on the gas conditioning facilities; and
- installing ice barriers.

Warming of the global and regional climate could raise sea levels and affect weather patterns. The Niglintgak field is located in the low-lying Mackenzie Delta near the Beaufort Sea. We heard concerns that seasonal flooding and storm surges could affect these facilities during the life of the project. Shell provided evidence that the facilities would be high enough to protect them from storm surges and flooding even if sea levels rise.

The Sierra Club of Canada was concerned about the lack of peer-reviewed research publications on the effects of climate change, specifically for the Mackenzie Delta over the 30 year life span that was used by Shell in the design of the Niglintgak facilities. The Sierra Club of Canada stated that from a design perspective, there is uncertainty regarding the effects of climate change on the permafrost, the rise in sea level and the degree of flooding. The Sierra Club of Canada referred to the Arctic Climate Impact Assessment prepared by the International Arctic Science Committee. The Arctic Climate Impact Assessment states that the Arctic is experiencing the most rapid and severe climate change on earth, including the disappearance of Arctic sea ice which allows higher waves and storm surges.

Shell indicated that the direct impact of sea level rise over 30 years should not exceed 0.1 metre This was based on research from the United States Environmental Protection Agency (September 1995) and the Intergovernmental Panel on Climate Change in 2001.

These documents contain extensive analysis of all the parameters that could influence sea level rise from climate change. Shell noted that the change in the annual average mean sea level, recorded at Tuktoyaktuk between 1971 and 2005 indicates that sea level changes are at a low level (less than 0.1 metres over 35 years). Shell believes previously mentioned research and Environment Canada data endorses its view that the direct impact of sea level rise over 30 years should not exceed 0.1 metres, but that an increase in the magnitude of storm surges needs to be considered. Shell indicated that it will look at whatever evidence and information is available, and if it leads to a different conclusion, Shell would need to increase design margins and would do that. Facility designs



Note: based on preliminary design information

Figure 4-7

Niglintgak substructure design height

will include adaptive management and future mitigations, where appropriate.

The Joint Review Panel was generally satisfied that Shell had taken climate change into account in its design. Nevertheless the Joint Review Panel recommended that the National Energy Board add a condition to the certificate which would require Shell to file final design plans that incorporate further design analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that this analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

Indian and Northern Affairs Canada suggested in final argument that the Proponents should demonstrate how upper limit temperature scenarios have been considered in their design.

Further specific discussion on climate change regarding project design is found in Chapter 6.

Views of the Board

We are satisfied with Shell's climate change estimates used in the design. Given the uncertainty regarding climate change predictions and the vintage of studies and data used by Shell, a prudent step would be to assess the design using upper limit temperature scenarios as suggested by the Joint Review Panel. As the name implies, upper limit temperature scenarios would be less likely to occur than what has been used by Shell for the design of the project.

Condition N8 requires Shell to provide final detailed design information that incorporates an analysis of the impacts of climate change and variability on permafrost and terrain stability for the Niglintgak facility using potential upper limit temperature scenarios which may occur during the operational life of the facilities. Shell will also provide information about how upper limit temperature scenarios may impact precipitation, rise in sea level, storm surges, ice floes and flood levels, and watercourse crossing designs. We are of the view that government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise for the field design.

Air quality issues

Air quality in the North is considered to be of high quality and Northerners are very concerned that it remains that way. Both Environment Canada and the Proponents agreed that existing air quality in the proposed project area is good and, along with other government regulators, emphasized the need to "keep clean areas clean." This principle requires new industrial development to be "planned, constructed and operated in a manner that minimizes the degradation of air quality in these areas."

Air quality issues for the project included project emissions for the pipeline and development fields, monitoring, and greenhouse gases in the context of monitoring climate change. The Joint Review Panel noted that the National Energy Board would be the prime regulator of air emissions from the project and that Environment Canada and the Government of the Northwest Territories would play advisory roles. The Joint Review Panel recognized the National Energy Board's expertise and experience in regulating interprovincial aspects of the oil, gas and electric utility industries, including environmental matters. The Joint Review Panel also recognized the extensive environmental and local knowledge that Environment Canada and the Government of the Northwest Territories can provide.

Air emissions can be related to the project-specific effects of construction, operations, and waste incineration. Air quality impacts can be local to regional in the case of particulate matter and sulphur dioxide, or global in the case of greenhouse gases. Emissions would occur during the construction phase through intermittent flaring during well testing at the Niglintgak field.

Further specific details pertaining to emissions for the pipeline are discussed in Chapter 3 and discussion on air emissions pertaining to facility design is found in Chapter 6.

The Joint Review Panel report indicated that the Proponents' baseline information was compiled from historical data and results of air quality monitoring that was carried out over one year near the communities of Inuvik and Norman Wells, and periodically at the Parsons Lake and Taglu gas fields. The Proponents' monitoring data and other sources indicated that background concentrations of air contaminants are generally below detection levels or applicable guidelines. The one exception that is not below detection levels is ozone; relatively high background levels were monitored in Inuvik and Norman Wells. The Proponents indicated that elevated ozone levels at high latitudes in the northern hemisphere are thought to result from the intrusion of stratospheric ozone. The Proponents stated that all ground-level concentrations of compounds released by the project during operations at the gas fields, the Inuvik Area Facility, and compressor and heater station sites would increase, but would be below those outlined in applicable federal and territorial guidelines at all locations in the production area and along the pipeline corridor.

Environment Canada recommended that the Proponents design and implement suitable air quality monitoring programs with its help. Environment Canada focused its recommendations on pollution prevention and the use of best available technology and best management practices to minimize the degradation of air quality. Further discussion around application of these principles may be found in Chapter 6.

The Dehcho Elders and Harvesters indicated that the project needs to be designed to minimize air quality impacts, with monitoring plans in place to verify the predicted emissions and impacts. Corrective action needs to be taken quickly to avoid impacts upon the land and wildlife from degraded air quality.

Greenhouse gas emissions

Parties were concerned about the impacts of the project on climate change, especially in light of Canada's international efforts under the United Nations Framework Convention on Climate Change and the *Kyoto Protocol*.

Greenhouse gas emissions arising from the project include carbon dioxide, methane and nitrous oxides with each compound having a different climate change potential. During operation, the project would emit greenhouse gases from burning natural gas at combustion related sources such as compressors and methane gas released through normal venting procedures and minor leaks (fugitive emissions). Further specific discussion on air emissions pertaining to facility design is found in Chapter 6.

Alternatives North submitted that the National Energy Board and the Government of Canada have a public interest mandate that requires consideration of greenhouse gas emissions.

Ecology North deemed that high project-specific standards for greenhouse gas emissions based on a robust and strong definition of best available technology and accompanied by penalties in the cases where they do not meet those project standards or targets, would provide the best possible protection in terms of minimizing upstream greenhouse gas emissions associated with the project.

Sierra Club of Canada submitted that we need to specify an actual target and it is not enough to just leave it up to the Proponents. Sierra Club of Canada indicated that the target should at least match the general recommended target in Joint Review Panel recommendation 8-8.

Views of the Board

We understand the importance of clean air in the North and that air quality must be considered in a cumulative manner. We also recognize the need to minimize greenhouse gas emissions resulting from the project. The Joint Review Panel directed several recommendations to us relating to air quality and air emissions. We have addressed air issues through several conditions for the Mackenzie Gas Project. These conditions are focused on the Proponents taking appropriate measures to minimize air emissions and address air quality. We are committed to working collaboratively with Environment Canada and the Government of the Northwest Territories to protect air quality in the North, recognizing the extensive environmental and local knowledge that these agencies can provide.

Conditions N14 and N16 address technologies for reducing emissions, incorporation of best management practices and best available technologies, and facility design. Condition N15 requires the submission of a report evaluating incinerator emissions from camps and station facilities and technologies and practices must be reflected in the waste management plans required by Condition N12. Condition N17 requires Shell to minimize and reduce emissions from flaring. Further specific discussion for these conditions regarding air emissions pertaining to facility design is found in Chapter 6.

Air quality monitoring is part of comprehensive environmental monitoring under an environmental management system. Through environmental management, systems are established to address effects of the project on the environment and of the environment on the project, with the overall goal of minimizing negative impacts. Adaptive management is a systematic process for continually improving management practices by learning from their outcomes.

Environmental monitoring is an important part of environmental management that directly supports adaptive management by observing and evaluating the effects that occur, then changing or adding mitigative measures as appropriate to limit or reverse the environmental effects. Environmental monitoring can include:

- compliance monitoring, to verify that all environmental mitigation is implemented as presented in the Environmental Protection Plan and environmental alignment sheets and that work is in compliance with environmental regulations; and
- effects monitoring, to assess the effects resulting from project-environment interactions and evaluate the effectiveness of approved mitigation measures. This is further discussed in section 3.3.6.

Shell is expected to implement Environmental Protection and Monitoring and Surveillance Programs which include protection of the environment as one of the main goals. A monitoring program may:

- identify any issues or potential concerns that may compromise the protection of the environment;
- include methods for developing measures to prevent or mitigate the impact of the identified issues;
- provide for continued monitoring of sites to evaluate success of mitigative measures undertaken;
- provide a system for implementing additional mitigative measures as necessary; and
- provide a feedback system that allows for adaptation of successful mitigation to future pipeline projects.

Monitoring programs may have specific goals and targets and could include methods for evaluating and interpreting collected data such as air quality or emissions data. Monitoring may include any relevant environmental practices (e.g., vegetation establishment, water quality sampling, waste disposal).

Responsibilities of the National Energy Board regarding monitoring include:

- conducting environmental inspections of facilities, verifying compliance with terms and conditions, and assessing the effectiveness of mitigation;
- monitoring ongoing operation, verifying reclamation and maintenance of the project site to acceptable standards; and
- conducting environmental audits, evaluating environmental management systems and environmental programs.

We generally require the filing of environmental post-construction monitoring reports as a condition of an authorization. The information in monitoring reports should include:

- confirmation of proper implementation of mitigation and reclamation measures used;

- identification of the outstanding environmental issues; and
- discussion of the company's plans for how outstanding issues will be resolved.

Condition N11 requires Shell to submit an Environmental Protection Plan which includes monitoring of activities. Condition N15 includes the requirement for monitoring incinerator emissions.

A commitment to continuous improvement, outlined in Joint Review Panel recommendation 8-6, is expected to be a component of an operator's management system pursuant to paragraph 5(2)(b) of the *Canada Oil and Gas Drilling and Production Regulations*. This is addressed in Condition N11. We are of the view that the commitment to continuous improvement is not limited to greenhouse gas emissions but should apply to all discharges to the environment, which in this case is the atmosphere. Condition N11 also covers the requirements for methods and locations of monitoring.

Condition N16 requires the Proponents to file a report outlining the use of best available technology for station facility construction. Selection of best available technology is the most significant factor in determining achievable air emissions targets. Condition N11 outlines the requirements for an Environmental Protection Plan. The condition requires the Proponents to submit maximum proposed greenhouse gas targets and reduction strategies for air emissions including particulate matter, NOx and greenhouse gases. Condition N11 also addresses other matters from the Joint Review Panel recommendations including employee training, monitoring, public communication, and required consultation with Environment Canada and the Government of the Northwest Territories. With these conditions, we find it acceptable for the Proponents to develop greenhouse gas targets for the project consistent with use of best management practices and in consultation with appropriate government agencies.

Kendall Island Bird Sanctuary

Kendall Island Bird Sanctuary was established in 1961 and is the only protected area in the Mackenzie Delta. It is one of the most significant wetland complexes in North America and the deltaic landscape of the Niglintgak field is a haven for the more than 90 species of birds that migrate to the region annually. The 623 square kilometre Kendall Island Bird Sanctuary provides critical habitat for thousands of songbirds, waterfowl and shore birds that use the area for breeding and staging. Kendall Island Bird Sanctuary has been identified as a Key Habitat Site which is defined as an area that supports at least one percent of the national population of a migratory bird species for any portion of its annual cycle. Kendall Island Bird Sanctuary is considered by Environment Canada to be an important component of Canada's effort to conserve biodiversity. Under the *Migratory Birds Sanctuary Regulations*, Environment Canada has authority over surface developments in Kendall Island Bird Sanctuary and has established a limit of one percent or 600 hectares as the allowable surface disturbance in the Sanctuary for all oil and gas activities. As a result, Environment Canada encourages project design considerations that result in the least possible long-term impact on habitat. To reduce impacts on migratory birds, Environment Canada has indicated that it may restrict or apply special conditions to activities such as construction, operation, monitoring and decommissioning in Kendall Island Bird Sanctuary during the period between May through October when the Sanctuary is occupied by birds. Furthermore, Environment Canada has indicated its preference for Shell to construct above-ground flow lines within Kendall Island Bird Sanctuary. In final argument Shell indicated it is committed to using above-ground flow lines to reduce surface disturbance.

Activity and facility noise levels

The Niglintgak anchor field is located in Kendall Island Bird Sanctuary which is a federally protected area managed for the conservation of migratory birds and protection of habitat for northern-breeding birds. Shell holds Significant Discovery Licence SDL019 that grants it subsurface oil and gas rights. Environment Canada has regulatory authority for activities within Kendall Island Bird Sanctuary, and will issue permit conditions governing noise emissions from development under the *Migratory Bird Sanctuary Regulations*. Environment Canada and the Proponent have both agreed to follow Alberta's Energy Resources Conservation Board Directive 038 for noise regulation. There is currently no legislation or standard in the Northwest Territories governing noise emissions.

Alberta's Energy Resources Conservation Board Directive 038 indicates a recommended noise target for remote areas even if no human residences are present. This is considered the "business as usual" requirement. The Directive has provisions to change the typical target when there are unique circumstances, including if an area is "pristine"—a pure, natural area that might have dwellings but no industrial presence. Environment Canada recommends continuous noise emissions, as measured from the fence line of the facility, not exceed Alberta's Energy Resources Conservation Board Directive 038 "best practices" permissible sound levels during the period from 10 May to 30 September when migratory birds are present in the Sanctuary because Kendall Island Bird Sanctuary is considered a pristine area.

Shell has indicated the primary noise generation sources at the Niglintgak facilities such as compressors, power generation equipment and aerial coolers, will be designed so that the resulting sound levels will be below the maximum permissible noise levels provided in Alberta's Energy Resources Conservation Board Directive 038. The Proponents agree with Environment Canada that the appropriateness, both technically and economically, of the proposed regulatory requirement will be further informed when detailed design progresses and before finalizing Environment Canada permit conditions. For facilities in Kendall Island Bird Sanctuary, the Proponents will continue to evaluate and apply noise mitigation options beyond those required to meet the "business as usual" interpretation of Alberta's Energy Resources Conservation Board Directive 038, provided these are practical. Shell is expected to provide detailed engineering and noise modeling results to Environment Canada.

Shell plans to schedule activities to avoid critical migratory bird nesting periods where practical. Because the Niglintgak field is relatively shallow at 1000 metres, drilling times can be reduced compared to Taglu and Parsons Lake. Shell is proposing a winter-only drilling program, and completions for most wells during winter months over three to four consecutive years. However, two well completions are proposed by Shell in the intervening summer seasons. Other construction activities such as barging, bathymetric work, dredging, transporting and setting of the gas conditioning facility would also occur in summer.

Both the Proponents and Environment Canada shared the view that requirements for noise regulation in Kendall Island Bird Sanctuary, both for the National Energy Board and migratory bird sanctuary requirements, can only be finalized after detailed engineering and design work is completed, after the noise impact analysis is prepared, and after discussions between the parties. Environment Canada will continue to work with the National Energy Board, Proponents and other regulators on issues related to noise in Kendall Island Bird Sanctuary. Shell indicated that it is committed to adhering to requirements in Alberta's Energy Resources Conservation Board Directive 038, as well as continuing evaluation of noise mitigation through detailed engineering and planning in order to arrive at practical solutions to concerns raised by Environment Canada.

Views of the Board

We agree with Environment Canada that regulating impacts of noise in a nationally protected bird sanctuary requires special consideration and application of best practices and the use of best available technology with the intent of "continuous improvement of pipeline safety and environmental protection". Condition N9 applies to regulating noise in the Niglintgak field and is intended to minimize disturbance from facilities inside Kendall Island Bird Sanctuary. The Condition requires meeting Alberta's Energy Resources Conservation Board Directive 038 "business as usual" standard with allowance for achieving the more stringent standard that Environment Canada recommended to the Joint Review Panel and the Joint Review Panel accepted. There is flexibility built in to the condition to adjust the standard as informed by final detailed engineering, an independently verified noise impact analysis report, and continued consultation for final determination of the fence line, which is the measurement base for a distance-based regulatory standard.

Overall footprint

Shell's preliminary design anticipates less than ten hectares of total new disturbance within Kendall Island Bird Sanctuary. This new disturbance includes the entire gas conditioning facility, the three well pads, the above-ground flow lines and modifications to the pre-existing Camp Farewell and a stockpile site.

To prepare a level set-down site for the gas conditioning facility, up to 50 000 cubic metres of silt, mud and other material would need to be excavated. The majority of material would be removed in the winter and, if required, some minor dredging or the removal of mud from the channel floor would occur the following summer. One reason Shell chose the proposed location for the gas conditioning facility is that the site is underlain by permafrost, which provides several options for excavation of the area. Shell's preferred approach is a combination of winter mechanical excavation and summer dredging.

Shell reduced the scope of dredging and made design modifications to avoid or reduce dredging in the delta area. As a result, the gas conditioning facility barge draught was reduced from 1.9 to 1.5 metres, the location was moved outside of Little Kumak Channel, and Shell committed to schedule its dredging activities to avoid impacts on the beluga harvest.

Shell's current plan is to deposit the excavated material adjacent to the gas conditioning facility site within Kendall Island Bird Sanctuary. Environment Canada indicated that it would not allow placement of the excavated stockpile within Kendall Island Bird Sanctuary if it were to result in the permanent loss of habitat. The best placement for these materials will be finalized by Shell after discussions with regulators and stakeholders, including Environment Canada, to reduce the impact on local wildlife.

To reduce the level of permanent disturbance, Shell plans to locate the well pads at previously drilled well locations and would incorporate as much of the previously disturbed land as feasible. Shell also plans to augment the steel pads with temporary ice pads for the drilling equipment. The ice pads would not leave a permanent footprint once drilling is complete.

Access to the field would be by winter road or helicopter from Camp Farewell. Shell does not propose permanent access.

In addition to the permanent footprint, Shell estimates a 17.5 hectare temporary footprint or land disturbed during the construction of ice pads and an ice road.

The disposal of drilling waste is not permitted within the Sanctuary, so Shell's initial plan was to dispose of these drill cuttings in a sump located outside of Kendall Island Bird Sanctuary. However, Shell has since adopted its alternative method which is to transport the cuttings out of the Northwest Territories to an approved landfill in Alberta or British Columbia.

In developing its Development Plan Application, Shell met with a variety of stakeholders including Aboriginal peoples and other Northerners, various government representatives, communities and oil and gas companies. Information from these discussions was used to develop and refine Shell's plans. Examples of community-driven design changes to the Niglintgak Project were discussed during final argument and include reducing overall footprint by locating drilling sites at pre-disturbed locations, preferentially scheduling drilling and construction activities in the winter and using above-ground flow lines to reduce surface disturbance.

Dredging activities will occur within Kendall Island Bird Sanctuary and Environment Canada will not permit the spoil to be placed on undisturbed terrestrial habitat within Kendall Island Bird Sanctuary. Environment Canada requested that we require that Shell's plan for excavation and dredging at the site of the gas conditioning facility at Niglintgak describe the potential impacts associated with dredging, and include spoil management and the site-specific mitigation measures to address adverse impacts.

To address Joint Review Panel Report recommendation 9-9 regarding dredging and excavation of the set-down location for the barge-based gas conditioning facility, we proposed Condition N10 on 9 March 2010. During final argument, Environment Canada suggested that the condition be expanded to require a dredging spoil management plan. Environment Canada and a number of other parties indicated that consultation needed to be defined or clarified. Shell asked that the timing of the condition be adjusted so that the dredging plan is not linked to well pad construction.

Views of the Board

We have considered the various comments regarding Condition N10 and the condition has been amended to require a dredging spoil management plan, to clarify requirements for consultation and to adjust the timing so it is no longer linked to construction of the well pads. The best placement of dredging materials will be finalized by Shell after consultation with regulators and stakeholders, including Environment Canada, to reduce the impact on local wildlife. Environment Canada has authority over activities in Kendall Island Bird Sanctuary under the regulations.

4.3 Taglu

4.3.1 Design of the Taglu facilities

The Taglu field lies above the Arctic Circle near the northern edge of the Mackenzie Delta. Currently the largest onshore gas field ever discovered in the Mackenzie Delta, it is estimated that Taglu contains nearly three trillion cubic feet of recoverable natural gas—enough to fuel all the gas-heated homes in Canada for three years.

The Taglu field is 120 kilometres northwest of Inuvik and 70 kilometres west of Tuktoyaktuk close to the Beaufort Sea. A single development site is proposed near the middle of the field, close to the confluence of the Kuluarpak and Harry channels (see Figure 4-8).

The reservoir reaches under Richards Island and, like the proposed Niglintgak field fifteen kilometres to the southwest, much of the reservoir stretches underneath Kendall Island Bird Sanctuary, a key habitat site for local shore birds and waterfowl. The Taglu field is found within the same geological formation as the Niglintgak field—the Reindeer Sands, a formation that is known to be poorly consolidated.

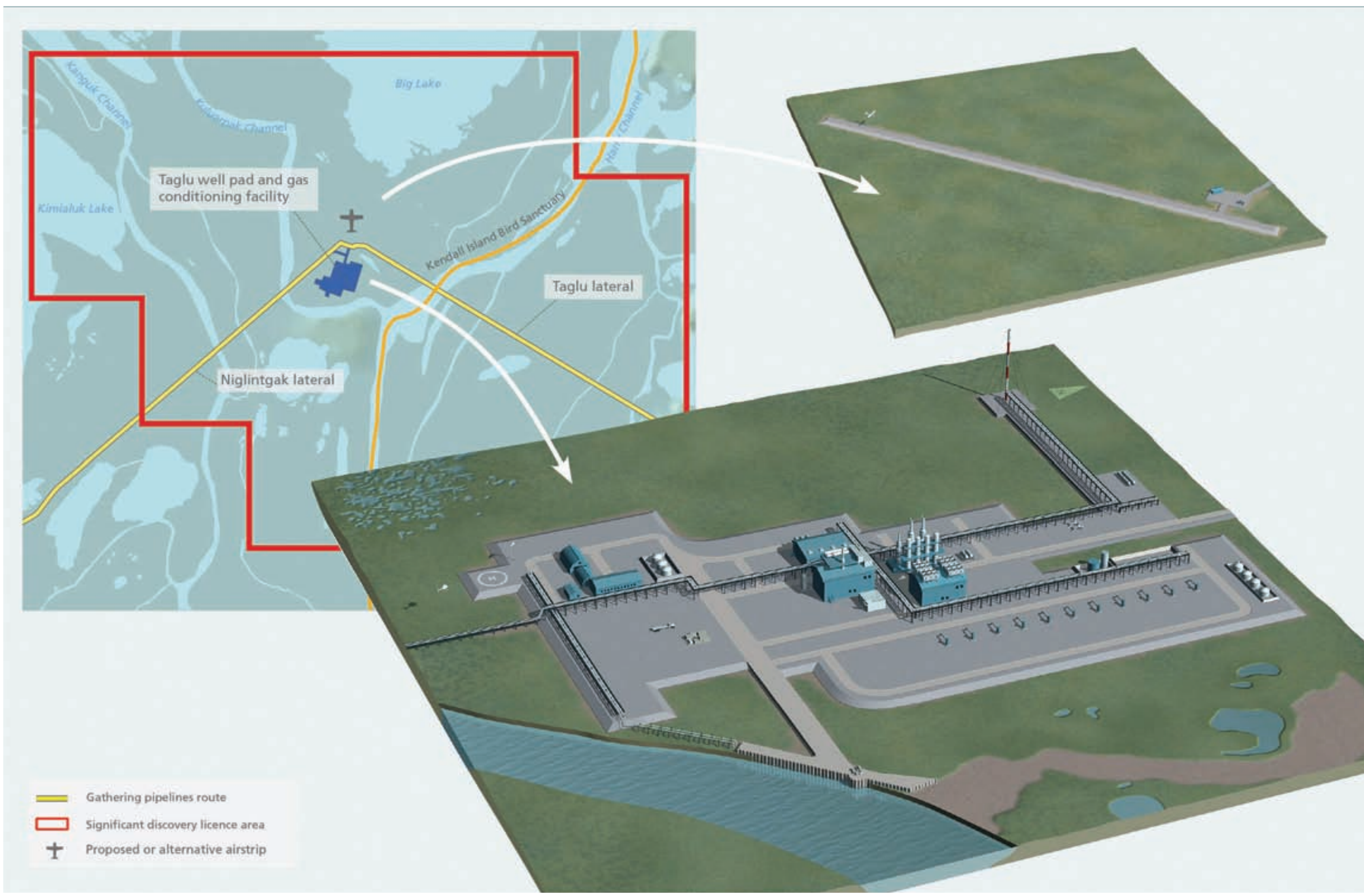


Figure 4-8

Taglu production facilities

Imperial Oil Resources Limited (Imperial) filed a Development Plan for the Taglu field under section 5.1 of the *Canada Oil and Gas Operations Act*. The proposed production facilities include:

- up to 15 production wells drilled from a single pad;
- one or two disposal wells;
- a gas conditioning facility;
- associated infrastructure including pads and foundations;
- a barge landing site;
- an airstrip and helicopter pad;
- buildings; and
- a water treatment system.

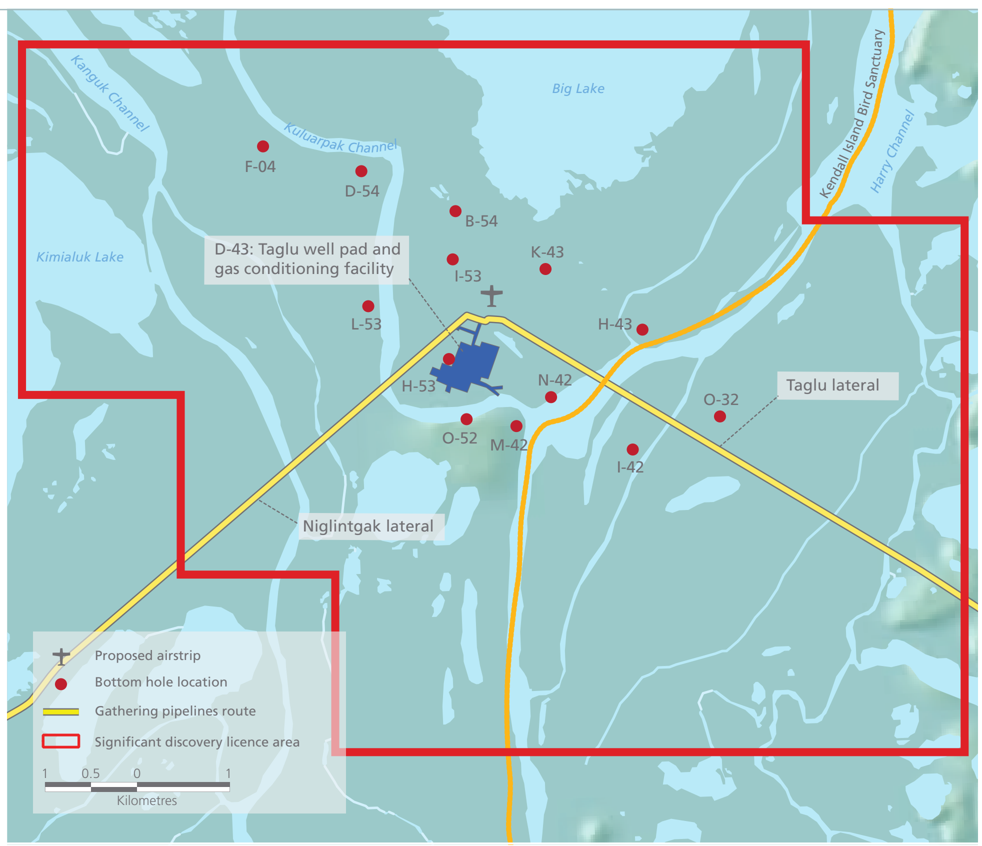
The well pad and the gas conditioning facility would be located adjacent to each other (see Figure 4-9).

Construction is planned to take place from 2014 to 2018 with operations commencing in 2018. The cost for developing the field is estimated to be $2,550 million with an estimated average operations and maintenance expenditure of $26 million per year for the period 2019 to 2023.

Imperial proposes to start constructing winter roads and moving equipment onto the site in 2014. Drilling would start in the winter of 2016/17 with production beginning in the summer of 2018. An overview of the construction schedule is provided in Table 4-3.

Figure 4-9

Taglu field map



Wells and well pads

Imperial plans to directionally drill 10 to 15 production wells and one or two disposal wells from a single well pad. Figure 4-9 shows the plan view of 11 potential locations of production wells and the preliminary locations of two disposal wells. This well pad would be located near the centre of the reservoir just inside the east boundary of Kendall Island Bird Sanctuary. Once production begins and additional reservoir data becomes available, Imperial may shift the current locations of its contingent wells to optimize production of the field. Imperial plans to build its well pad facilities on elevated pile foundations. Imperial's depletion plan for the Taglu field shows that some wells would incorporate commingled production.

The well pad would be either gravel filled with a matted and fluid sealed surface or a steel deck supported by steel piles. Gravel for the well pad and other facilities will come from existing borrow sites at Yaya Lakes (see Figure 4-1).

Flow lines

The wellheads would be located beneath the surface of the well pad in a long cellar. This cellar would provide personnel with easy access to any well for drilling or servicing with a conventional rig and provides a heated space for the flow lines and other support systems.

Gas would travel above ground on a pipe rack via insulated and heat-traced flow lines to a manifold facility and on to the gas conditioning facility. The manifold facility would direct the flow from each well to either a production line for processing or a line for testing.

Gas conditioning facility

Reservoir fluids would be processed at the gas conditioning facility to remove free water and natural gas liquids and to dehydrate and chill the gas to meet the specifications of the gathering pipeline. Although the gas would not need to be compressed initially, the facility would be designed so that it could do so if compression were needed. Natural gas liquids and gas volumes would be measured and transported to the gathering system and produced water would be injected about one kilometre below the surface into the disposal well.

Imperial would install a safety system in the gas conditioning facility for blowdown and pressure relief to lower the gas conditioning facility pressure and to direct hydrocarbon fluids to the flare system in a safe and controlled manner, when required.

The average daily design capacity for the Taglu gas conditioning facility would be 12.6 Mm^3/d (445 MMcf/d). The facility would be designed to handle a peak maximum design capacity of 14.5 Mm^3/d (510 MMcf/d), about 15 percent above average daily rates, to accommodate scheduled maintenance and production downtime among the development fields.

Infrastructure

The following infrastructure would be provided to support construction, operations and maintenance activities and to access the site:

- pads and foundations;
- barge landing site;
- airstrip and helicopter pad;
- roads;
- living quarters;
- control room;
- office and administration buildings;
- domestic water system;
- sewage treatment system;
- storage; and
- telecommunication facilities.

Barging

Currently, Imperial plans to enter the East Channel of the Mackenzie River through Kittigazuit Bay, where there is a historical shipping channel. Vessel movement through Kittigazuit Bay, which is part of the Kugmallit Bay 1A Beluga Management Zone, would be scheduled in August following prime beluga whale activity in the area. Preliminary engineering indicates dredging is not required in Kittigazuit Bay to successfully transport these modules (see Figure 4-1).

Third-party use and future expansion

The Taglu production facilities are designed to produce and process the Taglu volumes predicted for the Taglu field, however, the gas conditioning facility could accommodate or be expanded to accept additional production volumes. This would depend on the timing and volume of the additional gas, the gas properties, and acceptable commercial arrangements. The well pad may also be extended, but at this point, Imperial does not have a need to extend the well pad.

Table 4-3

Taglu construction highlights schedule

Activity	Season and year
Construct winter roads, gas conditioning facility pad, drilling pad and airstrip	Winter 2014/15
Compact gravel pads and transport construction equipment, materials and fuel	Summer 2015
Construct the dock and complete construction of gravel pads for gas conditioning facility, drilling pad and completions	Winter 2015/16
Barge and install small gas conditioning facility modules	Summer 2016
Begin drilling program	Winter 2016/17
Barge and install large gas conditioning facility modules	Summer 2017
Begin well completions	Winter 2017/18
Startup operations and production	Summer 2018

Views of the Board

We find Imperial's general approach, conceptual design and plan proposed for the Taglu field to be satisfactory. We note that new geological and reservoir data acquired during drilling and production will be used by Imperial to determine if additional faulting and compartmentalization exists and whether any contingent wells would be required. Condition T17 requires that Imperial file an updated resource management plan with the National Energy Board within 18 months after production commences or prior to the drilling of contingent wells.

Condition T18 requires Imperial to comply with the *2009 Draft Spacing Requirements* in order to protect the correlative rights of any adjacent subsurface rights holders. Imperial's preliminary production well locations for the Taglu field comply with the *2009 Draft Spacing Requirements*.

We are of the view that Imperial's conceptual plan whereby some wells would utilize commingled production to achieve maximum gas recovery is acceptable. Commingled production is production of oil and gas from more than one pool or zone through a common well-bore without separate measurement of the production from each pool or zone. The National Energy Board will consider commingled production on an individual well basis during drilling and production operations in accordance with section 66 of the *Canada Oil and Gas Drilling and Production Regulations.*

Condition T30 stipulates that the approval of the Development Plan for the Taglu Field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that Imperial has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

4.3.2 Development plan issues

During the hearing, Imperial discussed the following issues associated with developing the Taglu field:

- design issues related to permafrost, subsidence, flood protection and climate change;
- air quality issues and greenhouse gas emissions;
- activity and facility noise levels and environmental footprint in Kendall Island Bird Sanctuary; and
- management of spoil from dredging operations.

The design of the development field facilities is linked to the physical environment. The Taglu field is located in an active delta floodplain, with permafrost under parts of the proposed development. Facility locations are periodically flooded and the effects of flooding are a safety and facility design priority.

Permafrost and design issues

The Taglu field is located within a zone of intermediate discontinuous permafrost. As with the Niglintgak field, if the permafrost thaws, the landscape may be permanently altered. Imperial has proposed using a number of different types of design techniques to prevent the permafrost from thawing beneath its production facilities. One of these methods would be to separate each well by 18 metres. This interwell spacing is similar to the 15 metres Shell has adopted for its wells in Niglintgak. As previously mentioned, wellheads and flow lines would be located in a heated "cellar" below the well pad. To preserve the permafrost, Imperial plans to include an active refrigeration system with the wellbore conductor in their wellsite facility. This system keeps the permafrost from melting by chilling the ground below the wellsite, to about 37 metres deep, during drilling and production. Well pad facilities and flow lines would be constructed on elevated pile foundations to prevent permafrost damage and to avoid seasonal floods during operations.

Views of the Board

We are satisfied with Imperial's approach to addressing permafrost integrity with respect to the Taglu development. We note that all Taglu wells would be located on one well pad and that warm fluids would flow through those wellbores during drilling and production. Condition T2 requires the interwell spacing on the well pad to be no less than 15 metres unless Imperial utilizes mitigation measures approved by the National Energy Board. It is important for safety and environmental protection reasons that the permafrost thaw bulbs around wellbores do not coalesce.

Subsidence

The Taglu reservoir is within the same geological formation as the Niglintgak reservoir, the Reindeer Sands Formation. This formation of poorly consolidated sands from the Early Tertiary Period is nearly 60 million years old. As with Niglintgak, these sands could crumble and partially collapse, or subside, as gas is withdrawn from the field.

Imperial estimates the maximum amount of subsidence resulting from gas extraction would range from 0.20 to 0.42 metres. The deepest subsidence would be a low drainage area to the north of the proposed Taglu gas conditioning facility towards Big Lake. Imperial indicated that the predicted subsidence would not materially change the drainage patterns within the affected area and no "subsidence dish" would be formed.

Subsidence may also occur if the permafrost thaws as a result of climate change. This effect was estimated by Imperial to be much smaller, by an order of magnitude, compared to extraction-induced subsidence described above.

Imperial is considering using a three-dimensional global positioning system survey method to monitor and measure accumulated ground subsidence on the Taglu facilities. Details of such a program are still being assessed by Imperial.

Joint Review Panel Report recommendation 6-10 asked us to require Imperial to file with the National Energy Board a program to monitor subsidence and flooding due to hydrocarbon extraction for the Taglu field. In a letter dated 28 January 2010 responding to the Joint Review Panel Report recommendations the Proponents submitted to us that recommendation 6-10 be rejected as our proposed Condition 7 (dated 5 February 2007) for the Taglu field was sufficient. In the Proponents' view, it was unlikely to be technically feasible to monitor flooding due to hydrocarbon extraction since it would be very difficult to differentiate flooding due to hydrocarbon extraction from natural flooding. The Proponents said that flooding at Taglu is a natural and annual occurrence.

In argument, Environment Canada suggested the following revisions to the condition:

- clarify and enhance consultation;
- include the monitoring of flooding due to subsidence in order to determine the loss of nesting habitat;
- include monitoring of reservoir compaction in order to differentiate project-induced subsidence from natural changes in ground elevation; and
- allow the use of the most appropriate technology at the time including airborne and remote sensing techniques.

Views of the Board

We are of the view that it will be important to monitor and confirm Imperial's estimates of subsidence due to hydrocarbon extraction because the Taglu field is located inside Kendall Island Bird Sanctuary and is one of the first proposed developments in the Mackenzie Delta where subsidence due to gas extraction is predicted to occur. Condition T3 requires Imperial to submit a program to measure and monitor accumulated subsidence and to monitor flooding for the life of the field.

Environment Canada indicated monitoring of reservoir compaction was needed to differentiate project-induced subsidence from natural changes in ground elevation. Condition T3 requires that elevation benchmarks be located outside of the projected gas-extraction-subsidence-area. We believe that these elevation benchmarks will act as control or reference points to provide data to estimate natural subsidence. We are not persuaded that monitoring of reservoir compaction is necessary.

We agree with Environment Canada that the condition should allow for the use of the most appropriate technology at the time. Condition T3 has been amended to reflect this.

We agree with Environment Canada's suggestion to clarify and enhance consultation and Condition T3 has been revised in this regard.

Climate change and flood protection

The Taglu reservoir is found under low lying terrain with a mean elevation of 1.5 to 1.7 metres above sea level. Imperial expects the site to be periodically flooded during spring runoff and later in the season by storm surges from the nearby Beaufort Sea. As a result, Imperial considered the following factors in the design height of the Taglu pad:

- maximum flood level;
- maximum wave height;
- rise in sea level; and
- surface effect of gas extraction induced subsidence on flood depth.

These factors and a safety margin of 0.2 metres were used by Imperial to design a well pad and facility foundation height of 3.1 metres (see Figure 4-10).

Imperial plans to monitor the facilities and implement adaptive management and contingency plans as needed. If Imperial's design height is too low, it is possible to accommodate higher water levels by adding earthen fill material to certain areas of the site to protect them from flooding. In addition, select pile-mounted facilities, such as modules and flow lines, could be raised if flooding becomes a problem. Furthermore, protective measures, such as bumper posts or strengthened pipe supports could be used to protect those parts of the Taglu facility that would be at risk from ice floes.

Although there would be a risk that flood levels during the 30 year operating life of the Taglu field could exceed the design height, Imperial considers this risk to be relatively low. However, if water levels reach an extreme height, it would be possible to shut down production. Onsite activity could cease and some or all personnel would be removed from the site.

Warming of the global and regional climate could raise sea levels and affect weather patterns. The Taglu field is located in the low-lying Mackenzie Delta near the Beaufort Sea. We heard concerns that seasonal flooding and storm surges could affect the facilities during the life of the project. The Taglu airstrip could also be subject to flooding, but in that event workers and equipment would be brought to the site by helicopter. The companies provided evidence that the facilities would be high enough to protect them from storm surges and flooding even if sea levels were to rise.

As with the Niglintgak field, the Sierra Club of Canada was concerned about the lack of peer-reviewed research publications on the effects of climate change, specifically for the Mackenzie Delta over the 30 year life span that was used by Imperial in the design of the Taglu field facilities. The Sierra Club of Canada stated that in designing infrastructure in the Mackenzie Delta there is uncertainty as to the effects of climate change, including the effects on the permafrost, the rise in sea level and the degree of flooding.

The Joint Review Panel was generally satisfied that Imperial had taken climate change into account in its design. Nevertheless the Joint Review Panel recommended that the National Energy Board add a condition to the certificate which would require Imperial to file final design plans that incorporate further analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that further design analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

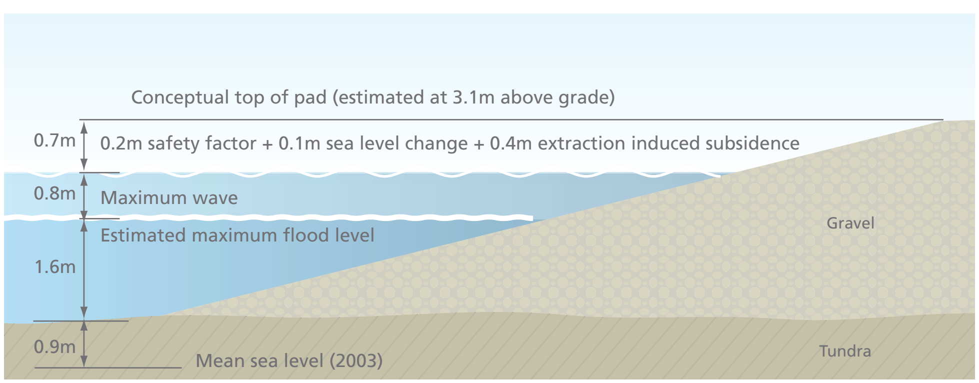
The Taglu field would produce natural gas from relatively shallow underground formations. As the natural gas is removed, the ground could settle by up to almost half a metre due to the removal of natural gas. This possibility was taken into account in the design of the facilities. Imperial also indicates that climate change is implicit in the way it completed its modeling for the facility and pipeline design specifically; that is, trends in climate warming regionally have been incorporated into the modeling.

Indian and Northern Affairs Canada suggested in final argument that the Proponents should demonstrate how upper limit temperature scenarios have been considered in their design.

Further specific discussion on climate change regarding project design is found in Chapter 6.

Figure 4-10

Design height for top of Taglu well pad and facility foundations



Note: Preliminary design. Dimensions shown might be adjusted as design is developed.

Views of the Board

We are satisfied with Imperial's climate change rates used in the design. Given the uncertainty regarding climate change predictions and the vintage of any climate change studies or data used by Imperial, a prudent step would be to assess the design using upper limit temperature scenarios as suggested by the Joint Review Panel. As the name implies, upper limit temperature scenarios would be less likely to occur than what has been used by Imperial for the design of the project.

Condition T7 requires Imperial to provide final detailed design information that incorporates an analysis fo the impacts of climate change and variability on permafrost and terrain stability for the Taglu facility using potential upper limit temperature scenarios which may occur during the operational life of the facilities. Imperial will also provide information about how upper limit temperature scenarios may impact precipitation, rise in sea level, storm surges, ice floes and flood levels. We are of the view that government departments such as Environment Canada, Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise for the field design.

Air quality issues

Air quality in the North is considered to be of high quality and Northerners are very concerned that it remains that way. Both Environment Canada and the Proponents agreed that existing air quality in the proposed project area is good and, along with other government regulators, emphasized the need to "keep clean areas clean." This principle requires new industrial development to be "planned, constructed and operated in a manner that minimizes the degradation of air quality in these areas."

Air quality issues for the project included project emissions for the pipeline and development fields, monitoring, and greenhouse gases in the context of monitoring climate change. The Joint Review Panel noted that the National Energy Board would be the prime regulator of air emissions from the project and that Environment Canada and the Government of the Northwest Territories would play advisory roles. The Joint Review Panel recognized the National Energy Board's expertise and experience in regulating interprovincial aspects of the oil, gas and electric utility industries, including environmental matters. The Joint Review Panel also recognized the extensive environmental and local knowledge that Environment Canada and the Government of the Northwest Territories can provide.

Air emissions can be related to the project-specific effects of construction, operations, and waste incineration. Air quality impacts can be local to regional in the case of particulate matter and sulphur dioxide, or global in the case of greenhouse gases. Emissions would occur during the construction phase through intermittent flaring during well testing at the Taglu field.

Further specific details pertaining to emissions for the pipeline are discussed in Chapter 3 and discussion on air emissions pertaining to facility design is found in Chapter 6.

The Joint Review Panel report indicated that the Proponents' baseline information was compiled from historical data and results of air quality monitoring that was carried out over one year near the communities of Inuvik and Norman Wells, and periodically at the Parsons Lake and Taglu gas fields. The Proponents' monitoring data and other sources indicated that background concentrations of air contaminants are generally below detection levels or applicable guidelines. The one exception that is not below detection levels is ozone; relatively high background levels were monitored in Inuvik and Norman Wells. The Proponents indicated that elevated ozone levels at high latitudes in the northern hemisphere are thought to result from the intrusion of stratospheric ozone. The Proponents stated that all ground-level concentrations of compounds released by the project during operations at the gas fields, the Inuvik Area Facility, and compressor and heater station sites would increase, but would be below those outlined in applicable federal and territorial guidelines at all locations in the production area and along the pipeline corridor.

Environment Canada recommended that the Proponents design and implement suitable air quality monitoring programs with its help. Environment Canada focused its recommendations on pollution prevention and the use of best available technology and best management practices to minimize the degradation of air quality. Further discussion around application of these principles may be found in Chapter 6.

The Dehcho Elders and Harvesters indicated that the project needs to be designed to minimize air quality impacts, with monitoring plans in place to verify the predicted emissions and impacts. Corrective action needs to be taken quickly to avoid impacts upon the land and wildlife from degraded air quality.

Greenhouse gas emissions

Parties were concerned about the impacts of the project on climate change, especially in light of Canada's international efforts under the United Nations Framework Convention on Climate Change and the *Kyoto Protocol*.

Greenhouse gas emissions arising from the project include carbon dioxide, methane and nitrous oxides with each compound having a different climate change potential. During operation, the project would emit greenhouse gases from burning natural gas at combustion related sources such as compressors and methane gas released through normal venting procedures and minor leaks (fugitive emissions). Further specific discussion on air emissions pertaining to facility design is found in Chapter 6.

Alternatives North submitted that the National Energy Board and the Government of Canada have a public interest mandate that requires consideration of greenhouse gas emissions.

Ecology North deemed that high project-specific standards for greenhouse gas emissions based on a robust and strong definition of best available technology and accompanied by penalties in the cases where they do not meet those project standards or targets, would provide the best possible protection in terms of minimizing upstream greenhouse gas emissions associated with the project.

Sierra Club of Canada submitted that we need to specify an actual target and it is not enough to just leave it up to the Proponents. Sierra Club of Canada indicated that the target should at least match the general recommended target in Joint Review Panel recommendation 8-8.

Views of the Board

We understand the importance of clean air in the North and that air quality must be considered in a cumulative manner. We also recognize the need to minimize greenhouse gas emissions resulting from the project. The Joint Review Panel directed several recommendations to us relating to air quality and air emissions. We have addressed air issues through several conditions for the Mackenzie Gas Project. These conditions are focused on the Proponents taking appropriate measures to minimize air emissions and address air quality. We are committed to working collaboratively with Environment Canada and the Government of the Northwest Territories to protect air quality in the North, recognizing the extensive environmental and local knowledge that these agencies can provide.

Conditions T13 and T15 address technologies for reducing emissions, incorporation of best management practices and best available technologies, and facility design. Condition T14 requires the submission of a report evaluating incinerator emissions from camps and station facilities and technologies and practices must be reflected in the waste management plans required by Condition T11. Condition T16 requires Imperial to minimize and reduce emissions from flaring. Further specific discussion for these conditions regarding air emissions pertaining to facility design is found in Chapter 6.

Air quality monitoring is part of comprehensive environmental monitoring under an environmental management system. Through environmental management, systems are established to address effects of the project on the environment and of the environment on the project, with the overall goal of minimizing negative impacts. Adaptive management is a systematic process for continually improving management practices by learning from their outcomes.

Environmental monitoring is an important part of environmental management that directly supports adaptive management by observing and evaluating the effects that occur, then changing or adding mitigative measures as appropriate to limit or reverse the environmental effects. Environmental monitoring can include:

- compliance monitoring, to verify that all environmental mitigation is implemented as presented in the Environmental Protection Plan and environmental alignment sheets and that work is in compliance with environmental regulations; and
- effects monitoring, to assess the effects resulting from project-environment interactions and evaluate the effectiveness of approved mitigation measures. This is further discussed in section 3.3.6.

Imperial is expected to implement Environmental Protection and Monitoring and Surveillance Programs which include protection of the environment as one of the main goals. A monitoring program may:

- identify any issues or potential concerns that may compromise the protection of the environment;
- include methods for developing measures to prevent or mitigate the impact of the identified issues;
- provide for continued monitoring of sites to evaluate success of mitigative measures undertaken;
- provide a system for implementing additional mitigative measures as necessary; and
- provide a feedback system that allows for adaptation of successful mitigation to future pipeline projects.

Monitoring programs may have specific goals and targets and could include methods for evaluating and interpreting collected data such as air quality or emissions data. Monitoring may include any relevant environmental practices (e.g., vegetation establishment, water quality sampling, waste disposal).

Responsibilities of the National Energy Board regarding monitoring include:

- conducting environmental inspections of facilities, verifying compliance with terms and conditions, and assessing the effectiveness of mitigation;
- monitoring ongoing operation, verifying reclamation and maintenance of the project site to acceptable standards; and
- conducting environmental audits, evaluating environmental management systems and environmental programs.

We generally require the filing of environmental post-construction monitoring reports as a condition of an authorization. The information in monitoring reports should include:

- confirmation of proper implementation of mitigation and reclamation measures used;
- identification of the outstanding environmental issues; and
- discussion of the company's plans for how outstanding issues will be resolved.

Condition T10 requires Imperial to submit an Environmental Protection Plan which includes monitoring of activities. Condition T14 includes the requirement for monitoring incinerator emissions.

A commitment to continuous improvement, outlined in Joint Review Panel recommendation in 8-6, is expected to be a component of an operator's Management system pursuant to paragraph 5(2)(b) of the *Canada Oil and Gas Drilling and Production Regulations*. This is addressed in Condition T10. We are of the view that the commitment to continuous improvement is not limited to greenhouse gas emissions but should apply to all discharges to the environment, which in this case is the atmosphere. Condition T10 also covers the requirements for methods and locations of monitoring.

Condition T15 requires the Proponents to file a report outlining the use of best available technology for station facility construction. Selection of best available technology is the most significant factor in determining achievable air emissions targets. Condition T10 outlines the requirements for an Environmental Protection Plan. The condition requires the Proponents to submit maximum proposed greenhouse gas targets and reduction strategies for air emissions including particulate matter, NOx and greenhouse gases. Condition T10 also addresses other matters from the Joint Review Panel recommendations including employee training, monitoring, public communication, and required consultation with Environment Canada and the Government of the Northwest Territories. With these conditions, we find it acceptable for the Proponents to develop greenhouse gas targets for the project consistent with use of best management practices and in consultation with appropriate government agencies.

Environmental footprint in Kendall Island Bird Sanctuary

The proposed site of the Taglu development is located near the meeting of the Kuluarpak and Harry channels of the Mackenzie River, and it lies within Kendall Island Bird Sanctuary. As discussed previously, Environment Canada has regulatory authority over the surface of the Sanctuary and has determined that the maximum allowable surface disturbance related to all oil and gas activities within Kendall Island Bird Sanctuary should be no more than one percent of the Sanctuary or 600 hectares. Environment Canada expressed concern with not only the size of the area being disturbed but also with Imperial's plan for continuous drilling and year-round activity. The estimated total area of surface disturbance is approximately 30 hectares, representing 0.05 percent of all of Kendall Island Bird Sanctuary. All production wells would be drilled from the same well pad using directional drilling techniques. This helps to reduce the overall footprint of the development. The well pad is likely to be located just inside the eastern boundary of Kendall Island Bird Sanctuary, just west of the existing D-43 well site (see Figure 4-9). The initial drilling program would occur uninterrupted for about 16 months, with well completions to follow. Imperial is proposing a development plan which is flexible enough to accommodate contingencies that could arise during detailed design, construction and operation of the Taglu field.

The Imperial project management team will continue to look for opportunities to further reduce the footprint of the Taglu development in Kendall Island Bird Sanctuary. For example, Imperial will look at the use of existing disturbed space adjacent to the development site, being the D-43 well site pad and connecting road. The project's engineering team is also investigating the merits of using a wet gas metering system instead of the test separator system in an effort to reduce footprint. The project will also consider tankage requirements for fuel needs, as there may be opportunities for offsite staging, as well as the fabrication and construction of the gas conditioning facilities modules. Imperial hopes that by implementing options such as these, the Taglu footprint could be reduced by approximately 10 percent of the current footprint estimate.

Activity and facility noise levels

The Taglu anchor field is located in Kendall Island Bird Sanctuary which is a federally protected area managed for the conservation of migratory birds and protection of habitat for northern-breeding birds. Imperial holds Significant Discovery Licence SDL063 that grants it subsurface oil and gas rights. Environment Canada has regulatory authority for activities within Kendall Island Bird Sanctuary, and may issue permit conditions governing noise emissions from development under the *Migratory Bird Sanctuary Regulations*. Environment Canada and Imperial have both agreed to follow Alberta's Energy Resources Conservation Board Directive 038 for noise regulation. This provides a solid basis for noise regulation that currently does not exist in the Northwest Territories, in other words, there is currently no legislation or standard in the Northwest Territories governing noise emissions.

Alberta's Energy Resources Conservation Board Directive 038 indicates a recommended noise target for remote areas even if no human residences are present. This is considered the "business as usual" requirement. The Directive has provisions to change the typical target when there are unique circumstances, including if an area is "pristine"—a pure, natural area that might have dwellings but no industrial presence. Environment Canada is recommending continuous noise emissions, as measured from the fence line of the facility, not exceed the Alberta's Energy Resources Conservation Board Directive 038 "best practices" permissible sound levels during the period from 10 May to 30 September when migratory birds are present in the Sanctuary because Kendall Island Bird Sanctuary is considered a pristine area.

Imperial intends to design all equipment at the Taglu gas conditioning facility so that the resulting sound levels would be below the maximum permissible noise levels provided in Alberta's Energy Resources Conservation Board Directive 038. This would include primary sources of noise generation such compressors, power generation equipment and aerial coolers. Environment Canada has also indicated that Imperial has committed to evaluating and applying noise mitigation options beyond those required to meet Alberta's Energy Resources Conservation Board Directive 38 minimum standards provided that such options are practical. Environment Canada is awaiting detailed engineering and noise modeling results from Imperial.

Environment Canada has concerns with the level of noise associated with Imperial's Taglu well drilling operations while birds are present. Unlike Niglintgak, Imperial plans to drill in Taglu for 16 months starting in the winter of 2016 followed by year-round oil and gas activities. However, May to October is the time when birds are typically present in Kendall Island Bird Sanctuary and therefore sensitive to disturbance. As a result, Environment Canada may restrict activity or access within Kendall Island Bird Sanctuary during this period to protect bird habitat.

Imperial indicated that this would not meet its need to service and access personnel year-round for drilling, construction and operational activity. On a related matter, Imperial stated it would consider scheduling planned maintenance flaring outside the migratory birds nesting season.

When we asked how operations would be affected if drilling was restricted from May to October, Imperial indicated it would have to reassess the entire design and execution plan associated with the development. Environment Canada is continuing to have discussions with Imperial on this matter.

Imperial indicated it is committed to adhering, at a minimum, to Alberta's Energy Resources Conservation Board Directive 038. Imperial recognized that operating facilities in Kendall Island Bird Sanctuary requires additional consideration, and Imperial is committed to continuing evaluations of noise mitigation options through detailed engineering and planning, in order to arrive at practical solutions to address concerns raised by Environment Canada. As indicated in previous submissions, Imperial is committed to working with Environment Canada in reducing noise levels of production facilities in Kendall Island Bird Sanctuary, and Imperial will endeavour to reduce noise emissions beyond the requirements of Directive 038 where technically and economically possible.

In final argument both the Proponents and Environment Canada shared the view that requirements for noise regulation in Kendall Island Bird Sanctuary, both for the National Energy Board and migratory bird sanctuary requirements, can only be finalized after detailed engineering and design work is completed, after the noise impact analysis is prepared, and after discussions between the parties. Environment Canada will continue to work with the National Energy Board, Proponents and other regulators on issues related to noise in Kendall Island Bird Sanctuary. Imperial indicated during final argument it is committed to adhering to requirements in Alberta's Energy Resources Conservation Board Directive 038, as well as continuing evaluation of noise mitigation through detailed engineering and planning in order to arrive at practical solutions to concerns raised by Environment Canada.

Views of the Board

We agree with Environment Canada that regulating impacts of noise in a nationally protected bird sanctuary requires special consideration and application of best practices and the use of best available technology with the intent of "continuous improvement of pipeline safety and environmental protection." Condition T8 applies to regulating noise in the Taglu field and is intended to minimize disturbance from facilities inside Kendall Island Bird Sanctuary. The condition requires meeting the Alberta's Energy Resources Conservation Board Directive 038 "business as usual" standard with allowance for achieving the more stringent standard that Environment Canada recommended to the Joint Review Panel, and the Joint Review Panel accepted. There is flexibility built in to adjust the standard as informed by final engineering, an independently verified noise impact analysis document, and final determination of the fence line, which is the measurement base for a distance-based regulatory standard.

We acknowledge the parallel permitting process for Kendall Island Bird Sanctuary and support the need for consistency and clarity between Environment Canada and National Energy Board conditions.

Overall footprint

Many of the proposed facilities for the Taglu field, such as the well pad, gas conditioning facility, flow lines and air strip would be located inside the east boundary of Kendall Island Bird Sanctuary. The total area of permanent surface disturbance would be approximately 30 hectares.

During the project design phase, Imperial incorporated measures to reduce the overall footprint for the proposed Taglu development by:

- locating a single well pad near the centre of the reservoir and using directional drilling techniques to drill all of the proposed wells from one common well pad. This pad would be approximately 70 metres wide by 300 metres in length with 15 metres of road access on both sides and would cause 100 metres of disturbance;
- locating the gas conditioning facility adjacent to the well pad to eliminate the need for a network of connecting roads;
- accessing the site with river barges in the summer and by winter road without adding a substantial number of additional access roads through Kendall Island Bird Sanctuary;
- locating the well pad and gas conditioning facility on already disturbed land;
- using storage areas outside of Kendall Island Bird Sanctuary for some tankage requirements; and
- using staging areas outside of Kendall Island Bird Sanctuary, such as Tununuk Point (Bar C) for drilling materials. Tununuk Point is a previously disturbed lease area located approximately 50 kilometres south of the proposed Taglu site (see Figure 4-1).

Imperial intends to build its facilities offsite, in large modules, and ship them to Taglu for assembly. Based on consultations with area stakeholders, Imperial has identified an opportunity to increase the size of offsite fabricated modules, if the modules can be successfully transported and installed at the site. Based on the construction execution plan descriptions, the concept would reduce:

- the footprint at Taglu within Kendall Island Bird Sanctuary;
- some air traffic support at the site within Kendall Island Bird Sanctuary; and
- barge traffic on the Mackenzie River.

Imperial also indicated that it considered building a barge-based gas conditioning facility, like the one planned for the Niglintgak field; however, this did not reduce the overall footprint.

The proposed location of the Taglu airstrip within Kendall Island Bird Sanctuary was a concern for Environment Canada, as it will occupy approximately seven or eight hectares.

Drilling waste in Taglu can be separated into solids (drill cuttings) and liquids (reserve pit fluids). Typically, these wastes are disposed of in a sump. However, sumps are not permitted in Kendall Island Bird Sanctuary.

Imperial plans to initially inject both solids and liquids into a dedicated disposal well and then, as drilling progresses, into the annuli of a previously drilled production well (see Figure 4-11). With this approach, Imperial would use the dedicated disposal well as a backup if there are any issues with the production well annuli. In addition, Imperial would have a temporary onsite storage area for drill cuttings in case of any equipment or disposal problems with either the production well annuli or the dedicated disposal well.

The solids, or drill cuttings, represent about 20 percent of the total volume to be disposed of in the wells. Before the solids can be injected into a well, they would be mixed with water to create a slurry. Injection of the cuttings is planned as discrete "batch injection operations" for limited volume and discretely scheduled drilling programs. During injection operations, injection pressure and fluid properties would be monitored to verify that the reservoir is behaving as predicted and unexpected fractures are not occurring. Subsurface slurry injection of the scale and extent proposed by Imperial has not been practiced before in the Northwest Territories.

Imperial's alternative method for the disposal of drill cuttings would be to inject the reserve pit fluids into the well annuli and incinerate the drill cuttings. The residual material from incineration would be hauled to an approved disposal facility.

Insofar as air traffic operations are concerned, as the Joint Review Panel noted:

> Environment Canada and the Proponents assessed alternative means of accessing the Taglu site and agreed that the proposed Taglu airstrip would pose the least adverse effects.

The Joint Review Panel similarly agreed that the proposed airstrip was the best option. Imperial will continue to consult with Environment Canada in relation to the details of its proposed air operations at Taglu.

Dredging activities will occur within Kendall Island Bird Sanctuary and Environment Canada will not permit the spoil to be placed on undisturbed terrestrial habitat within Kendall Island Bird Sanctuary. Environment Canada requested that we require that Imperial's plan for dredging the barge landing at the Taglu field should describe the potential impacts associated with dredging, including spoil management and the site-specific mitigation measures proposed to address adverse impacts. As discussed earlier, this is a condition that should also refer to the success of the consultations between the Proponents and Environment Canada.

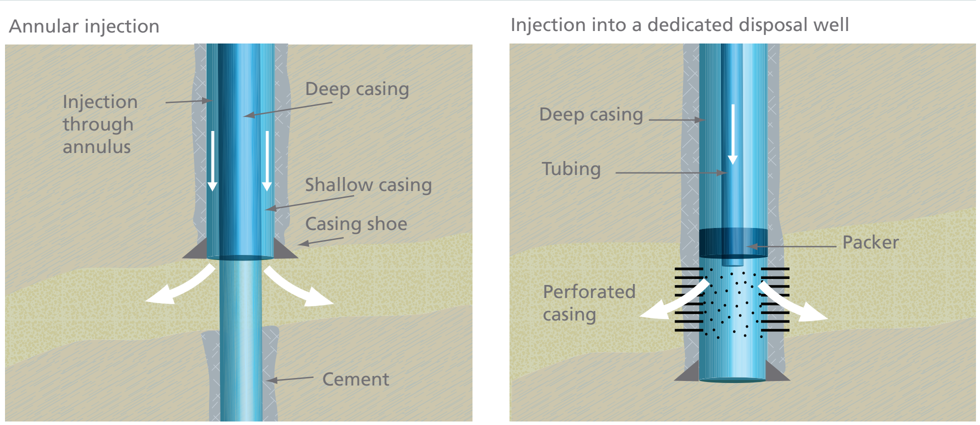
Views of the Board

We accept Imperial's conceptual plan to dispose drill cuttings by subsurface slurry injection as this avoids the use of sumps and would minimize the environmental footprint within Kendall Island Bird Sanctuary. However, as down-hole slurry injection of this scale and extent has not been utilized in the Mackenzie Delta before, Condition T4 requires Imperial to submit a drill cuttings slurry injection management program. The National Energy Board would assess such a program with respect to subsurface containment as well as safety, protection of the environment and conservation of resources.

We have considered the various comments regarding Condition T9 for dredging and the condition has been amended to require a dredging spoil management plan and to clarify requirements for consultation with Environment Canada, Department of Fisheries and Oceans, Indian and Northern Affairs Canada and Transport Canada.

Figure 4-11

Drilling waste disposal



4.4 Parsons Lake

The Parsons Lake field borders the Mackenzie Delta to the east and is located 70 kilometres north of Inuvik and 55 kilometres southwest of Tuktoyaktuk on the Tuktoyaktuk Peninsula. Unlike the neighbouring Niglintgak and Taglu fields to the northwest, the Parsons Lake field is not located within the Mackenzie Delta or Kendall Island Bird Sanctuary.

ConocoPhillips Canada (North) Limited (ConocoPhillips) has requested approval of a Development Plan application for the Parsons Lake field pursuant to section 5.1 of the *Canada Oil and Gas Operations Act*. ConocoPhillips and ExxonMobil Canada Properties (ExxonMobil) propose to develop natural gas and natural gas liquids from Parsons Lake and ship these hydrocarbons with those from the Taglu and Niglintgak fields via the Mackenzie Gathering System to the Inuvik Area Facility.

The capital expenditures for development of the Parsons Lake field are estimated to be $1,550 million with an estimated average operations and maintenance expenditure of $25 million per year for the period 2019 to 2023.

The Parson's Lake development (see Figure 4-12) would include:

- construction of a north pad with nine to nineteen production wells, two disposal wells, and a gas conditioning facility;

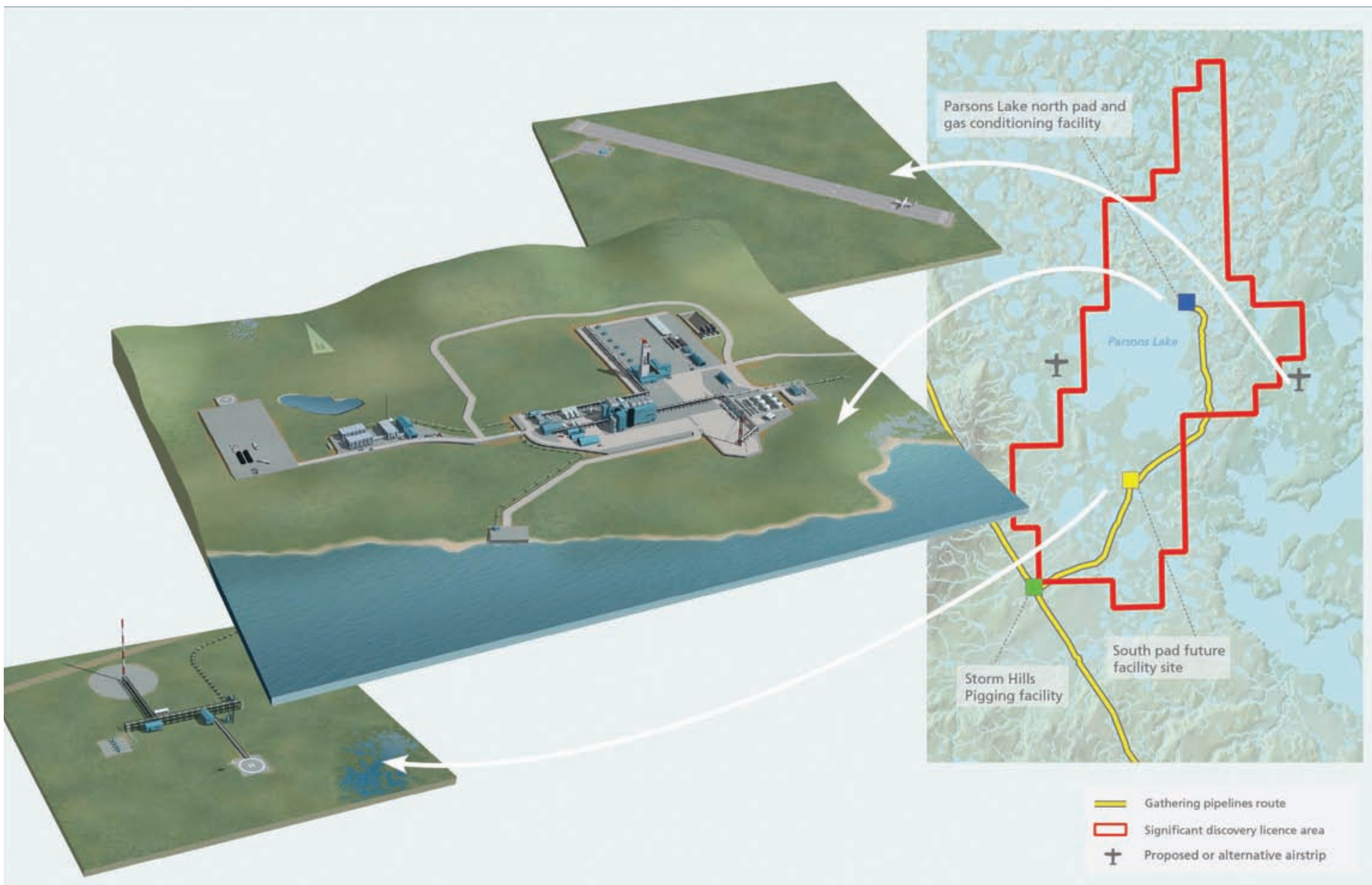


Figure 4-12

Parsons Lake production facilities

- a south pad with three to seven production wells;
- construction and operation of flow lines from the south pad to the north pad; and
- supporting infrastructure, including an all-weather airstrip.

Construction is planned to take place from 2014 to 2018 with production operations commencing in 2018 and expected to continue for 25 or 30 years.

4.4.1 Design of the Parsons Lake facilities

ConocoPhillips plans to transport and stage construction equipment during the summer of 2014 for winter activities. An overview of the construction schedule is shown in Table 4-4.

ConocoPhillips estimates 28 hectares would be required for the development, including the north and south well pads, the airstrip, and a 2.5 kilometre long all-weather road connecting the airstrip to the main road.

Wells and well pads

Proposed phase one development would include constructing well site facilities at the north and south pads and up to three contingent satellite well pads. The north pad would initially house up to nine production wells, one waste disposal well and one cuttings injection well, with the possibility of up to ten contingent production wells.

Phase two, preliminary plans for 2024, includes drilling three production wells and as many as four contingent production wells from the south pad.

ConocoPhillips believes that it may not be able to reach parts of the Parsons Lake field by drilling only from the north or south pads. Therefore, ConocoPhillips has identified three possible sites for contingent satellite well pads, each accommodating up to three wells. ConocoPhillips would develop the contingent wells if drilling and production operations identify and locate faults that compartmentalize the reservoir.

ConocoPhillips' Development Plan provides preliminary bottomhole locations for nine production wells, two contingent wells, one cuttings injection well and one waste disposal well located on the north pad and for three production wells and one contingent well from the south pad (see Figure 4-13). All would be directionally drilled except for the cuttings injection well which would likely be a vertical well. The preliminary total vertical and measured depth of these wells range from 1000 to 3150 metres and from 1000 to 4734 metres, respectively. ConocoPhillips also provided a commingled production strategy for Parsons Lake in order to effectively and economically deplete reservoir compartments.

The north pad would be built on granular material about 1.5 metres thick. The south pad and contingent satellite wells pads would be built on ice pads and with only a small area of granular material around the wellhead. All well pads would include individual wellbores, wellheads and wellhouses. Thermosiphons would be installed to maintain the permafrost below the pads.

Table 4-4

Parsons Lake construction highlights schedule

Activity	Season and year
Transport and stage construction equipment to delta staging location	Summer 2014
Begin construction of winter access road, begin development of borrow sites, transport material to the north pad, all-weather access road and airstrip	Winter 2014/15
Construct and complete commissioning of airstrip	Summer 2016
Construct winter access road for heavy module transport, transport very large modules and begin installing very large modules as part of the gas conditioning facility	Winter 2016/17
Commence drilling program at north pad	Winter 2016/17
Complete north pad drilling and testing program	Winter 2018/19
Start up the gas conditioning facility	Winter 2018
South pad drilling program, construction of the flow line from the south pad to the north pad	Beyond 2019

Flow lines

Once the natural gas and natural gas liquids have been extracted, they would flow through above-ground flow lines from the wells to the gas conditioning facility on the north pad. The 16 kilometre long flow line from the south pad would rest on piled metal supports at least 2.2 metres above the ground, and run parallel to the Parsons Lake lateral of the Mackenzie Gathering System. Hydrocarbons from the south pad would be metered and heated before traveling to the north pad. The flow lines would be insulated to keep temperatures inside the flow lines between 30°C and 50°C. This would help prevent the natural gas, natural gas liquids and any produced water from freezing and plugging the lines.

Production from any satellite well pads would be transported in insulated above-ground flow lines to the north pad and the gas conditioning facility.

Gas conditioning facility

The gas conditioning facility would be able to handle a maximum volume of 9.0 Mm³/d (324 MMcf/d). It would process the reservoir fluids to meet the specifications of the gathering system and would include components to:

- separate gas from free water and hydrocarbon liquids (natural gas liquids);
- compress and dehydrate the gas;
- chill and meter the hydrocarbons before they enter the gathering system; and
- collect any water and send it to a disposal well.

The gas dehydration unit is designed to reduce the moisture content of the sales gas to 6 mg/m³ and to neutralize any potential for corrosion caused by the carbon dioxide in the gas stream. ConocoPhillips' design also incorporates a relief and blowdown system, including flare stacks, to handle any emergency relief and flaring at the north and south pads. Equipment to compress the gas so it would flow through the gathering system would be added in stages as the wellhead pressure declines.

Project facilities would be built from very large modules constructed offsite, shipped by barge to Tuktoyaktuk, and transported via winter road to Parsons Lake. Once the modules were onsite, they would be placed on steel piles and elevated about one to two metres above the gravel

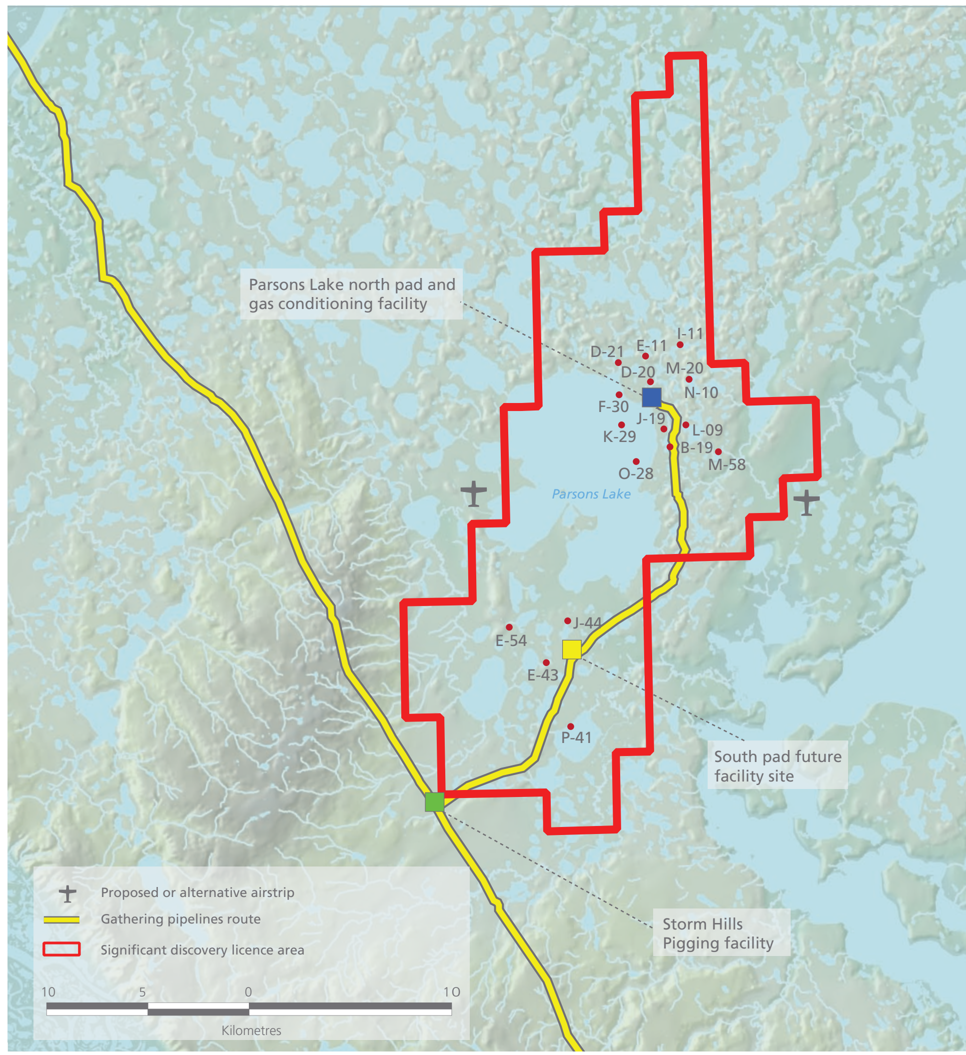


Figure 4-13

Parsons Lake field map

surface. Buildings installed on the gravel pad would have insulated foundations, and thermosiphons.

Alternative production system

ConocoPhillips considered a number of alternative configurations for production such as locating the main gas conditioning facility at the south pad, housing only a minimal satellite facility on the north pad and using a flow line to transport gas from the north pad to the south pad. However, this alternative would require a larger flow line than the current proposal and would be costlier.

Another alternative configuration evaluated by ConocoPhillips was to construct gas conditioning facilities at both north and south pads. This would be costlier and the north pad gas conditioning facility would not be fully utilized.

Because the Parsons Lake north pool contains about three percent carbon dioxide and the south pool about five percent carbon dioxide, ConocoPhillips evaluated whether removal facilities for carbon dioxide would be required. Four different options for removing carbon dioxide were studied, and costs for these options ranged from $80 to $100 million. Rather than design the Parsons Lake facilities to extract the carbon dioxide, ConocoPhillips chose to rely on blending the gas from Parsons Lake with gas from Niglintgak and Taglu that would have lower concentrations of carbon dioxide. Blending would allow ConocoPhillips to meet the Inuvik Area Facility's carbon dioxide content specification.

Winter transportation

ConocoPhillips plans to move the seven pre-assembled gas conditioning facility very large modules from Tuktoyaktuk to Parsons Lake on a purpose-built heavy load ice road the winter before commercial gas production begins. The proposed ice road would be specially prepared with a smooth ice surface and designed to accommodate the heavy-lift trailers carrying the oversized and heavy gas conditioning facility modules. Because of the load's size and weight, the road would need to about 20 metres wide with a 50 metre right of way, have a three percent gradient, contain no tight curves and avoid frozen bodies of water. The wide ice road would be completed late in the season and likely used for six to eight weeks. However, a shortened winter season would mean significant delays to the construction of the gas conditioning facility if the ice road could not be used to transport all seven modules.

Furthermore, ConocoPhillips is proposing to drill the south pool and satellite wells from ice pads. ConocoPhillips is aware that this drilling schedule could be delayed by an unseasonably warm winter. If that happened, the wells would not be drilled until the following winter.

Views of the Board

We are of the view that the general approach and the conceptual design and plan outlined by ConocoPhillips for the Parsons Lake field are reasonable. We note that ConocoPhillips will use new geological and reservoir data acquired from drilling and production to determine if additional faulting and compartmentalization exists and whether any contingent wells would be required. In this regard, Condition P17 requests ConocoPhillips submit an updated resource management plan with the National Energy Board within 18 months after production commences or prior to the drilling of contingent wells.

Condition P5 requires ConocoPhillips to provide adequate gas sampling and analyses during drilling and production operations as the Parsons Lake field is expected to have three to five percent carbon dioxide gas content.

We accept ConocoPhillips' conceptual commingled production strategy to effectively deplete reservoir compartments. The National Energy Board will consider commingled production on an individual well basis during drilling and production operations in accordance with section 66 of the *Canada Oil and Gas Drilling and Production Regulations.*

Condition P30 stipulates that the approval of the Development Plan under for the Parsons Lake field under subsection 5.1(4) of the *Canada Oil and Gas Operations Act* is subject to the Minister of Indian Affairs and Northern Development Canada providing confirmation that ConocoPhillips has satisfactorily met the Benefits Plan requirements of section 5.2 of the *Canada Oil and Gas Operations Act*.

4.4.2 Development plan issues

During the hearing, the issues raised included:

- matters raised by adjacent rights holders;
- geographic and design issues related to permafrost, climate change, subsidence and flooding;
- air quality issues and greenhouse gas emissions; and
- drill cuttings disposal.

Matters raised by adjacent rights holders
The National Energy Board issued a Declaration of Commercial Discovery for the Parsons Lake field on 16 September 2004 which included lands held under Significant Discovery Licence 030, 032 and 062.

The Parsons Lake field is contained within Significant Discovery Licences SDL030 and SDL032. ConocoPhillips, the field operator, holds 75 percent of the working interest of these licences while ExxonMobil holds the other 25 percent. Exploration Licence EL406[8], of which PetroCanada is the representative interest holder, borders Significant Discovery Licence SDL030 and SDL032 to the east and south. Crown land lies to the north and west of Significant Discovery Licence SDL032. Imperial[9] is the registered interest holder and operator of Significant Discovery Licence SDL062 located on the northeast boundary with ConocoPhillips' Significant Discovery Licence SDL032. Other notable interest holders of Significant Discovery Licence SDL062 include ExxonMobil Canada, ConocoPhillips and Mosbacher. ExxonMobil holds between four and eight percent interest in the south, central and north segments of Significant Discovery Licence SDL062. ConocoPhillips holds approximately 1.2 percent interest only in the central segment. Mosbacher holds an average 3.1 percent interest in the central and north segments (see Figure 4-14).

Mosbacher, which holds an interest in lands adjacent to the Parsons Lake field, expressed concern that the proposed development would drain its gas resources. According to Mosbacher, the Parsons Lake Development Plan should not be approved because ConocoPhillips has failed to present plans that would respect the rightful economic interest of holders of adjacent lands.

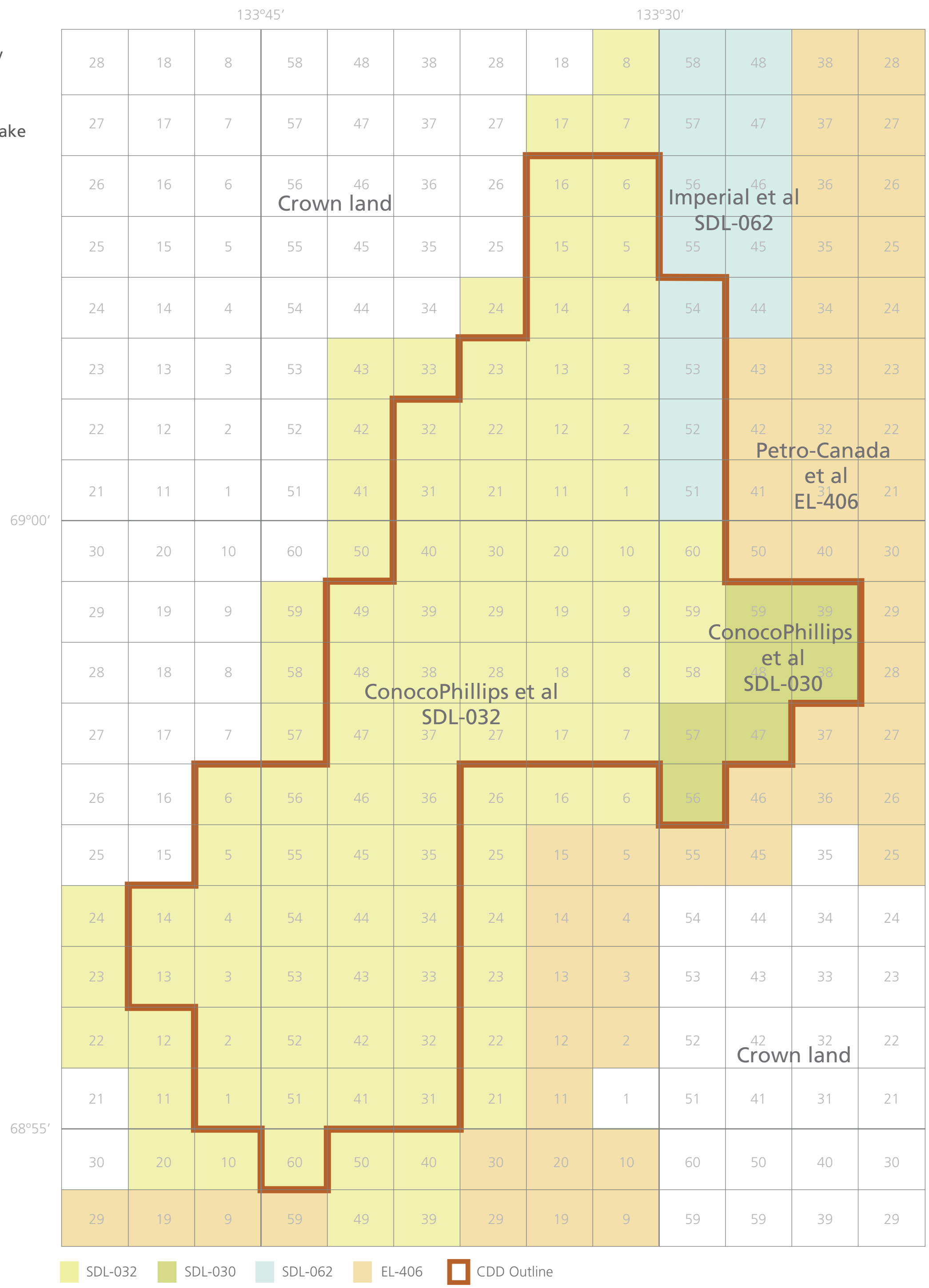
Mosbacher indicated that, although its estimate for gas-in-place for Significant Discovery Licence SDL062 is small compared to the gas-in-place for Significant Discovery Licences SDL030 and SDL032, it believes that approximately 5.4 percent of the total Parsons Lake original gas-in-place lies under Significant Discovery Licence SDL062. According to Mosbacher, the volumes under Significant Discovery Licence SDL062 are commercially producible. Mosbacher stated that the one grid unit buffer offered by ConocoPhillips would not adequately protect its resource from being drained by ConocoPhillips' operations on Significant Discovery Licences SDL030 and SDL032. Without a unitization agreement it is likely that the gas resource on Significant Discovery Licence SDL062 would be lost to the owners of Significant Discovery Licences SDL030 and SDL032.

[8] Exploration Licence EL406 was surrendered in 2007.

[9] In Exhibit MOL-3I, Imperial Oil Resources Limited, Imperial Oil Resources Ventures Limited and Imperial appear to have been used interchangeably.

Figure 4-14

Commercial discovery declaration area and significant discovery licences for Parsons Lake field as of 2006



Mosbacher indicated that it sought cooperative negotiation between the parties. Since its efforts in this regard were not successful, Mosbacher asked us to direct ConocoPhillips to make a comprehensive and compelling case that resources from adjacent lands will not be drained. Mosbacher stated that Imperial, the operator of Significant Discovery Licence SDL062, considered drilling a well, constructing facilities and tying into the proposed Parsons Lake development, but the stand-alone drilling project was not sufficiently robust to meet its internal hurdle rates. Mosbacher stated it then circulated an alternative cost-effective drilling scenario based on the cooperative use of the north pad by all partners of Significant Discovery Licence SDL062. The scenario proposes a single well with a horizontal reach[10] of approximately 7500 metres from the north pad into section 54 of Significant Discovery Licence SDL062 which may be approaching the current theoretical technical limit for the reservoir.

ConocoPhillips stated that Mosbacher has never been prevented from doing work and drilling wells like ConocoPhillips has done. No well has been drilled in Significant Discovery Licence SDL062 and ConocoPhillips believes there is a great deal of uncertainty as to what resources are included in Significant Discovery Licence SDL062. ConocoPhillips stated that serious and meaningful discussions on unitization cannot occur without a well. The gas

[10] Mosbacher stated in the hearing that the length of the drill was "7500 m reach measured depth distance." Measured depth is not horizontal reach, but has been taken to mean horizontal reach because the distance between the north pad and section 54 is approximately 7500 metres.

conditioning facility is designed to process only the gas produced from the Parsons Lake field and offers no spare capacity. Currently, ConocoPhillips has no plans to expand the gas conditioning facility; however, the gas conditioning facility could be upgraded to accommodate third-party gas if the volume, delivery conditions and gas composition were known before detailed engineering plans are finalized. Upgrading would require expansion of the pad size. In addition, ConocoPhillips would consider allowing a third-party to drill a well from the north well pad as this pad was designed to accommodate more wells than ConocoPhillips plans to drill. If Mosbacher were to drill a well into Significant Discovery Licence 062 from the north pad and the well was determined to be commercial, the gas conditioning facility may have to be upgraded.

ConocoPhillips requested approval for a variance to the National Energy Board's *2009 Draft Spacing Requirements* for Significant Discovery Licences SDL030 and SDL032 to allow the appropriate placement of wells to increase gas recovery.

Mosbacher submitted during final argument that the proposed Parsons Lake Development Plan was sub-optimal insofar as it does not address development of the whole field, and it encourages waste. In this regard, Mosbacher referenced sections 18 and 19 of the *Canada Oil and Gas Operations Act*. In the event there is no joint development, Mosbacher requested that we reject ConocoPhillips' applied-for spacing. Mosbacher asked us to consider a condition requiring ConocoPhillips to include all land in Significant Discovery Licence SDL062 within the commercial discovery declaration area as part of the Parsons Lake Development Plan. Another condition requested by Mosbacher would require ConocoPhillips to fully explore joint production arrangements with other interested parties. In addition, Mosbacher suggested a condition requiring ConocoPhillips to make available drilling pad space on reasonable commercial terms to allow Mosbacher and other interested parties the opportunity to drill additional wells on a timely basis.

Views of the Board

We consider joint development of the Parsons Lake field to be the desired approach if the interest holders of Significant Discovery Licence SDL062 agree to develop their lands. This would avoid duplication of facilities and would minimize the environmental footprint. It is also our view that joint development should be attained voluntarily through commercial negotiations and agreements between the interested parties. We note that the compulsory unitization provisions in the *Canada Oil and Gas Operations Act* require participation from ConocoPhillips as it holds a large portion of the lands comprising the Parsons Lake commercial discovery declaration area. ConocoPhillips stated that the first step that needs to be taken to begin meaningful talk on joint development or unitization is Mosbacher proving the extent of field by drilling a well on Significant Discovery Licence SDL062. Condition P2 requires both the north and south well pads to be designed for expansion allowing for the drilling of at least one well by adjacent interest holders. Contingent upon successful discussions between ConocoPhillips and Mosbacher to settle commercial terms including timing, the condition would provide Mosbacher the opportunity to drill directional wells to delineate the field on its lands with a minimal environmental footprint.

We consider there to be no basis for a condition directing ConocoPhillips to include all sections of land in Significant Discovery Licence SDL062 that are within the commercial discovery declaration area as part of the Parsons Lake Development Plan since there is currently no joint development agreement between the interest holders of Significant Discovery Licence SDL062 and ConocoPhillips and ExxonMobil. As the critical action that needs to occur before joint development discussions progress is that Mosbacher drills a well on its land, we are not persuaded to include the condition sought by Mosbacher requiring ConocoPhillips to fully explore joint production arrangements with other interested parties.

We are of the view that the National Energy Board's *2009 Draft Spacing Requirements* are appropriate in the absence of joint development arrangements. The *2009 Draft Spacing Requirements* are intended to provide a fair approach with respect to the optimization of gas recovery and the protection of the correlative rights of adjacent land interest holders. Condition P18 requires ConocoPhillips to comply with the *2009 Draft Spacing Requirements*. The *2009 Draft Spacing Requirements* establish a 250 metre off-target area from adjacent lands of differing ownership for gas wells. Alberta, British Columbia, Saskatchewan and Yukon utilize a similar set-back.

ConocoPhillips would not require a variance for the proposed preliminary well locations for the Parsons Lake field in accordance with the *2009 Draft Spacing Requirements*. The *2009 Draft Spacing Requirements* set a limit of one producing well in spacing units adjacent to lands of differing ownership, but for spacing units not adjacent to lands of differing ownership, there is no off-target area and more than one producing well is permitted[11]. The National Energy Board will consider any future application for a variance at that time and assess it in accordance with the *2009 Draft Spacing Requirements* or any orders dealing with spacing that may supersede it.

In our view, Mosbacher has not provided evidence to support a determination that the proposed Parsons Lake Development Plan encourages waste. We consider the proposed production scheme to be appropriate for a conventional gas field such as Parsons Lake. With Condition P19 in place requiring compliance with the *2009 Draft Spacing Requirements*, Mosbacher has the opportunity to drill wells and develop lands in Significant Discovery Licence SDL062[12].

[11] Part IV of the *2009 Draft Spacing Requirements*.

[12] Those lands of Significant Discovery Licence SDL062 that were included in the National Energy Board's commercial discovery declaration dated 3 November 2004 are eligible for a production licence.

Geographic and design issues

Permafrost and climate change

The Parsons Lake field lies within a zone of continuous permafrost. The permafrost thickness north and east of the lake ranges from 354 metres to 378 metres. Geotechnical drilling on the north pad and adjacent areas in 2004 identified massive ground ice throughout the north pad area. As with the other development fields, development could thaw the permafrost and significantly alter the northern landscape.

ConocoPhillips plans to use a number of measures to preserve the permafrost. These activities are divided into methods for protecting surface sites and methods for protecting the permafrost during drilling and production.

ConocoPhillips plans to insulate the ground from heat sources, such as buildings and flow lines using methods such as:

- piling 1.5 metres of gravel on all well pads and the airstrip to provide thermal stability and protect against contact pressure caused by vehicles. A layer of rigid insulation or geotextile may be incorporated in some areas to further protect the permafrost;
- using adfreeze-type steel pipe piles to elevate the buildings about 1.5 metres above the gravel pads and allow for air flow between the building and the gravel pad;
- using thermsiphons under any slab-on-grade foundations elevating and insulating the flow lines, as mentioned in section 4.4.1; and
- where embankments are created, slopes would be angled to minimize thaw degradation.

Preservation of the permafrost at well sites would be accomplished by:

- spacing all wells, including contingent wells, at least 25 metres apart. This exceeds the 15 metre interwell spacing suggested by the C-FER Technologies and EBA Engineering study of the effect of well spacing on permafrost, which predicted the coalescence of permafrost thaw bulbs in 20 years for wells spaced at 10 metre intervals;
- installing thermosiphons close to each well;
- placing an insulated conductor about 24 metres down each well; and
- using cooled mud to drill the surface holes; using permafrost cement for the conductor and the surface casing on each well; and using gelled diesel fuel in the tubing or casing annulus for insulation.

By using these methods, ConocoPhillips expects heat loss from conduction and convection of produced fluids would be reduced by at least 90 percent compared to using conventional packer fluids.

The Sierra Club of Canada raised questions about the projections of temperature change due to climate change over the life of the project used by ConocoPhillips in the design of the Parsons Lake field facilities.

ConocoPhillips evaluated the risk of surface subsidence caused by the extraction of natural gas and determined that no measurable subsidence is expected because of the nature of the reservoir and its depth (three kilometres). In addition, because ConocoPhillips plans to use a combination of wellbore insulation and thermosiphons it does not expect measurable amounts of well permafrost thaw subsidence.

The north pad sits approximately 45 metres above sea level and there is no evidence the site has been flooded. Accordingly, flooding is not expected at the north pad or, similarly, the south pad.

The Joint Review Panel was generally satisfied that ConocoPhillips had taken climate change into account in its design. Nevertheless the Joint Review Panel recommended that the National Energy Board require ConocoPhillips to file final design plans that incorporate further design analysis of the impacts of climate change on permafrost and terrain stability over the design life of the project and post-abandonment. The Joint Review Panel was of the view that this analysis should be conducted for a series of representative locations, conditions and terrain types and should incorporate climate variability, in particular, upper limit temperature scenarios to account for the range of future temperature conditions, including variability and extremes, and the impact of this variability on stream flow regimes. The Joint Review Panel added that the results should be incorporated into monitoring, mitigation and adaptive management plans. The Joint Review Panel thought that this analysis should be provided to other appropriate regulators in sufficient time for review and to provide input to the National Energy Board.

Indian and Northern Affairs Canada suggested in final argument that the Proponents should demonstrate how upper limit temperature scenarios have been considered in their design.

Further specific discussion on climate change regarding project design is found in Chapter 6.

Views of the Board

Warming of the global and regional climate could raise sea levels and affect weather patterns. Parsons Lake is located on higher ground and further from the sea, so its facilities would be less exposed to possible effects of climate change.

We are satisfied with ConocoPhillips' general approach to addressing permafrost integrity with respect to the Parsons Lake development. As warm fluids will flow through those wellbores during drilling and production operations, it is important for safety and environmental protection reasons that the permafrost thaw bulbs around wellbores do not coalesce. Condition P3 requires the interwell spacing on the Parsons Lake well pads to be no less than 15 metres unless ConocoPhillips utilizes mitigation measures approved by the National Energy Board.

Condition P8 requires ConocoPhillips to provide final detailed design information which incorporates an analysis of the impacts of climate change and variability on permafrost and terrain stability for the Parsons Lake facility using potential upper limit temperature scenarios which may occur during the operational life of the facilities. ConocoPhillips will also provide information about how upper limit temperature scenarios may impact precipitation and water levels of Parsons Lake and other nearby lakes. We are of the view that government departments such as Environment Canada. Indian and Northern Affairs Canada and Natural Resources Canada should be consulted to benefit from their expertise.

Air quality issues

Air quality in the North is considered to be of high quality and Northerners are very concerned that it remains that way. Both Environment Canada and the Proponents agreed that existing air quality in the proposed project area is good and, along with other government regulators, emphasized the need to "keep clean areas clean." This principle requires new industrial development to be "planned, constructed and operated in a manner that minimizes the degradation of air quality in these areas."

Air quality issues for the project included project emissions for the pipeline and development fields, monitoring, and greenhouse gases in the context of monitoring climate change. The Joint Review Panel noted that the National Energy Board would be the prime regulator of air emissions from the project and that Environment Canada and the Government of the Northwest Territories would play advisory roles. The Joint Review Panel recognized the National Energy Board's expertise and experience in regulating interprovincial aspects of the oil, gas and electric utility industries, including environmental matters. The Joint Review Panel also recognized the extensive environmental and local knowledge that Environment Canada and the Government of the Northwest Territories can provide.

Air emissions can be related to the project-specific effects of construction, operations, and waste incineration. Air quality impacts can be local to regional in the case of particulate matter and sulphur dioxide, or global in the case of greenhouse gases. Emissions would occur during the construction phase through intermittent flaring during well testing at the Parsons Lake field.

Further specific details pertaining to emissions for the pipeline are discussed in Chapter 3 and discussion on air emissions pertaining to facility design is found in Chapter 6.

The Joint Review Panel report indicated that the Proponents' baseline information was compiled from historical data and results of air quality monitoring that was carried out over one year near the communities of Inuvik and Norman Wells, and periodically at the Parsons Lake and Taglu gas fields. The Proponents' monitoring data and other sources indicated that background concentrations of air contaminants are generally below detection levels or applicable guidelines. The one exception that is not below detection levels is ozone; relatively high background levels were monitored in Inuvik and Norman Wells. The Proponents indicated that elevated ozone levels at high latitudes in the northern hemisphere are thought to result from the intrusion of stratospheric ozone. The Proponents stated that all ground-level concentrations of compounds released by the project during operations at the gas fields, the Inuvik Area Facility, and compressor and heater station sites would increase, but would be below those outlined in applicable federal and territorial guidelines at all locations in the production area and along the pipeline corridor.

Environment Canada recommended that the Proponents design and implement suitable air quality monitoring programs with its help. Environment Canada focused its recommendations on pollution prevention and the use of best available technology and best management practices to minimize the degradation of air quality. Further discussion around application of these principles may be found in Chapter 6.

The Dehcho Elders and Harvesters indicated that the project needs to be designed to minimize air quality impacts, with monitoring plans in place to verify the predicted emissions and impacts. Corrective action needs to be taken quickly to avoid impacts upon the land and wildlife from degraded air quality.

Greenhouse gas emissions

Parties were concerned about the impacts of the project on climate change, especially in light of Canada's international efforts under the United Nations Framework Convention on Climate Change and the *Kyoto Protocol*.

Greenhouse gas emissions arising from the project include carbon dioxide, methane and nitrous oxides with each compound having a different climate change potential. During operation, the project would emit greenhouse gases from burning natural gas at combustion related sources such as compressors and methane gas released through normal venting procedures and minor leaks (fugitive emissions). Further specific discussion on air emissions pertaining to facility design is found in Chapter 6.

Alternatives North submitted that the National Energy Board and the Government of Canada have a public interest mandate that requires consideration of greenhouse gas emissions.

Ecology North deemed that high project-specific standards for greenhouse gas emissions based on a robust and strong definition of best available technology and accompanied by penalties in the cases where they do not meet those project standards or targets, would provide the best possible protection in terms of minimizing upstream greenhouse gas emissions associated with the project.

Sierra Club of Canada submitted that we need to specify an actual target and it is not enough to just leave it up to the Proponents. Sierra Club of Canada indicated that the target should at least match the general recommended target in Joint Review Panel recommendation 8-8.

Views of the Board

We understand the importance of clean air in the North and that air quality must be considered in a cumulative manner. We also recognize the need to minimize greenhouse gas emissions resulting from the project. The Joint Review Panel directed several recommendations to us relating to air quality and air emissions. We have addressed air issues through several conditions for the Mackenzie Gas Project. These conditions are focused on the Proponents taking appropriate measures to minimize air emissions and address air quality. We are committed to working collaboratively with Environment Canada and the Government of the Northwest Territories to protect air quality in the North, recognizing the extensive environmental and local knowledge that these agencies can provide.

Conditions P13 and P14 address technologies for reducing emissions, incorporation of best management practices and best available technologies, and facility design. Condition P14 requires the submission of a report evaluating incinerator emissions from camps and station facilities and technologies and practices must be reflected in the waste management plans required by Condition P11. Condition P16 requires the ConocoPhillips to minimize and reduce emissions from flaring. Further specific discussion for these conditions regarding air emissions pertaining to facility design is found in Chapter 6.

Air quality monitoring is part of comprehensive environmental monitoring under an environmental management system. Through environmental management, systems are established to address effects of the project on the environment and of the environment on the project, with the overall goal of minimizing negative impacts. Adaptive management is a systematic process for continually improving management practices by learning from their outcomes.

Environmental monitoring is an important part of environmental management that directly supports adaptive management by observing and evaluating the effects that occur, then changing or adding mitigative measures as appropriate to limit or reverse the environmental effects. Environmental monitoring can include:

- compliance monitoring, to verify that all environmental mitigation is implemented as presented in the Environmental Protection Plan and environmental alignment sheets and that work is in compliance with environmental regulations; and
- effects monitoring, to assess the effects resulting from project-environment interactions and evaluate the effectiveness of approved mitigation measures.

This is further discussed in section 3.3.6.

ConocoPhillips is expected to implement Environmental Protection and Monitoring and Surveillance Programs which include protection of the environment as one of the main goals. A monitoring program may:

- identify any issues or potential concerns that may compromise the protection of the environment;
- include methods for developing measures to prevent or mitigate the impact of the identified issues;
- provide for continued monitoring of sites to evaluate success of mitigative measures undertaken;
- provide a system for implementing additional mitigative measures as necessary; and
- provide a feedback system that allows for adaptation of successful mitigation to future pipeline projects.

Monitoring programs may have specific goals and targets and could include methods for evaluating and interpreting collected data such as air quality or emissions data. Monitoring may include any relevant environmental practices (e.g., vegetation establishment, water quality sampling, waste disposal).

Responsibilities of the National Energy Board regarding monitoring include:

- conducting environmental inspections of facilities, verifying compliance with terms and conditions, and assessing the effectiveness of mitigation;
- monitoring ongoing operation, verifying reclamation and maintenance of the project site to acceptable standards; and
- conducting environmental audits, evaluating environmental management systems and environmental programs.

We generally require the filing of environmental post-construction monitoring reports as a condition of an authorization. The information in monitoring reports should include:

- confirmation of proper implementation of mitigation and reclamation measures used;
- identification of the outstanding environmental issues; and
- discussion of the company's plans for how outstanding issues will be resolved.

Condition P10 requires ConocoPhillips to submit an Environmental Protection Plan which includes monitoring of activities. Condition P13 includes the requirement for monitoring incinerator emissions.

A commitment to continuous improvement, outlined in Joint Review Panel recommendation 8-6, is expected to be a component of an operator's Management system pursuant to paragraph 5(2)(b) of the *Canada Oil and Gas Drilling and Production Regulations*. This is addressed in Condition P10. We are of the view that the commitment to continuous improvement is not limited to greenhouse gas emissions but should apply to all discharges to the environment, which in this case is the atmosphere. Condition P10 also covers the requirements for methods and locations of monitoring.

Condition P15 requires the Proponents to file a report outlining the use of best available technology for station facility construction. Selection of best available technology is the most significant factor in determining achievable air emissions targets. Condition P10 outlines the requirements for an Environmental Protection Plan. The condition requires the Proponents to submit maximum proposed greenhouse gas targets and reduction strategies for air emissions including particulate matter, NOx and greenhouse gases. Condition P10 also addresses other matters from the Joint Review Panel recommendations including employee training, monitoring, public communication, and required consultation with Environment Canada and the Government of the Northwest Territories. With these conditions, we find it acceptable for the Proponents to develop greenhouse gas targets for the project consistent with use of best management practices and in consultation with appropriate government agencies.

Drill cutting disposal

Like the operators of the Taglu field, ConocoPhillips plans to dispose of drill cuttings from the Parsons Lake field into a dedicated disposal well. Drill cuttings would be collected and transported to the cuttings processing station. At the station, the cuttings would be mixed with water, milled and sheared to create slurry. The slurry would then be pumped into the proposed D-20 dedicated cuttings disposal well (see Figure 4-13). Disposal would usually be done in batches at low pump rates. ConocoPhillips is planning a comprehensive program of testing and monitoring of subsurface containment during cuttings injection operations. Annular cuttings injection may be used as a back-up if ConocoPhillips was not able to use the dedicated cuttings injection well.

As mentioned for Taglu, subsurface slurry injection has not been used in the Northwest Territories at this scale before. If cuttings injection is not viable, ConocoPhillips' alternative method for the disposal of drill cuttings would be to stabilize, store and subsequently transport the cuttings to an approved disposal site.

Noise

The Parsons Lake anchor field is located outside of Kendall Island Bird Sanctuary. The physical footprint of the facility, particularly the north pad, is an area of relatively low numbers and diversity of migratory birds compared to the nearby Mackenzie Delta. ConocoPhillips believes that it is appropriate for the Parsons Lake production facility to follow Alberta's Energy Resources Conservation Board Directive 038 "business as usual" Permissible Sound Level.

Views of the Board

We are of the view that the conceptual plan by ConocoPhillips to dispose its drill cuttings by subsurface slurry injection is satisfactory as it avoids the use of sumps and minimizes the environmental footprint. However, as down-hole slurry injection of this scale and extent has not been utilized in the Mackenzie Delta before, Condition P4 requires ConocoPhillips to submit a drill cuttings slurry injection management program. The National Energy Board would assess such a program with respect to subsurface containment as well as safety, protection of the environment and conservation of resources.

Condition P9 requires meeting requirements of Alberta's Energy Resources Conservation Board Directive 038 for noise regulation and filing a post construction noise assessment report 90 days following the start of operation.