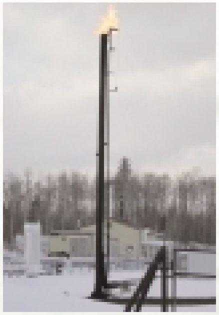
the PEMBINA institute

Oil & Gas Processing

Environment & Energy in the North



A PRIMER

About the Pembina Institute

The Pembina Institute is an independent non-profit research, education and advocacy organization. It promotes environmental, social and economic sustainability through the development of practical solutions for businesses, governments, individuals and communities. The Pembina Institute provides policy research leadership on climate change, energy policy, green economics, renewable energy, and environmental governance, as well as extensive formal and public education programs. More information about the **Pembina Institute** is available at **www.pembina.org** or by contacting

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Contents

About the Primers

The Pembina Institute's Energy Watch program has developed a series of eight primers to help northern communities understand the potential environmental and, where applicable, human health impacts of oil and gas development. The primers also aim to help these communities effectively take part in managing these risks, ensuring that governments and oil and gas developers are using the best environmental practices available.

Each of the first six primers focuses on a different phase of oil and gas development.

There are four parts to each of these primers:

1. A basic description of the activities of that phase
2. The potential environmental and human health risks of that phase
3. The best practices available to reduce those risks
4. Opportunities for citizens to get involved in deciding how developers carry out the activity.

The following are the six phases of oil and gas development addressed by the primers:

Seismic Exploration — industry activities to create a picture or map of the geology below the Earth's surface to find oil and gas reserves.

Land Disposition — the actions companies need to take to get the rights to explore for and produce oil and gas reserves.

Exploration and Production Drilling — the activities companies perform to first locate oil and gas, then to find out the size and usability of an oil and gas reservoir, and finally to reach the oil and gas using intensive production drilling.

Well Site Operation — industry practices to remove oil and gas from underground reservoirs and transport them to the surface.

Oil and Gas Processing — actions companies take to process oil and gas to prepare it for sale.

Pipeline Construction and Operation — industry activity to set up pipelines that carry oil and gas from the place it comes out of the ground to the places where consumers will use it.

The last two primers focus specifically on citizens' rights around oil and gas development projects:

Citizens' Rights and Oil and Gas Development: Northwest Territories explains the rights that citizens have related to oil and gas development in the Northwest Territories.

Citizens' Rights and Oil and Gas Development: Yukon Territory explains the rights that citizens have related to oil and gas development in the Yukon Territory.

To produce these primers, the authors reviewed the limited oil and gas development already under way in Canada's North. They also researched the current issues and practices in Alberta, northeast British Columbia, and the Alaskan North Slope, where intensive oil and gas development is already occurring.

Introduction

Just as they were about twenty years ago, companies are once again actively exploring for oil and gas reserves in the frontier regions of the Northwest Territories and the Yukon Territory. If developers decide to develop these resources, they will have to build a large capacity (or large diameter) pipeline to export the oil and gas from the far North to other regions. Once developers make a final decision to build one or more pipelines, and once regulators approve the plans, oil and gas exploration and production activity in the North will quickly increase.

Developing the oil and gas resources of the North would offer the people living there many opportunities for economic development. But it is important that companies developing oil and gas reserves, and governments and other regulators overseeing the work, make sure they do not damage the cold, slow-growing and sensitive northern ecosystems. While there will be unavoidable environmental impacts because of oil and gas exploration, developers and regulators can reduce impacts with careful planning and by using the best available technologies and practices.

Since it is the people of the North who will experience the most direct impacts, it is important that they play a strong role in setting the terms and conditions of such development. When deciding on the actions they will take, industry and various levels of government need to be respectful of and consider the needs and wishes of Northern communities.

During the past few decades, the oil and gas industry has become more aware of the environmental impacts associated with its work. Technologies and practices have become much less environmentally damaging than they were in the past. And most, though not all, companies have responded to social and environmental concerns. Despite these improvements, there are still negative environmental impacts associated with oil and gas development and production. This is especially true in areas where the activity is intensive.

When the public shares their questions, concerns and expectations about this work — directly to companies, through the media, and through regulators that inspect the work and

enforce regulations — this helps to uphold and improve industry performance. When the public is able to take part in effectively influencing decisions around oil and gas exploration, this pushes companies to higher levels of performance. When the public gives their input they tend to examine all companies equally; their participation ensures that all developers follow the best practices possible.

This primer, **Oil and Gas Processing**, focuses on the way industry processes the recovered oil and gas resources to prepare them for market and the role of governments in setting and enforcing the rules to which industry must abide.

There are four sections in this primer:

- Part 1 provides an overview of oil and gas processing
- Part 2 outlines the potential environmental impacts associated with oil and gas processing
- Part 3 contains the recommendations and options for technologies and practices that can help to reduce environmental risks
- Part 4 offers information and advice for concerned members of the public regarding their rights and opportunities to influence decisions on oil and gas processing facility proposals.

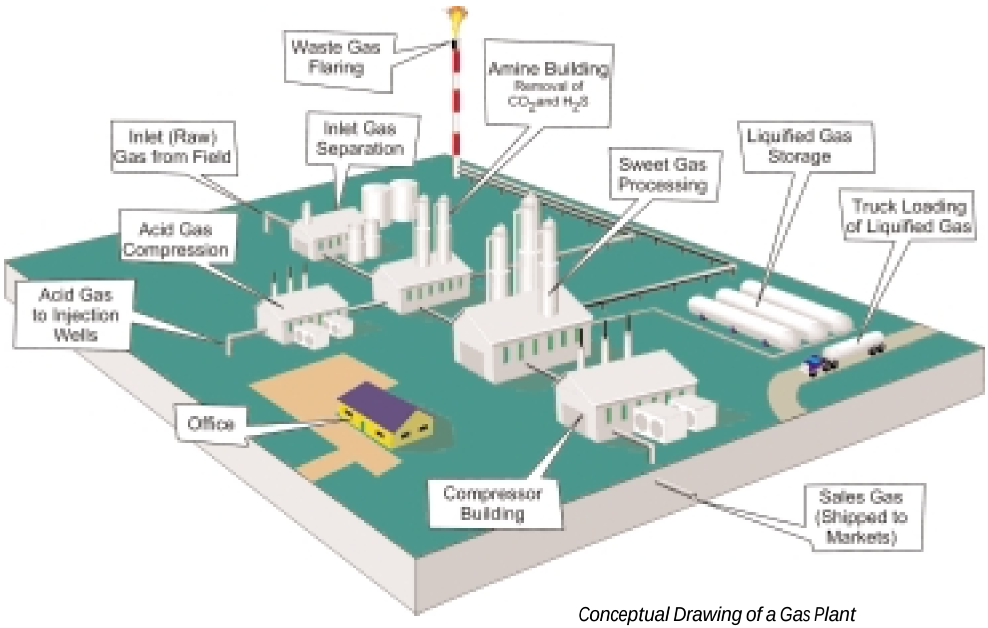
What is Oil and Gas Processing?

When crews bring crude oil or gas to the surface through production wells, it may contain a variety of substances. These include natural gas liquids (propane, butane and condensate), hydrogen sulphide (H_2S), carbon dioxide (CO_2), water, sand, silt, and asphaltenes. Before companies can send the oil or gas to market, they must process it to remove some or all of these impurities.

Workers can carry out some simple processing treatments at the well site, such as separating the water from the oil (oil/water separation) or drying the gas to eliminate any liquids present (gas dehydration). After these initial preparations, workers send the oil or gas through a pipeline to a large, centralized

FACILITIES

The terms "gas plant" and "oil battery" are commonly used to describe a collection of many different facilities that process raw gas and crude oil.



Conceptual Drawing of a Gas Plant

SOURCE: PEMBINA INSTITUTE CREDIT: DAVE MUSSELL

Waste Gas Flaring

SOURCE: PEMBINA INSTITUTE

processing facility such as an oil battery or a gas plant.

Gas Plant

At a gas plant, workers use various processes to remove impurities from the raw natural gas taken out of the ground. When the gas is clean enough, it can be sent through gas transmission pipelines and then burned in a typical home furnace or electrical power plant.

Gas plants are classified as "sour" or "sweet" depending on whether the raw gas contains hydrogen sulphide (H_2S). H_2S is a deadly toxin that occurs naturally in some gas formations. It is removed from natural gas using a process called "sweetening." Gas may undergo some or all of the following processes at a gas plant, depending on the type of raw gas being processed and the end products being sold (see Table 1 for more detailed information on these processes):

- ***Inlet separation:*** separates the majority of water and condensate from gas before the gas is further processed
- ***Sweetening:*** removes hydrogen sulphide and carbon dioxide from gas
- ***Sulphur recovery:*** converts hydrogen sulphide to elemental sulphur that can then be stored or marketed as a chemical feedstock

SOUR GAS

Gas is considered "sour" if it contains hydrogen sulphide (H_2S).[1] H_2S is very toxic to humans at low levels. Humans exposed to levels of 1,000 parts per million (ppm) of H_2S can instantly die.

1 H2S is not found in all oil and gas formations. For example the gas reserves that have been found in the Mackenzie Delta in NWT are "sweet" (i.e., they do not contain H2S).

Compressor Station

SOURCE: PEMBINA INSTITUTE

Dehydrator at well site

SOURCE: PEMBINA INSTITUTE

- ***Acid gas injection:*** disposes of acid gas by injecting it into deep wells; used as an alternative to sulphur recovery
- ***Flaring or incineration:*** burns any unusable waste gas or acid gas
- ***Dehydration and refrigeration:*** removes small quantities of water in natural gas before it enters a pipeline system; prevents the gas from freezing in the pipelines and causing corrosion
- ***Fractionation:*** separates out the different components of the gas
- ***Compression:*** uses gas or electric engines to increase gas pressure so it will flow through pipelines
- ***Pumping:*** uses gas or electric engines to apply pressure to oil or water so it will flow through pipelines
- ***Storage:*** uses tanks to store oil, condensate or water, and high pressure vessels to store compressed gas and gas liquidsAfter workers have processed the oil at an oil battery, they ship it by pipeline to a refinery. At the refinery it is made into a variety of products, such as gasoline and diesel.

Workers process raw gas in a gas plant so that the gas will meet pipeline specifications for water and liquid hydrocarbon content. They then send it in large transmission pipelines for sale to markets around North America. The hydrocarbons removed from the gas at the plant, such as ethane, propane and butane, may be further processed into other valuable products. Companies sell these natural gas liquids to petrochemical markets throughout North America.

West Coast Pine River Gas Plant BC

SOURCE: WAYNE SAWCHUK

Oil Battery

At oil batteries, workers use equipment to receive and condition oil coming from one or more wells before they send it to a refinery by pipeline or another form of transport.

Crude oil from wells generally arrives at an oil battery as a mixture of oil, water, and sand. While water and oil don't usually mix (that is, they are "immiscible"), the fact that the process of extracting oil from the well is usually very turbulent can mean that any water may become distributed throughout the oil in very tiny droplets. The opposite may also happen, where oil becomes distributed throughout the water in droplets. When one liquid is dispersed throughout another liquid with which it doesn't usually mix the resulting mixture is called an emulsion.

Crude oil goes through a fluid separation process to separate the mixture into distinct layers of sand, oil-free water, emulsion, and relatively pure oil. A process called "free-water knockout" uses gravity to remove the free water and sand. The emulsion is broken down and separated by heating the fluid in a "treater" to temperatures ranging from 38 to 70°C, and/or by treating it with emulsion-breaking chemicals. A properly designed and operated treater will produce oil that is pure enough (over 99.5% oil) to store in tanks or transport to a refinery.

Oil battery

SOURCE: PEMBINA INSTITUTE

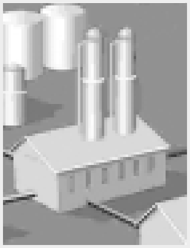
As oil is treated, gas called "solution gas" or "associated gas" is given off in varying amounts. Capturing this, instead of allowing it to evaporate into the air, gas reduces greenhouse gas emissions in the oil and gas industry.

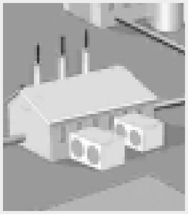
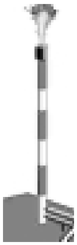
Oil batteries contain some or all of the following equipment (see Table 2 for more detailed information):

- ***Free-water knockouts:*** vessels that separate oil and water
- ***Treaters:*** vessels that separate emulsified oil and water
- ***Vapour recovery units:*** small compressors used to capture vapours from tanks and other units so the vapours can be conserved or destroyed
- ***Storage tanks and tank farms:*** groups of tanks that store treated oil and produced water
- ***Pump stations:*** gas or electric engines that apply pressure to oil or water so it will flow through pipelines

Oil batteries and gas plants are often located close together and occasionally on the same site.

Table 1. Typical Oil and Gas Processes Associated with Gas Plants and Oil Batteries

Process	Primarily Found In	Description of Facility
Inlet Separation	Gas Plants	Inlet Separation consists of vessels and equipment used to separate water and heavier hydrocarbons (condensate) from raw gas. The water, condensate and gas are typically metered at the inlet separator facilities.
Sweetening 	Gas Plants	Amine Treating is the most common way to sweeten natural gas. An amine solution is added to the raw gas. The amine absorbs the H_2S and CO_2 (collectively called acid gas). Like boiling water to produce steam, the amine is heated to remove the acid gas. As the amine is heated, the H_2S and CO_2 molecules become free and are typically sent to a sulphur recovery unit or sometimes directly to a flare or incinerator system. The regenerated (cleaned) amine is then re-circulated to absorb more H_2S and CO_2. Flared or incinerated H_2S from sour gas plants is a considerable source of sulphur dioxide (SO_2) in the oil and gas industry in Alberta and British Columbia.
Sulphur Recovery Units	Gas Plants	Sulphur Recovery Units are typically used to convert H_2S into elemental sulphur. The most common sulphur recovery process used in the oil and gas industry is the Claus process, which breaks most of the sulphur out of the H_2S molecules. The Claus process uses "multistage catalytic oxidation," which means that it breaks apart the molecules in different stages and uses a catalyst to make the process faster. In the first step, the H_2S is put into a furnace and exposed to very hot air (1000–1400°C). This separates out some, but not all, of the sulphur. There is still some H_2S left, and some SO_2 is created. In the next step, the remaining H_2S is reacted with the SO_2 at lower temperatures (about 200–350°C) over a catalyst, which speeds up the process of breaking down the molecules to make more sulphur. This second step is repeated two or three times to remove as much sulphur as possible.

Process	Primarily Found In	Description of Facility
		Each catalytic stage can recover half to two-thirds of the incoming (inlet) sulphur. A two-bed catalytic Claus plant can recover 94–96% of the inlet sulphur. Three-bed plants recover 96–97.5%, and four-bed catalytic plants can recover 97–98.5% of inlet sulphur.[2] A modified four-bed Claus catalytic process can recover 99% of inlet sulphur. Any H_2S that is not converted to elemental sulphur is typically incinerated to SO_2.
Acid Gas Injection 	Gas Plants	Acid Gas Injection is used as an alternative to sulphur recovery units. Acid gas injection involves taking acid gas (H_2S and CO_2) from the amine unit of a gas sweetening facility, compressing it, and then injecting it into a suitable down-hole formation. Acid gas injection has a significant advantage over sulphur recovery plants as it produces virtually no emissions. However, there are some risks with handling high-pressure sour gas. Acid gas disposal formations are selected primarily for their injectivity rate (that is, their ability to take up gas or liquids) and their isolation from other formations. Disposal wells must be free of defects and corrosion.
Incineration and Flare Systems 	Gas Plants and Oil Batteries	Incineration Systems are designed to destroy waste gases. They combust gas more completely than flares by regulating combustion temperature and injecting air into the combustion chamber. Emissions from incinerators include SO_2, CO_2, and residual fugitive H_2S. Flare Systems, with at least one flare stack, are found in every gas plant. They are used either for the continuous disposal of waste gases or to dispose of gas during plant upsets (operational problems that result in the need to shut down all or part of the gas plant). Some plants may substitute incinerators for continuous waste gas streams. Flaring produces a number of emissions, including CO_2, SO_2, a range of VOCs, and H_2S.

2 Background Report AP-42 Section 5.18, Sulfur Recovery, Prepared for U.S. EPA, OAQPS/TSD/EIB, Pacific Environmental Services Inc., Research Triangle Park, 1996.

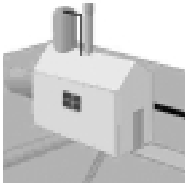
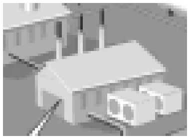
Process	Primarily Found In	Description of Facility
Dehydration 	Gas Plants	Gas Dehydration also occurs at gas plants. If water has not already been removed at the well site, it must be removed to prevent the gas from freezing when it is in the refrigeration system. The two most common technologies used for dehydration in gas plants are as follows: • Glycol dehydrators — Gas is exposed to a glycol that absorbs the water. Glycol also absorbs benzene, toluene, ethyl benzene, and xylene molecules (collectively referred to as "BTEX"). The water and other substances are evaporated from the glycol by a process called heat regeneration, allowing the glycol to be reused. Emissions from glycol dehydrators include BTEX if the vapours from the regeneration process are vented to the atmosphere. These emissions may also be recovered, incinerated or flared. • Molecular sieves — Gas is exposed to crystals that have a large surface area that attracts the water molecules. Heating the crystals to above the boiling point of water releases the water from the crystals as vapour, regenerating the crystals so they can be reused.
Refrigeration	Gas Plants	Refrigeration units cool raw gas to a point where propane, butane and condensate or natural gas liquids (NGLs) turn into a liquid and can be separated from the raw gas. These units use a cooling process similar to a conventional household freezer, but the refrigerant medium is usually propane or ammonia. Some larger gas plants use turbo-expanders, which can achieve very low temperatures, have a very high recovery rate for propane, and can also recover ethane.
Fractionation	Gas Plants and Oil Batteries	After the NGLs have been separated from the raw gas as part of the refrigeration process, the fractionation plant then separates the NGLs into ethane, butane, and propane. The fractionation plant typically consists of large vertical vessels/towers used to physically separate each component.

Table 2. Typical Oil and Gas Equipment Associated with Gas Plants and Oil Batteries

Process	Primarily Found In	Description of Facility
Compressors 	Gas Plants and Oil Batteries	Compressors are driven by large gas or electric engines to increase gas pressure so it will flow through gas processing units and pipelines. Compressors can be located at gas plants or batteries or at separate facilities. Long pipelines may require a series of compressor stations along the pipeline to boost gas pressure.
Pumping Stations	Oil Batteries and Gas Plants	Pumping stations are driven by large gas or electric engines. They apply pressure to oil and water so that it will flow through process units and pipelines. Pumps can be located at gas plants, batteries or other facilities. Long pipelines may require a series of pumping stations along the pipeline to boost pressure. Pumps are similar to compressors but deal with a liquid instead of a gas.
Underground Storage	Gas Plants	In a few places in Western Canada, natural gas and natural gas liquids are placed in large underground storage facilities such as salt caverns or depleted oil or gas reservoirs. These facilities are used to store large quantities of oil and gas so that there is a consistent flow in large-scale transmission pipelines, and so that operators can respond to changes in demand for oil and gas. Fractionation, refrigeration and dehydration facilities are commonly included as part of underground storage facilities.
Heaters and Boilers	Gas Plants and Oil Batteries	Heaters and boilers provide heat for process units in the plant and for tanks and buildings.

Equipment	Primarily Found In	Description of Facility
Treaters	Oil Batteries	Treaters are horizontal heated vessels that separate oil, water and solution gas.
Free-water Knockouts	Oil Batteries	Free-water knockouts are typically large conical tanks. The crude oil sits in the tanks to settle, so that the water can then be removed.
Vapour Recovery Units	Oil Batteries and Gas Plants	Vapour recovery units (VRUs) gather vapours from the vent outlets of tanks, glycol dehydrators, and other units that are otherwise open to the atmosphere. VRUs have small diameter pipes and a compressor suction apparatus to capture the gases, which would otherwise be released to the air. They then re-direct the gases to a gas plant to be processed, or to a flare or incinerator.
Tank Farms	Gas Plants and Oil Batteries	Oil from oil batteries and condensate from gas plants is commonly stored in tank farms. Oil and condensate that have been properly treated or stabilized should not emit volatile gases; however, if proper treating has not been done, hydrocarbon storage tanks can emit substantial fugitive hydrocarbon emissions. It is estimated that 24% of all total hydrocarbon emissions by the upstream oil and gas industry came from tank farm vents prior to 1992.[3]

3 "Options for Reducing Methane and VOC Emissions from Upstream Oil and Gas Operations, Technical and Cost Evaluation," Canadian Association of Petroleum Producers, December 1993.

Equipment	Primarily Found In	Description of Facility
Fractionation	Oil Batteries and Gas Plants	Deep well disposal facility — A deep disposal well is a well drilled into a confined, non-oil- or gas-producing formation with a high injectivity rate. These types of facilities normally include a receiving tank, pipeline and pump. They are often used to dispose of oil waste, produced water or spent chemicals. Produced water disposal wells can be part of an oil battery and may be used as part of an oil reservoir pressure maintenance scheme. Wastes can arrive at the facility by pipeline or by truck.
Disposal Facilities	Oil Batteries	Deep well disposal facility — A deep disposal well is a well drilled into a confined, non-oil- or gas-producing formation with a high injectivity rate. These types of facilities normally include a receiving tank, pipeline and pump. They are often used to dispose of oil waste, produced water or spent chemicals. Produced water disposal wells can be part of an oil battery and may be used as part of an oil reservoir pressure maintenance scheme. Wastes can arrive at the facility by pipeline or by truck.
Aerial or Water Cooling Systems	Gas Plants	Water cooling systems consist of vessels and piping used to circulate water for the purposes of cooling large gas processing units. These units require the ongoing addition of "make-up" water to compensate for water losses due to evaporation. They periodically require "blowdown" or change-out of water in the cooling system cycle to prevent the build-up of salts and solids within the unit. Aerial cooling systems use air to cool large gas processing units. Aerial cooling systems do not require make-up water and do not generate blowdown waste water.

Environmental Impacts

Canada's north is a diverse landscape. It contains seven distinct ecological areas:

Arctic Cordillera Ecozone	mountains, rock, ice and glaciers, few plants and animals
Northern Arctic Ecozone	barren plains, permafrost, some rock, seabirds and muskox
Southern Arctic Ecozone	shrubs, meadows, lakes, large mammals
Taiga Cordillera Ecozone	mountains, arctic shrubs and flowers, wetlands, valleys, waterfalls, canyons, rivers, wide range of mammals
Taiga Plains Ecozone	low-lying plains, large rivers, rich diversity of plants, birds and mammals
Taiga Shield Ecozone	coniferous forest, bedrock, lakes, wetlands, meeting of the boreal and arctic zones
Boreal Cordillera Ecozone	mountains and valleys separated by wide lowlands

Since each area is unique, any oil and gas development will impact each area differently. The nature and extent of environmental impacts will depend upon the regional ecosystem type, local terrain characteristics, the presence or absence of tree cover and permafrost, and the type of soil.

This section identifies potential land disturbances that may result from oil and gas processing. Some impacts are common to all areas; others are particular to an area that may be sensitive in some way.

Disturbance of the Land Surface

When companies build roads, plant sites, pipelines and utility corridors, and associated facilities to support the processing of oil and gas resources they disturb the surface of the land. This disturbance happens at the same time that oil or gas production begins.[4] It lasts until companies finish oil or gas production, and fully reclaim and restore plant sites, roads, pipeline and utility corridors.

The time it takes for crews to reclaim these areas can vary significantly, depending upon

4 See the fourth primer in this series, Well Site Operations: A Primer.

the climate of the area, the materials and construction methods that the workers used, and the sensitivity of the soil and vegetation. Processing facilities and roads may remain open and active for decades before companies finally abandon the facilities and reclaim the surface.

Over time, as companies build more and more pipeline and processing infrastructure in an area, production costs become cheaper. This can result in waves of development in an area by companies. Some areas may experience multiple waves of oil and gas exploration and production before crews have finally drained the reserves and reclaimed the surface.

Permafrost

In arctic environments, the extent of surface disturbance depends on the type of soil and whether the soil is permafrost (a permanently frozen layer of soil underlying the "active layer" on top that melts and re-freezes each year). Permafrost soils are easily damaged. They are very sensitive to changes in temperature. Human activities, including the operation of large equipment, can result in dramatic reshaping of the land through rutting of roads, "melt-outs" and subsidence (settling of the land). Disturbing, compressing or removing any surface material and vegetation can result in increased soil temperatures in summer months. This can seriously damage the permafrost.

Wildlife

Areas where there are many cutlines and access roads damage wildlife and wildlife movement. For example, although boreal caribou often freely cross cutlines, they will avoid bedding or feeding within 250 metres of them.[5] In addition, wolves will use cleared pathways to more quickly access certain areas, thus increasing predation on certain animals. Also, cleared areas have created more habitat for moose. Larger moose populations may decrease habitat available to other animals, attract predators to the area and thereby upset the ecological balance.[6] Oil and gas processing may affect the size of wildlife populations, the location of herds, and their traditional migratory paths.

Noise from oil and gas processing facilities, such as motors, compressors and engines, can also disturb wildlife. When workers transport personnel and equipment to and from processing facilities

Vegetation

Besides wildlife, land disturbance caused by well site operation also affects trees and other plants. When crews damage or remove vegetation in arctic regions it takes a long time to grow back. This is because the growing

5 Dyer, S.J. Summary of master of Science Thesis: Movement and distribution of woodland caribou in response to industrial development in northeastern Alberta (University of Alberta, 1999). http://www.deer.rr.ualberta.ca/caribou. October 5, 2000.

6 Bob Wyne's presentation at the CPAWS Oil and Gas Workshop, Boreal Caribou Research Program, Alberta's Boreal Caribou and Oil and Gas Development, May 26, 2000.

season is short and many areas have permafrost soils and slow- growing plant species. Compared with more southern parts of Canada, northern Canadian vegetation takes more time to recover from surface disturbances like roads and pipeline corridors.

Since oil and gas are non-renewable resources, companies will eventually exhaust supplies. Any surface impacts associated with resource extraction should, in theory, be temporary. However, surface impacts associated with oil and gas development often last far longer than initially expected. This is because oil and gas production typically becomes cheaper as developers build production and transmission infrastructure and as there are advances in technology. This means that previously uneconomic reserves of oil and gas can become economic to produce. In other words, oil and gas processing can continue longer and companies may begin production in areas initially thought to be fully exploited.

Dead Caribou

SOURCE: WAYNE SAWCHUK

Damage to Soil and Water

Oil and gas processing can cause damage to both soil and water quality, as outlined in detail below.

Spills and Leaks

Oil and gas processing facilities can contaminate soil, surface water, and groundwater through leaks and spills from pipelines, valves, connections, loading and unloading areas, and tanks. Processing facilities also generate many different types of liquid and solid wastes that require handling, storage, and disposal.

Waste

At medium and large oil and gas processing facilities, industrial activity is intense and workers handle a large volume of hazardous materials. This poses an increased risk of contamination to soil and water. For this reason, processing facility operating licences or operating approvals usually include conditions relating to handling waste and managing surface waters, as well as detailed requirements for monitoring surface water, soil and groundwater.

Water Use

Sometimes companies will use fresh water to cool large gas processing units. These units require ongoing addition of water, called "make-up water," to compensate (or make up) for water losses due to evaporation. Over time, salts and solids build up in the processing units and crews must therefore change the water inside them. This change of water is called a "blowdown." When companies take water out of, or put water back into, surface water bodies this can impact the surface water quantity and quality.

Camp Farewell Staging area, NWT

SOURCE: ENVIRONMENT CANADA

Damage to Air Quality

There are many air emissions associated with oil and gas processing facilities. These can include

- carbon dioxide (CO_2) — a greenhouse gas
- methane (CH_4) — a greenhouse gas
- sulphur dioxide (SO_2) — contributes to acid precipitation
- nitrogen oxides (NOx) — contributes to acid precipitation
- polycyclic aromatic hydrocarbons (PAHs) — include toxic compounds
- volatile organic carbon compounds (VOCs) — include toxic compounds
- fine particulate matter — impacts human health (SO_2, NOx, VOCs, PAHs combine in the air to form fine particulate matter)
- hydrogen sulphide (H_2S) — a very toxic air pollutant

The burning of large quantities of natural gas to drive engines, motors and heaters is a key source of air emissions (primarily carbon dioxide and nitrogen oxides) from oil and gas processing facilities. If facilities use electrically powered units, this will avoid the creation of local combustion emissions. However, if using electricity requires power generation facilities to be expanded, or new sources of power to be developed, this may contribute to the creation of emissions and impacts wherever the power is generated.

Facilities that take hydrogen sulphide out of oil or gas (also known as sour facilities) can emit large volumes of sulphur dioxide depending on the process used to recover the sulphur, the recovery rate, and the way the

ARCTIC CARIBOU

Arctic caribou can be affected by the presence of oil and gas well pads, roads, processing facilities and pipeline and utility corridors:[7]

Surface disturbances can impact wildlife, especially at key stages in their life cycle.

CPAWS YUKON CHAPTER

Increased Predation

Oil-field development may increase the impact of predators on caribou by forcing them to move into areas that have more predators, by increasing access of predators into areas where the caribou live, and by making caribou more vulnerable to predators by forcing them into open areas more often where they have less protection.

Changes in Distribution

Studies in Alaska have found that, when they give birth to their calves, caribou will move away from areas where companies are developing. Caribou that have just given birth are sensitive to disturbance and avoid roads and gravel pads with human activity for up to two to three weeks. Conversely, caribou will sometimes stand or lie on gravel pads and roads during times when there are a lot of insects. The lack of vegetation and the cooler air on gravel surfaces means there are fewer insects to trouble the caribou.

Energy Stress

When vehicles and roads disturb an area, caribou react by becoming more active. This means that they spend more time and energy walking and running than do undisturbed caribou. However, caribou that are also being harassed by insects tend to be less sensitive to oil-field disturbances.

Productivity

The amount of weight that Arctic caribou gain depends on the vegetation they eat during the summer. Caribou that do not gain enough weight during the summer are less likely to become pregnant. The size of caribou herds could become smaller if oil and gas activity were to reduce the quality of and access to the vegetation they eat.

7 Truett, J. and S. Johnson. 2000. The Natural History of an Arctic Oil Field: Development and Biota.

sulphur is disposed. Leaks and venting from facility pipelines, connections, process units, and tanks can allow large quantities of emissions to escape into the atmosphere, including methane, hydrogen sulphide and volatile organic compounds.

Since medium to large processing facilities contain many sources of air pollution, they can emit a large volume of pollutants into the atmosphere. For this reason, when regulatory authorities issue operating permits or approvals to companies running these facilities, they specify which processing units are allowed to emit pollutants to the air, and they sometimes set limits on how much of a pollutant the facility can release.

Fishermen on lake

SOURCE: CANADIAN PARKS AND WILDERNESS SOCIETY – YUKON CHAPTER

When there is a problem at a gas plant, companies may have to flare some or all of the gas being processed. This is called a "plant upset." Gas plant upsets can result in flaring the full volume of gas entering the plant (referred to as the "inlet gas"), the full volume of gas leaving the plant (referred to as the "sales gas"), or the highly concentrated acid gas stream created by the sweetening process in sour gas plants. Upset flaring can produce very large volumes of air emissions. Therefore, gas plant operating approvals usually limit the length of time gas can be flared before companies must shut down both the plant and the pipeline that brings gas to the plant.

The many valves and pipe connections in oil and gas processing facilities can develop tiny

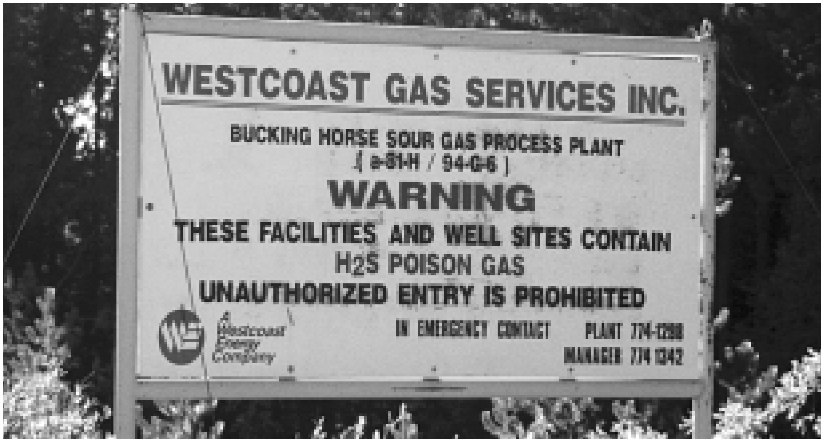
WORKING WITH SOUR GAS

Gas is considered "sour" if it contains hydrogen sulphide (H_2S).[9] H_2S is acutely toxic to humans at low levels. Humans exposed to levels of 1,000 parts per million (ppm) of H_2S can instantly die.

At sour oil or gas processing facilities, where the operator is handling potentially dangerous H_2S gas, there are additional air quality risks and potential impacts that must be managed.

8 Volatile organic compounds are comprised of hydrocarbon compounds larger than three carbon molecules in size and that volatilize under ambient conditions.

9 H2S is not found in all oil and gas formations. For example the gas reserves that have been found in the Mackenzie Delta in NWT is "sweet" (i.e., it does not contain H2S).



A sign indicating a risk of sour gas exposure in the area

SOURCE: NIKI WILSON

leaks. These leaks can release methane and volatile organic compounds (VOCs)[8] into the air. These types of emissions are referred to as "fugitive emissions." Another source of fugitive emissions at these facilities is vapours from liquid hydrocarbon storage tanks.

Accidental releases of sour gas pose a serious safety risk. Wells, pipelines, and facilities are prone to leaks and accidents and as such are potential sources of hydrogen sulphide exposure. In Alberta, Occupational Health and Safety standards dictate strict exposure limits for workers. While accidents are rare, between 1976 and 1994 approximately 30 people were killed by hydrogen sulphide poisoning.

To address the risk associated with sour gas exposure and risks associated with explosions, sour facilities are generally required to have lower rates of fugitive emissions than gas plants that do not process sour gas (sweet gas facilities), and to have in place emergency response plans that address the hazard of hydrogen sulphide exposure.

Cumulative Impacts

A single oil and gas project, including for example a well, a pipeline and a road, may by itself have only a small impact on the environment. However, in combination with other projects that occur over time, the impacts can become bigger and bigger. Since many wells, roads and pipelines will be needed over time to exploit the large oil or gas reserves in the North, such cumulative impacts will likely be significant.

OIL AND GAS IN ALASKA

Oil and gas development in Alaska started in 1960 with one producing oil field. By 2001 oil development consisted of 19 producing fields, 20 pads with processing facilities, 115 pads with support facilities, 91 exploration sites, 13 off-shore exploration islands, 4 offshore production islands, 16 airstrips, 1,395 culverts, 960 km of roads and permanent trails, 725 km of pipeline corridors, 353 km of transmission lines, and gravel mines affecting 2,600 ha.[10]

10 National Research Council of the National Academies, Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope. March 2003.

THERE IS STILL A LOT WE DON'T KNOW

There may be more environmental impacts associated with oil and gas development than are described in this primer. There are many things we still do not know about the impact of the oil and gas industry on the environment in Arctic Canada.

The Committee on Cumulative Environmental Effects of Alaskan North Slope Oil and Gas Activities has identified several major knowledge gaps in Alaska: [11]

Need for Comprehensive Planning
The government has typically decided who is given a permit to develop on a case-by-case, individual application basis. There is not a comprehensive plan to identify the scope, intensity, direction, or consequences of all industrial activities over time.

Ecosystem-level Research
Most ecological research in the Prudhoe Bay region of Alaska has focused on local studies of the behaviour and population of animal species. Long-term studies are needed to determine the impact of industrial activity on the productivity of tundra ecosystems.

Human Health Effects
There is not much information available on the effect of oil and gas activities on human health. More research is needed in this area.

Zones of Influence
The effects of industrial activities go beyond the industrial sites themselves and even the immediate area. Animals can be affected by gravel roads and well pads to a distance of several kilometres. Industrial structures on the tundra can be seen as far as 100 km away. More research is needed to learn about the impacts of activities and structures, and the distances over which the effects occur.

Air Contamination and its Effects
More research is needed to find out how much local emissions oil and gas facilities produce, and to determine ways that local and regional air masses and their contaminants interact.

Seismic Exploration and Other Off-Road Traffic
Studies are needed to determine the amount of snow cover and the depth of frost penetration into the soil that is required to adequately protect the tundra from the effects of seismic exploration vehicles. We need more information on the effects of trails from off-road vehicles, and how long these impacts last.

Bowhead Whales
Studies are needed to find out whether there is a relationship between noise generated by offshore oil and gas activity and the behaviour of bowhead whales.

Water Withdrawals
In Alaska, developers that wish to extract water from fish bearing lakes in the winter time are required to estimate the minimum water volume of the lake and then take no more than 15% of that volume. This level was arbitrarily set. Researchers need to find out whether this level of water withdrawal actually protects fish and invertebrates.

11 National Research Council of the National Academies, Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope. March 2003.

Using the Best Practices Available

Oil and gas processing involves activities that will result in some environmental damage. Regulators and developers can minimize disruption of the environment by using "best practices and technologies" — the most environmentally effective standards, practices and technologies that have been proven to minimize environmental damage.

Overall, best practices aim to ensure community sustainability. When companies use best practices they take a "triple bottom line" approach, considering the economic, environmental, and social impacts on the community of any action they take. In each of these areas, regulators and developers design best practices to minimize damage to the community's well-being and to increase its viability.

In oil and gas development there are three types of best practices:

- those that apply to the principles of how the work is planned and carried out
- those that refer to the practices and standards used in the field
- those that have to do with the equipment that is used.

At this stage of oil and gas development regulators can also use best practices to minimize waste and air pollution. They can also prevent long-term problems, by considering immediate and future cumulative impacts of any proposed development.

With oil and gas processing most of the best practices refer to equipment and technology choices that industry should make when designing a facility. Compared to the past, companies today use practices and technologies that result in fewer air emissions, leaks and accidents, and that generate less waste.

The best practices that are used during oil and gas processing are designed to

- avoid or minimize air emissions
- avoid and contain leaks, drips or spills from facility equipment
- ensure the availability and proper use of appropriate waste treatment and disposal facilities
- ensure effective and credible emission tracking, compliance monitoring, and ambient air quality monitoring
- minimize wildlife disturbance
- ensure worker and public safety in the event of an accident or upset.

The particular suite of practices and measures adopted for a specific oil or gas processing project should reflect local circumstances. Not all of the best practices or measures listed below are appropriate in all cases.

Planning

Integrated Land Use Planning

Governments should carry out as much land use planning as possible before the oil and gas development activity occurs. Governments should identify and map the areas that are most important from an ecological and cultural perspective, as well as the important habitat areas and wildlife corridors that are needed to connect protected areas together in a way that preserves the overall ecological integrity of the region.

Arctic Fox

CPAWS-YUKON CHAPTER.

By designating regions as protected, regulators preserve wildlife habitat, sacred sites, areas of traditional use for travel, hunting and gathering, burial grounds, and other sites of deep cultural significance. More work is needed to establish a network of protected areas that is representative of Canada's natural regions. In 1992, federal, territorial and provincial governments in Canada committed to a plan to establish a national network of terrestrial protected areas by 2000. The goal was not achieved. By 2000 only one-third of Canada's 486 terrestrial natural regions were adequately or moderately represented.[12]

Limiting the Number of Processing Facilities

In areas where there has been previous oil, gas or other industrial activity, companies should expand existing gas plants and oil batteries instead of building additional smaller new facilities. Regulators and companies should consider the long-term development potential of undeveloped areas when they decide on the location, size and number of oil and gas processing facilities.

Regulators can require oil and gas companies to prepare regional development plans that

12 World Wildlife Fund, 2003. Position Statement on Mackenzie Valley Natural Gas Pipeline and Associated Developments.

consider the potential for longer term drilling activity by their own company and by their competitors before they approve an application to build a processing facility. This will help avoid unnecessary or redundant developments. Regulators can set up and enforce an "anti-proliferation policy" (a policy that limits the number of new facilities). The policy could include the following:[13]

- Require companies applying for permits that would allow them to build new facilities to evaluate the technical and economic feasibility of expanding existing facilities.
- Require companies to consider and design for future processing needs in the area.
- Ensure companies plan and build regional waste treatment facilities that are large enough to handle present and future demands.

SOURCE: PEMBINA INSTITUTE

Local and Regional Air Quality Monitoring

Companies should place air quality monitoring equipment at their property line or close to the plant so that they can monitor air contaminants of concern. Companies usually place this equipment in the area where they expect there to be the highest concentrations of an air pollutant at ground level (also called the "maximum point of impingement"). Regulators can use the monitoring devices to make sure the facility is operating in compliance with the approval it was given.

Local governments can monitor the air quality of a region to measure overall levels of air contaminants from multiple sources in a given area over a long period of time. One of the first regional airshed management systems in Canada is the network of monitoring stations operated by the multi-stakeholder West Central Airshed Society in Alberta.[14] The Clean Air Strategic Alliance (CASA)[15] of Alberta has developed guidelines for forming and operating airshed management zones in that province.[16]

13 See also the Alberta Energy and Utilities Board Information Letter IL 91-1, Applications for Approval of Gas Processing Schemes — Policy on Plant Proliferation, and Alberta Energy and Utilities Board Guide 56, Volume 2, Energy Development Application Guide and Schedules. www.eub.gov.ab.ca/BBS/requirements/Guides/guides.htm (June 2002)

14 The West Central Airshed Society, www.casadata.org/wcas/indexj.htm

15 The Clean Air Strategic Alliance (CASA) is a non-profit association composed of diverse stakeholders from government, industry, and non-government organizations (such as health and environment groups). Senior representatives from each of the three sectors are committed to developing and applying a comprehensive air quality management system for the people of Alberta through a consensus-based process.

16 The Clean Air Strategic Alliance (CASA) Zone Air Quality Management Guidelines, www.casahome.org. (January 2004)

Managing Surface Water

When managing surface water, companies must prevent contact between rainwater and contaminants at the processing facility. They must also properly design the sites to ensure that rainwater that lands on a gas plant or oil battery site is collected in a central location where it can be stored, treated, and re-used or released into the environment in a controlled manner.

Sour gas plants that store recovered sulphur in huge blocks on the plant site present additional surface water runoff challenges. Water that runs off of these blocks and onto the land can be high in sulphuric acid. Sulphur dust can also be transported off the site onto nearby land.

Some facilities use cooling water systems and a cooling tower. These systems cool equipment by evaporating water. This means that new water is constantly needed to replace that which has evaporated. This is called "fresh water makeup." Over time, minerals and acids build up in these water systems and workers must remove these substances by flushing the systems out with water. The "blowdown" water that is removed contains high concentrations of contaminants. Workers usually dispose of this contaminated water in deep disposal wells. To conserve and protect surface water, plant operators can use aerial coolers instead of cooling water systems in nearly all situations in Canada. Although more expensive to buy initially, aerial coolers do not require large quantities of water and they are less expensive than cooling water systems to operate over the long term.

Groundwater Management

Groundwater contamination is a serious concern at many older oil and gas sites in Canada. Companies that use effective liners and secondary containment systems, and continue to monitor groundwater throughout the life of the project, can ensure that leaks and spills are prevented and any contamination that does happen can be detected and cleaned up quickly.

Drip tray to prevent soil and water contamination

SOURCE: PEMBINA INSTITUTE

Selection, Handling and Storage of Materials

Storage Vessel Spill Prevention[17]

Because of the risk of soil or groundwater contamination, companies should not use below-ground storage tanks.

Developers should ensure that they build tanks on an impermeable or lined surface. Companies should use tanks that have extra containment features, such as double walls, or they should surround the tanks with a diked area that has the capacity to contain at least 110 percent of the tank storage volume.

Workers should be careful not to overfill or put too much pressure in tanks. They can do this by using high-level alarms that warn workers when tanks are close to being filled, automatic shut-off devices that stop the filling of tanks when high levels are reached, and simple periodic visual checks to make sure that the products in the tanks are at safe levels.

At well sites workers should use oil drip pans on major equipment such as generators, trucks and other vehicles to avoid impacts associated with ongoing small leaks and spills. Workers can also limit soil impacts by refuelling and servicing equipment in dedicated areas that are equipped with spill capture and containment devices.

Companies should develop fuel spill contingency plans for fuel storage and refuelling sites. To minimize environmental impacts and personal safety hazards, all workers should be aware of what to do in the event of a spill.

Preventing Tank Sludge

When crews keep oil in storage vessels, solids that are heavier than the oil settle at the bottom of the tank forming a layer of sludge. "Tank sludge" (or "tank bottoms") is form of toxic waste. Companies can minimize oily sludge formation in well-site storage vessels by using recirculating pumps or mixers inside tanks to keep heavier parts suspended throughout the oil, rather than allowing them to collect on the bottom. Cone-shaped tanks also help prevent solids from building up. Workers can also minimize oily sludge by preventing contact with an oxidizing nvironment (that is, exposure to air). They can do this by using a "gas blanket" (replacing air in the tank eadspace with a non-oxidizing gas) or by using a "floating top" (a top that moves up and down depending on the volume of product in the tanks, so there is no tank headspace filled with air).

"Zero Drip" Policy

There are many sources of potential surface contamination in the form of leaks and spills at oil and gas processing sites. Drips and small leaks can occur at pipe connections, loading and unloading areas, and process units, and in storage areas.

Companies that have a zero drip policy try to avoid surface contamination by preventing

17 "Alberta Environment Guidelines for New Above Ground Storage Tanks" – Draft, March 2000.

spills from happening, and to contain and quickly clean up any spills that do occur. In areas where there is a high potential for spills to occur, workers can install permanent spill trays to capture any contaminants that drip or leak.

Minimizing Air Emissions

Acid Gas Injection

Facilities that dispose of acid gas by deep well injection generally have far lower emissions of sulphur dioxide than facilities that recover sulphur or that flare acid gas. Acid gas injection provides the additional benefit of "sequestering" the carbon dioxide part of the acid gas stream.

Acid gas disposal is a proven technology that a growing number of new and existing oil and gas facilities are using. In 1990, there were two acid gas disposal facilities in Canada. By 1998, there were 20, disposing of over 700 tonnes of CO_2 annually.[18]

Acid gas injection was initially used in small sour gas plants (processing less than 10 tonnes of gas/day) where the cost of a sulphur recovery unit could not be justified. Today, companies use acid gas injection in all sizes of sour gas plants.

Companies must dispose of acid gas in an underground formation where there is no chance that the gas will escape and contaminate other formations. Workers must specifically design the acid gas injection well bore to handle highly corrosive wet acid gas.

Sulphur Recovery

Sulphur recovery normally refers to the process of converting hydrogen sulphide into elemental sulphur. Companies flare or incinerate any hydrogen sulphide that they cannot recover. Therefore, the efficiency of the sulphur recovery units at a sour gas processing plant will determine the amount of sulphur dioxide that is not recovered and is instead emitted to the atmosphere.

Regulators generally require the largest sour gas plants to recover the most sulphur. For example, in Alberta, any oil or gas facility that processes more than one tonne/day of sulphur must have sulphur recovery units. Plants producing one to five tonnes/day must recover a minimum of 70% of the sulphur they produce. Plants producing more than 2,000 tonnes/day must recover 99.8% of the sulphur they generate.[19]

There are many ways to recover sulphur. The most common is the modified Claus process. A four-bed catalytic Claus unit can recover up to 98.5% of the sulphur contained in acid gas. To achieve recovery levels better than 99%, companies must install a modified Claus or tail gas clean-up unit.[20]

18 Oil and Natural Gas Industry Foundation Paper, Background Information on the Ability of the Industry to Contribute to Greenhouse Gas Emission Reductions, Prepared for the National Climate Change Secretariat, September 1998.

19 IL 88-13 Sulphur Recovery Guidelines — Gas Processing Operations, Alberta Energy Utilities Board, 1988.

20 There are a number of tail gas clean-up processes available, including BSR/Selectox, Sulfreen, Cold Bed Absorption, Maxisulf, IFP-1, Wellman-Lord, Beavon MDEA, SCOT and ARCO. Taken from Background Report AP-42 Section 5.18, Sulfur Recovery, Prepared for U.S. EPA, OAQPS/TSD/EIB, Pacific Environmental Services Inc., Research Triangle Park, 1996.

Companies can also recover sour gas at the well site using a non-regenerative sulphur scrubbers. However, these units are usually expensive to operate. In addition, once the sulphur "scavengers" of the machine are full, they usually have to be landfilled or disposed of by deep well injection.

Reducing Flaring at Gas Plants

Gas plant workers flare gases when they depressure equipment for maintenance, and dispose of waste gas, gas that doesn't meet pipeline specifications. Sometimes workers must do emergency flaring for safety purposes. Flaring at sweet and sour gas plants and acid gas injection facilities can generate a large volume of air emissions that could negatively affect local air quality. Sometimes it will be less expensive for plant operators to flare gas for a long time while they try to fix a problem, instead of shutting down the plant completely.

Operators can reduce the impacts of flaring at gas processing/disposal facilities by minimizing the total volume of gas they flare at the plant and by reducing the frequency and duration of upset flaring events. Operators can prevent air impacts from ongoing flaring by shutting down all or part of a facility in phases, according to pre-set time increments. This will still give them some time to resolve any problems while the plant is running.

Remote Shut-down Capability of Gas Field

When a plant operator shuts down a gas plant due to an upset, s/he must shut off or flare the inlet (incoming) gas. Shutting off the inlet increases the pressure in each of the well sites from which the gas is flowing through the pipelines. The plant operator, therefore, has to flare all of the inlet gas to the gas plant to avoid an overpressure situation at the well site or in the gathering system. Companies can prevent this flaring with proper design and proper well site controls:

- Design the gas gathering system and well facilities to ensure that all pressure components can handle the full well shut-in pressure; and
- Install well site controls that close valves automatically in a high-pressure situation (e.g., Presco valves). Ideally, these valves should automatically open when the pressure is lowered as the gas plant is brought back online and the gathering system pressure is lowered. This can also be done with a central computer, located at the gas plant. Supervisory Control and Data Acquisition (SCADA) technology and Distributed Control Systems (DCSs) are examples of remote operating systems that allow an operator to start and stop wells and pipelines from a remote location, avoiding the need to drive to each site and manually close valves.

FLARING FROM UPSTREAM FACILITIES

Since September 2000 the Clean Air Strategic Alliance (CASA) has been working to resolve issues associated with all forms of oil and gas industry flaring.[21] The following is a summary of the CASA Flaring/Venting Project Team's recommendations that deal with flaring from upstream facilities:[22]

- *That a maximum annual total gas plant flaring limit based on the size of the facility be established:*
    - *1.0% of receipts in the first year of operation and 0.5 % each year thereafter (this is the current EUB requirement for plants) for plants processing less than 1.0 billion (109) m^3/year; and*
    - *The greater of 5.0 106 m^3/year or 0.2% of receipts for plants processing more than 1.0 109 m^3/year.*
- *That gas plants be limited to not have more than six major flaring events in a six-month period, based on the size of the facility:*
- *That sour gas plant operators adopt the preferred practice of minimizing sour gas and acid gas flaring, even though in doing so incinerator stack contraventions could result.*

Facility flaring

SOURCE: ALBERTA ENERGY AND UTILITIES BOARD

Incinerator stack emissions that exceed plant limits are expected to have less impact on air quality than flaring the equivalent volume of sour or acid gas.

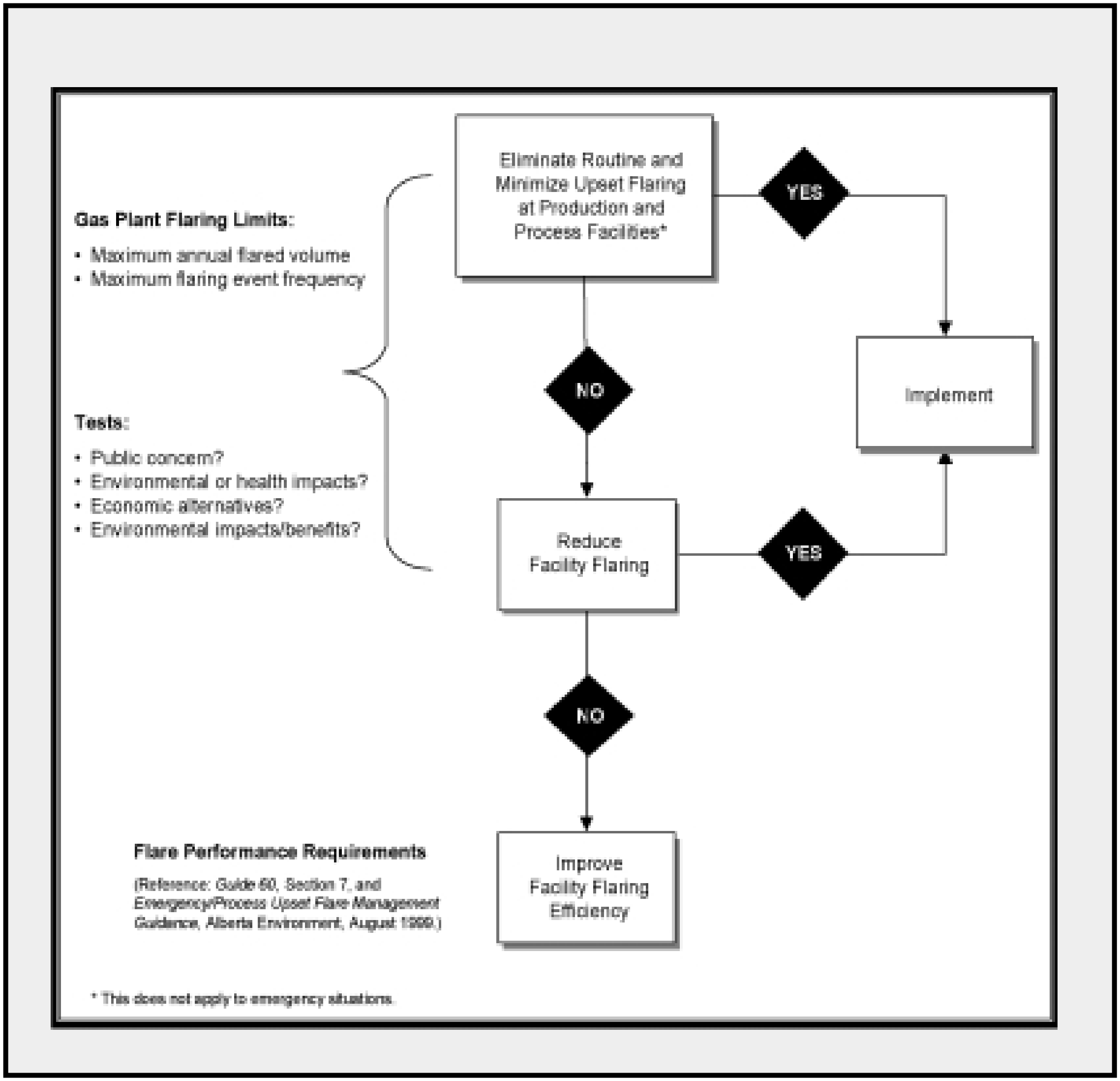
- *That industry follow a decision-making tree designed to reduce flaring and improve practices at upstream oil and gas facilities:*

Approved Plant Inlet Capacity	***Flaring Event***
> 500 10^3 m^3/d	*100 10^3 m^3 or more*
150–500 10^3 m^3/d	*20% of plant design daily inlet or more*
< 150 10^3 m^3/d	*30 10^3 m^3 or more*

21 The Clean Air Strategic Alliance (CASA) is a multi-stakeholder association established to manage air quality issues in Alberta. www.casahome.org (June 2002).

22 Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industryby the Flaring/Venting Project Team, Clean Air Strategic Alliance, June 2002. www.casahome.org (June 2002).

Flaring Facility Decision Tree



Blowdowns and Depressuring

Operators occasionally, and in some cases routinely, blow down (completely change the water used in) or depressurize (release all the gas from) gas plants, oil batteries, field compressors and individual instruments. They must depressurize entire gas plants to do annual or bi-annual maintenance work. Some field compressors are de-pressurized before each start. Workers routinely blow down individual instruments at plants and batteries to check for accuracy.

If operators use a compressor to draw gas out of processing units, this will minimize the amount of gas they have to dispose. The next best alternative is to incinerate or flare the depressurized gas.

Waste gas flaring

SOURCE: PEMBINA INSTITUTE

Benzene Emission Reductions — Glycol Dehydrators

Most gas processing plants use glycol dehydrators in a manner similar to those used at individual well sites.[23] Operators commonly use glycol dehydration to remove water from gas as it enters a pipeline to prevent freezing and corrosion. Even if workers have dehydrated gas at the well site, it may need to be dehydrated further. Due to the large volume of gas to be treated at a gas processing facility, glycol dehydrators at gas plants are typically much larger than those at individual well sites.

In addition to extracting water from natural gas, glycol will extract some benzene, toluene, ethyl benzene, and xylene (collectively referred to as BTEX) molecules. When heat is used to re-generate the glycol, both water and BTEX molecules are driven off. Operators commonly vent these emissions to the atmosphere. Glycol dehydrators can be significant sources of hydrocarbon emissions. In 1996, approximately 3,500 glycol dehydrators were in use in Canada.[24] In 1995, glycol dehydrators emitted 9,000 tonnes of benzene into the atmosphere.

Benzene has been declared a toxic substance under the Canadian Environmental Protection Act. A working group formed by Environment Canada discussed alternatives to glycol dehydrators and other benzene emission reduction measures in its final report entitled *Best Management Practices for the Control of Benzene Emissions from Glycol Dehydrators*.[25] Efforts by industry to reduce benzene emissions from glycol dehydrators

23 See the fourth primer in this series, Well Site Operations: A Primer.

24 "Best Management Practices for the Control of Benzene Emissions from Glycol Dehydrators," Working Group on Benzene Emissions from Glycol Dehydrators, November 1997.

25 Ibid.

have so far been successful in achieving a roughly 75% reduction compared with the 1995 baseline. Industry has committed to a target of 90% reduction by 2005.

There are a number of ways operators can reduce or eliminate emissions from glycol dehydrators. On existing dehydration units, operators can reduce emissions by optimizing the dehydration unit — for example, reducing the glycol circulation rate to the minimum required to ensure adequate freeze protection, or optimizing the temperature of the unit. Operators can also use a separator to remove water from gas before it enters the dehydration unit; this will also reduce the amount of glycol they need to use in the dehydrator and will reduce the quantity of emissions.

If plant operators collect vapours from the regeneration column, the glycol pump, and any gas-operated instrumentation, and then flare or incinerator these vapours, they can achieve near-zero emissions from glycol dehydrators.

Other alternatives, which can be an improvement over glycol, include the following:

Line Heaters / Insulated Gathering Systems — Instead of using individual well-site dehydrators, workers can use line heaters to heat the gas at the well site and raise the gas temperature above the freezing point. They can then transport the gas to a central processing plant through an insulated gas gathering system. At the plant, an operator can use one large dehydrator (either glycol or molecular sieve) to remove water from the gas. The advantage of this system is that it allows for fewer individual well-site dehydrators and results in better overall efficiency, with lower overall emissions, than if the gas was dehydrated at each well site.

Molecular Sieve Dehydrators — For many years companies have successfully used molecular sieve technology in large liquid recovery plants where they needed extreme freeze protection. Molecular sieve dehydration involves "adsorbing" water by capturing it and making it accumulate on the surface of a crystalline solid. It is typically a closed system that removes water by heating the crystals to above the boiling point of water. This to releases the water and regenerates the crystals so they can be reused. This process almost eliminates vapour and BTEX emissions. Because of its closed-system process, molecular sieve is suitable for dehydration of sour gas where the release of H_2S could be lethal.

Methane-controlled Pneumatic Devices

At processing facilities without electrical power, workers can use pneumatic devices, which can run on natural gas from oil and gas formations, to drive pumps as well as power instrumentation and control equipment. High-bleed pneumatic devices can be major sources of methane emissions. Alternative technology is available that, while still using natural gas to drive pumps and instruments, does not vent to the atmosphere. An example of this is the

Handfield Glycol Pump.[26] The gas used in this natural gas dehydrator pump is captured and used to partially fuel the glycol dehydrator.

Another system uses a small compressor to draw vented vapours back into the gas gathering system.

Many instrumentation suppliers now offer low-bleed or no-bleed pneumatic devices.[27] Although low-bleed devices cost more, most operators that install them (either initially or as a retrofit) end up making their money back on the investment.[28]

As a last resort, crews could collect vapours from high-bleed pneumatic devices and burn them in a flare or incinerator system.

Air can be used instead of natural gas to power pneumatic devices. However, instrument air systems require electrical power to be available on site. In some cases, bottled nitrogen instead of instrument air or natural gas can be used for smaller services.

PNEUMATIC DEVICES

Pneumatic devices are devices that are moved or worked by the pressure or flow of a gas. These devices can use the pressure from natural gas wells to provide the force needed to operate control equipment on gas distribution systems, such as the opening and closing valves. Some of this "power" gas is emitted to the atmosphere when these devices are operated. In some cases, natural gas must be continuously vented to the atmosphere for the equipment to operate properly. Over time, the vented gas adds up to a significant amount of greenhouse gas emissions.

Leak Detection and Repair

All pipe connections and processing plant components leak to some degree. Companies can minimize "fugitive emissions" (emissions that escape) by designing facilities with the fewest possible components and connections, and avoiding components known to cause significant fugitive emissions.

Leak detection and repair (LDR) programs involve workers performing routine preventative maintenance on equipment that is known to leak, as well as physically checking equipment for methane emissions and repairs.

For a leak detection program to be effective, workers must regularly inspect equipment. They can use handheld devices to detect gas in the air. One of the simplest methods to pinpoint a leak is to apply a soap and water solution to fittings and valves where the leaks generally occur and watch for bubbles. Workers can also use new handheld devices, such as high flow samplers, to quantify sweet gas fugitive emissions. When companies quantify fugitive emissions, this provides them with

26 Handfield Pump – Handfield Pumps Corporation;, www.pumps.ab.ca (July 2003).

27 By definition, an instrument that emits more than six cubic feet per hour is considered to be a "high-bleed" device. It is common for older instruments to bleed 50 or 100 times this amount.

28 U.S. DOE Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology, "Production Tech Facts," http://www.fe.doe.gov/oil_gas/environ_rpt/index.html.

important information they can then use to design the most effective leak repair program for their company. It also enables them to provide to the government accurate estimates of their greenhouse gas emissions.[29,30]

Tank Vapour Control and Recovery

Fugitive emissions are created when vapours in tanks are displaced by incoming liquids or when vapours evaporate from unsealed tanks. There are several ways operators can prevent fugitive emissions from tanks:[31,32]

- *Minimize Tankage* — Design gas plants and oil batteries to minimize the number of tanks. This prevents fugitive emissions and reduces the formation of tank sludge and other wastes.
- *Stabilization of Liquids* — Properly stabilize or de-gasify all liquids to minimize evaporation. Ideally, products that can be de-gasified so that their vapour pressure is below 10 kPa should not release vapours.
- *Floating Roofs* — Use floating roofs to minimize the exposure of tank liquids to air, thereby reducing evaporative losses and displacement losses. Floating roofs can be installed on virtually any tank used in the upstream oil and gas industry.
- *Vapour Recovery Units* — Install Vapour Recovery Units (VRUs) to recover vapours from high vapour pressure products (over 10 kPa). Operators can then recycle the recovered vapours and send them to a gas plant for processing to be used as fuel gas or sold as sales gas. These systems may involve compression (suction) and they work best if contamination with air can be avoided. On large tank farms, operators can combine these systems with a refrigeration unit to recover condensable hydrocarbons, leaving mostly methane that can be used as fuel or destroyed.
- *Vapour Balancing Systems* — Use vapour balancing to transport hydrocarbon vapours between tanks during filling and emptying. As a tank is filled, it displaces vapour. Instead of venting this vapour to the atmosphere, workers can expel the vapours into an adjacent tank that is being emptied. Companies can use these same systems when filling transport trucks and should install them at all truck loading stations.
- *Carbon Adsorption* — Install a carbon adsorption unit to recover hydrocarbons from vent flows containing significant amounts of air. The unit consists of two carbon beds and a steam or vacuum regeneration system. The surface of carbon physically absorbs the hydrocarbon compounds (including hydrogen sulphide).

29 US DOE Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology, "Production Tech Facts," http://www.fe.doe.gov/oil_gas/environ_rpt/index.html. (July 2003)

30 Options for Reducing Methane and VOC Emissions from Upstream Oil and Gas Operations, Technical and Cost Evaluation, Canadian Association of Petroleum Producers, December 1993.

31 Options for Reducing Methane and VOC Emissions from Upstream Oil and Gas Operations, Technical and Cost Evaluation, Canadian Association of Petroleum Producers, December 1993.

32 Environmental Guidelines for Controlling Emissions of VOCs from Above Ground Storage Tanks, Canadian Council of Ministers of the Environment, 1995.

While one bed is active the other is regenerating. This technology may be most applicable to truck loading terminals.

Dry Low-NOx Burners

In the oil and gas industry, companies use gas turbines to drive compressors and electrical generators. These turbines generally burn at very high temperatures and as a result emit high concentrations of NOx. Most turbine manufacturers now offer low-NOx burners on their turbines. The US Environmental Protection Agency considers the use of dry low-NOx burners to be Best Available Control Technology (BACT). This technology is being used for BP Amoco operations in Alaska's North Slope to reduce NOx emissions.

Industry Best Practice Commitment to Reduce Greenhouse Gas Emissions

The Kyoto Protocol, ratified by Canada in December 2002, requires a reduction in Canada's greenhouse gas emissions to 6% below the 1990 level during 2008–2012. Industrial facilities, including electricity generation, accounted for 53% of Canada's greenhouse gas emissions in 2001.[33]

Oil and gas companies and jurisdictions within Canada should develop and carry out greenhouse gas management plans to minimize the cost of complying with Kyoto and with subsequent emission reduction requirements. Such plans should include ways to reduce emissions through internal energy efficiency, investments in offsets and "green power," and a commitment to limiting absolute volumes of emissions. One company, BP, has set a goal to maintain its greenhouse gases emissions at 10 percent below its 1990 baseline level until the year 2012.[34]

Co-generation and Heat Integration

"Co-generation" means using waste heat from one process in another process. It is commonly used in electricity generation where the exhaust heat from a gas turbine (which drives an electric generator) is used to heat water into steam. The steam is then used to drive a turbine, which drives another electrical generator. Overall efficiencies of electrical co-generation projects can be as high as 60% — a significant improvement over an efficiency of less than 40% for a gas turbine by itself.

Instead of producing electricity with the waste heat from a gas turbine, companies can use the waste heat to heat the gas plant, thus eliminating the need to burn natural gas for heating.

Continuous Emission Monitoring

Continuous emission monitoring (CEM) devices are in-stack air quality monitoring devices that continuously measure specific pollutants from process stacks. Readings are often averaged every five minutes. CEM devices are normally required in large sour gas plants with sulphur recovery units.

33 Environment Canada, Greenhouse Gas Emission Summary, http://www.ec.gc.ca/pdb/ghg/canada_2001_e.cfm (July 2003)
34 BP: www.bp.com/environ_social/environment/clim_change/position.asp (July 2003)

Winter landscape

SOURCE: CPAWS – YUKON CHAPTER

Operators use the information from CEM devices to monitor the performance of the facility and to ensure compliance with the emission limits specified in the plant's operating approval.

Maintenance and Follow-up

Filter Change-out and Disposal Management

Filters are used in many different segments of the oil and gas industry. Nearly all process fluids are filtered in some way, including lube oil, produced water, glycol, amines, charcoal and coalescing fluids. Workers need to replace (change out) filters when they become blocked. Many companies change these filters according to fixed schedules. However, as the amount of filterable material varies over time, companies can reduce operating costs and the number of filters they dispose if they change filters only when necessary. Companies can do this by installing differential pressure monitoring devices across the filter. Operators change the filters when a pre-determined differential pressure is reached, thereby reducing the number of filters that must be disposed. Regulators must properly manage the way in which filters can be disposed. In some urisdictions in North America certain filters can be landfilled, while in other jurisdictions they must be incinerated at an approved waste disposal site.

Noise Mitigation

There are many ways to reduce noise from processing facilities, such as attaching mufflers, erecting acoustic buildings, or adding insulation around equipment.

Some jurisdictions have developed noise guidelines for the upstream oil and gas industry.[35] Alberta's guidelines, for example, set out allowable noise levels for affected residents near oil and gas industry development. The government could apply comparable guidelines to control noise impacts on recreation use and wildlife.

35 "Alberta Energy and Utilities Board Noise Control Directive" (ID 99-08).

Table 3. Oil and Gas Processing Summary

Traditional Practice or Area of Concern	Best Practice
Proliferation of processing plants	• Expand existing gas plants and oil batteries before building new facilities. • Ensure that regulatory requirements are in place specifying that oil and gas companies prepare regional development plans before they receive approvals. This can avoid unnecessary or redundant developments while ensuring that proactive developments occur.
Spills/leaks from storage vessels	• Locate above ground storage vessels more than 100 metres above the normal high water mark of a body of water, watercourse or water well. • Build storage facility pads on an impermeable or lined surface and have a leak detection and/or collection system. • Use secondary containment. • Use measures to prevent overfilling tanks, including automatic shut-off devices, high level alarms, and visual checks. Use over-pressure and under-pressure protection to prevent rupture.
Formation of tank solids and sludge	• Use re-circulating pumps inside tanks to keep heavier components in suspension. • Use cone-shaped tanks. • To minimize sludge formation, use an inert gas or natural gas in the vapour space in tanks instead of air.
Drips and small leaks at pipe connections, loading and unloading areas, and process units, and in storage areas	• Adopt a "zero-drip policy" to eliminate surface contamination by using spill prevention measures, containment of spills and rapid clean-up of all spill material.
Sulphur dioxide (SO2) emissions	Use acid gas injection where a good deep well disposal formation is available.

Traditional Practice or Area of Concern	Best Practice
Sulphur recovery	• To achieve recovery levels better than 99%, install a modified Claus or tail gas clean-up unit. Examples include BSR/Selectox, Sulfreen, Cold Bed Absorption, Maxisulf, IFP-1, Wellman-Lord, Beavon MDEA, SCOT and ARCO.
Gas plant flaring events	• Have phased shut-down policies to limit the duration of upset flaring incidents. • Establish maximum annual total gas plant flaring limits. • Establish limits on the number of flaring events in a calendar year. • Ensure sour gas plant operators adopt the preferred practice of minimizing sour gas and acid gas flaring, even though, in doing so, incinerator stack contraventions could result. • Encourage industry to follow the CASA facility flaring decision-making tree designed to reduce flaring and improve practices at upstream oil and gas facilities.
Shut-down capability of gas field	• Design gas gathering systems and well facilities to ensure that all pressure components can handle the full well shut-in pressure. • Use well site controls that close valves automatically in a high-pressure situation (e.g., Presco valves, SCADA or Distributed Control Systems (DCSs)).
Benzene emissions from glycol dehydrators	• Choose low-emission dehydrator options such as the following: - optimizing the operation of the dehydration unit (reduce the glycol circulation rate to the minimum required to ensure adequate freeze protection). - removing free water using a separator before the dehydration unit. - collecting and incinerating all vapours off the regeneration column, the glycol pump and all gas-operated instrumentation.
Methane emissions	• Use “low-bleed” or “no-bleed” devices. • Route any vented gas from pneumatic devices to an incinerator.

Traditional Practice or Area of Concern	Best Practice
Leak detection and repair	• Use low-methane measurement thresholds to determine when a repair is warranted. • Schedule planned activities to fix leaks at every turnaround.
Tank vapours — Fugitive emissions	• Use the following approaches to minimize fugitive tank emissions: - minimal tankage - stabilized liquids - floating roofs - vapour recovery units (VRUs) - vapour balancing systems - carbon absorption
Nitrogen oxides (NOx) emissions	• Use low-NOx burners on all turbines, boilers, and heaters. • Consider use of selective non-catalytic reduction and selective catalytic reduction to further reduce NOx emissions from large sources.
Greenhouse gas emissions	• Introduce greenhouse gas tracking and reporting systems.
Energy losses	• Maximize cogeneration use (electrical integration or heat integration).
Periodic stack surveys	• Use continuous emission monitoring (CEM) devices for all large point sources.

Traditional Practice or Area of Concern	Best Practice
Compliance monitoring	• Place ambient air quality monitors at the property line or in close proximity to the plant to monitor air contaminants of concern. • Locate air quality monitoring equipment at locations that monitor overall levels of pollutants at a regional level.
Routine filter change-out and disposal	• Change filters only when necessary by using differential pressure monitoring devices across the filter. This reduces the number of filters that must be managed.
Surface water releases to environment	• Manage surface water by - eliminating or minimizing the amount of contaminated surface water. - collecting and treating all contaminated surface water. - storing hazardous materials in bermed areas. - recycling runoff water that has been collected. - using a zero-drip policy. - using "zero blowdown" cooling water systems or aerial cooling.
Absence of groundwater monitoring data	• Set up a groundwater quality monitoring network.
Blowdowns and depressurizing	• Depressurize into the suction of a compressor to minimize the amount of gas that has to be flared. • Alternatively, depressurize to an incinerator or a flare stack.

Citizens' Rights

If you are concerned about an oil or gas processing facility and think that you may want to take part in the regulatory approval process, this section gives you information and advice on how to go about it.

It explains how you can get information and summarizes the key issues associated with an oil or gas processing facility. It also gives advice on how to have a say in the government's decision-making process when approving such a project. It is important to note that, in many cases, the best opportunity for the public to participate in the regulatory review of a well occurs before the well goes into production, at the well drilling stage (see the third primer in this series, Exploration and Production Drilling).

To conduct oil and gas exploration, companies have to get a permit or licence from the government that will allow them to do the work. The way companies get these rights and permits and licences varies between the NWT and the Yukon, and from region to region within each territory. The rules about public consultation and public intervention opportunities can also vary. You can find more details about the laws and procedures for each region of the Yukon and NWT in Citizens' Rights and Oil and Gas Development: Northwest Territories and Citizens' Rights and Oil and Gas Development Yukon Territory respectively.

If you have concerns about an oil or gas processing facility that is in production and has been granted permits and licences to operate, you should direct your questions, comments or concerns to the company and/or appropriate regulatory agency directly — in person, by phone or in writing. Most companies will be interested in addressing public concerns even if the project has already received government approvals.

Here are some steps to follow if you wish to review and comment on an oil or gas processing facility that requires a government approval or licence, or if you are concerned about an oil or gas processing facility that already has the necessary government approvals:

Find out about Proposed Projects

The first thing you need to do is make sure you know what proposals there are for companies to carry out oil or gas processing projects.

Companies send copies of oil or gas processing proposals and licence applications to government agencies, Aboriginal Nations or Groups, and interested parties. Companies may also arrange for copies to be available for public viewing at libraries and government offices.

You can register yourself as an "interested party" by contacting the primary government agency responsible for oil and gas development in your region. You will receive notice of new well site operation proposals and information about timelines for public comment on the regulatory approvals process.

Another way to get information about a proposed oil or gas processing facility is to contact the company directly and ask for a copy of detailed proposals or licence applications, as well as information about future development plans.

A company planning to conduct oil or gas processing (the proponent) must give public notice of their plans before they receive regulatory approval. Notice requirements vary from region to region. Sometimes companies will post notices in local newspapers or other media to announce proposed projects; other times you may have to be more active to ensure you are aware of new proposals.

Learn about Public Consultation Rules

Next, you need to find out the rules for public consultation in your area.

Contact the primary government agency responsible for oil and gas development in your region and get answers to the following questions:

- What does the company have to do to give notice of their proposed project?
- Who do they have to consult? What form does the consultation have to take (meetings, open houses, etc.)?
- What does the company have to do with the public comments they receive?
- What is the deadline for public comments?
- To what government agency approving bodies does the company have to send public comments?
- What do government agencies do with public comments and concerns they receive?
- What happens if the public objects to or wants conditions attached to the approval, licence or permit?
- What is the process for deciding whether and how the project will proceed?
- Is it possible to call for a public hearing, if needed?
- How can the public find out whether the government has granted a drilling approval, licence or permit?
- How can the public get a copy of approvals, licences or permits?
- Can the public appeal an approval, licence or permit? If so, how?

Review the Oil or Gas Processing Facility Application

Once you've received a copy of a company's proposal for an oil or gas processing facility, and have learned about the rules for public consultation, you'll next want to review the project application.

When you review the application you may find that you are satisfied with the information presented or you may have questions or concerns about the project.

If you have questions or concerns, make of list of these and call a meeting with the company and/or proper government agency to discuss them (see box on page 49 : *How to negotiate with companies*).

If you can't resolve your concerns about the project directly with the company or government agency you may wish to call for a public hearing (see section on page 48: *Participate in Decision Making*) if such a legal avenue is available.

Key questions to ask when reviewing an oil or gas processing facility operation permit or licence application (note that this is a general list and only a subset will be applicable to specific licence and permit applications):

- ❑ What type of a facility is the developer proposing? How often will vehicles travel to the facility?
- ❑ How many years does the company estimate the facility will operate?
- ❑ How will crews manage and dispose of surface water?
- ❑ How will crews manage and dispose of waste?
- ❑ What does the developer estimate will be the emissions to air and water?
- ❑ What are the company's spill detection, response and cleanup capacity and measures?
- ❑ How large is the site?
- ❑ What permafrost protection measures will crews use?
- ❑ What sources of freshwater will they use? How much water will they need?
- ❑ How will crews manage and dispose of produced water?
- ❑ Is there any chance the workers will encounter hydrogen sulphide?
- ❑ Does the developer have an Emergency Response Plan? How big is the evacuation zone?
- ❑ Will crews use alternatives to flares and flare reduction measures?
- ❑ What type of fugitive emission detection/ control system does the developer have in place?
- ❑ Are there emission controls on pneumatic devices?

- ❑ Are there emission controls on dehydration units?
- ❑ What well casing protection measures does the company have in place?
- ❑ How will the developer monitor groundwater quality?
- ❑ What noise mitigation measures are being utilized?
- ❑ Has the company clearly outlined measures to avoid disturbing wildlife? Does the company have policies to ensure workers know how to minimize impacts on wildlife?
- ❑ Has the developer assessed socio-economic benefits (e.g., employment of local residents) and impacts associated with the proposed project?
- ❑ How will the company manage any newly created recreational access to the area?

Participate in Decision Making

If you meet with the company and government agencies directly and find you can't resolve your concerns about the project, you may wish to call for a public hearing.

Public hearings are meetings held to get comments from the general public, businesses, special interest groups, and local officials about proposed regulations, permits, or other changes that could affect the public.

You'll need to find out the rules for holding public hearings in your region, whether such a legal avenue is available for commenting on drilling projects and what the terms are. You can find more details about public participation in regulatory decision making in Citizens' Rights and Oil and Gas Development: Northwest Territories and Citizens' Rights and Oil and Gas Development: Yukon Territory. These guides include government agency contacts that you can call to get more information about how governments conduct hearings and the specific rules for members of the public to call for and participate in hearings.

You'll want to find out

- When are the deadlines for letters calling for hearings and for written and oral submissions?
- Who has intervener status — that is, the legal right to call for a hearing?
- Is there funding available for interveners to hire experts, including lawyers?
- What are the hearing procedures?
- Are there any appeal mechanisms?

HOW TO NEGOTIATE WITH COMPANIES

Most companies have experience dealing directly with members of the public who have questions and concerns about oil and gas projects. They usually welcome opportunities to meet with interested parties, to provide information and to try to resolve issues outside of formal regulatory decision-making forums.

When involved in discussions with a company, make sure you

- ❑ *Get everything in writing. If you have an oral agreement or telephone conversation with a company representative, ask him or her to confirm it in writing and to send copies to the proper government agencies.*
- ❑ *Ask the company to explain anything you do not understand. If some of the written information the company has provided is ambiguous, ask for clarification in writing.*
- ❑ *Tell the company any concerns you have about the project. Suggest ways they could change the project to address your concerns. Be persistent if the company does not adequately resolve your concerns right away.*
- ❑ *Don't make a deal with the company wherein they only agree to deal with your issues of concern if you agree to not take part in a hearing. Sometimes it is not possible for you and the company to resolve all of the issues. But, if a public hearing is held, it will be shorter and more focused if you have resolved as many of the issues as possible. A shorter, more focused hearing is to the benefit of all parties involved.*
- ❑ *Recognize that some "give and take" may be necessary. For successful negotiation, both parties must be able to reach their final objectives and be willing to agree with the other.*
- ❑ *Negotiations can take a long time. Often members need a lot of time to both review and write documents. Therefore, it is important to research opportunities for intervener funding. It may be reasonable to ask the company for funding to make sure that members of the public can be more effectively engaged in the consultation.*

WORKING WITH THE MEDIA

Using the media to raise public awareness about an issue is not always appropriate. Under some circumstances, however, it can be an important tool:

- ❑ *It can make other members of the public aware of the proposed project and your concerns. This can help build support for your activities and increase your chances of success in negotiating with the company.*
- ❑ *It can encourage a company to negotiate. Many companies worry about their public image and would like to avoid negative publicity. Real or potential media attention on an issue may be an incentive for a company to try to resolve issues.*
- ❑ *It may ensure the government agencies are aware of and involved in your issue.*

Media include:

- ❑ *local, regional and national newspapers*
- ❑ *local and regional radio stations*
- ❑ *community and regional television stations*

If you have a message to get out, sending out a news release can be helpful. It does not have to be long, but you need to consider the following:

- ❑ *Decide on your main message and state this clearly in the first sentence.*
- ❑ *Include a brief outline of your key concerns and the outcome you want.*
- ❑ *Include one or more contact names and numbers.*
- ❑ *Put a short title at the top of the release — something eye-catching. Put the date at the top as well.*
- ❑ *Keep the release short — less than a page. You may want to include quotes and position statements.*
- ❑ *Consider including a separate "backgrounder piece." A backgrounder gives only factual information on the subject, rather than opinions.*
- ❑ *Make sure you are aware of the deadline for making submissions to the media.*
- ❑ *When your news release is ready, you should fax or deliver it to your local and regional newspapers, radio and television stations. Follow up with phone calls to select media contacts.*
- ❑ *Send a copy of your news release to both the company and the proper government agency. This will allow them to be better prepared to respond to the media if they know in advance what you are saying.*

For More Information

For information on government agencies, industry associations, and further reading on this issue, please consult the companion publication entitled: **Resources and Contacts.**

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