WRAP Oil & Gas Scoping Paper

Draft 1a

Development of Scoping Paper for the Oil and Gas Industry – Draft 1a

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Western Regional Air Partnership

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1 INTRODUCTION

1.1 PURPOSE

The purpose of this Background and Scoping paper is to provide the Western Governor's Association (WGA) Project Steering Committee, the Technical Workgroup, and the Protocol Advisory Group (PAG) with a detailed, comprehensive analysis of the technical issues surrounding the estimation of greenhouse gas (GHG) emissions in the Oil and Gas (O&G) Exploration and Production (E&P) sector. This paper discusses the options (including pros and cons) and presents recommendations for addressing these issues.

This background and scoping paper provides an overview of the O&G E&P and gas processing sectors in those North American states that are within the jurisdictions of the Western Climate Initiative, provides a comprehensive catalogue, including a description and prioritization, of emissions of the six Kyoto GHGs (carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons and perfluorocarbons) by source and provides an examination of current GHG estimation methodologies. Additional chapters that review reporting and verification issues within the sector will be fully developed at a later stage of this work.

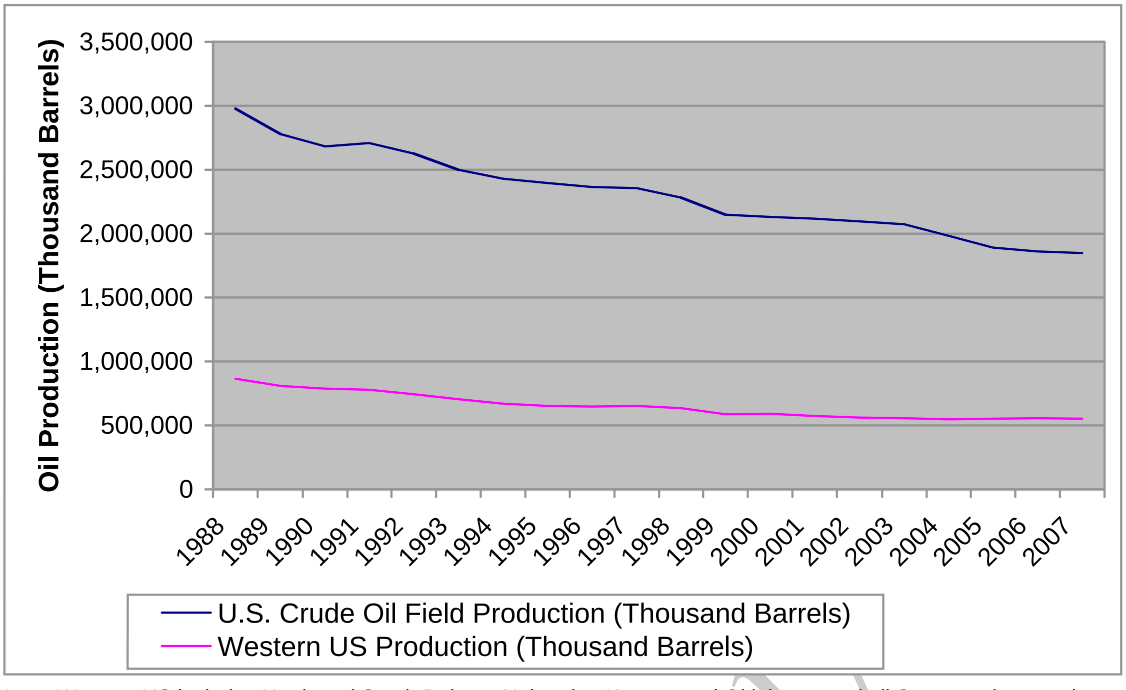
1.2 BACKGROUND

In 2006, nearly 19.4 trillion cubic feet of natural gas and about 1.9 billion barrels of crude oil were drawn from oil and gas wells in the United States[1]. Of the totals in 2006, the Western states[2] comprised about 7.5 trillion cubic feet of natural gas and 0.55 billion barrels of crude oil. Trends in oil and gas production over the past 10 to 15 years are shown in Figure 1 and Figure 2, where the total US field production is compared to the Western US onshore production. Figure 1 shows the gradual decline in onshore oil production over the past 20 years.

Most Western states onshore oil production followed the same trend with the exception of Montana whose crude production has grown from about 15,000 barrels in the year 2000 to about 35,000 barrels in the year 2007 or about a 233 percent increase. Likewise, North Dakota production increased production from about 30,000 in 2003 to about 45,000 in 2007 representing about a 150% increase. South Dakota had a similar increase in natural gas production from 1200 barrels in 2000 to over 1600 barrels in 2007.

[1] Energy Information Administration, Annual Energy Outlook 2008 (http://www.eia.doe.gov/oiaf/aeo/supplement/index.html)

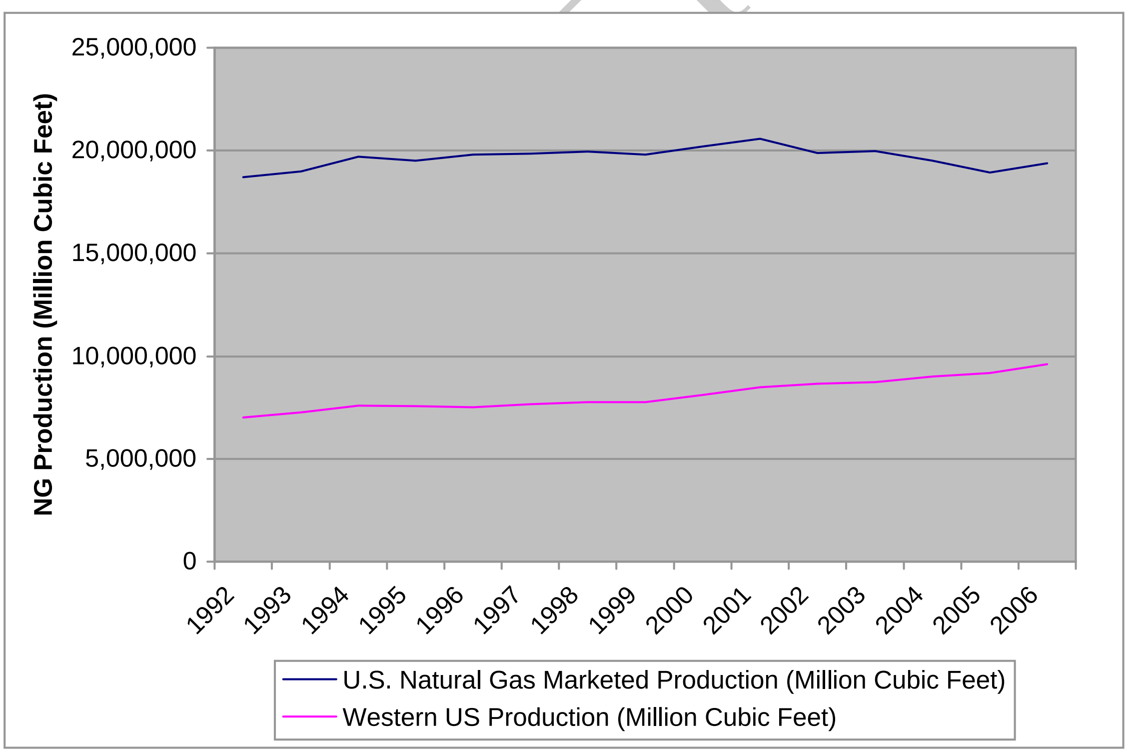
[2] For the purpose of this project, Western U.S. O&G E&P activities refer to all onshore and offshore E&P operations within the following states: California, New Mexico, Washington, Oregon, Montana, Idaho, Wyoming, North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Colorado, Utah, Arizona, and Nevada. This definition excludes the state of Alaska.



Note: Western US includes North and South Dakota, Nebraska, Kansas and Oklahoma and all States to the west but excludes Texas and Alaska.

Figure 1 US & Western US Onshore Oil Production per year

Source: EIA Annual Energy Outlook 2008



Note: Western US includes North and South Dakota, Nebraska, Kansas and Oklahoma and all States to the west but excludes Texas and Alaska.

Figure 2 US & Western US Onshore Natural Gas Production per year

Source: EIA Annual Energy Outlook 2008

Figure 2 shows the trends in natural gas production from 1992 to 2006. While overall US production has remained fairly constant over the past 7 years, natural gas production in the West has shown an increasing trend over the same period.

Most states in the Western US have shown trends similar to the overall levels of natural gas production and in some cases have shown significant increases over previous years. The states of Montana, New Mexico, Utah and Colorado have shown significant increases in natural gas production over the past 10 years. For example natural gas production in Colorado has risen from about 572,000 million cubic feet (MMcf) to over 1,200,000 million cubic feet from 1996 to 2006. It is also worth noting that natural gas production in Wyoming has risen from 666,000 million cubic feet in 1996 to over 1,800,000 million cubic feet in 2006, more than doubling its production. Finally, natural gas production in Utah has risen from about 251,000 million cubic feet in 1996 to 348,000 million cubic feet in 2006.

To achieve the levels of production shown in Figure 1 and Figure 2, an extensive fleet of oil and gas production equipment operates continuously across the Western U.S. The sizes and types of equipment in that fleet vary from small chemical injection pumps up to gas turbines of several thousand horsepower. Even the smallest of these source types has the potential to generate significant greenhouse gas (GHG) emissions when the continuous operation and the number of units are taken into consideration. Many previous regional and state emission inventories have addressed limited segments of the oil and gas production industry but have not provided a detailed inventory of GHG[3,4].

Emissions of GHG occur in all sectors of the oil and gas industry in the form of both methane (CH_4) and carbon dioxide (CO_2). Methane emissions occur in all sectors of the natural gas industry, from drilling and production, through processing and transmission, to distribution. They primarily result from normal operations, routine maintenance, fugitive leaks and system upsets. As gas moves through the system, emissions occur through intentional venting and unintentional leaks. Venting can occur through equipment design or operational practices, such as the continuous bleed of gas from pneumatic devices (that control gas flows, levels, temperatures, and pressures in the equipment), or venting from well completions during production. In addition to vented emissions, methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment. In addition to emissions from natural gas operations, methane emissions can result from the oil industry, primarily from field production operations, such as venting of associated gas from oil wells, oil storage tanks, and production-related equipment such as gas dehydrators and pneumatic devices[5].

CO_2 emissions occur from combustion of fossil fuels in various oil and gas operations such as internal combustion engines used for driving compressors at well heads and from other combustion equipment used in natural gas processing plants and refineries including turbines, boilers and heaters. Vented CO_2 emissions are associated with field operations such as storage tanks, pneumatic devices and process upsets, although the amount of CO_2 present would be small compared to the CH_4 emissions. Flaring emissions account for a majority of the non-energy CO_2

[3] WRAP Phase I and II oil and gas area source inventories (http://www.wrapair.org/forums/ogwg/Phases_I_and_II_Inventories.html)
[4] Texas Commission on Environmental Quality, 2005 oil and gas emission inventory
[5] US EPA Natural Gas STAR Program. http://www.epa.gov/gasstar/basic-information/index.html

emissions in field operations while the majority of CO_2 emissions from processing plants come from acid gas removal units, which are designed to remove CO_2 from natural gas.

Emissions of other GHGs may include sulfur hexafluoride (SF_6) from their use as tracers in hydrocarbon reservoir characterization and recovery and several hydrofluorocarbons and perfluorocarbons used in vehicle air conditioning systems, these emissions are not likely to be significant. In addition, nitrous oxide (N_2O) is a byproduct of combustion from mobile and stationary sources although emissions are small compared to CO_2 and CH_4.[6]

This paper will only address the oil production processes that include exploration (drilling and completions), production (surface facilities) and processing. This includes the chain of processes up to the point of custody transfer. Refining, transmission, storage and distribution of petroleum productions are not addressed in this paper. However, "Heavy Oil Upgraders" which refine heavy oil and bitumen into lighter, more desirable crude will be included in this paper if such a facility is associated with a production field. For natural gas production operations, this paper will only address the processes that include exploration (drilling and completions), production (surface facilities) and natural gas processing up to the point of custody transfer via injection into a transmission pipeline. Transmission, storage and distribution of natural gas productions are not addressed in this paper. Accordingly, all processes up to the inlet valve[7] of the distribution system are included in this paper.

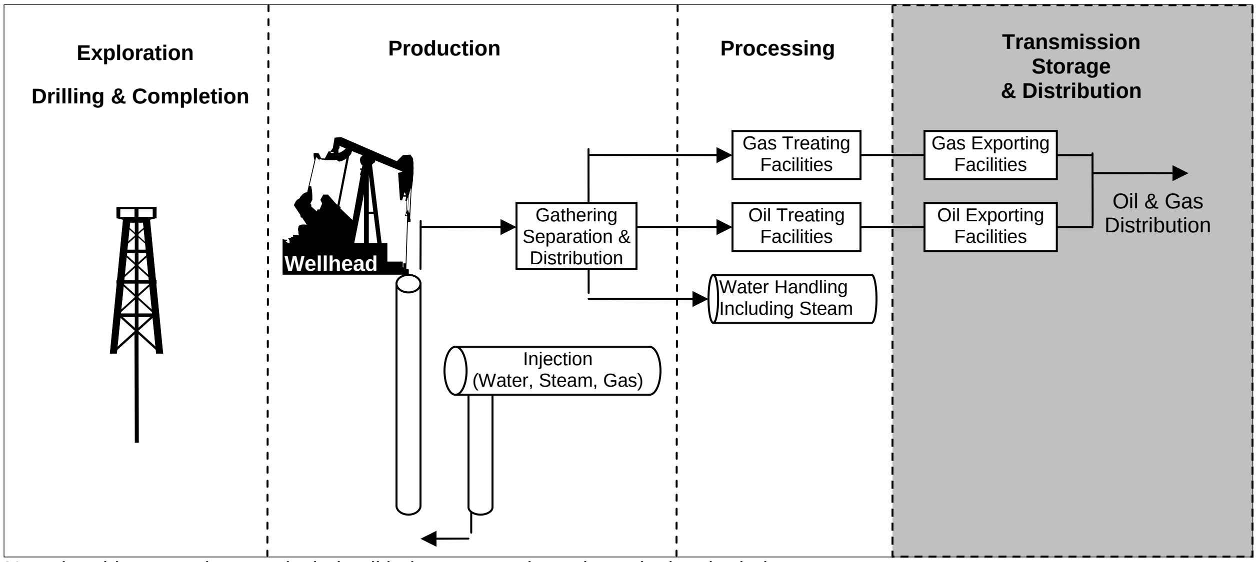
The Natural Gas STAR is a program that has been developed by the EPA in partnership with the oil and gas industry to provide a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities. Under this program the industry, in conjunction with Natural Gas STAR partnership, has pioneered some of the most widely used, innovative technologies and practices that reduce methane emissions. These practices are recognized in this paper and are accounted for in determining the methodologies for estimating GHG emissions, which includes methane reductions that have occurred as a result of this program.

1.3 ONSHORE OIL PRODUCTION OPERATION AND TRENDS

Onshore oil exploration and production consists of a wide range of activities ranging from exploratory drilling to extraction, gathering, processing and distribution to refining. To be commercially viable, a well must be able to produce enough oil or gas to justify the costs of drilling and placing it in production. If exploratory wells establish the presence of producible quantities of oil or gas, "development" wells are drilled to define the size and extent of the field. Depending on the type of product, the technology also can have an impact on exploration activity. For example, extensive exploitation of the large volumes of heavy oil such as that found in California is dependent on the development of enhanced recovery techniques. Figure 3 shows the wide range of activities in each sector of the process.

[6] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006, April 15, 2008, U.S. Environmental Protection Agency

[7] Point of custody transfer



Note that this report does not include oil industry operations shown in the shaded area

Figure 3 Primary Sectors in the Oil Industry

Typically, about 10 percent of the oil is recovered from a typical reservoir by natural means or primary recovery techniques[8]. Therefore as production declines or as crude oil, natural gas, or their products and byproducts become more valuable it is necessary to optimize recovery using more advanced techniques. Formations that may have been considered capable of only minimal production in the past may now achieve good production rates through completion practices that, with better prices for oil and gas or improved technology, are worth implementing.

Crude oil development and production from U.S. oil reservoirs can include up to three distinct phases: primary, secondary, and tertiary (or enhanced) recovery. While oil wells can sometimes produce through their own natural pressure, most require some method of lifting or pumping the oil to the surface. During primary recovery, the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumpjacks or electric submersible pumps), bring the oil to the surface. Associated natural gas can also provide pressure within the well to support oil recovery[9]. However, only about 10 percent of a reservoir's original oil in place is typically produced during primary recovery. Secondary recovery techniques add to the field's productive life generally by injecting water or gas to displace oil and drive it to a production wellbore, resulting in the recovery of 20 percent to 40 percent of the original oil in place[10].

Fugitive GHG emissions and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and comparatively less from the processing of the oil because much of the methane escapes prior to delivery to the refineries. Production operations that have the potential for significant GHG emissions include venting from field storage tanks, CO_2 emissions from diesel fired engines, CO_2 emissions resulting from combustion and CH_4 emissions resulting from fugitive methane emissions and methane released through incomplete combustion, chemical injection pumps, heaters and process upset emissions and pneumatic devices

[8] U.S.DOE, http://fossil.energy.gov/programs/oilgas/eor/index.html
[9] Natural Gas Supply Association: http://www.naturalgas.org/naturalgas/well_completion.asp
[10] US DOE. Enhanced Oil Recovery/CO2 Injection. http://fossil.energy.gov/programs/oilgas/eor/index.html

Several techniques are now employed to increase production. Common techniques include fracturing where materials are pumped down the well under high pressure to enhance existing[11] or to create new[12] cracks in the reservoir rock so that the oil or gas can move more freely through the formation. The most common enhanced-recovery method, water injection, involves injecting water into the oil-bearing formation; the water forces the oil toward the producing well bore.

To recover additional resources, producers use several tertiary, or enhanced oil recovery (EOR), techniques that offer prospects for ultimately producing a significantly higher percentage of the resources. EOR techniques include:

- Thermal recovery, which involves the introduction of heat such as the injection of steam to lower the viscosity, or thin, the heavy viscous oil, and improve its ability to flow through the reservoir. It is estimated that thermal techniques account for over 50 percent of U.S. EOR production, primarily in California[13].
- Gas injection, which uses gases such as natural gas, nitrogen, or carbon dioxide that expands in a reservoir to push additional oil to a production wellbore, or other gases that dissolve in the oil to lower its viscosity and improves its flow rate. Gas injection accounts for nearly 50 percent of EOR production in the United States[1].
- Chemical injection, which can involve the use of long-chained molecules called polymers to increase the effectiveness of waterfloods, or the use of detergent-like surfactants to help lower the surface tension that often prevents oil droplets from moving through a reservoir. Chemical techniques account for less than one percent of U.S. EOR production[1].
- Acidizing a well consists of injecting acid (usually hydrochloric acid) into the well. In limestone or carbonate formations, the acid dissolves portions of the rock in the formation, opening up existing spaces to allow for the flow of petroleum.

Other methods are also used, including fire flood and other flood methods for recovering petroleum from oil reservoirs of low permeability and temperature. With the fire flood method, the combustion of petroleum in the reservoir is provided by injecting into the reservoir a combustion supporting medium consisting essentially of oxygen, ozone, or a combination thereof. The heat of combustion and the products of this combustion, which consist essentially of gaseous carbon dioxide and water vapor, sufficiently decrease the viscosity of oil adjacent to the fire front to form an oil bank that moves through the reservoir towards a recovery well ahead of the fire front. The gaseous carbon dioxide and the water vapor are driven into the reservoir ahead of the fire front by pressure at the injection well. As the gaseous carbon dioxide cools to less than about 88° F. it is converted to liquid which is dissolved in the oil bank to further increase the recovery.

Fugitive GHG emissions and vented CO_2 emissions from petroleum systems are primarily associated with crude oil production and comparatively less from the processing of the oil. Production operations that have the potential for significant GHG emissions include field storage

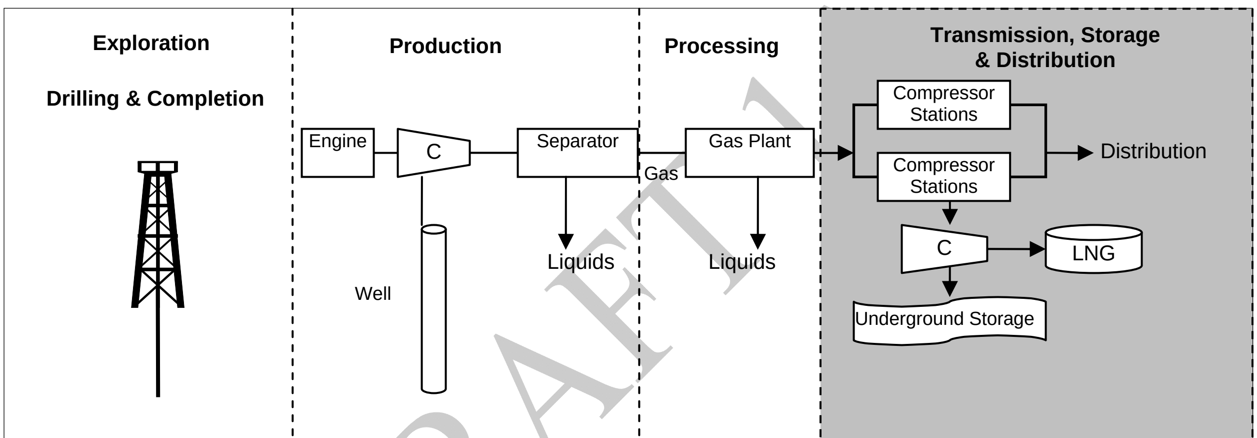
[11] US DOE: http://nuclear.energy.gov/pdfFiles/nationalEnergyPolicy.pdf
[12] US DOE EERE: http://www1.eere.energy.gov/geothermal/pdfs/egs_appendix.pdf
[13] DOE: http://fossil.energy.gov/programs/oilgas/eor/index.html

tanks, gas and diesel fired engines, chemical injection pumps, heaters and process upset emissions.

1.4 ONSHORE NATURAL GAS PRODUCTION

As with oil exploration and production, natural gas operations consist of a variety of activities ranging from exploratory drilling to extraction, gathering, processing and distribution. The following diagram shows the primary sectors in the natural gas industry

Figure 4 shows the wide range of activities in each sector of the process. Natural gas, as it exists underground, usually undergoes processing before it is of a sufficient quality to be distributed through the pipelines. Processed natural gas is almost entirely methane. Natural gas as found underground, however, can come associated with a variety of other compounds and gases, as well as oil and water, which must be removed. To meet specifications for end users, most natural gas processing occurs near the well.



Note that this report does not include natural gas operations shown in the shaded area

Figure 4 Primary Sectors in the Natural Gas Industry

Natural gas is obtained from oil wells, dry gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'non-associated gas'. While natural gas by itself is produced from gas wells, condensate wells produce free natural gas along with a very low density liquid hydrocarbon called natural gas condensate[14]. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas can contain water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

At the beginning of a gas well life, if sufficient pressure exists, the gas generally flows to the surface through its own pressure; thus, a natural-gas wellhead is usually composed of only a series of chokes and valves to control flow. As production and pressure drop, and wellhead compressors are used to maintain the flow. Wellhead compressors are generally fueled with

[14] "A semi-liquid hydrocarbon condensate". Natural Gas Supply Association: http://www.naturalgas.org/naturalgas/processing_ng.asp

natural gas where significant gas production is found. Such compressors are prevalent throughout the Western US and are a significant source of CO_2 emissions. Crude oil, which typically contains some natural gas or solution gases, is sometimes produced through its natural pressure, but most crude oil wells require some method of lifting or pumping the oil to the surface. A surface pumping unit is often referred to as a “pump jack”, but newer methods of lifting include electric submersible pumps (ESP)

Methane and CO_2 emissions from natural gas systems are generally process related with normal field operations (e.g., gas engines and compressors) routine maintenance and system upsets being significant contributors. Natural gas engines, bleed and discharge from pneumatic devices, and fugitive emissions from components throughout the production and processing system contribute to the GHG emissions. GHG are emitted during production activities, including methane escaping from the wells themselves through venting during well completions and well workovers, fugitives from oil and condensate storage tanks and gathering lines, and from gas treatment equipment at the well site, e.g., dehydrators and separators. Likewise, during the processing of natural gas, CH_4 is emitted from compressors. Specifically, emissions occur from compressor seals due to the entrainment of process gas in the oil seal that is released as methane into the degassing drum and through the vent line from wet seal centrifugal compressors. Poorly maintained compressor rod packing is a source of methane emissions from reciprocating compressors. Other sources include acid gas removal units and CO_2 emissions resulting from combustion processes such as engines and turbines.

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas[15]. First, natural gas must be separated from any oil that was also extracted from the well. The separation of natural gas from oil is most often done using equipment installed at or near the wellhead. Such equipment can include Low-Temperature Separator (LTX), which uses pressure differentials to cool the wet natural gas and separate the oil and condensate. Glycol Dehydration is a process where a liquid desiccant dehydrator serves to absorb water vapor from the gas stream. The glycol solution, usually either diethylene glycol (DEG) or triethylene glycol (TEG), absorbs water from the wet gas along with some methane. The dehydrated “dry” natural gas exits the contactor tower from the top and is fed into a pipeline or gas plant, while the water-rich glycol exits through the bottom[16]. The glycol solution, bearing all of the water that was stripped from the natural gas, is then fed through a specialized boiler that is designed to vaporize the absorbed water out of the solution in order to recover the glycol solution[17]. Glycol dehydrators are a large source of avoidable methane emissions. Technologies exist to recover methane emissions from the dehydrators, such as flash tank separators and routing the gas to a fuel use.

Then, prior to distributing the natural gas into the pipeline, products known as associated hydrocarbons must be removed. Associated hydrocarbons from this process are also known as 'natural gas liquids' (NGLs) and include ethane, propane, butane, iso-butane, and natural gasoline. There are two basic steps to the treatment of natural gas liquids in the natural gas stream. First, the liquids must be extracted from the natural gas. Second, these natural gas liquids must be separated themselves, down to their base components. These NGLs are sold separately

[15] Natural Gas Supply Association: http://www.naturalgas.org/naturalgas/processing_ng.asp
[16] Kidnay, A.J., and W. Parrish. Fundamentals of Natural Gas Processing. Pg. 140.
[17] Natural Gas Supply Association: http://www.naturalgas.org/naturalgas/processing_ng.asp

and have a variety of different uses including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy.

In contrast to processes to separate natural gas from oil, the removal and separation of natural gas liquids often takes place in a relatively centralized gas processing plant. NGL separation generally uses techniques similar to those used to dehydrate natural gas, or cryogenic processes. While absorption methods are generally sufficient to remove heavier hydrocarbons, lighter NGLs, such as ethane may be economic to recover as well. In such cases, cryogenic processes are usually used. Cryogenic methods drop the temperature of the natural gas stream in order to cause the NGLs to condense in the stream, enabling separation and removal from the still-gaseous methane. In areas such as the San Juan Basin, dehydration processing at the well site as opposed to a central processing plant is prevalent. In these regions, wellhead separators are used to remove significant quantities of condensate from produced gas. The condensate is then usually stored in tanks or tank batteries located at the wellhead. Condensate tank emissions are a very large source of methane emissions and are substantially underreported in the U.S. greenhouse gas inventory by more than an order of magnitude, yet using available technologies, methane emissions can be captured off of tanks. Recovering methane emissions also offers an ancillary benefit of reducing emissions of heavier hydrocarbons which are criteria pollutants. These tank batteries are periodically unloaded by truck and transported to be sold to a refinery.

In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal from so-called "acid gases" of sulfur, carbon dioxide and nitrogen. The natural gas from some wells contains significant amounts of sulfur compounds, including hydrogen sulfide and mercaptans. These sulfur compounds must be removed because the Public Utilities Commission has set maximum allowable total sulfur and H_2S content. Further, many utility companies set maximum allowable levels in their purchasing contract agreements[18]. Such natural gas, because of the rotten smell provided by its sulfur content, is commonly called "sour gas." Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful, even lethal, to breathe as hydrogen sulfide is toxic. Sour gas can also be extremely corrosive[19]. These sulfur compounds, however, can be extracted via processes known as "sweetening" and marketed on their own. A variety of sulfur extraction processes are in use across the natural gas industry today. Methods include amine systems, LoCat systems (using a mixed solution of iron chealate, caustic and water), SulfaCheck (liquid chemical), SulfaTreat (solid packed bed scrubber) and Stretford systems[20]. The primary process for sweetening sour natural gas involves the use of amine solutions to remove the hydrogen sulfide through absorption, much like the use of glycol to absorb water content. ,Known as the "amine process," this method of removal is used in 95 percent of U.S. gas sweetening operations[21]. Then in order to recover elemental sulfur from the gas processing plant, the sulfur-containing discharge from the gas sweetening process must be further treated. This process is known as the Claus process and it involves using thermal and catalytic reactions in a Claus unit to extract elemental sulfur from the concentrated hydrogen sulfide acid gas.

[18] Kidnay, A.J., and W. Parrish. Fundamentals of Natural Gas Processing. Pg. 91.
[19] Natural Gas Supply Association: http://www.naturalgas.org/naturalgas/processing_ng.asp
[20] "Gas Industry Assesses New Ways to Remove Small Amounts of H2S." *Oil & Gas Journal*. 23 May 1994, Vol. 92, No. 21. http://www.ogj.com/articles/save_screen.cfm?ARTICLE_ID=13017.
[21] Natural Gas Supply Association: http://www.naturalgas.org/naturalgas/processing_ng.asp

Carbon dioxide and nitrogen may also have to be removed from the natural gas stream before it is of saleable quality. Because many purchasers of natural gas set standards for the inert gas content of the product they receive, some gas producers must install systems to remove CO_2 and N_2 from the stream. CO_2 removal is typically also done using amine systems, or by molecular sieve systems. The CO_2 removed using the amine process is typically vented, or where it is produced in marketable quantities, it may be sold for other processes, such as EOR[22]. Nitrogen-contaminated natural gas has a low Btu value, and thus must be upgraded by removing the nitrogen. Cryogenic processes are the most typical for this purpose, although other methods are necessary in plants with low gas throughput[23].

1.4.1 Unconventional Natural Gas Resources

Historically, conventional natural gas deposits have been the most practical, and easiest, deposits to extract. However, as technology and geological knowledge advance, unconventional natural gas deposits are beginning to make up an increasingly larger percent of the supply picture. Three such categories are relevant to the Western States; tight gas, shale gas and coal bed methane.

Tight Gas

Tight gas refers to gas that is located in a very tight formation underground, trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (tight sand). Extracting gas from a tight formation requires a great deal more effort than extraction from more permeable reservoirs. Several techniques exist that allow natural gas to be extracted, including fracturing and acidizing, however, these techniques are also very costly. Fracturing consists of injecting a fluid into the well, the pressure of which cracks or opens up fractures already present in the formation.

Like all unconventional natural gas, the economic incentive must be there to incite companies to extract this costly gas instead of more easily obtainable, conventional natural gas. The EIA provides an estimate of the potential basins containing such formations[24]. One of the largest Basins in the US, the Wattenberg Basin in Colorado represents 126 Bcf (1999). It was estimated (in 1999) that the Jonah Field in the Green River Basin has 2 Tcf of estimated reserves. Overall the Rocky Mountain area represented nearly 40% of the total annual tight gas production in the lower 48 states from 2000 - 2007. Tight gas production itself accounted for less than 30% of total on-shore gas production in the lower 48 states in 2000, but has been growing and accounted for roughly 37% of total on-shore production in 2007.

Shale Gas

Shale has low matrix permeability, so the production of shale gas, like tight gas, requires fracturing to produce gas in commercial quantities. Past shale gas production has utilized naturally fractured sources. Further development of shale gas requires conditions where

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[22] Kidnay, A.J., and W. Parrish. Fundamentals of Natural Gas Processing. Pg. 93.

[23] US DOE NETL: Nitrogen Removal from Natural Gas Using Membranes, http://www.netl.doe.gov/publications/proceedings/97/97ng/ng97_pdf/NG8-2.PDF.

[24] A Long Term View for Unconventional Gas, Presented at the National Energy Modeling System/Annual Energy Outlook Conference 2001, presented by Vello A. Kuuskraa and Brian T. Kuck of Advanced Resources International, Inc.

hydraulic fracturing or other improving technologies are an economic means to stimulate additional gas production[25].

Coalbed Methane (CBM)

In many locations throughout the Mountain States, coal deposits are found in underground seams. Many coal seams also contain natural gas, either within the seam itself or the surrounding rock. Coalbed methane (CBM) is contained within an unmined seam. Coal mine methane (CMM) refers to methane that is desorbed from the seam or surrounding strata due to relaxation of the strata during mining operations. Historically, CBM has been considered a nuisance in the coal mining industry, because the natural desorption of methane from the seam creates a safety hazard in the mine. In the past, the methane that accumulated in a coal mine was intentionally vented into the atmosphere. Today, however, both coalbed and coal mine methane have become popular resources of unconventional natural gas. CBM may be extracted independent of any current or future coal mining operations, typically producing a high quality methane resource. CMM is that which is extracted from seams that are currently mined or that lie within a mine plan and will be mined through in the future. CBM and CMM can be extracted and injected into natural gas pipelines for resale, used as an industrial feedstock, or used for heating and electricity generation. In some cases, CMM production requires removing water from the coal seam before production begins. In the Western States, the primary basin where CBM and CMM are produced is the San Juan Basin in New Mexico. It was estimated (in 1999) that the Powder River Basin, located in Wyoming, had 12 trillion cubic feet of technically recoverable gas within its coal seams. Overall it was estimated that the San Juan Basin and the Rocky Mountain area together represented about 85 percent of the total annual CBM production in the US from 2000-2006. The EIA estimates that during this period CBM production accounted for 10 percent to 12 percent of the total US on-shore gas production.

1.5 ONSHORE DRILLING OPERATIONS

Drilling operations are treated separately here as these operations have their own characteristics such as the drilling horsepower, the anticipated drilling depth and drilling time. Emissions of GHG are related to the size of drilling engines and fuel burned as well as other drilling related operations such as completions. In addition, drilling rigs are moved from field to field to find new resources or to optimize the recovery of existing once.

Drilling is generally accomplished by a bit at the end of lengths of steel pipe. Each piece of pipe is typically 30 feet long and is added, a length at a time, by threading onto the next piece of pipe. The revolving bit cuts and grinds through rock formations, and is lubricated and cooled by drilling fluid commonly called drilling "mud," a mixture of water or oil, clay and chemicals.

A deep-rated drilling rig, which might be used to drill wells up to 10,000 feet deep, is composed of much heavier, larger and stronger equipment than one used to drill shallow wells (e.g., 3000 ft deep) thereby resulting in greater GHG emissions.

A potential limiting factor is the number of drilling rigs in operation at any given time. The number of rigs depends on oil prices. New drilling rigs can cost about $20 million, depending on

[25] US DOE EIA. *Energy in Brief: Is US Natural Gas Production Increasing?* 11 June 2008. http://tonto.eia.doe.gov/energy_in_brief/natural_gas_production.cfm

the type of drilling. Additionally, aging rigs have less efficient equipment and, thus, higher GHG emissions. Some such rigs are torn down and completely refurbished every few years. As oil demand increases and prices rise, drilling becomes more attractive. The number of active rigs in the US bottomed out at fewer than 500 in the second quarter of 1999 and has steadily increased to over 1,700 by the beginning of 2007. The rise in drilling activity, spurred by high oil prices, has increased demand for oil and gas field services and equipment. High demand has driven up prices for both third-party drilling services and field machinery and equipment. Over the past three years, prices for oil and gas support services have risen 40 percent; prices for oil and gas field machinery and equipment increased 27 percent.[26]

In addition to rig count, the percentage of wells completed as oil or gas wells is frequently used as a measure of success. In fact, this percentage is often referred to as the success rate. When a well is drilled, the fact that oil or gas is found does not mean that the well will be completed as a producing well. The determining factor is economics. If the well can produce enough oil or gas to cover the additional cost of completion and the ongoing production costs it will be put into production. Otherwise, it will be plugged and abandoned and designated a dry hole. Improved technology and the shift to a higher percentage of natural gas drilling activity can account for much of the increase in production.

Throughout the drilling process, progress of the well is monitored to determine whether completion or abandonment of the well is appropriate. Throughout the drilling operation, the rock cuttings are examined for traces of hydrocarbons and other evaluations and analyses are made. If the well is judged a dry hole, it will be plugged with cement and abandoned. However, if the well can produce hydrocarbons at economically viable rates, the well will be "completed." Completion consists of installing of production casing, and cementing a tubular steel pipe the length of the well bore. After this process, the drilling rig is usually removed from the well and a truck-mounted service rig is moved into place. The production casing is perforated to allow entry of fluids and gases from the producing formation into the well bore. The perforations also provide access to the producing formation for other completion activities that may be undertaken.

Green completions are a method to reduce the amount of GHG emissions (methane) that are released during the completion process. Traditionally, the well completion involves producing the well to open pits or tankage where sand, cuttings and reservoir fluids are collected for disposal and the produced natural gas is vented to the atmosphere. Natural Gas Star Program partners have reported that equipment has been brought to the site to clean up the gas traditionally released to the atmosphere. The equipment includes more tankage, gas-to-liquid-sand separator traps and portable gas dehydration. Reported methane savings were estimated to be 7,410 Mcf per year for 63 wells using this technique in an EPA Natural Gas Star pilot program.[27]

Workover rigs are used to pull tubing for repair or replacement of rods, pumps and tubular goods that are subject to wear and corrosion. These rigs are usually used for existing wells that may need to be completed or repaired. Emissions of GHG are from engines used on the workover

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[26] Hoovers, Oil & Gas Exploration & Production Industry Trends, http://industries.hoovers.com/energy-and-utilities/oil-and-gas-exploration-and-production/industry_trends

[27] Green Completions Fact Sheet No. 703, Natural Gas Star Program. http://www.epa.gov/gasstar/documents/greencompletions.pdf

rigs for these type of operations. According to Baker-Hughes, Energy Information Administration (DOE) WTRG Economics, the US Workover rig count over the past 7 years has steadily increased from about 700 to about 1400 reaching a level similar to that in the 1990's.[28]

Several techniques are now employed to enhance exploration. In practice, using seismology for exploring onshore areas involves artificially creating seismic waves, used to map underground geologic formations. The increased use of and improvements to seismic data and analysis combined with horizontal and directional drilling have improved prospects for successful completions.

The practice of horizontal drilling, which uses a flexible pipe with a steerable drill bit on the end, has had a significant impact on increasing production. Multi-laterals, multiple horizontal wells, can be drilled from a single vertical shaft, allowing production of more petroleum or gas from a single well. Horizontal drilling from a single well can also reduce the impact of drilling in environmentally sensitive areas. As with conventional drilling, GHG emission levels relate to the power requirements of the individual drilling engines and their fuel consumption, as well as other drilling-related operations, such as completions. Thus, directional drilling may result in increased emissions due to larger engines and increased drilling depths and times relative to those, which might result from solely conventional development of a well.

1.6 OFFSHORE OIL PRODUCTION TRENDS

Between 1988 and 2003, U.S. domestic offshore crude oil production increased from 435 million barrels (1988) to 734 million barrels (2003). However, between 2003 and 2006 domestic production declined from 734 to 604 million barrels. In 2006, offshore crude oil production accounted for 30 percent of total U.S oil production.

Since 1996, California and the West Coast Federal offshore area (PADD5) have experienced a decline in offshore crude oil production. Offshore crude oil production accounted for approximately 16 percent of total U.S. offshore production in 1995, 8 percent in 2000 and 6 percent in 2006. Figure 5 shows the trends and relationship between total U.S. and Western States offshore crude oil production over the last 18 years.

1.7 OFFSHORE NATURAL GAS PRODUCTION TRENDS

In 2006, offshore natural gas production accounted for approximately 13 percent of total U.S. offshore natural gas production. Figure 6 shows that total U.S. offshore natural gas production has been declining since the year 2000. The state of California presents a similar trend, decreasing 13 percent from 2001 to 2002. In 2006, California's natural gas production was around 47 million cubic feet.

[28] WRTG Economics, http://wrtg.com/prices.htm

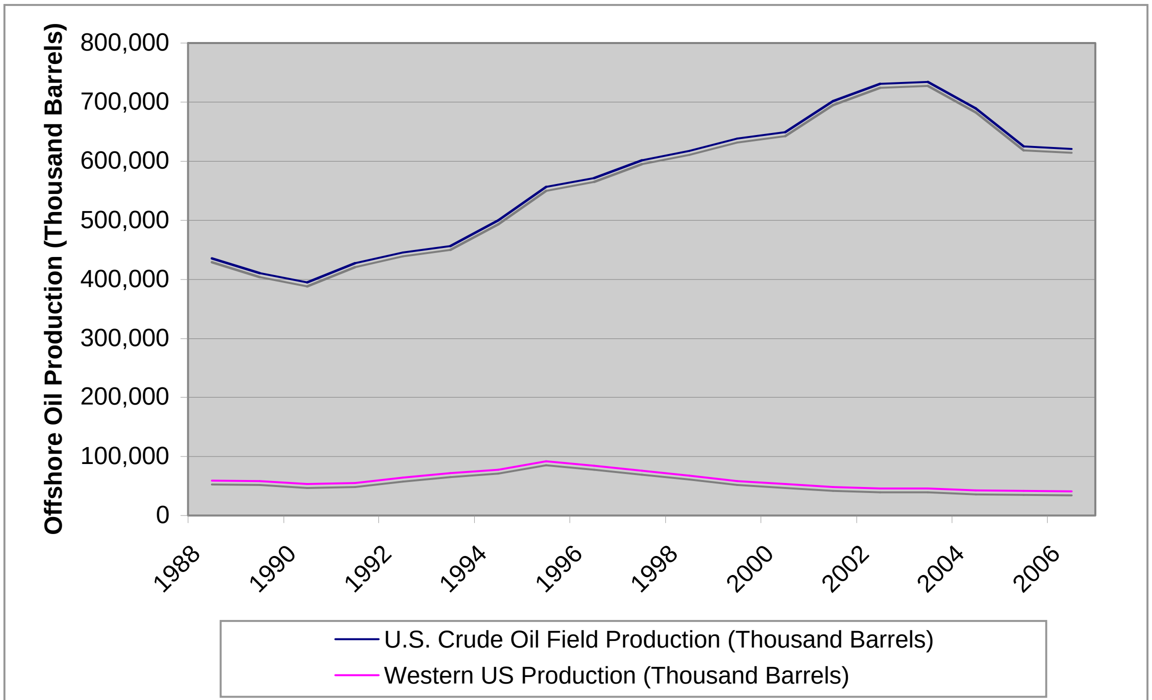

Figure 5 Total U.S. and Western States Offshore Crude Oil Production per year
Source: Energy Information Administration Crude Oil Production data, www.eia.doe.gov
Note: (1) U.S. Crude Oil Production includes the offshore production of Louisiana, Texas, Alaska, California, Federal offshore (PADD 3) and Federal offshore (PADD 5) areas (2) Western US production refers to offshore production in California and the Federal offshore (PADD 5) area[29].

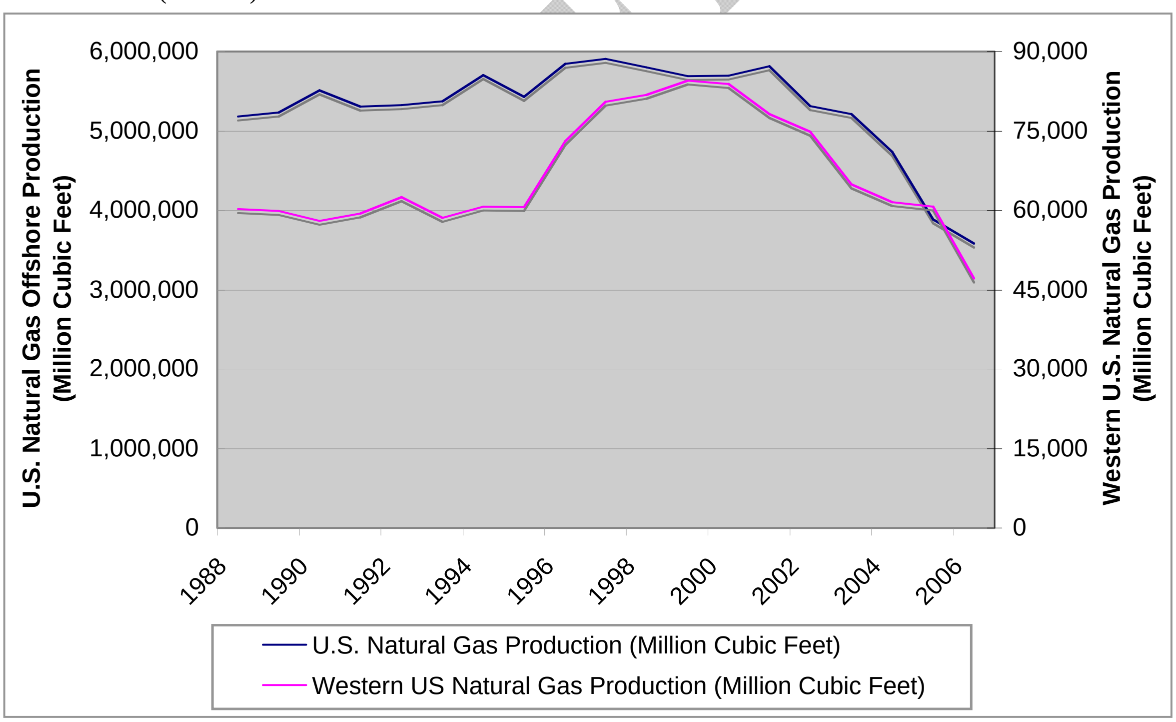

Figure 6 Total U.S. and Western States Offshore Natural Gas Production per year
Source: Energy Information Administration Natural Gas Production data, www.eia.doe.gov
Note: (1) U.S. Natural Gas Production includes States and Federal gross withdrawals (2) Western US Natural Gas Production refers to the gross withdrawals in California and its Federal offshore area.

[29] Federal offshore PADD 3 refers to the Gulf of Mexico and Federal offshore PADD 5 to the west coast

1.8 OFFSHORE EXPLORATION AND PRODUCTION OPERATIONS

Offshore exploration and production activities, have a number of differences from onshore operations, (as described above) and present additional challenges such as limited availability of storage before transportation to onshore facilities, the confined and crowded nature of the producing equipment and wells, the frequent requirement to generate power at the facility and offshore drilling in deeper waters. During the last 50 years, advances in technology have allowed the oil and natural gas industry to overcome challenges to production and to access reserves in deeper water and from farther beneath the ocean floor.

1.8.1 Offshore Drilling Technologies

The equipment for offshore sea floor drilling is different than the equipment used for onshore operations (see above). Drilling can occur during the exploration phase before a permanent platform is installed. In this case, it is conducted in deeper waters from either a semi submersible drilling rig or a drilling ship that moves from location to location each time a well is drilled. In shallower waters, jack up rigs can be used and moved from site to site. These platforms typically do not contain production systems such as oil and gas processing equipment (portable engines, oil storage tanks, gas/liquid separators, gas scrubbers, flares, etc), which must be brought onboard by the company in charge of the operations and /or a subcontractor. Exploratory drilling is generally performed to verify the presence and quality of producible quantities of oil and gas on an offshore field gas prior to a company making a decision to install a permanent offshore production platform. Sometimes, these drillships or semi submersible rigs can be converted and used as floating productions systems, although this is not common. Most often, floating production systems (as shown in Figure 7) are purpose-built structures for the particular field to be produced.

1.8.2 Offshore Production Technologies

Once a platform has been installed on a site, additional wells are typically drilled to fully exploit the field. One of the key differences of drilling equipment during offshore field development is that the drilling rig does not typically have separate diesel engines to drive its activities. Rather, the platform-drilling rig is driven by electric motors with the power from the motors provided by the central power plant on the platform. Platform drilling rigs are not used for floating production systems, however. For these cases, a semi submersible rig or drillship must be brought back to the site and will access the wells through the subsea template at the sea floor.

There are several types of platforms currently used in offshore operations (See Figure 7)[30], primarily depending on the water depth at the platform location and the number of producing wells. The following examples describe some of the most common platforms currently used in E&P operations:

- **Fixed Platform (FP)** consists of a jacket (a tall vertical section made of tubular steel members supported by piles driven into the seabed) with a deck placed on top, providing space for crew quarters, a drilling rig, and production facilities. The fixed platform is

[30] http://www.gomr.mms.gov/homepg/offshore/deepwatr/options.html

designed for long-term use and is economically feasible for installation in water depths up to 1,700 feet.

- **Compliant Tower (CT)** consists of a slender, flexible tower and a piled foundation that can support a conventional deck for drilling and production operations. Compliant towers are designed to withstand large lateral forces by sustaining significant lateral deflections, and are usually used in water depths between 1,500 and 3,000 feet.

- **Tension Leg Platform (TLP)** is a floating structure held in place by vertical, tensioned tendons, which are connected to the sea floor by pile-secured templates and eliminate most vertical movement. Tensioned tendons provide for the use of a TLP across a broad range of water depths - larger TLP's have been successfully used to a depth of 4,000 feet.

- **Mini-Tension Leg Platform (Mini-TLP)** is a relatively low cost platform developed for production of smaller deepwater wells, which would be financially unviable using conventional deepwater production systems. The Mini TLP can also be used as a utility, satellite, or early production platform for larger deepwater discoveries.

- **SPAR Platform (SPAR)** consists of a single large diameter vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a moored hull using a system of six to twenty lines anchored into the seafloor. It also has the ability to move horizontally over the oil or natural gas well through the use of chain-jacks attached to the mooring lines. SPAR's are currently used in water depths up to 3,000 feet, although existing technology could extend its application to depths as great as 7,500 feet.

- **Floating Production System (FPS)** is a semi-submersible unit containing drilling and production equipment. It is anchored in place with wire rope and chain, or can be dynamically positioned using rotating thrusters. Oil flows to the surface deck through production risers designed to accommodate platform motion. The FPS can be used in a range of water depths from 600 to 7,500 feet.

- **Subsea System (SS)** can accommodate a single subsea well producing to a nearby platform, FPS, or TLP or multiple wells producing through a manifold and pipeline system to a distant production facility. These systems are currently used in water depths greater than 5,000 feet.

- **Floating Production, Storage & Offloading System (FPSO)** consists of a large tanker type vessel moored to the seafloor. An FPSO is designed to process and stow oil from nearby subsea wells and periodically offload to a smaller shuttle tanker. The shuttle tanker then transports the oil to an onshore facility for further processing. An FPSO may be suited for fields located in remote deepwater areas where pipeline infrastructure does not exist.

Platform crane engines are used on a daily basis and are a structure integral to the platform. They are normally powered by diesel engines. Crew boats have both main engines and auxiliary generator engines. Crew boats are used daily (weather permitting) for platforms nearer to shore facilities. For more remote platforms, helicopters perform the crew changes. Supply boats are larger than crew boats and are used less frequently to bring supplies, drilling equipment or workover equipment to each platform. Supply boats are typically equipped with main engines, auxiliary generator engines and a bow thruster engine.

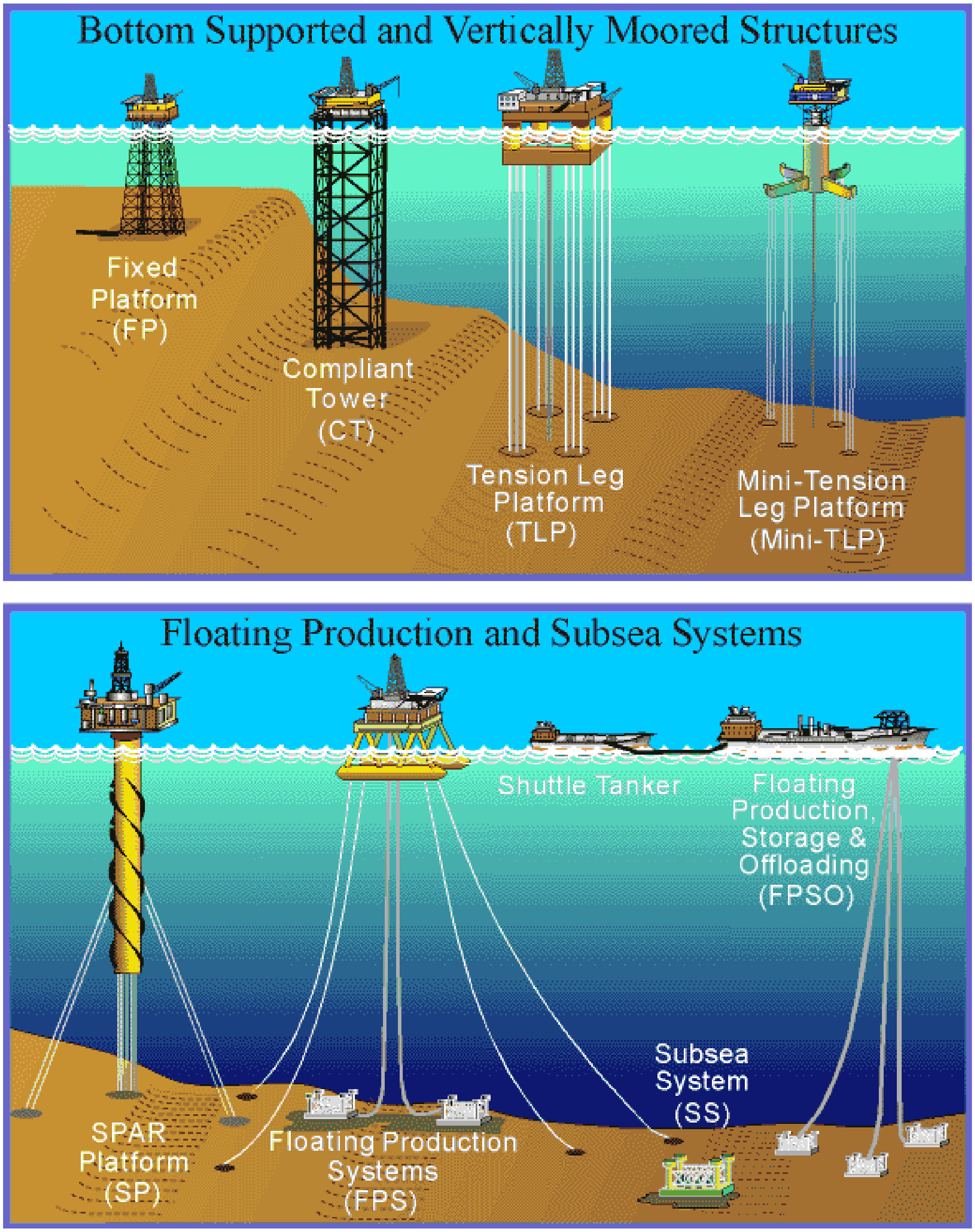

Figure 7 Offshore Exploration and Production Systems

1.9 OIL SANDS PRODUCTION TRENDS

Oil sands (also called tar sands, extra heavy oil, non-conventional oil or crude bitumen) are naturally occurring mixtures of sand or clay, water and a dense and viscous form of oil called bitumen. Due to higher oil prices and advances in technology that have enabled them to be profitably extracted and upgraded to useful products, oil sands have recently been considered to be part of the world's oil reserves. The world's largest oil sands deposits are located in Canada and Venezuela. Both countries have oil sands reserves equivalent to the world's total reserves of conventional crude oil. While many other countries have large deposits of oil sands including the United States, commercial oil sands operations are limited to northern Alberta in Canada.

Alberta's three major deposits of crude bitumen are Athabasca Oil Sands, Peace River and Cold Lake, which together hold 1.7 trillion barrels of crude bitumen in place, measures indicate that there are 173 billion barrels of proven recoverable reserves. This represents 97 percent of Canadian oil reserves and three-quarters of total North American oil reserves[31].

In 2006, crude bitumen production averaged 1.25 million barrels per day from eighty-one oil sands projects, which represented approximately 47 percent of total crude oil and equivalent produced in Canada[32]. This proportion is expected to increase over time as bitumen production grows while conventional oil production declines.

In 2007, 44 percent of Canadian oil production came from oil sands, 38 percent from light oil and condensate and 18 percent from heavy oil (See Figure 8)[33]. Generally, around 80 percent of the recoverable oil sands are obtained using in-situ technologies and the remaining 20 percent is recovered using mining techniques[34]. In 2007, Canada production[35] of mined crude bitumen was around 307 million cubic feet whereas in-situ crude bitumen production was around 1.1 billion cubic feet[36].

As of January 2009, there are ninety-one active oil sands projects in Alberta. Five are mining projects and the remaining projects use different in-situ recovery methods (See Oil Sands Extraction Techniques, section 1.9.1).[37] Currently, there are only four companies with mining operations in Alberta, these companies are: Shell Muskeg River, CNRL Horizon, Suncor Millennium and Syncrude Mildred Lake and Aurora. The mines operated by these companies are all located in an area north of Fort McMurray in the Athabasca.

Oil Sands projects can vary considerably in size, from small in-situ sites that are in the pilot phase to large mega-projects, which include bitumen upgraders. During the upgrader process, crude bitumen is transformed into synthetic crude oil (See Oil Sands Upgrader Facilities, section 2.3.1). Not all of the crude bitumen produced in Canada is processed in the country, some is diluted and delivered by pipeline to facilities in the U.S. Five companies in Canada operate the following upgrader facilities: CNRL Horizon upgrader, Suncor Base and Millennium upgraders (adjacent and integrated facilities that send the synthetic crude oil to several refineries in Canada and in the U.S.), Shell Scotford upgrader (facility integrated with the Shell Scotford Refinery) and Nexan Long Lake upgrader.

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[31] http://www.environment.alberta.ca/documents/Oil_Sands_Opportunity_Balance.pdf
[32] http://www.environment.alberta.ca/documents/Oil_Sands_Opportunity_Balance.pdf
[33] http://www.neb.gc.ca/clfnsi/rnrgynfmtn/nrgyrprt/nrgyvrvw/cndnnrgyvrvw2007/cndnnrgyvrvw2007-eng.html#s4_2
[34] http://www.oilsands.alberta.ca/519.cfm
[35] Conversion factor: 1 cubic meter = 35.32 cubic feet
[36] Canadian Association of Petroleum Producers (CAPP). Statistical Handbook for Canada's Upstream Petroleum Industry, January 2009
[37] http://www.oilsands.alberta.ca/519.cfm

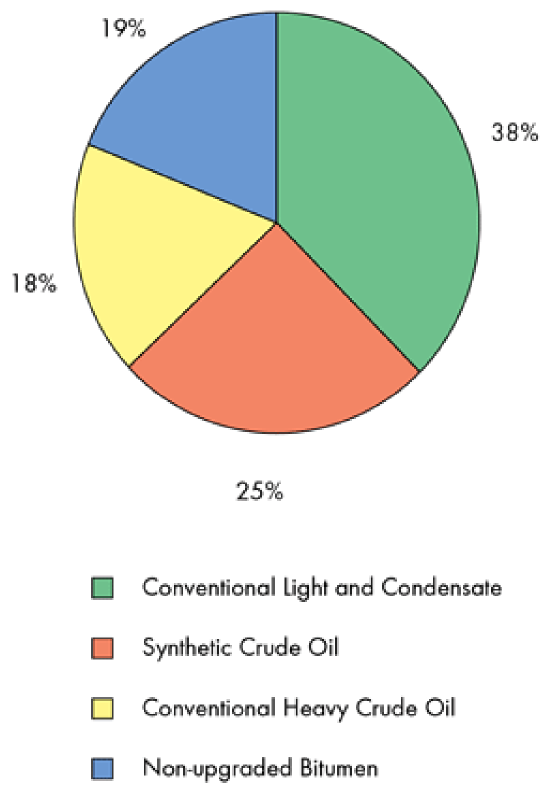

Figure 8 Canadian Crude Oil and Equivalent Production by Type (2007).

Of the three deposits of crude bitumen in Canada, the largest and only deposit suitable for surface mining, is the Athabasca Oil Sands that contains approximately 80 percent of the total Canadian reserves. The mineable area - defined by the Alberta government - includes 37 townships covering about 1,300 square miles. The smaller Cold Lake deposits are important because some of the oil is fluid enough to be extracted by conventional methods.

All three Alberta areas are suitable for production using in-situ methods[38]. In addition to the Alberta deposits, there are important oil sands deposits on Melville Island in the Canadian Artic Islands, but these deposits are unlikely to be commercially produced in the foreseeable future.

Currently, oil is not commercially produced from oil sands in the United States. In addition to being much smaller than the Canadian deposits, U.S oil sands are hydrocarbon wetted, whereas Canadian oil sands are water wetted[39]. As a result of this difference, extraction techniques for the oil sands in Utah will be different than for those used in Canada. A considerable amount of research must be done before a commercially viable production technique can be developed for the U.S. oil sands. In the United States, oil sands deposits are concentrated in Eastern Utah.

[38] http://www.energy.gov.ab.ca/OilSands/pdfs/osgenbrf.pdf

[39] Canadian oil sands have a wet interface between the sand grain and the oil coating, which allows for the separation of oil from the grain (water wet oil shales) whereas oil sands in the U.S. don’t have that interface (hydrocarbon wet oil shales) making the separation process more difficult.

Utah's oil sands consist of eight major deposits with a combined inventory of about 32 billion barrels of oil. The largest of these deposits is the Tar Sand Triangle[40], which covers an area of 232 square miles. The Triangle is located in Wayne and Garfield Counties, between the Dirty Devil River and the Colorado River.

1.9.1 Oil Sands Extraction Techniques

Conventional crude oil is normally extracted from the ground by drilling into an oil reservoir and allowing the oil to flow through the pipelines under natural pressures. As reservoir pressure drops, techniques such as artificial lift, gas injection and water flooding are used to maintain production until the field is exhausted. However, under normal reservoir conditions crude bitumen flows very slowly, toward producing wells or sometimes not at all. Therefore the oil sands must be extracted by either strip mining or in situ techniques, which reduce the viscosity of the bitumen through injection of steam, solvents and hot air into the oil sands deposits. These processes can use larger amounts of water and require more significant amounts of energy than conventional oil extraction.

Existing oil sands extraction processes include:

- **Surface Mining or Open Pit Mining[41].** In the Athabasca sands there are very large amounts of bitumen covered by little overburden - water-laden muskeg (peat bog) over tops of clay and barren sand. These are ideal conditions for surface mining, which is the most efficient method of extraction. The oil sands themselves are typically 130 to 190 feet deep, sitting on top of flat limestone rock. Historically, oil sands were mined with draglines and bucket-wheel excavators and transported to processing plants by conveyor belts. In recent years companies have switched to less expensive shovel-and-truck operations using big power shovels and dump trucks. After excavation, hot water and caustic soda ($NaOH$)[42] is added to the sand, and the resulting mix is piped to the extraction plant. Provided that the water chemistry is appropriate to allow bitumen to separate from sand and clay, the combination of hot water and agitation releases bitumen from the oil sand, and allows small air bubbles to attach to the bitumen droplets. The bitumen froth floats to the top of separation vessels, and is further treated to remove residual water and fine solids. Crude Bitumen is much thicker than crude oil, so it is then either diluted with petroleum naphtha or chemically split (cracking or hydrocracking process) before being transported by pipeline for upgrading into synthetic crude oil.

  About two tons of oil sands are required to produce one barrel of oil. Around 75 percent of the crude bitumen can be recovered from sand. After oil extraction, the spent sand and other materials are then returned to the mine, which is eventually reclaimed. Recent enhancements have been added to the final step of the process to increase the recovery to over 90 percent of the bitumen from the sand. Some examples include Tailings Oil Recovery (TOR) units, Diluent Recovery Units, Inclined Plate Settlers (IPS) and disc centrifuges. While not currently used at a commercial scale, the Alberta Taciuk Process technology extracts bitumen from oil sands through an innovative process called ‘dry-retorting’. During this process, oil sand is moved through a rotating drum, cracking the

[40] http://ostseis.anl.gov/guide/tarsands/index.cfm
[41] http://www.albertacanada.com/documents/AIS-EC_oilSandsUpdate_1207.pdf
[42] http://www.oilsandsdiscovery.com/oil_sands_story/story.html

bitumen with heat and producing lighter hydrocarbons[43].

- **Cold Heavy Oil Production with Sand (CHOPS).**[44] This technique is used in areas where the oil in the sands is very fluid. This technique is used in the southern part of the Cold Lake and Peace River Oil Sands. CHOPS began as a technique called 'cold flow' which extracted oil out of the sands using progressive cavity pumps. While an inexpensive technique, cold flow only recovered approximately 6 percent of the oil. Several years ago Canadian oil companies discovered that if they removed the sand filters from the wells and extracted sand with the oil, production rates improved remarkably (up to 10 percent). Further research revealed that pumping out sand opened "wormholes" which allowed more oil to reach the wellbore. One challenge of the CHOPS technique is disposing of the extracted spent sand.

- **Cyclic Steam Stimulation (CSS).** This process was patented and developed by Imperial Oil. In this technique, steam is injected into a well at a temperature of 570 to 645 degrees Fahrenheit for several weeks or months. The well then is left idle for days to weeks to allow heat to soak into the formation. Once ready, the hot oil is pumped out of the well until the production is exhausted and the well is once again put through another cycle of injection, soak and production. This process is repeated until the cost of injecting steam becomes higher than the profit made from producing the oil. The CSS method recovers around 25 percent of the oil in place.

- **Steam Assisted Gravity Drainage (SAGD)[45].** As in the case of CSS, Imperial Oil patented and developed this technique in the 1980s. In SAGD[46], two horizontal wells are drilled in the oil sands, one at the bottom of the formation and the other 15 feet above. These wells are typically drilled in groups from pads and can extend for miles in all directions. In each well pair, steam is injected into the upper-well; the heat melts the crude bitumen allowing it to flow into the lower well, where it is pumped to the surface. SAGD's recovery rate is range from 40 percent to 60 percent of the oil in place.

- **Vapor Extraction Process (VAPEX).** VAPEX[47] is similar to SAGD but instead of steam, hydrocarbon solvents are injected into the upper well to dilute the crude bitumen and allow it to flow into the lower well. VAPEX is more energy efficient than steam injection and can partially upgrade the crude bitumen to oil whilst in the formation. VAPEX is a new technique but has attracted much attention from oil companies, who are beginning to experiment with it. It is becoming common for wells to be put through one CSS injection-soak-production cycle to condition the formation prior to going to SAGD production, and then combining VAPEX with SAGD to improve recovery rates and lower energy costs.

- **Toe to Heel Air Injection (THAI).** This is a very new and experimental method that

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[43] http://www.advancededandtech.alberta.ca/technology/wwwtechnology_asp/techprior/techcomm/energy/energy_stories_937.asp
[44] http://www.energy.gov.ab.ca/OilSands/1189.asp
[45] http://www.advancededucation.gov.ab.ca/technology/wwwtechnology_asp/techprior/techcomm/energy/energy_stories_936.asp
[46] http://www.uofaweb.ualberta.ca/ccg/pdfs/Vol3-IntroSAGD.pdf
[47] http://www.gov.ab.ca/home/NewsFrame.cfm?ReleaseID=/acn/200309/15062.html

combines a vertical air injection well with a horizontal production well. The process ignites oil in the reservoir and creates a vertical wall of fire moving from the "toe" of the horizontal well toward the "heel". The fire burns the heavier oil components and drives the lighter components into the production well, where the oil is pumped out. In addition, the heat from the fire upgrades some of the heavy bitumen into lighter oil whilst in the formation[48]. Advocates of this method of extraction state that it uses less freshwater and produces 50% less greenhouse gases compared to other production techniques[49].

1.9.2 Oil Sands Environmental Issues

Climate Change

The production of crude bitumen and synthetic crude oil emits higher greenhouse gas (GHG) emissions than the production of conventional crude oil and has been identified as the largest contributor to GHG emissions growth in Canada, as it accounts for 40 million tons of CO_2 emissions per year.

While the emissions intensity of producing oil sands has decreased substantially (26 percent over the past decade), total emissions are expected to increase due to higher production levels. In January 2008, the Alberta government released Alberta’s 2008 Climate Change Strategy. Alberta’s emissions are projected to grow to 400 millions of tons of CO_2 equivalent ($MtCO_2e$) by 2050, largely due to forecast growth in the oil sands sector[50]. The new plan aims to cut the projected increase in half by 2050 when compare to business as usual, or 14 percent reduction below 2005 levels (205 $MtCO_2e$). A reduction of 139 $MtCO_2e$ is expected to come from carbon capture and storage; the bulk of those reductions (100 $MtCO_2e$) will come from activities related to oil sands production[51].

Carbon Dioxide Sequestration[52]

Sequestration of GHG emissions operations is becoming a viable emissions reduction measure for oil sands operators. Future plants are expected to start sequestering more carbon dioxide emissions from production, but CO_2 from current plants is released to the atmosphere. A Canadian initiative called the Integrated CO_2 Network (ICO2N)[53] is a proposed system for the future capture, transport and storage of CO_2 from large industrial sources. The members represent a group of industry participants providing a framework for carbon capture and storage development in Canada. In addition, on March 10, 2008 the Canadian Environment Ministry[54] announced climate change regulations requiring new oil sands projects to implement carbon sequestration techniques from 2010, these new set of regulations include criminal sanctions for violators.

[48] http://www.petrobank.com/hea-thaiprocess.html
[49] http://www.theoildrum.com/node/2907
[50] http://alberta.ca/home/NewsFrame.cfm?ReleaseID=/acn/200801/22943ACC446ED-ED74-6A1E-6CF263E59920969B.html
[51] http://environment.gov.ab.ca/info/library/7894.pdf
[52] http://www.environment.alberta.ca/documents/Oil_Sands_Opportunity_Balance.pdf
[53] http://www.ico2n.com/thebasics.php
[54] http://www.theglobeandmail.com/servlet/Page/document/v5/content/subscribe?user_URL=http://www.theglobeandmail.com%2Fservlet%2Fstory%2FLAC.20080310.BAIRD10%2FTPStory%2FNational&ord=70884694&brand=theglobeandmail&force_login=true

1.10 OIL SHALES PRODUCTION TRENDS

Oil shales are organic-rich sedimentary rocks. Shales differ from oil sands in that heat and pressure have not yet transformed the kerogen in oil shales into petroleum.

The U.S is home to the largest deposits of oil shales in the world, located in the Green River basin, which covers portions of Colorado, Utah and Wyoming. Around 70 percent of this resource lies in Federally owned land[55]. These federal lands contain about 1.23 trillion barrels of oil, more than 50 times the nation's proven conventional oil reserves[56]. Oil shales, unlike oil sands, have not been exploited on a significant commercial scale to date; currently there is only one small oil shale demonstration project in operation, in Colorado[57].

1.10.1 Oil Shales Extraction and Processing Techniques

Oil shales contain an important amount of kerogen from which the oil industry can extract liquid hydrocarbons. A chemical process called pyrolysis converts the kerogen in the shale to synthetic crude oil (a non-conventional oil), shale gas and a solid residue. Oil shales can also be burned directly as a low-grade fuel for power generation and heating purposes.

Exploitation of oil shale involves two methods mining and a heating process called retorting. Mining and retorting can occur both on the surface or in-situ. Surface mining is practical when the deposits occur near the surface and is the most efficient approach to extract shale oil. It involves removing most of the overlying material to expose the deposits of oil shale. Underground mining of oil shale, which removes less of the overlying material, employs a method called the room-and-pillar technique.

Once the mining process is over, the retorting process begins. At this stage the oil shale is crushed and heated (retorted) at about 900 to 1,000 degrees Fahrenheit in a vessel, which provides an oxygen-free environment. In the absence of oxygen, the kerogen in the shale decomposes into gas, condensable oil and a solid residue. This chemical process is called pyrolysis. In-situ retorting involves heating the oil shale underground, extracting the liquid and transporting it to an upgrading facility[58].

The oil derived from oil shale does not directly substitute for crude oil in all applications as it can contain higher concentrations of olefins, oxygen and nitrogen. Ex-situ retorting processes tend to yield a lower API gravity[59] shale oil than the in situ processes. Shale oil serves best for producing kerosene, diesel fuel and jet fuel. However, appropriate refining processes equivalent to hydrocracking can transform shale oil into a lighter hydrocarbon such as gasoline[60].

[55] http://pubs.usgs.gov/sir/2005/5294/pdf/sir5294_508.pdf
[56] http://www.blm.gov/wo/st/en/prog/energy/oilshale_2.html
[57] http://ostseis.anl.gov/guide/oilshale/index.cfm
[58] http://www.netl.doe.gov/energy-analyses/pubs/Oil%20Shale%20Development%20in%20the%20United%20States%20-%20RAND%20August%20200.pdf
[59] A measure of how heavy or light crude oil or another hydrocarbon liquid is compared to water.
[60] http://www.fas.org/sgp/crs/misc/RL33359.pdf

Shell's In-situ Conversion Process

A new in-situ shale oil conversion process started being tested at Shell's research facilities in Houston in the early 1980s. It consists of heating the shale oil rock using electric heaters, which are placed in vertical holes across the entire oil shale deposit. The area heats at a temperature between 650 and 700 degrees Fahrenheit for a period of two or three years prompts a chemical reaction to release oil from the shale. The oil produced from this process will be chemically stable, which means that fewer processing steps are needed to obtain a high quality transportation fuel. This process is currently being tested in Colorado and is expected to reach commercial potential in the next 10 years[61].

1.10.2 Oil Shales Environmental Issues

Climate Change

Similarly to oil sands, oil shale processing and combustion is GHG emissions-intensive. Experimental in situ conversion processes and carbon capture and storage technologies may reduce GHG emissions in the future.

[61]http://www.shell.us/home/content/usa/aboutshell/shell_businesses/upstream/locations_projects/onshore/mahogany/mrp_technology.html

2 EMISSION SOURCES

2.1 GREENHOUSE GAS EMISSION SOURCES

This section details the direct (Scope 1) emissions sources. Sources are categorized by types of Kyoto GHG pollutants from specific oil and gas operations including combustion equipment, oil and gas exploration and production equipment, natural gas processing operations and mobile sources associated with such operations. In addition, downstream boundaries including the interface between oil and natural gas production operations and transmission/distribution are identified.

2.2 DOWNSTREAM BOUNDARY OF E&P OPERATIONS AND OTHER GHG REPORTING PROTOCOLS

To address the question of GHG emission sources from E&P activities, an agreed definition of where E&P is completed and the next stage (transportation) begins is necessary. Traditionally, this point has been defined as the point where custody of the oil or gas is transferred to a common carrier transportation pipeline or licensed carrier vessel. This point of custody transfer is a defining boundary for E&P and is used in a variety of Federal regulations such as NESHAPS and Title V permitting.

In the case of natural gas production, the point of custody transfer is normally from a natural gas processing plant into a gas transmission pipeline. If natural gas processing to meet pipeline transportation specifications is not required, the point of custody transfer occurs after collection facilities. This also allows for a clear boundary definition for a GHG reporting protocol that has been in development by CCAR (and now TCR) for the natural gas transmission and distribution industry.

In the case of oil production, the point of custody transfer is also to a pipeline in many cases, but sometimes to a truck or offshore tanker that transports the oil for processing at a refinery. These activities downstream of the custody transfer point are outside of the legally defined boundary of E&P operations. In addition, no concurrent GHG protocol currently exists for the oil transportation sector and any GHG reporting methods for this stage of the process do not yet follow a structured protocol.

2.3 TYPES OF GHG EMISSIONS BY SOURCE

Oil and gas exploration and production activities that are considered in this scoping paper can be categorized into five broad categories; 1) drilling and exploration, 2) petroleum production, 3) natural gas production, 4) natural gas processing and 5) mobile sources. These activities generate GHG emissions through a number of processes including exploratory testing and drilling of wells, production activities that involve venting of wells and processes, fugitive emissions from leaks in components, and fuel combustion. Emissions from these activities are primarily carbon dioxide (CO_2) and methane (CH_4) but may also include the other four categories of Kyoto Protocol-defined GHGs: nitrous oxide (N_2O), sulfur hexafluoride (SF_6) , hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs). A list of activities associated with oil and gas testing, exploration and drilling operations is included in Table 1, which also identifies the specific types of GHG emissions for each of these systems.

Table 2 presents a list of activities associated with oil production operations and identifies the specific types of GHG emissions associated with each activity.

Source Category	Methane (CH_4)[1]	Carbon Dioxide (CO_2)[2]	Nitrous Oxide (N_2O)[3]	Hydrofluoro-carbons (HFCs)[5]	Sulfur Hexafluoride (SF6)[4]	Perfluoro-carbons (PFCs)[5]
Well testing	x	x	x		x	
Exploratory drilling	x	x	x		x	
Completion activities (non-venting)	x	x	x			
Completion venting	x					
Drill mud degassing	x					
Drill rigs	x	x	x			
Workover rigs	x	x	x			
Misc. I.C engines	x	x	x			
Glycol Dehydrators	x	x				
Flares/incinerators	x	x	x			
Heavy-duty trucks	x	x	x	x		x
Medium-duty trucks	x	x	x	x		x
Light-duty trucks	x	x	x	x		x
Light-duty automobiles	x	x	x	x		x
Offshore Support and Seismic Vessels (OSV)	x	x	x			
Helicopters (Offshore)	x	x	x			

1 CH_4 is the principle component of natural gas which is emitted during oil and gas operations such as venting.
2 CO_2 is a byproduct of fossil fuel combustion when using fuels containing a carbon atom (e.g., CH_4)
3 N_2O is a product of the reaction that occurs between nitrogen and oxygen during fossil fuel combustion.
4 SF_6 may be used as a tracer in hydrocarbon reservoir characterization and recovery and hence emitted to the atmosphere
5 Several hydrofluorocarbons and perfluorocarbons are used in vehicle air conditioning systems and may be emitted.

Table 1 List of Sources from oil and gas drilling and exploration and potential GHGs

Source Category	Methane (CH_4)[1]	Carbon Dioxide (CO_2)[2]	Nitrous Oxide (N_2O)[3]	Hydrofluoro-carbons (HFCs)[5]	Sulfur Hexafluoride (SF6)[4]	Perfluoro-carbons (PFCs)[5]
Artificial lift engines (pumpjacks)	x	x	x			
Oil well tanks	x	x				
Oil well truck loading	x	x	x	x		x
Pneumatic devices	x	x				
Oil well fugitives	x	x				
Chemical injection pumps	x	x				
Vapor recovery unit (VRU) engines	x	x	x			
Heaters	x	x	x			
Boilers	x	x	x			
Cogen Units (EOR)	x	x	x			
Miscellaneous Engines	x	x	x			
Glycol Dehydrators	x	x				
Flares/incinerators	x	x	x			
Process heat/steam imports	x	x	x			

Salt-water disposal (SWD) engines	x	x	x			
Gas Actuated Pumps	x	x				
Landfarms	x	x	x			
Central Power Plant Turbines (Offshore)	X	x	x			
Central Power Plant ICEngines (Offshore)	x	x	x			
Converted Diesel Ship Engines (Offshore)	x	x	x			
Tankers in Floating Production, Storage and Offloading Systems - FPSO (Offshore)	x	x	x	x		
Oil Sands Upgrader equipment, including:						
Coke Gasification Unit	x	x	x			
Hydrogen Production Unit	x	x	x			
Primary Upgrading Coker Unit	x	x	x			

1 CH_4 is the principle component of natural gas which is emitted during oil and gas operations such as venting.
2 CO_2 is a byproduct of fossil fuel combustion when using fuels containing a carbon atom (e.g., CH_4)
3 N_2O is a product of the reaction that occurs between nitrogen and oxygen during fossil fuel combustion.
4 SF_6 may be used as a tracer in hydrocarbon reservoir characterization and recovery and hence emitted to the atmosphere
5 Several hydrofluorocarbons and perfluorocarbons are used in vehicle air conditioning systems and may be emitted.

Table 2 List of Sources from oil production operations and potential GHGs

A list of systems associated with natural gas production and processing operations is included in Table 3. In some cases similar systems are used because both oil and gas operations exist at a well site. As with Table 2, this table identifies specific types of GHG associated with each of these systems.

Source Category	Methane (CH_4)[1]	Carbon Dioxide (CO_2)[2]	Nitrous Oxide (N_2O)[3]	Hydrofluoro-carbons (HFCs)[5]	Sulfur Hexafluoride (SF6)[4]	Perfluoro-carbons (PFCs)[5]
Gas well condensate tanks	x	x				
Gas well truck loading	x	x	x	x		x
Pneumatic devices	x	x				
Gas well fugitives	x	x				
Gas well venting	x	x				
Chemical injection pumps	x	x				
Vapor recovery unit (VRU) engines	x	x	x			
Compressor start-ups and shutdowns	x	x				
Miscellaneous gas-fired heaters or boilers	x	x	x			
Dehydrators	x	x				
Amine units	x	x				
Well blowdowns	x	x				
Compressor blowdowns	x	x				
Heaters	x	x	x			

Boilers	x	x	x			
Lateral/wellhead compressor engines	x	x	x			
CBM pump engines	x	x	x			
Process heat/steam imports	x	x	x			
Salt-water disposal (SWD) engines	x	x	x			
Gas Actuated Pumps	x	x				
Landfarms	x	x	x			
Central Power Plant Turbines (Offshore)	x	x	x			
Central Power Plant IC Engines (Offshore)	x	x	x			
Converted Diesel Ship Engines (Offshore)	x	x	x			
Tankers in Floating Production, Storage and Offloading Systems - FPSO (Offshore)	x	x	x	x		

1 CH_4 is the principle component of natural gas which is emitted during oil and gas operations such as venting.
2 CO_2 is a byproduct of fossil fuel combustion when using fuels containing a carbon atom (e.g., CH_4)
3 N_2O is a product of the reaction that occurs between nitrogen and oxygen during fossil fuel combustion.
4 SF_6 may be used as a tracer in hydrocarbon reservoir characterization and recovery and hence emitted to the atmosphere
5 Several hydrofluorocarbons and perfluorocarbons are used in vehicle air conditioning systems and may be emitted.

Table 3 List of sources from natural gas production operations and potential GHGs

A list of systems associated with natural gas processing operations is included in Table 4, which also identifies the specific types of GHGs associated with each system.

Source Category	Methane (CH_4)[1]	Carbon Dioxide (CO_2)[2]	Nitrous Oxide (N_2O)[3]	Hydrofluoro-carbons (HFCs)[5]	Sulfur Hexafluoride (SF6)[4]	Perfluoro-carbons (PFCs)[5]
Gas well and plant truck loading	x	x	x	x		x
Gas Pipeline fugitives	x	x				
Land farms	x	x	x			
Water treatment facilities (evaporative ponds)	x	x	x			
Gas processing plant fugitives	x	x	x			
Vapor recovery unit (VRU) engines	x	x	x			
Compressor start-ups and shutdowns	x	x				
Miscellaneous gas-fired heaters or boilers	x	x	x			
Condensate Tanks						
Dehydrators	x	x				
Amine units	x	x				
Acid gas removal systems	x	x				
Boilers/steam generators	x	x	x			
Gas turbines	x	x	x			
Vessel Blowdowns	x	x				
Pipeline blowdowns	x	x				

Miscellaneous engines	x	x	x			
Flares	x	x	x			
Incinerators	x	x	x			

1 CH_4 is the principle component of natural gas which is emitted during oil and gas operations such as venting.
2 CO_2 is a byproduct of fossil fuel combustion when using fuels containing a carbon atom (e.g., CH_4)
3 N_2O is a product of the reaction that occurs between nitrogen and oxygen during fossil fuel combustion.
4 SF_6 may be used as a tracer in hydrocarbon reservoir characterization and recovery and hence emitted to the atmosphere
5 Several hydrofluorocarbons and perfluorocarbons are used in vehicle air conditioning systems and may be emitted.

Table 4 List of sources from natural gas and straddle plants processing operations and potential GHGs

Table 5 lists the mobile sources Associated with oil and gas exploration and production and their associated emissions. These are mobile sources used directly during the E&P operations and does not include downstream transportation of oil and gas.

Source Category	Methane (CH_4)[1]	Carbon Dioxide (CO_2)[2]	Nitrous Oxide (N_2O)[3]	Hydrofluoro-carbons (HFCs)[5]	Sulfur Hexafluoride (SF6)[4]	Perfluoro-carbons (PFCs)[5]
Heavy-duty trucks	x	x	x	x		
Medium-duty trucks	x	x	x	x		
Light-duty trucks	x	x	x	x		
Light-duty automobiles	x	x	x	x		
Offshore Support Vessels (OSV)	x	x	x			
Helicopters (Offshore)	x	x	x			
Oil Sands Mining Equipment, Including:						
Haulers and dump trucks	x	x	x	x		
Bulldozers	x	x	x			
Scrapers	x	x	x			
Blasthole Drills	x	x	x			
Explosive loading trucks	x	x	x	x		
Front End Loaders	x	x	x			
Hydraulic excavators	x	x	x			
Other miscellaneous equipment (e.g., mobile cranes, forklifts, maintenance and supply trucks, road graders, etc.)	x	x	x	x		

1 CH_4 is the principle component of natural gas which is emitted during oil and gas operations such as venting.
2 CO_2 is a byproduct of fossil fuel combustion when using fuels containing a carbon atom (e.g., CH_4)
3 N_2O is a product of the reaction that occurs between nitrogen and oxygen during fossil fuel combustion.
4 SF_6 may be used as a tracer in hydrocarbon reservoir characterization and recovery and hence emitted to the atmosphere
5 Several hydrofluorocarbons and perfluorocarbons are used in vehicle air conditioning systems and may be emitted.

Table 5 List of Mobile Sources and Associated GHG Emissions

2.3.1 Direct (Scope 1) Emissions

Onshore and Offshore oil and natural gas systems encompass hundreds of thousands of individual wells, thousands of pieces of equipment and the associated operation and maintenance of this equipment at fields spread throughout the western U.S., parts of Mexico and Canada. Emissions from normal operations include: natural gas and diesel fired engines, gas-fired turbines (both combusted and uncombusted exhaust), fugitive emissions from system components, vented emissions from components such as flashing losses from production tanks , discharge emissions from pneumatic devices, and mobile source emissions. The primary GHG pollutants emitted by these activities are CO_2 emissions from combustion equipment. Emissions from process-related operations such as drilling, production and processing operations, routine maintenance, and system upsets include both CH_4 and non-combustion CO_2.

Stationary Combustion Emissions

Stationary combustion emissions result from operation of compressor engines, pumping unit engines, flares, dehydrators, heaters and boilers and other miscellaneous engines. All of these devices emit CO_2 but also may emit CH_4 and N_2O.

Reciprocating Gas Compressor Engine Emissions

Reciprocating compressor engines used in fields and central facilities range in size from the group of relatively small, dispersed wellhead compressor engines to the larger compressor engines used in natural gas processing plants. A great deal of information has been gathered from previous WRAP and other studies that provide activity information about these engines, including engine load in production, equipment usage and configuration in each basin. The number of well-head engines is defined by the need for the adequate compression to reach pressures sufficient for transmission to pipelines. Compared to mature fields and basins, virgin or newly developed fields and basins have a sufficiently high pressure that far fewer wellhead compressors are required. The only exceptions to this general rule are basins with significant coal-bed methane (CBM) wells, which often have low gas pressures and require more wellhead compression. The usage of wellhead compression is generally a small percentage of total wells in these CBM fields.

In addition to wellhead compressors, natural gas-fired, reciprocating lateral compressors are also used to boost field pressures for delivery to transmission pipelines. These compressor engines typically serve multiple well-sites simultaneously and are therefore larger than wellhead compressors with significantly larger annual emissions of CO_2, CH_4 and N_2O. Lateral compressors in the field may service dozens of wells.

Reciprocating gas compressor engines at central compressor stations and gas plants are the largest of the three compressor engine categories. These may be reciprocating engines or turbines (described below) and are used to provide central compression at stations to boost pipeline pressure for delivery to a processing plant or transmission/distribution system. Central gas compressor engines may be located at compressor stations (for pipeline transportation) or at gas plants (for additional processing). Central gas compressor engines may range in size from many hundreds to many thousands of horsepower and it is common practice to install multiple engines at a single facility.

Gas Turbines

Gas turbines are used in large central compressor stations or gas processing plants to provide compression boost gas to pipeline pressure for transportation to a transmission and delivery system. Gas turbines are used less frequently than reciprocating compressor engines, and generally are used only in large facilities with high production throughput. Other applications of gas turbines are for electrical power in cogeneration applications. Excess power is sometimes sold back to the grid. In this application, gas turbines range in size from 4 MW to 39 MW. Because their centrifugal configuration is different from traditional reciprocating engines these turbines are expected to have different GHG emissions characteristics than reciprocating engines. Gas turbines have GHG emissions of CO_2, CH_4 and N_2O, and emissions quantification requires information on the size of the turbine, the fuel flow rate or fuel usage, the fuel chemical composition or the usage of the turbine. Gas turbines in operation at compressor stations and gas plants range in size from several thousand horsepower to over 10,000 horsepower.

Miscellaneous Engines

Miscellaneous engines include all engines except those engines used for such applications as drilling rigs, workover rigs, CBM pumps, salt-water disposal engines, artificial lift engines, vapor recovery units and compressors. Producers may be required to obtain information on the size and type of these engines. Emission calculations for CO_2, CH_4 and N_2O follow a similar methodology as for drilling rig or workover rig engines.

Vapor Recovery Unit (VRU) Engines

VRU systems collect and transfer hydrocarbon vapors from condensate or oil storage tanks under low pressure and pipe vapors to a separator to collect any liquids. The vapors are then routed through a compressor that provides low-pressure suction for the VRU system. VRUs are equipped with a control pilot to shut down the compressor and permit the back flow of vapors to the tank. Using an engine, the vapors are then metered and removed from the VRU system for pipeline sale or onsite fuel supply. VRU systems are generally considered a VOC control technology for field condensate or oil tanks. VRUs substantially reduce overall methane and other hydrocarbon emissions and allow for recovery. As with other engines, emissions will depend on the type of engine and fuel used, estimates of the hours operated and loading of the engines. Due to the wide range of engine types and sizes emission may vary significantly. These engines are expected to have GHG emissions of CO_2, CH_4 and N_2O. It should also be noted that the GHG emissions from the VRU operations are dramatically offset by the recovery of methane that would have otherwise been emitted to the atmosphere.

Artificial Lift (Pumpjack) Engines

Artificial lift engines or pumpjacks refer to engines used to provide additional lift to assist in extracting oil from the reservoir to the wellhead via the borehole. These engines are often natural-gas fired spark-ignited engines, similar to gas compressor engines, and are small in size ranging from 15 – 100 horsepower. These engines are distributed in fields where significant liquid petroleum production is expected from wells. CO_2, CH_4, and N_2O emissions from these engines are calculated similarly to gas compressor engines.

Heaters and Boilers

Heaters (or heater treaters) and boilers are used in a variety of applications such as glycol dehydrator boilers (see separate Dehydrator discussion) or upstream of separators at gas wells and for water storage tanks in the winter. At conventional gas wells, heaters are used for separators when high levels of water production are expected from the well and water freezing is a concern. Generally, water produced from the conventional well formations is saline and there is little risk that it will freeze in the winter (NMOGA, 2006). Heaters are also used to generate steam for thermal recovery; the injection of steam to lower the viscosity of heavy oil and improve the flow through the reservoir. Onshore producers of medium and heavy (low) API gravity crude oil use line heaters, tank heaters and boilers to lower the viscosity of the produced crude oil. Heaters and boilers in this application range in size from 1.0 to 5.0 MMBtu/hr. Crude oil pipeline pump stations will also use boilers to heat the low API gravity of crude oil. These boilers range in size to 10.5 MMBtu/hr. Offshore platforms and associated onshore processing plants will use process heaters to heat therminol or equivalent for use as a heat transfer medium in the oil and gas heat exchangers located at the facilities. These process heaters can range in size to 25.0 to 30.0 MMBtu/hr. Gas Plants use boilers to provide process steam to the facility gas processing equipment. These boilers can range in size to 41.0 MMBtu/hr and larger. Boilers may also occasionally be used in drilling operations to keep water from freezing. Heater emissions are dependent on the annual flow rate of gas or other fuel to the heater. The annual gas flow rate can be calculated from the BTU rating of the heater, the local BTU content of the gas or heating value of the fuel. Most heaters or boilers are gas-fired but a small number of them utilize propane or diesel fuel. It is important to consider seasonal utilization rates of heaters and boilers to account for changes in usage throughout the year, depending on the particular usage of the heater or boiler. GHG emissions can be calculated on the basis of the emissions factor of the heater and the annual flow rate of gas to the heater, or through a fuel usage calculation that considers time utilized.

Saltwater Disposal Engines

This refers to pump engines often used by private contractors to pump salt water to disposal facilities but also used by exploration and production companies for their own salt water disposal wells. Large volumes of water may be generated as flow-back from drilling and fracturing operations and this water may contain significant amounts of salt. This water must be disposed of either at specific facilities or through deep injection into wells. Salt-water disposal engines are used to provide pumping power for these operations. Information such as the make and model of engines, fuel used, and estimated operating hours and engine load are required to estimate CO_2 emissions from these engines. Engines can be divided into several class categories including micro turbines and reciprocating engines. These engines are expected to have GHG emissions of CO_2, CH_4 and N_2O.

Dehydrators

Produced natural gas may be saturated with water which can condense and/or freeze in gathering, transmission and distribution piping causing plugging, pressure surges and corrosion. Dehydrators are used to remove water in the produced natural gas. This is done by passing the natural gas through a dewatering agent such as triethylene glycol (TEG), diethylene glycol (DEG) or propylene carbonate. The most common form used is TEG, which absorbs water along with methane. The absorbed water and hydrocarbons are then boiled off in a reboiler/regenerator and vented to the atmosphere. A diagram of the dehydration flow process is shown in Figure 9.

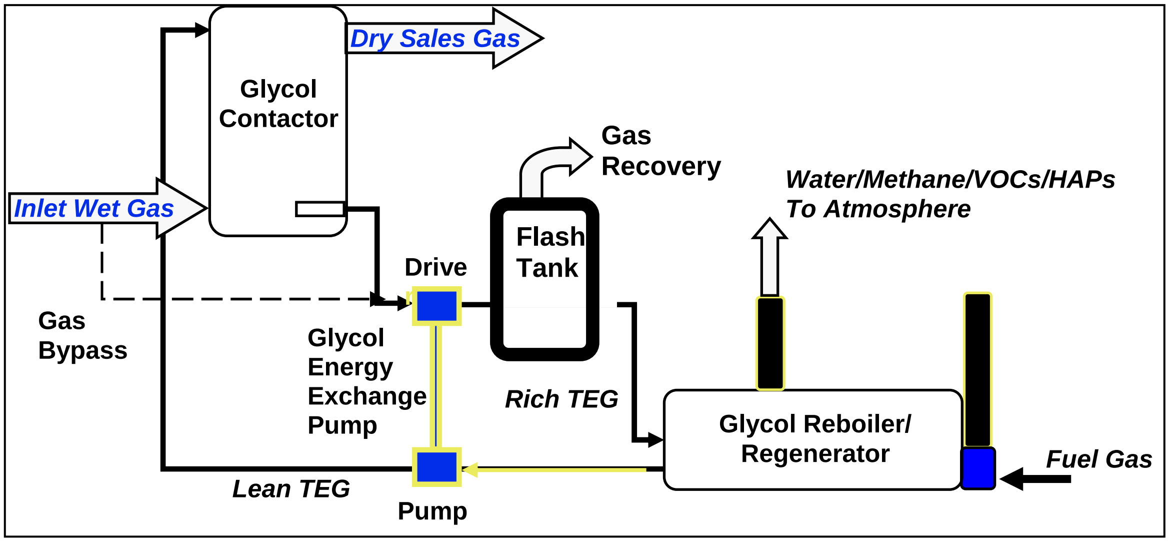

Figure 9 Glycol dehydrator process diagram

Source: Presentation on Minimizing Methane Emissions from Glycol Dehydrators, Offshore Technology Workshop, June 6, 2004

The parameters that affect dehydrator emissions include the type of glycol pump (electric or gas driven) and the presence of a flash tank. Dehydrator emissions include CH_4 from still vent emissions, CO_2 from reboiler emissions and fugitive as well as vented emissions from the glycol pump. Emission rates depend on the gas flow rate, the inlet and outlet water content, the glycol-to-water ratio, the percent over circulation and the methane entrainment rate. Reboiler emissions depend on the annual flow rate of gas to the reboiler. Some states, such as California, prohibit the use of uncontrolled glycol reboilers (reboilers not equipped with vapor recovery on the reboiler vent stack) due to the potential for HAPS emissions.

Natural Gas Processing Plants

Natural gas processing plants process produced gas for transmission distribution and potentially to extract natural gas liquids (NGL) for sale as a separate product. Natural gas plants associated with onshore oil production facilities may blend all or a portion of the NGLs with the produced crude oil to lighten the crude oil and increase the price per barrel of the crude oil. These facilities also mark the boundary of the scope of this protocol.

The major processes of these facilities include removal of hydrogen sulfide, carbon dioxide, nitrogen and water from sour natural gas, and recovery of natural gas liquids through cryogenic processes. Products include natural gas liquids (NGL), pipeline quality natural gas and hydrocarbon condensate. Equipment utilized in these plants includes inlet gas compressors (using reciprocating engines or gas turbines), amine units, heaters, glycol dehydrators, cryogenic gas-processing unit for natural gas liquids (NGL) recovery, acid gas injection systems (if applicable) and emergency flares. These facilities may also have associated fugitive emissions from the engines and other processes, as well as component fugitive emissions from piping and other transmission systems. These facilities may also have associated truck loading emissions from transport of condensate or NGL to a sale location.

In the U.S., typically natural gas processing plants have sufficiently high annual emissions of criteria air pollutants to require compliance with the federal Title V permit program, or Part 71 program for tribal land. Many states also track permits of these facilities in separate state databases. Permit data is typically used in inventory efforts to allocate emissions to these facilities and include information on major equipment and fugitive emissions. Truck loading is not generally included in gas processing plant permit data.

Straddle Plants

Straddle plants are gas processing plants that straddle an existing natural gas pipeline to extract a portion of the ethane, propane, butanes and/or condensates (natural gas liquids or NGLs) from the natural gas before returning it to the pipeline. As discussed herein, the straddle plant would be associated with the exploration and production gathering pipeline system. Straddle plants associated with natural gas transmission systems would be beyond the scope of this protocol. In the process, inlet gas from the pipeline system is passed through inlet separators to remove free liquids before being dehydrated by molecular sieve beds and passing through a pressure expander to cool the gas. The recovered stream is processed through a fractionation train consisting of up to three distillation towers in series: a demethanizer, a dethanizer and a depropanizer. This process generates NOx, CO_2, CH_4 and CO emissions depending on the amount of compression and dehydration needed.

Acid Gas Treatment Systems (Amine Units and Amine Plants)

Amine treating units are used to remove CO_2 and H_2S from sour gas and hydrocarbon streams. A diagram of the amine unit process is shown below in Figure 10.

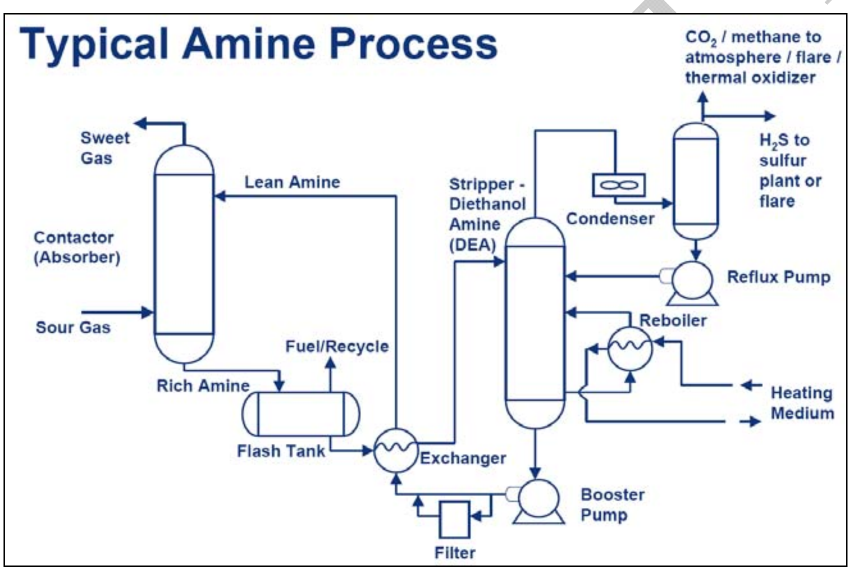

Figure 10 Amine process diagram
Source: Presentation on Minimizing Methane Emissions from Acid Gas Removal, EPA Natural Gas Star Technology Workshop, August, 2007

The stripping of H_2S and CO_2 in the amine regenerator creates a rich amine solution. A reboiler supplies the necessary heat to strip H_2S and CO_2 from the rich amine, using steam as the heating medium. Acid gas, primarily H_2S. CO_2 and water vapor is cooled in the regenerator overhead condenser. The mixture of gas and condensed liquid is collected in an overhead accumulator and depending on the H_2S content, the uncondensed gas is sent to sulfur recovery or may be recycled for CO_2 EOR as is widely done in West Texas or re-injected into a disposal well. . Amine units are generally located at gas processing plants and are therefore generally included in plant permits. Information on the size and type of equipment, processing volumes and liquid composition can be obtained from permit authorities. However, some field amine units are also located at gas wellheads and may or may not be permitted so additional data would need to be collected on these field units to determine GHG emissions. Amine units could be a source of CO_2 and CH_4 emissions from venting of uncondensed gas and CO_2, CH_4 and N_2O emissions from the reboilers.

Several alternatives to amine units for acid gas removal are available including the Morphysorb® process, Kvaerner Membrane technology, and the Molecular Gate® process.

Chemical Injection Pumps

Chemical injection pumps are small positive displacement, reciprocating units designed to inject precise amounts of chemicals into process streams. Typical chemicals injected into the process lines include anti-foam agents, methanol, biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and hydrogen sulfide (H_2S) scavengers (API Compendium). Depending on the area, chemical pump engines are either fired by natural gas or diesel or electric driven. These pumps are expected to have GHG emissions of CO_2, CH_4 and N_2O. As with saltwater disposal engines the emissions will depend on the type of engine, fuel used, estimates of the hours operated and loading of the engines. Small pneumatically driven chemical injection pumps, which use natural gas as the motive force, are also used throughout oil and natural gas fields. Due to the wide range of engine types and sizes emissions will very significantly.

Gas-Actuated (Pneumatic) Pumps

Emissions from gas pumps are based on the average gas consumption rate per gallon of chemical compound pumped. Information on the injection pressure, utilization rates and seasonal utilization factors are necessary for emissions estimation. Manufacturer specifications are often utilized to obtain average gas consumption rates for gas-actuated pumps. The pump gas consumption rate can then be used to calculate emissions using the same methodology as other vented gas sources. This relies on knowledge of the composition of the gas to actuate the pump and gas being injected into a reservoir. If this gas is used in EOR activities, these pumps can be a source of CH_4, CO_2 and N_2O emissions.

Flaring

Flaring is used to convert volatile organic hydrocarbon gases to less hazardous and less reactive compounds. Emissions include both CO_2 and CH_4 and some N_2O. Flaring in the field has been shown to have lower efficiencies than typical flares used in refineries and other processes. The results from one study conducted by the International Flare Consortium (IFC), showed that when the flares were operated under conditions representative of good industrial practice, the combustion efficiencies were > 98% (McDaniel M., 1983). Flares operated during well completion activities are required to handle large volumes of gas.

2.3.2 Fugitive Emissions

Fugitive emissions include wellhead fugitive losses, pipeline fugitive losses, and compressor station/gas plant fugitive losses.

Process Fugitive Losses

Fugitive losses are gases that escape through wellhead and pipeline systems due to leakage around seals and between fittings. GHG emissions estimates of fugitive emissions for the exploration and production sector generally rely on estimating the total volume of gas lost through components and estimating the CH_4 and/or CO_2 fraction of that fugitive gas. The total volume lost is often determined by identifying the number and type of components used per well or facility, or per unit length of pipeline. This can be determined for typical setups for oil wells, gas wells, small compressor stations and pipeline operations. It is necessary to segregate primary oil and gas production since distribution of components will vary between oil production (more heavy liquid components) and gas production (more gas/vapor and light liquid components) and the type of operation. The volume lost per component for typical gas and oil wellhead and pipeline pressures can be obtained from references cited in this report or additional field measurements to determine fugitive loss rates on a regional or field basis. Note that for large facilities considered in this protocol – central compressor stations and gas processing plants – fugitive emissions estimates are often part of the permit for the facility. While these permits do not require estimates of methane emissions, the permits can provide information that is useful for estimating GHG emissions.

Gas Plant Fugitive Losses

Similar to wellhead fugitive losses, gas plants are also susceptible to fugitive losses through components in the plant. These fugitive losses are usually estimated by plant operators and this information would be supplied along with the permit information for the facility. Because a gas plant may have a significant amount of equipment, operating multiple processes, there may be a significant number of components subject to fugitive losses. In addition, depending on the process from which the fugitive losses are occurring there may be variations in the chemical composition of the gas escaping. In general, gas plant fugitive losses are GHG emissions sources of CH_4, CO_2 and N_2O.

<u>Pneumatic Devices</u>

This category refers to pneumatically-powered devices located at gas wells. These devices function as pressure controllers, liquid level controllers, pressure safety high/low and liquid safety high/low controllers. and are used in lieu of electric devices in remote locations where electric power from the grid is unavailable. Natural gas is generally the pressurized fluid used to power these pneumatic devices since it is plentiful at the wellhead and at remote pipeline locations. Natural gas is also used for some utility services such as small pneumatic pumps, compressor motor starters and isolation shutoff valves. These devices are used in many locations where compressed air supplies are not available. Some companies have converted to compressed air supply and have received or are eligible to receive emission reduction credits.

Wellhead and Pipeline Pneumatic Control Devices

A variety of process control devices are used by the natural gas industry to operate valves that regulate pressure, flow, temperature and liquid levels. These instruments can be classified as pneumatic, electrical or mechanical devices. Due to the location of these remote sites, electricity is not available so most of the instruments used in production are pneumatic devices that make use of the available high-pressure natural gas. These devices control and monitor gas and liquid flows, temperature in dehydrator regenerators and pressure in flash tanks. Most of the pneumatic control systems are operated at 20 to 30 psi and consist of a network of distribution tubing to supply all of the control instruments.

As part of normal operation, natural gas powered pneumatic control devices release (or bleed) gas to the atmosphere and consequently, can be a major source of methane emissions from the natural gas industry. Recently some states have begun to push for the use of low-bleed pneumatic devices, or to run these devices using compressed air ("instrument air"). Widespread adoption of these devices in the future may change the methane source from potentially significant to minor.

Emissions from pneumatic devices rely on estimates of the bleed rate (volume rate of gas bled through the devices), usage information, and device counts for typical well setups or for facilities. However it is worth remembering that these devices are more commonly in place at well sites since central facilities are likely to have available electricity. GHG emissions are dependent on the methane or CO_2 content of bled gas, which would be determined by gas composition analysis. These devices are expected to have GHG emissions of CH_4 and possibly CO_2 if the bled gas has a non-negligible CO_2 content.

Compressed air is used to power a majority of the pneumatic devices at gas processing plants, though some devices are operated with natural gas. Many processing plants used gas-driven pneumatic controllers on isolation valves for emergency shut-down conditions or for maintenance work (API, Compendium).

<u>Tanks</u>

Oil Tanks

Oil storage tanks are used to hold produced oil for short periods of time to stabilize flow between production wells, pipelines and trucking transportation sites. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons and water are removed through a series of high pressure and low-pressure separators. The crude oil is then injected into a storage tank to await sale and transportation offsite. Losses of lighter hydrocarbons can occur by: (1) the fluid flashes when the separator or heater-treater, operating at higher pressures, dumps oil into the storage tank at or near atmospheric pressure; (2) working losses released from the changing fluid levels and agitation of tank contents associated with the circulation of fresh oil through the storage tanks and (3) standing losses from daily and seasonal temperature changes. Loss mechanisms (2) and (3) are often collectively referred to as "working and breathing" losses. Flashing and working and breathing losses can be significant sources of gas venting emissions, particularly CH_4 if it is a significant component of the flash gas or working and breathing loss gas. Tanks may be used extensively across oil fields, or their usage may be very minimal if significant pipeline infrastructure has been installed and produced oil is sent directly to pipeline.
Oil tanks may have control systems in place to reduce flashing and working and breathing losses in order to reduce VOC emissions, but this also impacts GHG emissions. The most common control strategy is to install flaring on these tanks, which converts methane and other hydrocarbons in the flash and working and breathing loss gases to CO_2. The methodology for calculating those emissions is described in the section on flaring above.

In some areas, such as California, the most common control strategy is to install a vapor recovery system on the tanks with an associated vapor recovery compressor that discharges to a gas gathering system. The gas gathering system sends the gas to a gas compression facility or gas processing plant. The gas may then be sold, used as fuel for fuel burning production and processing equipment or injected underground into the producing formation for EOR purposes. In these areas, flares are generally used for planned continuous flaring of produced gas only at locations where there is no other available or viable outlet for this resource. Reasons for the lack of an available or viable outlet for the gas may be due to the practicality of installing a pipeline to move the gas from the remote location to a processing facility or may be due to the lack of "right-of-way" approval. Facilities having an alternate outlet for the produced or process gas generally use flares for planned intermittent flaring for maintenance (de-pressuring) of tanks, vessels and process piping and for unplanned flaring resulting from process upset conditions. Finally, floating roofs are sometimes installed as a control technique.

Condensate Tanks

Condensate tanks are similar to oil tanks in that they are located at gas well sites where a significant quantity of associated liquid hydrocarbon is produced along with the primary gas. Gas wells typically do not have a pipeline infrastructure to deliver the condensate to a transmission system, and therefore condensate tanks are more common at gas wells with significant condensate production levels. However, condensate tanks may also be found in other locations such as straddle plants. As with oil tanks, flashing, and working and breathing losses can occur for condensate tanks. As with oil tanks, calculating emissions for condensate tanks depends on the type of well at which the tank is located. The determination of well type is often made using the gas-to-oil ratio (GOR) of the well. If the GOR is above a particular threshold the well is considered a gas well and then any associated liquid hydrocarbon production is considered condensate. The GOR cutoff threshold is usually determined for each state by the state's Oil and Gas Conservation Commission (OGCC) or equivalent.

The methodology for calculating emissions from condensate tanks is similar to oil tanks. As with oil tanks, condensate tanks are expected to be a source of CH_4 emissions if CH_4 is a significant component of the flash gas or working and breathing loss gas. Also similar to oil tanks, condensate tanks may be controlled with flares that would convert the CH_4 in the flash gas or working and breathing loss gas to CO_2.

Produced Water Tanks

Water produced from active gas wells may be stored on-site in water tanks. The produced water may contain dissolved hydrocarbon species that flash off the water in a process similar to oil and condensate tanks. These water tanks would also be subject to similar working and breathing losses. However, the hydrocarbon content of the water is expected to be significantly smaller on a volumetric or mass basis than for condensate or oil. In principle, similar methodologies can be used to determine flashing and working and breathing loss emissions from water tanks, but composition data for the gas is generally unavailable. These tanks would have GHG emissions of CH_4. In some areas produced water tanks are required to use gas blankets and tie into a flare system where they are used to store water from sour gas or oil reservoirs.

Floating Production, Storage and Offloading System (FPSO)

FPSO's are self-contained production facilities and can receive crude from nearby wellhead platforms. In fact, many FPSO's receive crude from subsea wellhead modules. This is a type of floating tank system used for the offshore oil and gas operations which is similar in appearance but designed differently to a ship This system carries on board all the necessary production and processing facilities normally associated with a fixed oil and gas platform, but with the addition of storage tanks for the crude oil recovered from the wells. It is designed to process and store produced oil or gas from nearby platforms until the oil or gas can be offloaded onto waiting tankers or sent through pipelines to production facilities. FPSOs operations can generate CO_2, CH_4 and N_2O emissions. Vapor recovery is frequently used during loading operations to minimize loss of product and emissions.

Vented Emissions

Vented emissions include completion venting, well testing, well blowdowns, vessel and facility upsets/blowdowns, gas plant venting, truck loading, compressor engine start-ups and shut-downs, water disposal, venting for maintenance purposes and land farms. Wells are also vented during some workover operations, such as during tubing and casing repair. It should be noted that many of these activities are regulated in areas such as California. Current air pollution control rules in many California districts only allow well blowdowns for maintenance and repair purposes, and well completion venting from drill rig gas busters. All other activities listed in this section as venting activities including crude oil storage and produced wastewater storage tank degassing activities must route the gases to a flare or thermal oxidizer for combustion

Completion Venting

The last step in a well becoming a "producing well" is cleaning the well bore and the reservoir immediately surrounding the well and stimulating the well to production through fracturing.

Once the well is stimulated into production, well completion traditionally involves producing the well to open pits or tanks where sand, cuttings, and the reservoir fluids are collected for disposal and the produced natural gas is vented to the atmosphere. Venting gas releases methane and , depending on the composition of the gas, other hydrocarbons and HAPs. Depending on the formation, natural gas may also contain nitrogen, carbon dioxide or sulfur compounds such as hydrogen sulfide (H_2S). Wellhead natural gas can range from 70 to 90 percent methane. Green completions recover natural gas and condensate by using portable equipment such as additional tanks, special gas-liquid-sand separator traps, and portable gas dehydration. The gas is directed through permanent dehydrators and meters to sales lines, reducing venting and flaring emissions. GHG emissions from well completions are estimated on the basis of the volume of gas vented during completion and the CH_4 and CO_2 content of that gas. This can be obtained from gas composition analyses. This process is not performed in some operations such as heavy oil wells.

Well Blowdowns and Well Testing

Venting of wells is routinely done to unload fluids that may block the well and over time reduce the amount of gas produced. A well is vented by simply opening the well to atmospheric pressure and allowing the pressure to lift fluids to the surface, or by using a plunger lift. In either case, the well is open to the atmosphere, which allows for relatively large volumes of gas to escape and may be a significant source of CH_4 emissions. While this practice does not occur at all wells, the produced gas in gas wells has a high weight fraction of methane, and therefore blowdowns may be a significant source of CH_4 emissions.

During well testing for production characteristics, venting to the atmosphere may occur. In principle this source category can be estimated using a methodology similar to well blowdowns, and would also be expected to be a source of CH_4 emissions.

Compressor Startups/Shutdowns

When compressors are taken offline for maintenance or the system shuts down, the gas within the compressors and associated piping is either manually or automatically vented to the atmosphere. Some systems route these vapors to a flare stack where they are combusted, while other systems simply vent the evacuated vapors to the atmosphere via a vent stack. Emissions are dependent on the frequency of startups and shutdowns, and the volume of gas vented. Compressor startups and shutdowns are a source of CH_4 emissions.

Truck Loading

Truck loading involves the transfer of liquids such as oil, condensate and produced water to processing plants or disposal. During truck loading some gas losses will result in CH_4 emissions. Depending on the frequency of truck loading events per well site, or the truck loading losses per unit of condensate or oil production CH_4 emissions estimates can be significant. API has developed a simplified methodology for estimating truck loading emissions with assumptions for composition of gas being loaded, and emissions factors per unit of liquid loaded for various truck loading operation types. Some producers support the development and use of a factor that is based on the volume of liquid loaded into trucks because the EPA AP-42 methodology is difficulty to apply to field-wide production of oil. It should be noted that many California air pollution control districts (APCDs) have rules requiring the use of vapor recovery systems for truck loading activities.

Natural Gas Liquid Plant Truck Loading

Similar to condensate or oil, truck loading occurs at gas processing plants that process natural gas liquids (NGL). Natural Gas Liquids result from refrigeration of plant feed gas, which induces condensation of individual liquid components, such as propane and butane. In turn, these are selectively purified using fractionation technology.. NGL truck loading emissions can occur from liquid left in transfer hoses and from displacement of gas in the truck tank if an inert gas or a vapor recovery unit is not used to capture vented gas. NGL tanks are typically high-pressure, and result in CH_4 emissions.

Gas Plant Venting

Venting from typical operations of gas plants can occur as a result of pressure build-up, or fluid build-up (blowdowns) in various processes. In many facilities venting events are controlled with the use of flares, vapor recovery units or other control mechanisms. However, if direct venting occurs to the atmosphere there will be sources of GHG emissions. This may include CH_4 and/or CO_2 depending on the process from which the venting occurs. Emissions will depend on the volume of gas vented and the chemical composition of the gas and whether controls such as flaring are applied. This information may be reported as part of a state or federal permit.

Vessel and Facility Upsets

Vessel and facility upsets refer to events in which a liquid or gas may be accidentally spilled or vented to the atmosphere. In the case of liquid petroleum spills from vessels or large-scale gas leaks from pipelines or processing facilities, the material released will most likely vent directly to atmosphere (for gases) or volatilize (for liquids) potentially releasing GHG emissions. For gas leaks due to system upsets at wellheads, pipelines or processing facilities, GHG emissions of CH4 and CO2 (if present in the gas) may occur. For spills of petroleum liquids, CH4 emissions may occur as a result of volatilization of the liquid. Emissions estimation of spills and upsets requires detailed knowledge of the number of upsets/spills, the volume of liquid or gas released, the chemical composition of the released material and volatilization properties.

Well Site Land Farming

Well completion and other activities occasionally involve using open pits for collection of sand, cuttings, and reservoir fluids. In other cases, fluid spills may result in materials exposed to the atmosphere. The type of material released (oil, produced water, methanol) and volume due to spills or land farming can be converted to weights using average specific gravity assumptions. Estimated weight fractions of the materials can then be applied to produce water, condensate, oil and methanol spill events to estimate emissions. It is also important to not double count larger spills transported to land farms. Land farms would primarily have GHG emissions of CH_4 but could have emissions of CO_2 if it were present in the gas or materials collected on the land farm. However, it should be noted that materials land farmed can be comprised of weathered products that do not contain CO_2 or CH_4.

Water Disposal Pits

Water disposal pits are used to store and dispose of produced water, or fluids from drilling and completion operations. The water in these pits may contain small amounts of hydrocarbons that may volatilize into the atmosphere if no other control measures are taken. These pits would have GHG emissions of CH_4 but could have emissions of CO_2 if it were present in the water. In California regulations would require demonstration that emissions be negligible or that emissions controls be applied.

2.3.3 Mobile Source Emissions

<u>On-Road Mobile Sources</u>

During the exploration stage of a well, offshore support vessels and heavy-duty and medium-duty diesel trucks are used for transport of construction and drilling equipment, and during well completion. The number of truckloads required depends on well location, depth, pressure, and rock strata. During production, heavy-duty diesel trucks are used for truck loading and transport of oil, condensate and natural gas liquids. During both exploration and production, light-duty trucks, passenger cars and, in the case of offshore operations, helicopters are also used to transport crew for well construction/completion and maintenance. Both diesel- and gasoline-powered vehicles have combustion emissions of CO_2, CH_4 and N_2O in exhaust gases, and HFC emissions from leaking air conditioners. GHG emissions due to vehicular movement for a single well will likely be minimal compared to other E&P emissions sources; however, vehicle emissions for a field or basin may be significant.

On-road vehicle emissions can be estimated using fuel consumption and vehicle miles traveled (VMT). Fuel consumption can be estimated from the number of trips, VMT, age distribution and fuel economy by trip type and vehicle category. Since emissions also occur during vehicle idling, idling times by type of activity and vehicle are also required. EPA's MOBILE6 emissions factor model can be used to derive CO_2 emission factors[62]. In late 2009 EPA is expected to release an update to this model called MOVES, which will estimate vehicle CO_2, CH_4 and N_2O emissions[63].

<u>Non-Road Mobile Sources</u>

Drilling Rig Engines

Drilling rigs are often composed of multiple engines of differing usages, loads and emissions factors (Flanders, C., 2007). Some drill rigs consist of four or more engines: two draw-works engines that control the drill string, one mud pump engine that controls all pumping activity, and one generator engine to provide electrical power. In most cases, drilling rigs use diesel fuel for the engines, however, some drilling rigs have been converted to use natural gas or constructed using highline electric power or fuel gas as the primary source to reduce emissions. GHG emissions from drilling rigs will depend on several factors including drilling horsepower, drilling time, engine load factors and fuel used. Drilling rig engines will have emissions of CO_2, CH_4 and N_2O.

Data for estimating drilling rig emissions can be obtained from a number of sources. For example, drilling horsepower requirements based upon the anticipated drilling depth and drilling time. The load factors are available for some areas based on specific information from producers or from engine manufacturer's literature. Emissions from drill rigs have traditionally been estimated by tracking the duration of drilling, engine load and horsepower and fuel usage and developing an emissions intensity per well drilled. This is combined with information on the total number of wells drilled in a particular geographic region for a particular time period. Data on the number of wells drilled is generally maintained by Oil and Gas Commissions (OGC) or their equivalents from various states. Companies can also provide this information, however it should be noted that drilling is an activity that is often contracted by oil and gas companies to drilling companies therefore data availability may be an issue.

There can be wide regional and rig-to-rig variations in the input data used to estimate GHG emissions from rigs. Drilling times vary by regional location and horsepower of the rig. Drill rigs are assembled with many varying configurations, including the number of engines, engine size and purpose. In addition the load factors on drilling rigs are highly variable and depend on the usage of the rig engines, and the needed power for drilling at a particular site.

Workover Rig Engines

Workover rigs are often used in existing wells to pull and replace tubing or rework a well for a different reservoir. Typically workover rigs are smaller in total installed horsepower than a primary drilling rig, and will often have fewer individual engines than a primary drilling rig – many workover rigs will have only one engine typically. As with drilling rig engines, these engines will have emissions of CO_2, CH_4 and N_2O. The activity of workover rigs is also variable depending on the extent of activity needed to repair or overhaul a well. Workover rigs are typically operated by third-party companies contracted by the well owner to provide this service,

[62] http://www.epa.gov/otaq/m6.htm
[63] http://www.epa.gov/otaq/ngm.htm

and data would therefore need to be obtained from the contractor to determine workover rig size and typical usage.

Completion Equipment (Non-Venting)

A variety of equipment may be used at well sites to complete a well. Well completion may require fracturing of the well which involves pumping high pressure water and/or sands to improve gas or liquid flow through the well bore. This process utilizes portable fracture pumps which are often diesel-fired engines up to several thousand horsepower in size. Usage of these pumps can range from less than a day to several days. Fracture pump engines have GHG emissions of CO_2, CH_4 and N_2O and these emissions would be calculated similar to other engines.

Other completion equipment and completion service rigs may be used to conduct completion activities such as perforation of a well or installation of tubing. The majority of this equipment is diesel-powered unless there is some nearby source of natural gas. Completion equipment is expected to have GHG emissions of CO_2, CH_4, and N_2O and these emissions would be calculated similar to other engines.

CBM Pump Engines

CBM pump engines are used to dewater CBM wells that have been flooded. Depending on the area, CBM pump engines may be natural gas- or diesel-fired. CBM pump engines in New Mexico and Colorado are primarily fired on natural gas or a mix of natural gas and diesel engines. In some areas such as Montana and Utah CBM pumps are electric. In Wyoming it was reported that the vast majority of the pumps used (over 90 percent) are electric submersible pumps (ESP).[64] Producers in other areas, such as the San Juan Basin and the Raton Basin, have reported predominantly using other types of pumps, including plunger lifts, progressing cavity pumps and rod lift systems.[5] Depending on the maturity of the field, less dewatering may be necessary and CBM pump engines are used comparatively less. CBM pump engines are expected to have GHG emissions of CO_2, CH_4 and N_2O.

Exploratory Drilling and Testing[65]

Major sources of gaseous pollution from drilling operations are exhaust gases from diesel driven power generators. As with drilling emissions, greenhouse gases from these sources are CO_2, CH_4 and N_2O

Well Pad and Other Construction Activities

Prior to initial drilling activities for a new well, the land on which the well is located must be cleared for the drill rig and associated equipment. This well pad construction activity utilizes construction equipment such as dozers, scrapers, graders and various heavy-duty trucks. Truck emissions are described in more detail in the on-road mobile sources section. The off-road equipment emits CO_2, CH_4 and N_2O. Off-road equipment emissions estimates require information on the quantity and type of equipment used, average usage on a per-well basis,

[64] Russell, James, Pollack, Alison, Oil and Gas Emissions Inventories for the Western States, ENVIRON International Corporation, prepared for the Western Governor's Association, December 27, 2005.
[65] http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/neworleans3.pdf

model year and information on controls installed on the equipment. Emissions can be calculated directly from manufacturer emissions factor data, or modeled using off-road equipment emissions modeling tools such as EPA's NONROAD or ARB's Offroad models. This would apply to other oil and gas construction activities as well including construction of roads, facilities and pipelines.

Oil Sands Mining Equipment

Oil sands are mined in northern Alberta using the open pit mining technique, in which trucks and shovels are used to strip the overburden and remove the underlying oil sands. Much of the equipment used at the mines including the crushers used to grind the sands, and the conveyors used to transfer the sands from the crushers to the cyclofeeder (where its mixed with hot water to produce a slurry), are electrically-powered and do not emit direct GHGs. Rather this stationary equipment either generates indirect emissions (discussed in the next section), or provides the load for an on-site generator(s).

Most of the mobile off-road equipment used at the mine is diesel powered (with the exception of the electric shovels used to strip the overburden). In addition to the haulers and dump trucks, a wide array of diesel (and some gasoline) equipment including bulldozers, scrapers, front-end loaders, hydraulic excavators and drills are used in various support functions (such as clearing and grubbing, drilling, blasting, supply and personnel transportation, road construction, grading and maintenance, and mine reclamation). This off-road equipment emits CO_2, CH_4, and N_2O. Although specific applications of the mobile equipment employed in oil sands may differ from conventional oil and gas production, applicable emission estimation methods described in the preceding subsections (wellpad construction and on-road mobile sources for trucks), are the same with one exception. Some Canadian operators use fuel from the upgraded oil rather than diesel for some of the larger mobile source equipment. Therefore, non-standard emission factors have been developed for oil sands mining equipment on a case-by-case basis.

Oil Sands Upgrader Facilities

Upgrading is a type of conversion process that changes the characteristics of the crude bitumen to create synthetic crude oil. This process is carried out in two phases. During the first stage, the diluent added to the bitumen to improve flow is removed and shipped back for re-use. The bitumen then enters an upgrading unit where the hydrocarbon molecules are broken down using either coking (Primary upgrading coker unit, Figure 11), hydrocracking processes or both. The excess carbon generated in this process forms a solid residue called coke which is transported to a gasification unit where it is transformed into natural gas and hydrogen.

In the second stage of upgrading, the lighter portion of the upgraded bitumen obtained during the coking process will go through a hydrotreater (Hydroprocessing unit, Figure 11) and the heavier portion will go to a hydrocracker (if needed). This allows the heavy molecules to be broken down further and the lighter oil molecules to be sent to the hydrotreater.

In the hydrotreater process, hydrogen is added at high pressure and high temperature to remove nitrogen, sulphur and metals from the bitumen. The hydrogen used for this process usually comes from a steam reforming process (hydrogen production unit, Figure 11) that uses water and natural gas. This process requires large amounts of water and can create significant quantities of

CO_2 emissions. Additionally, there is the option to implement a coke gasification process[66] to obtain synthetic natural gas for hydrogen production. Finally, the hydrogen sulphide obtained during the hydrotreater process is converted to elemental sulphur in a recovery unit, which can be either transported for use in other industrial processes or stored in large sulphur blocks. CO_2 emissions are the main emissions produced during the upgrading process.

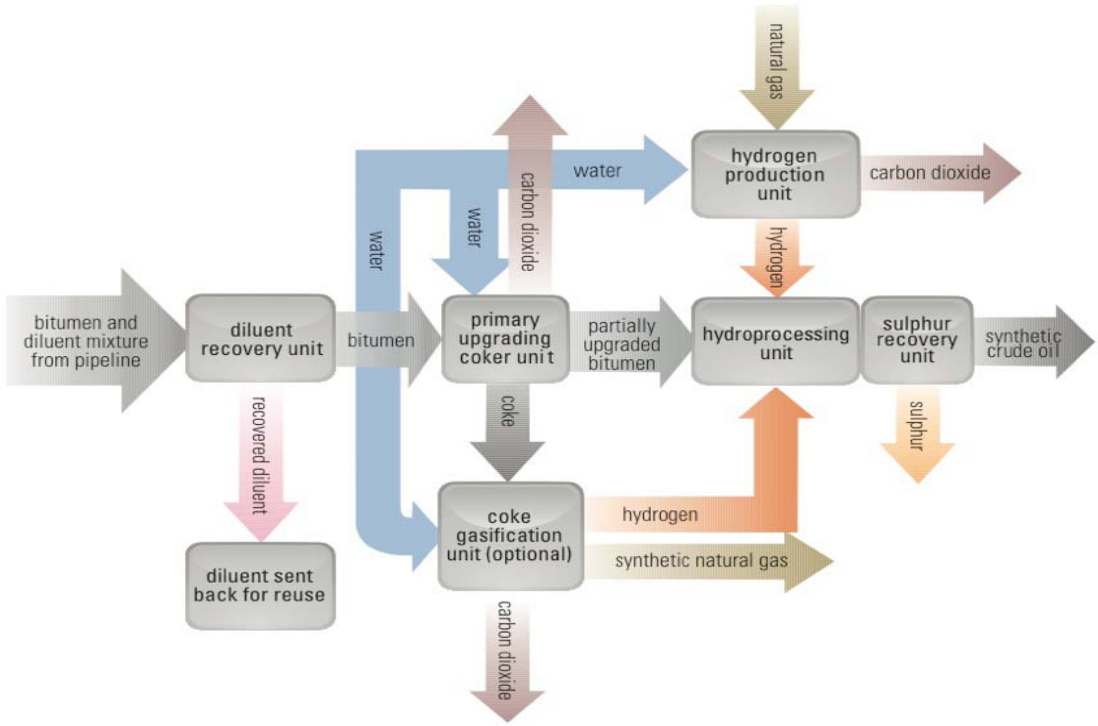

Figure 11 Upgrading Process Overview
Source: Upgrader Alley Oil Sands Fever Strikes Edmonton Report, The Pembina Institute: Oil Sands Fever Series, June 2008

2.3.4 Indirect (Scope 2) Emissions

Indirect emissions are defined as emissions that occur as a result of a particular entity's activities, but that occur at sources owned or controlled by another entity. For example, a manufacturing company, A, that purchases electricity to run its factories causes emissions to occur at power plants owned and controlled by a power generating company, B; these emissions are the indirect emissions of company A and the direct emissions of company B.

Indirect emissions are further subdivided into Scope 2 and Scope 3 emissions. Scope 2 emissions are defined as the indirect emissions associated with purchase or acquisition of electricity, steam, heating, or cooling. Scope 3 encompasses all other indirect emissions not classifiable as Scope 2. The reporting of Scope 3 emissions is generally treated as optional by most GHG programs (including TCR). Scope 3 emissions are discussed further in the next two chapters.

Scope 2 emissions, on the other hand, generally *must* be reported to the various GHG registries (including TCR). The requirement to report Scope 2 emissions in part reflects the existence of standard, relatively accurate and straightforward methodologies for the estimation of these

[66] Currently, Canada doesn't have upgraders using coke gasification, there is one upgrader using liquid asphaltene gasification to produce synthetic natural gas for hydrogen production and as fuel for steam generation.

emissions (the same cannot be said of Scope 3 emissions). In addition, Scope 2 emissions often comprise a significant percentage of an entity's total emissions. In fact, for some major sectors of the economy (for example, the commercial sector), Scope 2 emissions from electricity use represents the primary source of emissions. While emissions from purchased electricity are generally not the dominant emissions source for the E&P sector, they are nonetheless significant. Furthermore, although purchased steam is not a predominant source of emissions for the sector as a whole, it can be a major emissions source for some companies operating in heavy oil and oil sands fields. In the following pages indirect emissions from electricity and steam purchases are considered in greater detail.

Purchased Electricity

Oil and gas producers use electricity to power a wide variety of applications, from electric motors to lighting. Some companies (consisting usually of those with large operations in a particular field) use their own on-site generators to meet some or all of their electricity requirements. Furthermore, pipeline gas is sometimes used as a substitute for electricity to meet the energy needs of isolated facilities such as pipeline compressor and metering stations. Incidental electricity requirements of these facilities may be met by on-site solar power rather than grid purchases.

Relatively small or limited uses aside the E&P sector, like most other sectors of the economy, relies on purchases from the grid to meet its electricity needs. As noted above, there are well-established methodologies for the estimation of emissions from electricity purchases. Both WRI and TCR describe these methodologies in their reporting protocols. While these methodologies are generic rather than sector-specific, they apply just as well to the E&P sector as to all other sectors of the economy. In general, the established approach involves a simple multiplication of electricity purchased by either a site-specific emissions factor, or a generic emissions factor based on geographic location. Data on electricity purchases should be readily available from electricity bills or meter readings. When the specific generating source of the electricity is known (as might, e.g., be the case when one E&P company sells its own self-generated power to other companies working in the same field), and when data on the heat rate and fuel type(s) used by the source is available, the reporter should develop a generator-specific emission factor. This is calculated by applying data to fuel-specific (and, for CH_4 and N_2O, technology-specific) emissions factors. TCR's *General Reporting Protocol* (GRP) provides a compendium of fuel- and technology-specific emissions factors drawn from a wide variety of sources (including the U.S. EPA, the IPCC, Environment Canada and Statistics Canada) [GRP, pages 74 to 81].

In most situations—and almost always when electricity is purchased from the grid—specific source(s) of the electricity cannot be determined. In these cases generic emission factors, specified on a pounds GHG per MWh basis and available by region and gas, can be applied to the quantity of electricity purchased. For the U.S., the EPA's eGRID emission factors appear to have emerged as the most commonly cited and approved default factors. For example, TCR's GRP [p. 104] uses eGRID emissions factors by 26 separately defined eGRID subregions, and by the three GHGs emitted as a result of electricity generation (CO_2, CH_4, and N_2O).[67] For Canada, TCR uses CO_2-equivalent emission factors from Environment Canada[68] as its default

[67] U.S. EPA eGRID2006 Version 2.1, and U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005,* April 2007 (Annex 3, Table A-69).
[68] Environment Canada, *National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada* (April 2007), Annex 9: Electricity Intensity Tables.

factors. These emissions factors are broken down by province (with a separate factor provided for the three Canadian territories) [GRP, p. 105]. TCR's GRP [p. 106] provides national-level CO_2-equivalent emission factors for Mexico from the Ministry of Energy.[69]

<u>Purchased Heat or Steam</u>

Steam is used by the E&P sector for enhanced recovery operations in some heavy oil and oil sands fields. Unlike the case for electricity, steam is usually self-generated by the user. When self-generated, the emissions associated with the steam represent the operator's direct emissions, and the operator will have direct access to the fuel consumption data required.

While self-generation is the rule in the case of steam, there are occasional exceptions to this rule. Specifically, if one operator generates steam from a bank of steam generators or a cogeneration unit, and sells a portion of the steam to other operators working the same field, the operators relying on purchased steam must account for their indirect emissions associated with the steam's production. This approach depends on data availability. The preferred approach can be employed whenever data can be obtained on net heat (and, for CHP plants, electricity) generation, and emissions of the generating plant. Using this data, standard methodologies for the allocation of *direct* emissions between steam and electricity production can be used to determine the portion of emissions attributable to steam production. This step is necessary only in the case of cogeneration plants; for conventional boilers all of the emissions are attributable to the steam. The TCR's GRP describes one such method [GRP, Section 12.3], in which emissions are allocated on the basis of the energy input used to produce the separate steam and electricity products. Using the GRP's method, separate steam and electricity production efficiencies are used to estimate steam and electricity fuel inputs. Once the steam-related emissions are known, the purchaser's indirect emissions are simply equal to the product of the steam-related emissions multiplied by the quantity of steam purchased, expressed as a fraction of the plant's total net steam production. If the purchaser acquires electricity from the same source, the electricity-related indirect emissions would be calculated as the product of the plant's electricity related emissions multiplied by the quantity of electricity purchased as a fraction plant's total electricity generation.

TCR's GRP provides another method applicable to conventional (non-CHP) boilers when data on the steam plant's emissions are not available, but the plant's fuel types and efficiency are known [GRP, Section 15.2]. Using this method, plant-specific emission factors can be developed by dividing fuel-specific emissions factors (e.g., default factors such as those supplied by the GRP) by the plant's total efficiency factor. The resulting emission factors, expressed in pounds GHG per mmBtu, may then be applied to the thermal energy of the purchased steam to derive indirect emissions. The steam's thermal energy can be computed based on the quantity of steam purchased (in pounds) and the steam's enthalpy at delivered conditions (available from standard steam tables)[70].

[69] Asociación de Técnicos y Profesionistas en Aplicación Energética (ATPAE), 2003, *Metodologías para calcular el Coeficiente de Emisión Adecuado para Determinar las Reducciones de GEI Atribuibles a Proyectos de EE/ER – Justificación para la selección de la Metodología*, versión final 4.1 (junio de 2003), proyecto auspiciado por la Agencia Internacional de Estados Unidos para el Desarrollo Internacional, México, D.F., México.
[70] For example, International Association for the Properties of Water and Steam, *Industrial Formulation 1997 for the Thermodynamic Properties of Water and Steam*.

If data on the source plant's efficiency is not available, then it is necessary to use a default efficiency factor to estimate the emission factors. The resulting emissions factors can then be applied to the purchased thermal energy.

3 REGIONAL VARIATIONS

3.1 MAJOR OIL AND GAS DEVELOPMENT BASINS IN THE U.S

3.1.1 Western States

Exploration and production of oil and gas in the western region occurs in the major oil and gas development basins shown in Figure 12.

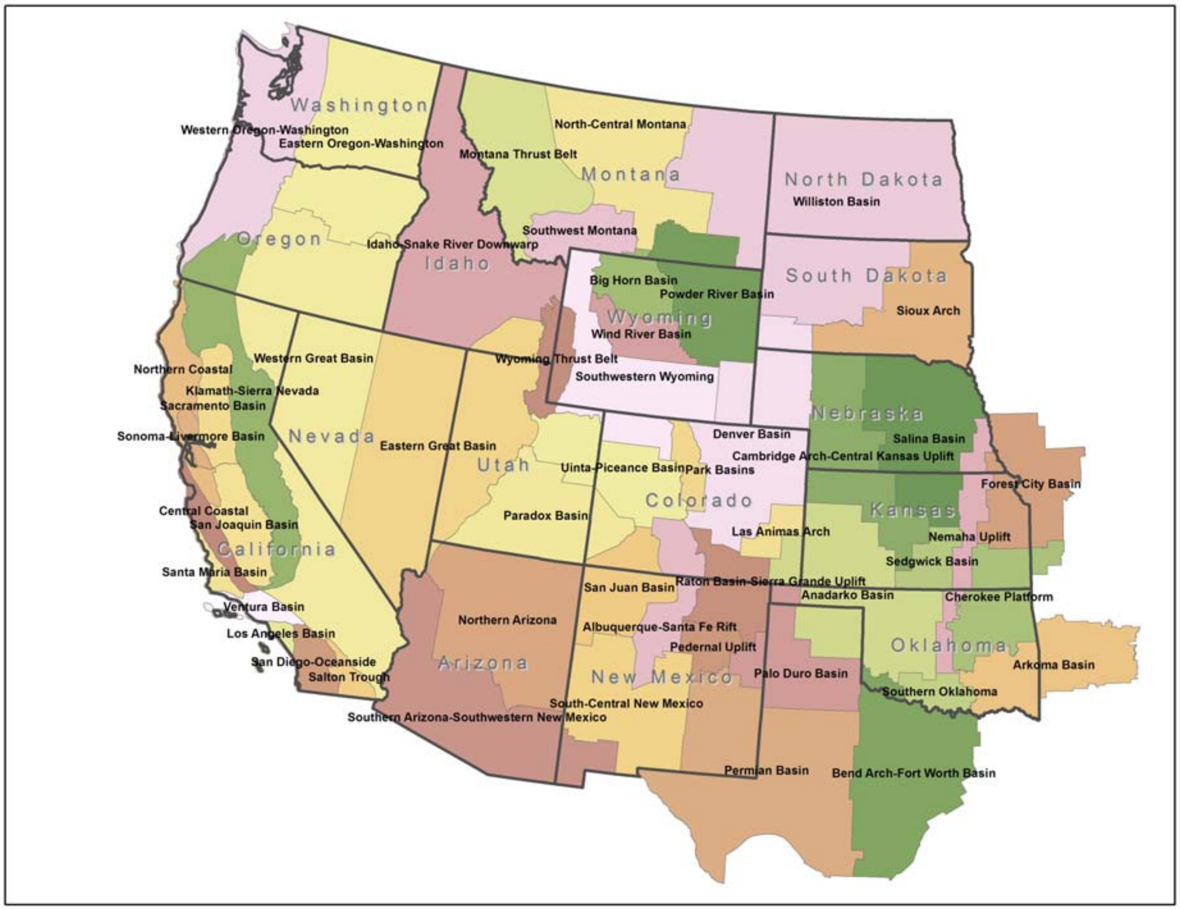

Figure 12 Major Oil and Gas Development Basins in the Western States

Within each oil and gas development basin, variations in production and production characteristics for both oil and gas can result from several factors. The oil and gas chemical compositions can vary significantly from one production region to another, resulting in a potentially significant impact on GHG emissions estimations (e.g., the CH_4 content may differ significantly from the gas produced from a gas well or oil well) or oil may have different viscosities (e.g. heavy oil resources that exist in California). The geologic gas reservoirs within basins may vary significantly, from conventional gas wells to coal bed methane (CBM) wells to tight sands reservoirs. In addition methods for recovering oil and gas resources can vary according to the type of resource and the type of reservoir, as well as the amount of oil or gas that is produced from a well. These regional variations affect various segments of the industry differently depending on the activity – exploration, production or gas processing. It is important to note that both oil and gas may be produced from the same well and therefore a variety of liquid and gas production equipment may be located at the well site. For purposes of determining whether a well is a gas well or an oil well, most state oil and gas conservation commissions (OGCC) or equivalent, use a gas-oil ratio (GOR) determined for a particular well. If the oil production or gas production are zero, the well can be easily labeled as an oil or gas well by determining the GOR. Where both gas and oil are produced, a reasonable cut-off GOR must be assumed for a well to be classified and the cut-off GOR is usually determined uniquely for each state. This ambiguity in the classification of well types may make it difficult to determine a true count of equipment for a particular region or in some instances for a particular entity.

The diversity of operations associated with the oil and gas industry presents a challenge in determining which operations have significant emissions of CO_2, N_2O, and CH_4 . Section 4 discusses operations that have been addressed by several organizations and includes and evaluation of the methodologies to evaluate the impact of these operations. This section focuses on a more detailed discussion of the types of production occurring in the major basins in the region of study for this protocol development effort, including quantitative data on the production of gas and oil in these regions in the recent past, and a discussion of some of the complexities in determining GHG emissions for specific regions.

California

Onshore

California's crude oil and natural gas deposits are located in six geological basins in the Central Valley and along the Pacific Coast. California has more than a dozen of the United States' largest oil fields, including the Midway-Sunset Oil Field , the second largest oil field in the contiguous United States. Other major fields in the Central Valley include the Kern River, South Belridge, Elk Hills, Cymric and Lost Hills fields. These oil and gas fields are considered to be in decline, and while no major discoveries have been made in the region for quite some time, the region retains more oil reserves than any other part of California. A major oil field outside of the San Joaquin Valley, is the Wilmington Oil Field in Los Angeles County.

Enhanced oil recovery is used in most oil production operations in the Central Valley oil fields due to the heavy oil deposits. Several enhanced oil recovery technologies have been employed in these areas including steamflooding, cyclic steam, fireflooding and waterflooding (see discussion of Heavy Oil Production later in this Section). Steamflooding operations result in the emissions of CO_2, CH_4 and N_2O due to the use of heaters and boilers for generating steam.

California natural gas production typically is less than 2 percent of total annual U.S. production and satisfies less than one-sixth of state demand.[71] Because natural gas provides less than the state's total energy requirements, California is a significant importer of natural gas. California receives most of its natural gas by pipeline from production regions in the Rocky Mountains, the Southwest, and Western Canada.[1]

Offshore

Offshore oil platforms and artificial oil and gas islands are distributed over an area of about 7,722 square miles along the coast of California [72]. Each of the platforms has between 10-50 wells and each produces between a few hundred to 20,000 bbl of oil per day. The distance the platform is located from the shore defines whether the operation sits in Federal (more than 3 miles from the shore) or State waters (less than 3 miles from the shore).

[71] Overview of Natural Gas in California". *Energy Almanac*. California Energy Commission. Retrieved on 2009-01-11.

[72] McCreary, M et al. *Oil and Gas Operations Offshore California: Status, Risks and Safety*. U.S. Department of the Interior, Minerals Management Service, Pacific OCS Region,

Most of California's offshore oil and gas platforms operate in Federal waters, an area commonly called the Outer Continental Shelf (OCS). Oil and gas operations in federal waters are under the jurisdiction of the U.S. Department of the Interior's Minerals Management Service (MMS). Many OCS platforms are leased to commercial companies with pipelines extending to onshore processing facilities. As of December 31, 2003, total original recoverable oil and gas reserves in the Pacific OCS were estimated to be 2,555 million barrels (MMbbl) and 2,601 billion cubic feet (Bcf), respectively. Total remaining reserves are estimated to be 1,469 million barrels of oil and 1,477 billion cubic feet of gas[73]. Figure 13 shows the recognized discoveries of oil and gas fields in the OCS.

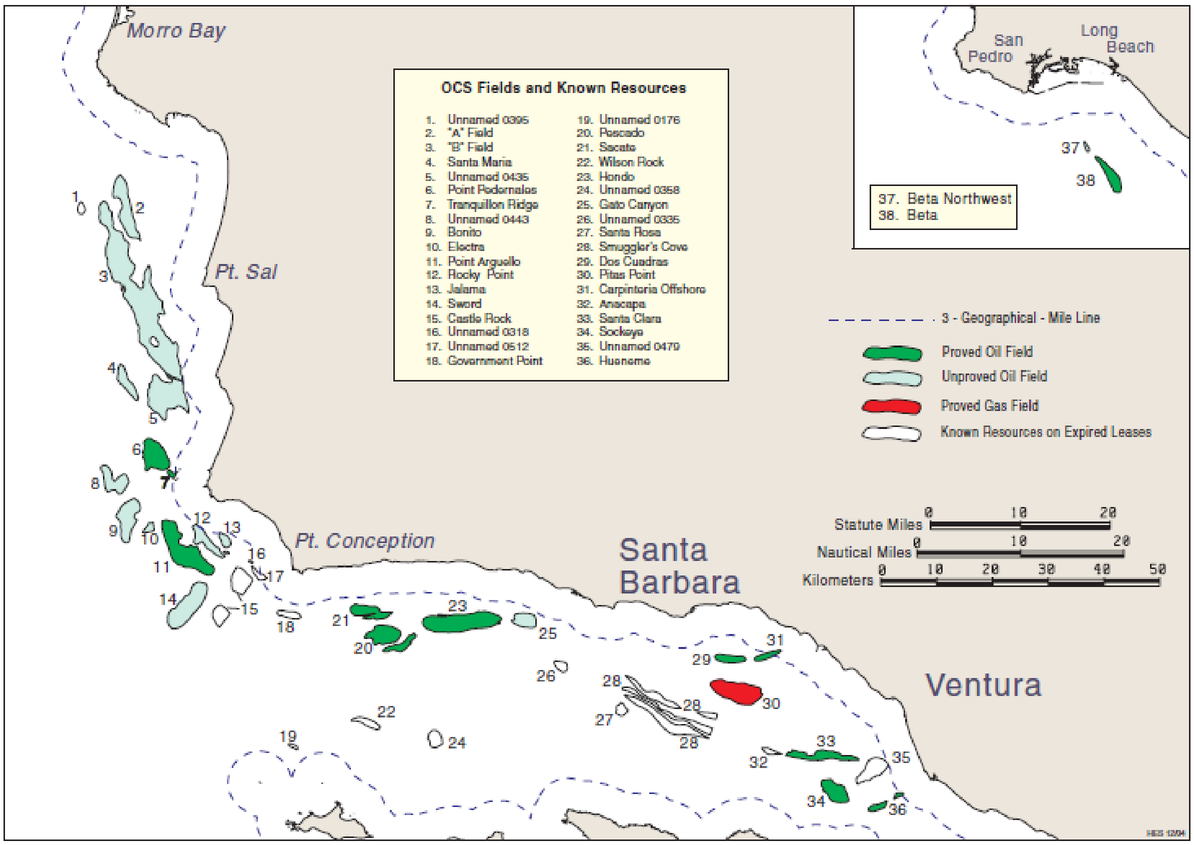

Figure 13 Oil and Gas Fields in the Pacific OCS[74]

Table 6 outlines the production rates for 2003 for the Pacific OCS oil and gas fields.

FIELD	OIL		GAS	
	Original Recoverable Reserves (MMbbl)	**2003 Production (MMbbl)**	**Original Recoverable Reserves (Bcf)**	**2003 Production (Bcf)**
Hondo	316.92	7.66	834.02	28.50
Dos Cuadras	264.64	1.75	150.50	2.34
Pt Arguello	208.00	4.71	143.84	10.08
Pescado	146.59	6.33	222.32	9.90
Beta	106.80	0.99	34.40	0.31

[73] OCS Report MMS 2007-012 - Estimated Oil and Gas Reserves Pacific Outer Continental Shelf (January 1, 1999 through December 31, 2003)
[74] OCS Report MMS 2007-012 - Estimated Oil and Gas Reserves Pacific Outer Continental Shelf (January 1, 1999 through December 31, 2003)

FIELD	OIL		GAS	
	Original Recoverable Reserves (MMbbl)	**2003 Production (MMbbl)**	**Original Recoverable Reserves (Bcf)**	**2003 Production (Bcf)**
Pt. Pedernales /Tranq. Ridge	80.00	2.32	27.50	0.91
Carpinteria	71.40	0.66	60.00	0.45
Sacate	71.30	2.78	160.69	1.55
Sockeye	61.83	1.73	150.45	1.79
Santa Clara	50.06	0.74	82.33	0.57
Hueneme	10.71	0.06	6.25	0.21
Pitas Point	0.22	<0.01	239.22	1.81
TOTAL	1,388.41	29.74	2,111.51	58.41

Table 6 Recoverable Reserves and 2003 Production of Pacific OCS Oil and Gas Fields[75]

Offshore production in State waters (within 3 miles of the shore) represents approximately 6 percent of California's total crude production[76]. State waters are regulated by the California State Lands Commission and the California Department of Oil, Gas, and Geothermal Resources. The oil rigs in State waters can be divided into two areas, the Santa Barbara channel and the Long Beach area. Figure 14 illustrates the installations of offshore operations and pipelines in these two areas.

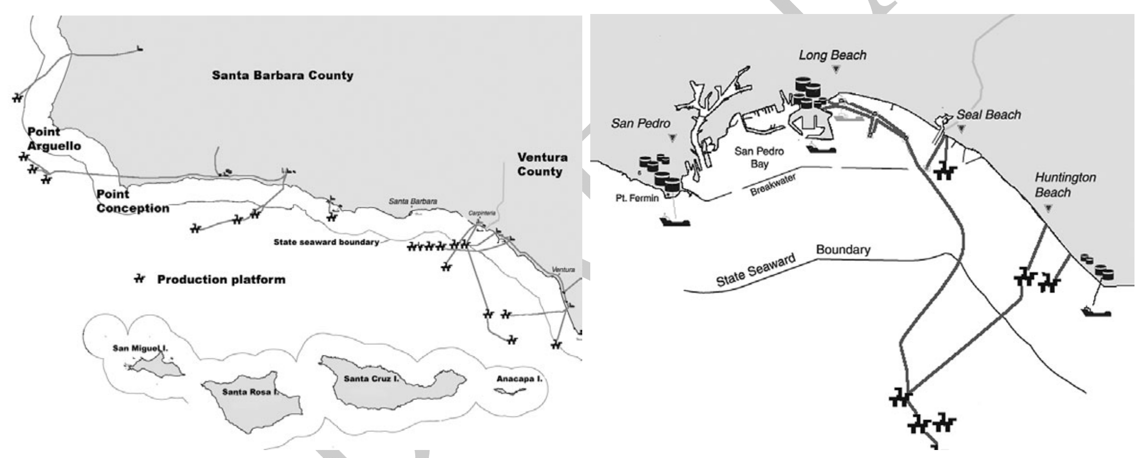

Figure 14 Offshore installations and pipelines in California State waters (Santa Barbara and Long Beach)[77]

As oil and gas produced offshore is piped to the mainland, there is a total of 142 miles of oil pipeline associated with California's offshore oil development.

<u>New Mexico</u>

Major basins in New Mexico are the Permian Basin in Southeast New Mexico and the San Juan Basin in Northwest New Mexico. The Permian Basin is primarily an oil production basin stretching into Western Texas, but also produces significant quantities of gas. There is significant sour gas production in the Permian – thus, in addition to traditional oil field equipment gas sweetening processes are used extensively in this basin. The San Juan Basin in Northwestern New Mexico is the largest gas production basin in the Rocky Mountain states, with both conventional and CBM gas production occurring. This basin has been in decline for a

[75] Ibid
[76] EIA Petroleum Supply Annual 2003 Volume 1, Production of Crude Oil by PAD District and State
[77] McCreary, M et al. *Oil and Gas Operations Offshore California: Status, Risks and Safety.* U.S. Department of the Interior, Minerals Management Service, Pacific OCS Region,

number of years, and due to the need for additional well site compression and the high permitting threshold for minor sources in New Mexico, significant numbers of wellhead compressors are in use in this basin.

Colorado

Major basins in Colorado include the Denver-Julesburg, the Piceance, the North San Juan and the Raton Basins. The North San Juan and Raton basins are primarily CBM basins, with low-pressure, shallow CBM wells with virtually no volatile content in the produced gas and little or no production of oil or other condensate liquids. The high CH_4 content of this gas will have implications for the GHG inventories for these regions. The Denver-Julesburg (D-J) Basin is a large basin stretching across mid- and northeastern Colorado and into parts of southeastern Wyoming and western Nebraska and Kansas. The region of the D-J Basin in the vicinity of the Denver metropolitan area has significant gas and condensate production from sandstone formations, but much of the associated E&P field equipment is subject to state regulations aimed at reducing NOx and VOC emissions to mitigate ozone exceedances – which will have impacts on GHG emissions as well. The eastern portion of the D-J Basin is primarily dry gas production with little condensate production. The Piceance Basin is located primarily in Northwestern Colorado and is a region that has seen extensive recent exploration and production activity as new gas reservoirs are explored. The primary reservoirs are shale and sandstone, and require fracturing to stimulate production. Minor CBM well groups are also found in the Piceance Basin, as well as some mature oil fields (centered in Rio Blanco County). The various Colorado basins described here have significant variations in the types of E&P operations occurring, the source categories in use and the chemical composition of the gas and oil produced.

Wyoming

Major basins in Wyoming include the Green River (Southwest Wyoming) Basin, the Powder River Basin, and to a limited extent the Wind River and Big Horn Basins. By far the region that has seen the greatest regulatory attention in Wyoming is the Green River Basin, which incorporates most of Southwestern Wyoming, including the major gas fields of the Jonah-Pinedale area, the Wamsutter area and the Moxa Arch formation. The Jonah-Pinedale fields are considered one of the world's top gas production fields and are estimated to hold over 10 trillion cubic feet of gas reserves. This field is primarily tapping tight sand formations which require significant hydraulic fracturing to stimulate economic gas production rates. Due to recent ozone exceedances in this area, the State of Wyoming has been active in developing inventories of exploration and process equipment for this field, which may be very useful for purposes of estimating GHG emissions. The Wamsutter, Moxa Arch, Hiawatha and other areas of the Greater Green River Basin are also active gas development areas. Some sour gas is also produced in regions of this basin and would entail the use of sweetening processes. The Powder River Basin in Northeastern Wyoming (and extending into Southern Montana) is one of the largest gas production basins in the Rocky Mountain states. The Powder River Basin is almost exclusively comprised of CBM wells and thus will have a different set of associated E&P equipment in usage than other basins in Wyoming.

Montana

Major basins in Montana include the North-Central Montana (Great Plains) Basin, and the Williston Basin. The North-Central Montana Basin primarily contains shallow sandstone formations with biogenic natural gas reservoirs. The Williston Basin is primarily shale and has been extensively developed for both oil and gas production since the 1950's. There has been significant recent interest in the Williston Basin due to the development of directional drilling techniques, which offer the possibility of economically viable recovery of oil from the Bakken shale formation. This formation spans both eastern Montana and western North Dakota.

North Dakota

The primary area of development in North Dakota is the Williston Basin in the western portion of the state. This is primarily composed of shale formations that have been developed for some decades for both oil and gas production. Oil production in this basin peaked in the 1980's and had been declining until the recent activity in the Bakken formation. Directional drilling techniques have made accessing the oil deposits in the Bakken shale more economical and since 2000 oil production has increased again in this basin. The directional drilling techniques employed in this region will have impacts on GHG emissions estimates from drilling and exploration activities that must be considered separately from other regional drilling GHG emissions estimates.

Nebraska

Nebraska does not have major oil and gas activity, and the activity is primarily located in the D-J Basin, which extends into western Nebraska. This is primarily dry gas production with little or no condensate or other liquid hydrocarbon production.

Kansas

The vast majority of gas and oil production in Kansas come from the Anadarko Basin and the Cambridge Arch-Central Kansas Uplift. The Cambridge Arch is primarily sandstone and dolomite formations and accounts for the majority of oil production in Kansas through conventional oil fields that have been in operation since the early 1900's. The Anadarko Basin accounts for the vast majority of gas production in Kansas and the majority of wells. The Anadarko Basin is one of the largest gas production basins in the U.S., with estimated reserves in excess of 100 trillion cubic feet. The Hugoton-Panhandle gas field is the primary source of gas production in the Kansas portion of the basin. These are primarily conventional dry gas wells and include some extremely deep wells in excess of 20,000 feet in depth.

Oklahoma

As described above, the major gas and oil production basin in Oklahoma is the Anadarko Basin which has seen E&P activity since the mid-1900's. The region is characterized by significant levels of conventional oil and gas production and associated equipment. The Southern Oklahoma (Ardmore) Basin is another major oil production basin in Oklahoma bordering on Northern Texas. The majority of the liquid hydrocarbon production from the Ardmore and Anadarko basins is true oil production, with little condensate production from gas wells. This is expected to have an impact on assessing the equipment types located at oil and gas wells throughout both of these basins, and subsequently on the GHG emissions estimates for these basins.

3.2 OIL AND GAS PRODUCTION STATISTICS FOR THE WESTERN STATES

The amount of production varies greatly between states, basins and oil and gas fields. The production of oil by State is shown in Table 7. As shown in Table 7, California, Oklahoma, New Mexico, Wyoming and North Dakota are the five largest oil producing states in the region covered in this analysis. As discussed in the above sections, oil production in most states has declined over the past several years. This decline and the ongoing search for additional economically recoverable oil are drivers for significant variability in the levels of exploration and production operations as well.

Area	Crude Oil Production (Thousand Barrels)					
	2002	2003	2004	2005	2006	2007
US Total	2,097,124	2,073,453	1,983,302	1,890,106	1,862,259	1,848,450
U.S. State Offshore	133,407	135,423	130,178	130,611	120,922	114,031
California	258,010	250,000	240,206	230,294	223,449	216,778
California offshore	16,294	15,900	15,654	15,294	15,077	13,600
Oklahoma	66,642	65,356	62,502	62,142	62,841	60,952
New Mexico	67,041	66,130	64,236	60,660	59,818	58,831
Wyoming	54,717	52,407	51,619	51,626	52,904	54,130
N. Dakota	30,993	29,406	31,154	35,660	39,911	45,058
Kansas	32,721	33,944	33,858	33,823	35,651	36,490
Montana	16,855	19,320	24,724	32,855	36,262	34,829
Colorado	17,734	21,109	22,097	22,823	23,390	23,237
Utah	13,676	13,096	14,629	16,651	17,910	19,520
Nebraska	2,779	2,755	2,507	2,413	2,313	2,334
S. Dakota	1,214	1,237	1,357	1,469	1,394	1,665
Nevada	553	493	463	447	426	408
Arizona	63	47	52	50	55	43

Table 7 Western States Crude Oil Production
Source: Energy Information Administration

The production of natural gas in the Western States is shown in Table 8. The five largest states with natural gas production are Wyoming, Oklahoma, New Mexico, Colorado and Kansas. As opposed to oil production, overall natural gas production has remained about the same or increased in the Western states over the past several years.

Area	Natural Gas Marketed Production (Million Cubic Feet)					
	2001	2002	2003	2004	2005	2006
US Production	20,570,295	19,884,780	19,974,360	19,517,491	18,927,095	19,381,895
U.S. State Offshore	110,054	133,407	135,423	130,178	130,611	120,922
Wyoming	1,363,879	1,453,957	1,539,318	1,592,203	1,639,317	1,816,201
Oklahoma	1,615,384	1,581,606	1,558,155	1,655,769	1,639,310	1,688,985
New Mexico	1,689,125	1,632,080	1,604,015	1,632,539	1,645,166	1,609,223
Colorado	817,206	937,245	1,011,285	1,079,235	1,133,086	1,202,821
Kansas	480,145	454,901	418,893	397,121	377,229	371,044
Utah	283,913	274,739	268,058	277,969	301,223	348,040
California	328,778	309,399	290,212	273,232	274,817	278,933
California State Offshore	6,823	6,909	6,087	6,803	6,617	6,652
California Offshore Federal	42,223	43,896	40,917	39,884	36,204	29,624
Montana	81,397	86,075	86,027	96,762	107,918	112,845
N.Dakota	54,732	57,048	55,693	55,009	52,557	55,273

Nebraska	1,208	1,188	1,454	1,476	1,172	1,200
S.Dakota	1,100	1,025	1,103	1,093	992	963
Oregon	1,110	837	731	467	454	621
Arizona	307	301	443	331	233	611
Nevada	7	6	6	5	5	5

Table 8 Western States Natural Gas Production
Source: Energy Information Administration

3.2.1 Coal Bed Methane Production

Coal bed methane (CBM) refers to a method of producing natural gas in which CH_4 is captured from coal seams and the surrounding rock strata. As discussed in Section 2, the methane at high pressures in the coal seam is released to the surface when gas production wells are drilled in CBM production areas. However, low pressures are found in the Powder River basin in Wyoming and the Raton Basin in New Mexico and Colorado requiring greater compression to bring the gas to a transmission system.

Figure 15 identifies the key areas were CBM wells are located in the Western US.

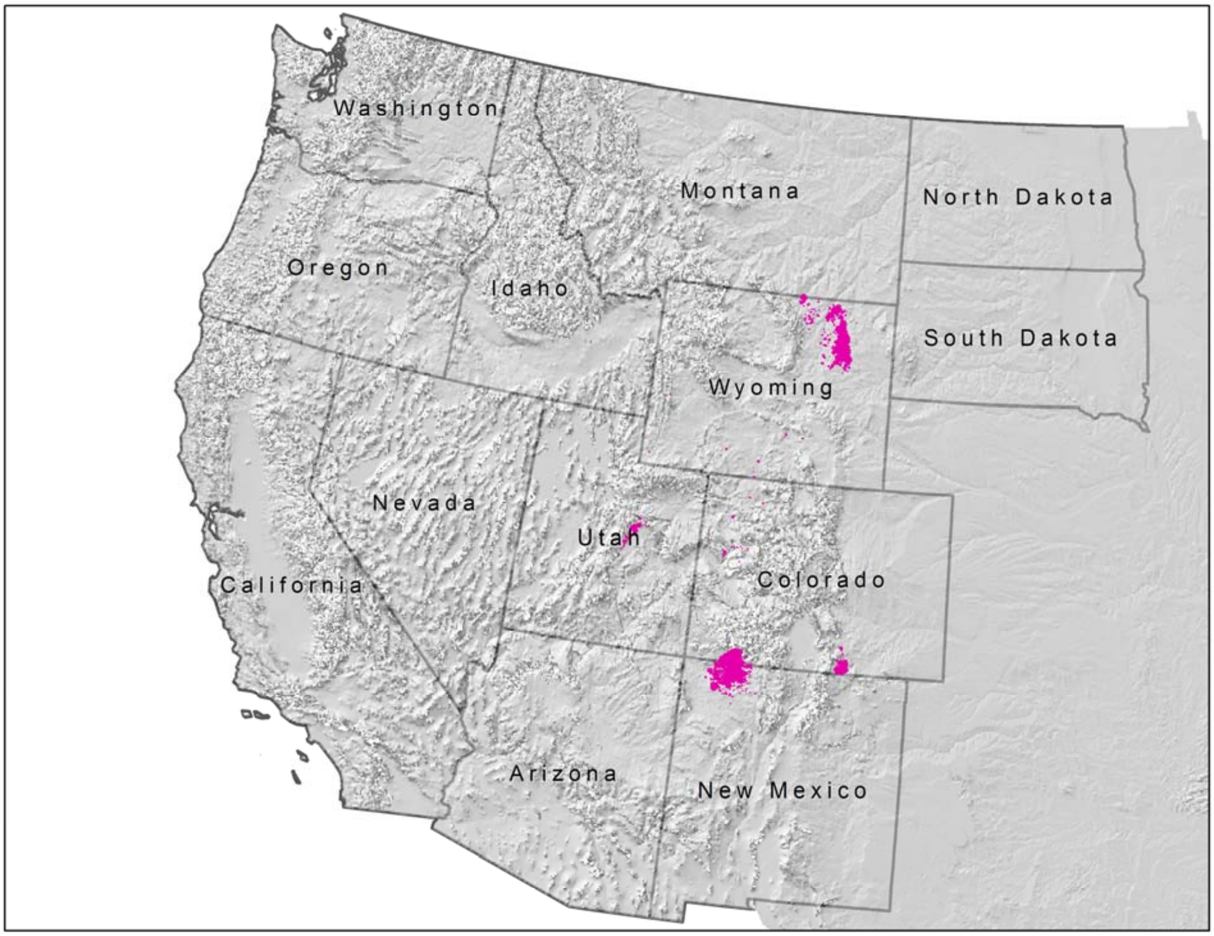

Figure 15 Western U.S. Coal bed methane fields
Source: EIA, 2004

Table 9 shows CBM production levels in these key areas as well as the total US production. As shown in the table, Colorado, Wyoming and New Mexico have the highest CBM production.

Area	Coal bed Methane Production (MMCF)					
	2002	2003	2004	2005	2006	2007
US Total	1.61	1.60	1.72	1.73	1.76	1.75
Colorado	0.52	0.49	0.52	0.52	0.48	0.52
Wyoming	0.30	0.34	0.32	0.34	0.38	0.40
New Mexico	0.47	0.45	0.53	0.51	0.51	0.40
Western States[1]	0.03	0.05	0.08	0.09	0.11	0.14
Utah	0.10	0.10	0.08	0.08	0.07	0.07

Table 9 Western States Coal Bed Methane Production.
Source: Energy Information Administration
[1]Western States Includes AR, KS, LA, MT, and OK

In CBM operations, production wells are drilled from the surface to the coal seam where the pressure in the coal beds is reduced, thereby releasing the CH_4. The CH_4 is recovered for use or sale similar to natural gas wells and associated gas recovered from oil production wells.

Some of the emission sources associated with producing CBM are the same as those associated with conventional natural gas production. GHG emissions resulting from this activity include combustion emissions resulting from the drilling engines used to drill the production wells and from combustion emissions resulting from compressors used to provide pressure boost to recover natural gas. CBM wells are generally low-pressure wells and in general see more use of wellhead compression than conventional wells. Flaring emissions may also be associated with a CBM production well if the natural gas is flared due to process upsets. CBM well production operations include separators to remove the gas from other contaminants (e.g., formation water, CO_2) at the surface. Process equipment such as water tanks and dehydrators may be used, but CBM wells generally do not produce significant quantities of liquid hydrocarbons and thus oil or condensate tanks are rarely associated with CBM wells.

3.2.2 Heavy Oil Production

A significant portion of the oil produced in California is heavy oil (20 degrees gravity or less) produced through enhanced oil recovery (EOR) steam methods. Extensive exploitation of the large volumes of heavy oil such as that found in California is dependent on the development of enhanced recovery techniques. Gas injection pumps are used to inject gases such as natural gas, nitrogen, or carbon to increase pressure or lower viscosity to improve flow rate. Gas injection pumps are generally large engine driven or electric motor driven compressors. Gas injection accounts for nearly 50 percent of EOR production in the U.S. Gas actuated pumps are also used to circulate glycol in glycol dehydration units. About two-thirds of the oil produced in California in 1999 is considered heavy oil that is predominantly produced through enhanced oil recovery (EOR) steam methods that use natural gas to generate the steam, and also produce natural gas as a co-product.[78] Natural gas is used in the generation of steam to be injected in the heavy oil recovery projects. According to the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, total oil production in the state in 2006 was approximately 250 million barrels, of which approximately 208 million barrels are from on-shore oil fields. Of that total, approximately 150 million barrels (or roughly 72 percent) was produced in 2006 using three enhanced oil recovery techniques: thermal-steam, water flood and gas injection.

[78] California Department of Conservation, Division of Oil, Gas, and Geothermal Resources

3.3 OTHER MAJOR OIL AND GAS PRODUCTION AREAS IN THE U.S.

Other major production areas in the U.S. include Texas and Louisiana, for both on-shore and off-shore production, and the vast oil and gas reserves in Alaska. Excluding federal off-shore oil production, Texas is the largest oil producing state in the U.S., and the largest gas producing state in the U.S. In 2002, Texas had nearly 375,000 active wells across its numerous production basins. Louisiana similarly has extensive on-shore oil and gas production, with totals nearly equivalent to those of Oklahoma. In addition to on-shore production, the Gulf of Mexico region is the site of extensive off-shore oil production in federally-managed waters. The federally-managed off-shore oil production in the Gulf of Mexico and California combined accounts for roughly 26 percent of total U.S. oil production. The Gulf of Mexico separately accounts for approximately 13 percent of U.S. marketed gas production in 2007. While gas production in Alaska accounts for only approximately 2 percent of U.S. total gas production, oil production in Alaska accounts for roughly 14 percent of total U.S. oil production. The primary production areas of Alaska are in South Alaska and the North Slope oil and gas fields in far northern Alaska.

Aside from these major regions, there are no other significant oil and gas production regions in the U.S. that would account for significant percentages of U.S. total production, and hence have a significant impact on GHG emissions from E&P activities. Even within the on-shore and off-shore regions in Texas, Louisiana, the Gulf of Mexico and Alaska there is expected to be significant regional variations in equipment usage, controls, composition of the produced gas or liquid and associated GHG emissions that these regions would require a separate focused analysis effort. Even with these regional variations, the GHG estimation methodologies developed this report will likely be applicable in these other areas. A separate analysis would identify current activity data and other parameters specific to these regions and thus the applicability of specific GHG methodologies.

3.4 CANADIAN OIL AND GAS PRODUCTION

On a global scale, after Saudi Arabia, Canada ranks second in terms of global crude oil reserves (15 percent of world reserves). The majority of these reserves are found in Alberta's oil sands. In 2007, oil sands production represented approximately half of Canada's total crude oil production.[79] In northern Alberta, oil sands are contained in three major areas across 54,132 square miles, an area larger than the state of Florida. The three major oil sand areas are Peace River, Athabasca (Fort McMurray area), and Cold Lake (north of Lloydminster). Of the remaining established reserves, about 82 percent is considered recoverable by in situ methods; the rest is recoverable by surface mining methods[80]. In 2007, the production of oils sands was 1.7 trillion barrels but the potential production is projected at 309 trillion barrels[81]. The Alberta Department of Energy administers mineral rights on behalf of Alberta citizens. Public offerings or sales of these rights are issued as leases or permits through a competitive bidding system. The highest bidder wins the right to "drill for, win, work, recover and remove" minerals. Annually, the province holds an average of 24 public offerings. Over the past five years, the province issued an average of 350 oil sands agreements per year[82].

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[79] Canada Energy Data, Statistics and Analysis-Oil, Gas, Electricity, Coal, Energy Information Administration, May 2008

[80] Alberta Energy Department – Oil Sands Fact Sheet 2006 http://www.energy.gov.ab.ca/OilSands/pdfs/osgenbrf.pdf

[81] Alberta Energy Department website http://www.energy.gov.ab.ca/OilSands/790.asp

[82] Alberta Energy Department – Tenure Fact Sheet http://www.energy.gov.ab.ca/OilSands/pdfs/FactSheet_OilSands_Tenure.pdf

Canada's natural gas production is concentrated in the Western Canada Sedimentary Basin (WCSB), particularly in Alberta but also including Saskatchewan and British Columbia. CBM production is still in its infancy in Canada, with the first wells drilled only in 1997. According to the EIA, CBM production may eventually replace some of the decline in conventional natural gas production. According to the Alberta Geological Service, there could be as much as 500 Tcf of CBM gas in place in Alberta alone. Table 10 provides a Summary of Natural Gas and Crude Oil Production by Province/Territory for the year 2000.

Province/Territory	Natural Gas Production	Crude Oil Production	In-Situ Bitumen Production
	[Million Cubic Feet]	[Barrels - U.S. Petroleum]	[Barrels - U.S. Petroleum]
Northwest Territories	15,080	6,400,511	
British Columbia	1,133,408	9,618,379	
Alberta	5,593,398	191,375,739	
Saskatchewan	313,854	156,057,344	
East Offshore	156,280	134,479,620	
Ontario	10,380	677,331	
Canada	7,222,400	506,713,345	183,851

Table 10 Summary of Gas and Oil Production by Province/Territory for Year 2000.
Source: "Statistical Handbook for Canada's Upstream Petroleum Industry , January 2009"

As with conventional and non-conventional described for the Western states, similar processes and equipment are used for production and processing. One difference is the need for hydrate control in gathering systems. Hydrates are solid crystalline ice-like structures composed of water and hydrocarbon molecules that can form in pipelines and restrict or stop flow.

Two types of gathering system are used: heated and dehydrated systems. Heated gathering systems guard against the formation of hydrates by maintaining gas temperature above some critical value. This temperature control is achieved by installing line heaters at appropriate points along the gathering system. The minimum temperature to be maintained depends on the composition and pressure of the gas. Consequently, it varies from one system to the next. Usually, heated gathering systems are employed if the gas is sour, and dehydrated systems are used if the gas is sweet. Dehydrated gathering systems prevent hydrates by removing water vapor from the process gas using dehydrators installed at appropriate junctions or receipt points on the gathering system. Absorption by diethylene or triethylene glycol is the most widely used dehydration process for this purpose. Desiccant dehydrators, although much less common, are also used. Emergency shutdown (ESD) valves may be installed at selected intervals along the pipeline to minimize the amount of gas released in the event of a line break, especially if the gas is sour. The gas processing plant will feature a selection of process units to treat and purify the gas as required, and may include both inlet and sales compression.

Associated gas produced from oil wells in association with the oil production is usually rich in condensable hydrocarbons and may contain some CO_2 and H_2S. Usually associated gas is used for on-site fuel requirements at the oil production facility, and any surplus is then vented or flared (i.e., if it is uneconomical to conserve), re-injected to maintain reservoir pressure or produced into a gas gathering system and ultimately processed and purified.

3.5 MEXICO OIL AND GAS PRODUCTION

In 2006, Mexico was the sixth-largest oil producer in the world, and the second largest in the Western Hemisphere (behind the United States). State-owned Petroleos Mexicanos (Pemex) holds a monopoly on oil production in the country and is one of the largest oil companies in the world. However, oil production in the country has begun to decrease, as production at the giant Cantarell field declines. In 2006, Mexico produced an average of 3.71 million barrels per day (bbl/d) of total oil liquids, down from 3.78 million bbl/d in 2005. Of Mexico's oil production about 88 percent was crude oil and condensate, the rest consisting of natural gas liquids (NGL) and refinery gain. Most of Mexico's oil production occurs in the Gulf of Campeche, located off the south eastern coast of the country in the Gulf of Mexico. Figure 16 below provides a comparison of Mexican oil production with that of the US and Canada

In 2006, Mexico produced 1.71 trillion cubic feet of natural gas. Mexico's natural gas production has grown in recent years, following steady declines during the late 1990s. Mexico's natural gas production is relatively spread throughout the country. Onshore fields in the northern part of the country represented 42 percent of Mexico's natural gas production in 2006, while onshore fields in the south contributed 25 percent, and offshore fields in the Gulf of Campeche represented the remainder. Mexico's natural gas production is split between associated (58 percent) and non-associated (42 percent) production.

For comparison, Figure 16 presents the natural gas production as it compares to the US and Canada.

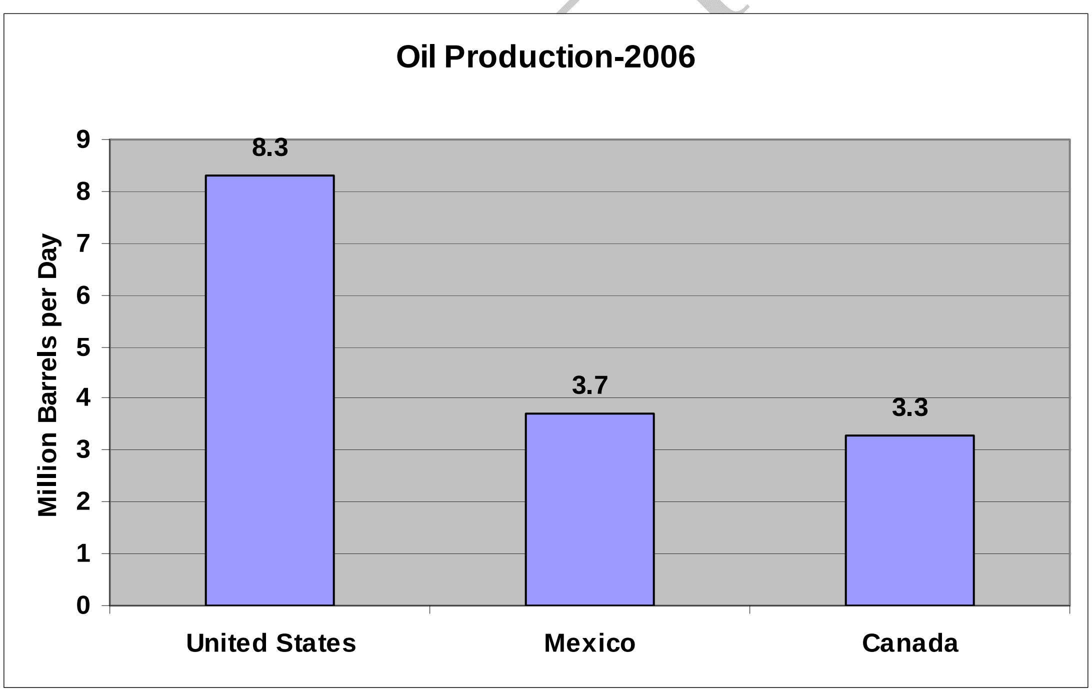

Figure 16 North America Oil Production and Consumption 2006

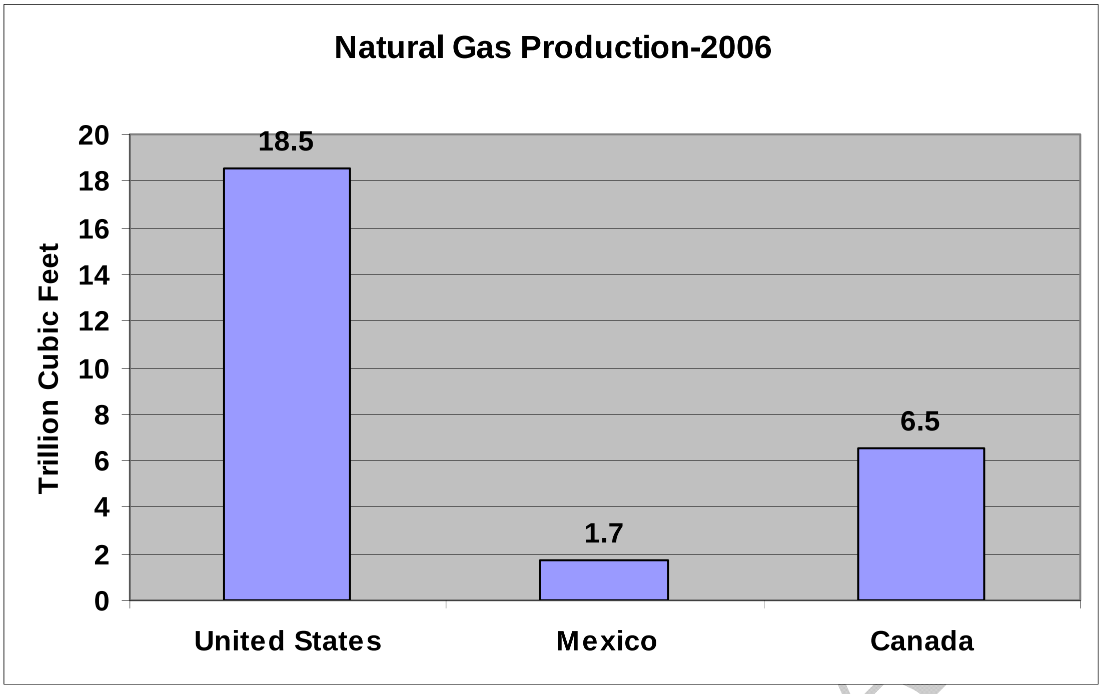

Figure 17 North America Natural Gas Production and Consumption 2006

4 REVIEW OF RELEVANT METHODOLOGIES

4.1 SUMMARY OF EMISSION ESTIMATING METHODS

Several national and international government and non-government organizations have published documents that promote the use of consistent, standardized methodologies for estimating GHG emissions from petroleum industry operations. Most of these documents provide calculation techniques and emission factors for estimating GHG emissions for oil and gas industry operations. These techniques cover a wide range of procedures for the calculation or estimation of emissions from various industry operations, some taking a more general approach than others. Several have provided techniques for estimating GHG emissions from oil and natural gas exploration and production (E&P). The methods focus primarily on preferred and alternative calculation approaches for carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions for all common emission sources, including combustion, vented, and fugitive emission sources. In evaluating these various techniques, we have relied on the following sources of information:

- Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, American Petroleum Institute, February 2004
- Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects, International Petroleum Industry Environmental Conservation Association/API, March 2007
- Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2006, USEPA, April 15, 2008
- Instructional Methods for Mandatory GHG Emissions Reporting, Ch 13, Common Calculations Methods, California Air Resources Board, December 2008
- 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Intergovernmental Panel on Climate Change, 2006
- WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation, Phase II, ENVIRON International Corporation, September 2007
- Recommendations for Improvements to the CENRAP States Oil and Gas Emissions Inventories, ENVIRON International Corporation, November 2008
- A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Canadian Association of Petroleum Producers, September 2004
- California Climate Action Registry General Reporting Protocol, Reporting Entity-Wide Greenhouse Gas Emissions, V. 3.0, April 2008
- Gulfwide Emission Inventory Study for the Regional Haze and Ozone Modeling Efforts. OCS Study MMS 2004-072, The Minerals Management Service, October 2004
- Greenhouse Gas Emission Estimation Methodologies for the Oil Sands/Heavy Oil Upgrader Industry report. Suncor Energy Inc. (Suncor), Syncrude Canada Limited (Syncrude), Shell Canada Limited (Shell) acting on behalf of the Athabasca Oil Sands Project, Husky Energy Inc., May 2004

A short summary of the organization and the approach or categories covered by each organization is as follows:

4.1.1 American Petroleum Institute (API)

The American Petroleum Institute (API) provides one of the most comprehensive descriptions and methodology for estimating GHG from exploration, production and gas processing activities. As stated in the *Compendium*, the methodologies do not represent a standard or a recommended practice for the development of emissions inventories. Rather, as the name implies, it represents a compilation of commonly used GHG emission estimation methodologies. The emission estimation approaches presented are practical approaches assembled by API for all segments of the oil and gas industry. The operations and facilities addressed range from the well-head to retail outlets, including exploration and production (E&P), refining, marine vessels, pipelines, bulk distribution, other transportation, and retail marketing. Industry data is provided throughout the document on the carbon content fraction for typical fuels in commerce, but no attempt is made to account for hypothetical efficiencies associated with products use.

4.1.2 International Petroleum Industry Environmental Conservation Association (IPIECA)

IPIECA is the single global association representing both the upstream and downstream oil and gas industry on key global environmental and social issues. Their report titled Oil and Natural Gas Industry Guidelines for GHG Reduction Projects is a work product of the IPIECA Joint Industry Task Force on Greenhouse Gas (GHG) Reporting Guidelines. The Task Force was convened under the auspices of the International Petroleum Industry Environmental Conservation Association (IPIECA) Climate Change Work Group, in collaboration with the American Petroleum Institute (API). The IPIECA document provides guidance by focusing on the technical aspects of reducing GHG emissions separate from the policy considerations and thus provides methodologies for estimating project reductions. Five broadly applicable categories are addressed including cogeneration, carbon capture and geological storage, flare reduction, fuel switching and energy efficiency improvements.

4.1.3 US Environmental Protection Agency (EPA)

Each year, the EPA publishes its report on the Inventory of U.S. Greenhouse Gas Emissions and Sinks. The emission and sink estimates are recalculated and revised for all years in the previous years' inventory. The EPA inventory identifies and quantifies a country's primary anthropogenic sources and sinks of greenhouse gases and is essential for addressing climate change. This Inventory adheres to both: (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases; and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change. Attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data. In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. Changes in historical data are generally the result of changes in statistical data supplied by other agencies. The general approach used for this inventory is a top down approach in which EPA uses Energy

Information Administration (EIA) data on national fuel consumption by fuel type and sector, and subsequently subtracts out uses that are not applicable to the specific category of the inventory. The inventory does include stationary and mobile combustion, natural gas systems and petroleum systems as well as many other categories not related to this report.

4.1.4 California Air Resources Board (CARB)

In response to California legislation, The Greenhouse Gas (GHG) Mandatory Reporting Regulation (Regulation) was approved by the California Air Resources Board (ARB or Board) in December 2007 and requires facilities to report their annual GHG emissions in 2009 and every year thereafter. The reporting document is intended to provide instructional guidance on GHG reporting to facility operators. A separate guidance document is being drafted to address the needs of third-party verifiers. ARB's mandatory GHG reporting regulation is a set of rules that establishes who must report GHG emissions to ARB and sets forth the requirements for measuring, calculating, reporting and verifying those emissions. This guidance includes explanatory detail and examples where additional information would be helpful to facilitate successful and accurate GHG reporting. The guidance related to oil and gas exploration and production includes CO_2 emissions from general stationary combustion facilities and common calculation methods for sector-specific reporting including general stationary combustion, cogeneration facilities and general stationary combustion facilities. Other than for refineries, CARB but does not address CH_4 emissions from process-related activities or fugitive emissions such as separators and storage tanks.

4.1.5 Intergovernmental Panel on Climate Change (IPCC)

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 Guidelines) were produced at the invitation of the United Nations Framework Convention on Climate Change (UNFCCC) to update the Revised 1996 Guidelines and associated good practice guidance which provide internationally agreed methodologies intended for use by countries to estimate greenhouse gas inventories to report to the UNFCCC. As with the 1996 Guidelines and IPCC Good Practice Guidance the most common simple methodological approach is to combine information on the extent to which a human activity takes place (called activity data or AD) with coefficients which quantify the emissions or removals per unit activity. IPCC usually provides three tiers: Tier 1 is the basic method, Tier 2 intermediate and Tier 3 most demanding in terms of complexity and data requirements. Tiers 2 and 3 are sometimes referred to as higher tier methods and are generally considered to be more accurate. IPPC addresses the energy sector which is comprised of exploitation of primary energy sources, conversion of primary energy sources into more useable energy forms in refineries and power plants, transmission and distribution of fuels, use of fuels in stationary and mobile applications and emissions arise from these activities by combustion and as fugitive emissions, or escape without combustion.

4.1.6 Western Regional Air Partnership (WRAP)

Several reports have been published by WRAP estimating emissions from the oil and gas exploration and production sector. Most of these documents provide calculation techniques and emission factors for estimating criteria pollutant emissions for oil and gas industry operations, however, many of these methodologies will be similar to the methodologies presented in these reports excluding methodologies for estimating Oxides of Nitrogen (NO_2) and Carbon Monoxide

(CO) from combustion sources and methodologies for estimating Volatile Organic Compound (VOC) emissions from other production operations. These techniques cover a wide range of procedures for the calculation or estimation of emissions from various industry operations, some taking a more general approach than others depending on the availability of data and other factors.. The methods focus primarily on preferred and alternative calculation approaches for all common emission sources, including combustion, vented, and fugitive emission sources. The general approach to estimating emissions has been to obtain (to the degree possible) specific details about the equipment in operation including for example with combustion related emissions the size of engine (hp), the hours operated per year and engine loads or assumed load factor and an emission factor. It should be noted that the equipment-specific emissions estimation methodologies of the WRAP regional inventories are similar in nature to those compiled in the API compendium, with modifications to these methodologies made to account for regional variability in an effort to develop basin-level inventories.

4.1.7 Central States Regional Air Partnership (CENRAP)

The Central States Regional Air Partnership also sponsored a report on recommendations for improvements to the central states' oil and gas emissions inventory. The majority of the analysis focuses on providing detailed methodologies for the major oil and gas area source categories, both for individual sources and for basin-level emissions totals. This input data included the fractional usage of equipment at well sites, equipment characteristics such as size, annual usage and emissions factors, process information such as venting rates and well component configurations, and chemical composition analyses used to determine pollutant emissions rates.

4.1.8 Canadian Association of Petroleum Producers (CAPP)

The Canadian Association of Petroleum Producers (CAPP) represents 150 companies that explore for, develop and produce natural gas, natural gas liquids, crude oil, oil sands, and elemental sulfur throughout Canada. CAPP member companies produce more than 98 per cent of Canada's natural gas and crude oil. CAPP also has 125 associate members that provide a wide range of services that support the upstream crude oil and natural gas industry. The greenhouse gas (GHG) portions of CAPP's report on the upstream oil and gas industry (Volumes 1, 3 and applicable parts of 5) are intended to present a detailed inventory of GHG emissions from the upstream oil and gas sector in Canada along with explanations of the methodologies and data sources used. The intent was to develop a practicable and defensible methodology that takes advantage of currently available information, and provides sensible methods for managing uncertainties and bridging data gaps. As with API, detailed methodologies have been developed for natural gas systems and processing and crude oil production and treatment. The focus of this effort is GHG emissions from oil sands and heavy oil upgrading industries.

4.1.9 California Climate Action Registry (CCAR)

The California Climate Action Registry (CCAR) has published The General Reporting Protocol (the Protocol or GRP) which provides guidance for businesses, government agencies, and non-profit organizations wishing to participate in the California Climate Action Registry (the California Registry), a voluntary greenhouse gas (GHG) registry. The Protocol provides the principles, approach, methodology, and procedures required for participation in the California Registry. It is designed to support the complete, transparent, and accurate reporting of an organization's GHG emissions inventory in a fashion that minimizes the reporting burden and maximizes the benefits associated with understanding the connection between fossil fuel consumption, electricity use, and GHG emissions in a quantifiable manner. The Protocol includes technical methodologies and estimation methods for grid-delivered electricity use, direct emissions from mobile combustion, direct emissions from stationary combustion, indirect emissions from imported steam, heating and cooling and electricity from a cogeneration plant, direct emissions from manufacturing processes and direct fugitive emission.

4.1.10 Minerals Management Service (MMS)

The Mineral Management Service (MMS) is responsible for assessing the impacts of air pollutant emissions from offshore oil and gas activities in the Outer Continental Shelf (OCS). This agency developed a Gulfwide emissions inventory study with the goal of establishing the year 2000 as a base for the air pollution emissions inventory of all the oil and gas production related sources in the Gulf of Mexico. This inventory covers GHG emissions from carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) as well as air pollutants such as volatile organic compounds (VOC), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter -10 (PM_{10}) and $PM_{2.5}$. The Gulfwide Offshore Activities Data System (GOADS) was developed to collect monthly data from platform sources; this data was combined with emission factor published by EPA and Emissions Inventory Improvement Program (EIIP) emission estimation methods to generate this GHG emission and criteria pollutant inventory. Table 12 to Table 19 present the ranking assigned to those methodologies that reduce GHG emissions.

4.1.11 Oil Sands / Heavy Oil Upgrader Industry (OS/HOU)

Representatives of the Canadian Oil Sands / Heavy Oil Upgrader Industry (OS/HOU) developed a document with proposed methodologies for reporting GHG emissions to meet the requirements of Alberta Government's mandatory GHG reporting under the Climate Change and Emissions Management Act (Bill 37) and Federal Government's GHG emission requierements under the Kyoto Protocol. The companies that participated in this study are: Suncor Energy Inc. (Suncor), Syncrude Canada Limited (Syncrude), Shell Canada Limited (Shell) acting on behalf of the Athabasca Oil Sands Project and Husky Energy Inc. The document summarizes the methodology for developing an inventory of GHG emissions from each of the OS / HOU participants, identifies acceptable primary and alternate methodologies for estimating GHG emissions, references the applicable industry standards that provide the detailed methodology, or where no such industry standards exist, describes the industry specific methodology to be used by the OS / HOU sector and documents common standards and conversion factors to be used by the OS / HOU participants or references the applicable industry standards utilized. Table 20 presents the ranking for the methodologies used to estimate GHG emissions from oil sands operations.

To summarize, Table 11 provides a list of the oil and gas exploration and production methodologies that are covered by these organizations.

Category	API[1]	IPIECA[2]	EPA[3]	CARB[4]	IPCC[5]	WRAP[6]	CAPP[7,8]	CCAR[9]	MMS[10]
Internal Combustion[11]	X		X	X	X		X	X	X
External Combustion[12]	X	X	X		X	X	X		X
Mobile Combustion	X		X		X		X	X	X
Drill Rigs	X		X		X	X	X		X
Workover Rigs	X		X			X	X		X
Electric Utility (Indirect)	X		X		X			X	
Steam Utility (Indirect)	X		X		X			X	
Co-gen (Indirect)	X	X	X		X			X	
Glycol Dehydrators	X		X			X	X		X
Glycol Pumps	X		X			X	X		
Amine Units	X				X	X			X
CO2 Venting	X					X	X		X
Storage Tank Emissions	X								X
Storage Tank Flashing	X		X			X	X		X
Storage Tanks Other	X		X			X	X		
Produced Water Tanks	X		X			X	X		
NG Blanketed Tanks	X								
Loading Loss Emissions	X		X			X	X		X
Pneumatic Devices	X		X			X	X		X
Chemical Injection Pumps	X		X			X			
Exploratory Drill/ Test	X				X		X		
Gas Casing (Heavy Oil)	X						X		
Blowdowns/Startups	X		X			X	X		
Process Turnaround	X		X			X	X		
Pipeline Fugitives	X		X				X		
Proc Plant Blowdown	X		X			X	X		
Fugitive Leaks	X		X		X	X	X		X
Hydrogen Plant	X			X			X		
Upgrading Coker Unit	X			X			X		
Mine Surface							X		
Pond Surface							X		
Flue Gas Desulphurization							X		

Table 11 Published Emission Estimate Methodologies for GHG.

[1] Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry, American Petroleum Institute, February 2004

[2] Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects , International Petroleum Industry Environmental Conservation Association/API, March 2007

[3] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2006, USEPA, April 15, 2008

[4] Instructional Methods for Mandatory GHG Emissions Reporting, Ch 13, Common Calculations Methods, California Air Resources Board, December 2008

[5] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Intergovernmental Panel on Climate Change, 2006

[6] WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation, Phase II, ENVIRON International Corporation, September 2007 and recommendations for Improvements to the CENRAP States Oil and Gas Emissions Inventories, ENVIRON International Corporation, November 2008
[7] A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Canadian Association of Petroleum Producers September 2004
[8] Greenhouse Gas Emission Estimation Methodologies for the Oil Sands/Heavy Oil Upgrader Industry report. Suncor Energy Inc. (Suncor), Syncrude Canada Limited (Syncrude), Shell Canada Limited (Shell) acting on behalf of the Athabasca Oil Sands Project, Husky Energy Inc., May 2004
[9] California Climate Action Registry General Reporting Protocol, Reporting Entity-Wide Greenhouse Gas Emissions, V. 3.0, April 2008
[10] Gulfwide Emission Inventory Study for the Regional Haze and Ozone Modeling Efforts. OCS Study MMS 2004-072, Minerals Management Service, October 2004.
[11] Internal Combustion Engines includes IC engines, Turbines, Salt Water Disposal Engines, Pumpjacks and CBM Pump Engines
[12] External Combustion includes Boilers, Heaters and Flares

4.2 RATING OF EMISSION ESTIMATING METHODOLOGIES

The methodologies that have been assembled by the organizations identified in Table 4.1 have been reviewed and ranked. The review was based on an evaluation of the relevant emission factors for estimating GHG emissions, the detailed operations in the oil and gas industry and various segments of the industry and associated emissions, applicability of these methodologies to selected facilities from the various segments and the need to promote the use of consistent, standardized methodologies for estimating GHG emissions from petroleum industry operations.

Based on the review of the various methodologies, the following categories of ranking criteria were developed to evaluate the methodologies:

- Accuracy of Method
- Degree of Completeness of Data
- Degree of Availability of Data
- Addresses Regional Variability
- Uncertainties in Analysis
- Addresses Temporal Variability

Using these criteria, a ranking system was developed to quantify the extent to which these criteria are addressed in each of these methodologies for determination of GHG emissions from oil and gas production operations. The quantitative rankings were as follows: 1=high, 2=medium, 3=low. Those methodologies with a total score of 1 to 10 for all of the above 6 criteria received a “high” overall ranking, scores of 11-15 received a “medium” overall ranking and a score of 16 and above received a “low” overall ranking. Based on these scores, all the methodologies were ranked relative to each other from high to low. It should be noted that while efforts were made to provide quantitative ranking, any ranking of methodologies is inherently subjective. However this ranking system is intended to provide the reader with a guide to those methodologies that are believed to be the most accurate and tractable for estimating entity-wide GHG emissions. It should also be noted that rankings were based on the current degree of completeness and availability of data. Thus, some methodologies that are very accurate may not receive as high a ranking as another methodology because such data is not currently collected in the field. It is expected that more complete and accurate data will be required as a result of new reporting requirements in the future. In addition, the rankings do not recognize that the methodologies may vary for each of emissions sources and the GHGs being estimated. Where gaps exist in existing methodologies for the E&P sector, potential measurement methods will be discussed in Task 2.

The discussion of methodologies below was divided into categories as follows:

1. Stationary Combustion Sources (Internal and External Combustion)
2. Indirect Sources of Electricity and Heat
3. Mobile Combustion Sources
4. Drilling and Exploration Sources
5. Sources of Venting Emissions
6. Sources of Fugitive Emissions

4.2.1 Stationary Combustion Sources

Methodologies for this category include both internal combustion (internal combustion engines, turbines, flares, heaters and pumpjacks and external combustion (boilers and heaters). Methodologies for these categories are quite common and have been developed by nearly all of the organizations cited in this report. However, there is a wide range of methodologies that are considered by these organizations. These methodologies range from a top-down approach such as that used by the EPA to a detailed methodology based on specific information about the specific source of emissions, the hours operated per year, a load factor of the combustion device, and brake-specific fuel consumption. Where available, the type of control device and an emission factor based on field testing or alternatively a generic factor for the specific engine is used. In general, based on evaluation of the criteria, the more detailed methodology received a higher factor than the more general top down approach such as that used by the EPA. Table 12 summarizes the methodologies and ranking of stationary combustion sources.

4.2.2 Indirect Sources of Electricity and Heat

Methodologies for estimating GHG emissions for energy sources that are generated offsite and imported or purchased for use on site are termed indirect sources. These sources include fuel combusted to generate electricity or to produce heat or steam and can include cogeneration of both electricity and steam or heat. Such sources emit CH_4, and N_2O. Procedures include sources where the electricity is from a known generator where the type of combustion device is identified such as a gas or steam turbine or from a combined cycle system. The type of fuel is generally available as well as the emissions factors. Separate procedures are also identified for cases where the purchased electricity is from an unknown generator and is supplied from a regional or national grid. Such procedures are more general and by nature less accurate. Procedures are developed for evaluating the emissions from imported steam generated due to combustion that occurs to produce the steam. Cogeneration is the last category where electricity and steam are produced. Finally procedures are available for cases where all the electricity or part of the electricity and/or steam is produced from a cogeneration facility and it is necessary to divide the emissions resulting from the multiple energy stream. Table 13 summarizes the methodologies and ranking of indirect sources.

4.2.3 Mobile Combustion Sources

Mobile Combustion Source methodologies also range from using vehicle miles traveled (VMT) per year and applying the VMT to simplified emissions factors for different classes and types of vehicles, to using a more specific emission factor that has been developed based on the vehicle distribution by location, the certified emission rate by vehicle model and year and engine size and type. In addition, emissions of non-CO_2 gases (CH_4 and N_2O) are addressed for off-road vehicles and construction equipment. These methodologies require the use of fuel consumption data and generalized vehicle construction equipment emission factors or information on the detailed type and size of equipment, load factors for specific activities, the type of fuel used and the total operating hours. Table 14 summarizes the methodologies and the ranking for mobile combustion.

4.2.4 Drilling and Exploration

This category includes not only drilling and exploration activities but also workover rig activities as well as exploration and testing activities. Methodologies for this category were not addressed specifically by most organizations. However, most organizations did develop a stationary source combustion methodology. These methodologies may not address specific drilling rigs and their operations. For example, the most accurate method would address individual rig configuration including each engine type, model years of each engine, load factors and the usage of each engine. In many cases, default emission factors are used to apply to annual fuel use. Such approaches do not address the regional and temporal variability and will likely not provide an accurate assessment of emissions. Another example of specific activities in this category is the use of CH_4 or natural gas rather than compressed air at some wells which may be used (if available) as a motive force to drill the well which is then vented or flared. In this case, a material balance based on gas consumption and composition of gas can be used to estimate emissions. Table 15 summarizes the methodologies and the ranking for drilling and exploration.

4.2.5 Sources of Vented Emissions

This category includes field operations that result in emissions (mostly CH_4 and CO_2) as result of process venting, such as dehydration process venting, other vented sources such as tanks, pneumatic devices and chemical injection pumps and vented emissions as a result of maintenance or turnarounds such as vessel blowdowns, compressor startups and shutdowns and gathering pipeline blowdowns. Finally, this category includes non-routine activities such as pressure relief valves, well blowdowns, and emergency shutdowns or safety blowdowns. Again, most organizations did not address this category with the exception of API and WRAP. Most of these methodologies rely on the volume of gas released from the particular event and the composition of the gas. In some cases (such as blowdowns) flaring or green practices are used to control emissions, which should be included in the methodology to estimate emissions. For larger gas processing plants, emissions have been required by the local permitting authority and emission factors have been developed which can be adjusted on the basis of the CH_4 (or CO_2) content of the site specific gas. Table 16 through Table 18 summarizes the methodologies and the ranking for vented sources.

4.2.6 Sources of Fugitive Emissions

Methodologies for estimating fugitive emissions include using equipment level average emission factors and then applying such a factor to counts of equipment for associated processes such as compressors, pumps and valves. The most accurate method is to make use of a Leak Detection and Repair (LDAR) program if available, typically only at a large gas processing facility. Such methods are not available in most oil and gas field operations. Therefore, for these operations, the methodology would consist of using AP-42 emission factors and component counts for typical well set-ups. The well set-up is typically characterized by the type of equipment installed and the type of service to which the equipment applies such as natural gas wells, light liquid wells, or heavy oil wells. Table 19 summarizes the methodologies and the ranking for fugitive sources.

Table 12 Stationary Combustion Sources

	Methodology – External Combustion				Methodology – Internal Combustion					
	Flares		Boilers Heaters		Combustion (ICE, Turbines, Salt Water Disposal Engines, Pump jacks, CBM Engines					
Org	Methodology	Rank	Methodology	Rank	Fuel Composition/Usage	Rank	Fuel Basis	Rank	Equipment Basis	Rank
API	Recommend test data or vendor specific information as preferred method,	1	With the exception of fuel gas fired boilers/furnaces/heaters, the emission factors from external combustion are provided on a volume (scf or gallons) of fuel basis for gaseous or liquid fuels and mass (tonnes) of fuel basis for solid fuels. If the fire rate is given on a heat basis, then the heating values for various fuels provided in Table 3-5 of this Compendium can be used to convert the fuel fire rate (energy input basis) to a volumetric basis or mass basis.	2	Based on gaseous fuel composition analysis and amount of fuel burned for source or group of sources	2	Based on type of fuel (e.g., No. 6 Residual) with known HHV and total amount of fuel burned (gallons) by source or group of sources	3	Based on the size of engine (hp), the hours operated per year, the load factor and the BSFC (brake-specific fuel consumption)	1
API	Using annual volume of field gas flared, use alternative approach which assumes 98% combustion efficiency and 0.5% unburned CH4 emission. N2O emissions use EF referenced1	2			Based on molecular weight and carbon content of gaseous fuel and amount of fuel burned for source or group of sources	2	Based on the amount of natural gas burned (no composition or HHV known) in a combustion device	3		
API					Based on density and carbon content of liquid fuel and amount of fuel burned for source or group of sources	2				
IPCC	Provides simple emission factors for N2O from IPCC (IPCC, 2000). IPCC cites U.S. measurement data for these factors. IPCC also provides CO2 and CH4 emission factors for the same flare sources.	3			Use data on the amount of fuel combusted in each source category and apply a country-specific emission factor for th4 source category and fuel for each gas (Tier 1)	2	Use data on the amount of fuel combusted in each source category, then apply a default emission factor (Tier 2)	3	Based on fuel type, combustion technology, operating conditions, control technology, quantify of maintenance and age of equipment used to burn the fuel (Tier 3)	1

	Methodology – External Combustion				Methodology – Internal Combustion					
	Flares		Boilers Heaters		Combustion (ICE, Turbines, Salt Water Disposal Engines, Pump jacks, CBM Engines					
Org	Methodology	Rank	Methodology	Rank	Fuel Composition/Usage	Rank	Fuel Basis	Rank	Equipment Basis	Rank
WRAP	Methodologies developed for three processes; oil and condensate tanks flash gas, dehydration processing and completion venting processes where an emission factor is applied to production volume of gas (AP-42). Vent rates are combined with the heat content of the gas being flared and the appropriate EF.	1	Heater emissions are calculated on the basis of the emissions factor of the heater (AP-42), and the annual flow rate of gas to the heater. The annual gas flow rate is calculated from the BTU rating of the heater and the local BTU content of the gas. Although this may vary between oil and gas wells, the lack of information on well counts by well type requires the calculation for this analysis to consider heater configurations to be identical for all wells. The volumetric heating value of the gas, expressed as [MMBTU/scf] varies with local gas composition.	2					Based on the size of engine (hp), the hours operated per year and engine loads or assumed load factor, the EF Provided by Producers or AP-42 EF and the BSFC (brake-specific fuel consumption)	1
CAPP	Provides emission factors for flatter operations (Table 14) including CO2, N2O and CH4 and hydrocarbon compositions of flare emissions including CH4 (Table 15)	1					In the absence of any better information, the theoretical fuel gas consumption by a stationary or portable combustion device is estimated based on its maximum rated power output, the heating value of the fuel and an appropriate thermal efficiency, load factor and operating factor	3	Based on the size of engine (hp), the hours operated per year and engine loads or assumed load factor and AP-42. EF provided in Table 7 (Reciprocation Engines) , Table 8 and 9 (natural gas fired turbines) and Table 10 and 11 (boilers and heaters)	1
IPIECA					Based on fuel consumption that is metered or tank measurements or actual measurements of fuel composition	2	Fuel emissions factors (mass/mass or mass/heating value based on default factors	3	Fuel consumption based on ratings, hours of operation and engine loads or assumed loads	1

	Methodology – External Combustion				Methodology – Internal Combustion					
	Flares		Boilers Heaters		Combustion (ICE, Turbines, Salt Water Disposal Engines, Pump jacks, CBM Engines					
Org	Methodology	Rank	Methodology	Rank	Fuel Composition/Usage	Rank	Fuel Basis	Rank	Equipment Basis	Rank
CARB					For gaseous fuels determine the amount of fuel used each month using flow meter, determine the carbon content of the fuel by sampling and lab analysis	2				
CARB					For liquid fuels determine the amount of fuel used each month using a fuel flow meter, determine the carbon content of the fuel using approved analytical methods	2				
EPA							Using EIA data on national fuel used, GHG estimated based on fuel consumption by fuel type and sector, then Fuel uses not applicable are subtracted	3		
MMS	AP-42 emission factors for industrial flares, flare gas heating value and the total volume of gas flared are used to estimate emissions	1	Boilers, heaters and burners emissions are calculated using AP-42 (EPA 2002) emission factors for each combustion unit. Boilers are assumend to have the same configuration . Emission factors for No. 6 residual oil are used to estimate emissions from waste-oil-fueled units.	1			Based on fuel usage, fuel heating value and AP-42 emission factors	1	Based on the size of engine (hp), the hours of operation and using AP-42 emission factors from diesel, gasoline and natural gas engines	1

Table 13 Indirect Sources of Electricity and Heat

Organization	Methodology					Rank
	Indirect					
	Methodology for Imported Electricity	Rank	Methodology for Imported Steam	Rank	Methodology for Cogeneration	
API	API-1 For the case where electricity is supplied from a known generator, the preferred approach for estimating combustion emissions associated with purchased or imported electricity is either to use fuel derived emission factors provided by the generator or to estimate emissions based on fuel data using the combustion emission approach presented in Section 4.1.1	1	API-3 Imported steam/heat or steam/heat generated onsite results in GHG emissions due to combustion that occurs to produce the steam. If the method of generation for the steam/heat is known, then the approach to estimate combustion emissions given in Section 4.1 can be used.	2	API-5 Where all or part of the electricity and/or steam/heat produced from the cogeneration facility is transferred, sold or otherwise used by another entity, emissions may need to be divided. The Cogeneration Emissions Allocation approach-UK trending scheme is recommended3	1
API	API-2 In the case where electricity is imported directly from a third party power supplier, the default approach is to assume that the electricity was supplied from the grid. Regional or national grid emission factors may be available from federal governments. Table 4-13[2] provides national emission factors from published sources or developed from International Energy Agency (IEA) data.	2	API-4 Where no information about the steam/heat generation method is known, then a simple approach of assuming that the steam/heat was generated in a natural gas boiler is suggested. A thermal based emission factor for this approach can be developed by dividing a boiler emission factor on a lower heating value (LHV) basis by assumed boiler efficiency.	3	API-6 An Efficiency Allocation approach is presented by the WRI/WBCSD approach based on assumed (or known) efficiencies of the steam generation system and the electricity generation system. This approach is preferred by the EPA's Climate Leaders Program (EPA 2003)	2
API					API-7 The Work Potential Allocation approach assigns the emissions to the energy streams in proportion to their contribution to the total work potential, or energy. The work potential for steam is calculated from the specific enthalpy (H) and specific entropy (S) of the stream. This approach sums the work potential of all streams and allocates the total emissions to the individual streams.	3
CCAR	Emissions from indirect electricity use are determined on annual electricity use in the applicable state or region and using EPA's eGRID database (Appendix C) and converting non-CO_2 gases to carbon dioxide equivalents	2			The California Climate Action Registry (CCAR, 2003) attributes emissions to heat and electricity production based on a ratio of the energy produced for each type (heat or steam) to the total energy produced (net heat production plus electricity production), where each of the energy streams are	3

Table 14 Mobile Combustion Sources.

Organization	Methodology					
	Combustion Mobile					
	Methodology for On-Road Vehicles	**Rank**	**Methodology for Off-Road Vehicles**	**Rank**	**Methodology for helicopters and Support Vessels**	**Rank**
API	Using vehicle miles traveled per year, apply emission factors from Canada for different classes and types of vehicles for N2O, CH4 [1] For fuel economy factors us WRI factors[2] For CO_2 EF use simplified factors from UK[3]	2				
API	Simple methodology would apply CO_2 emission factor/MMBtu for fuel[4] and calculate annual CO_2	3				
CCAR	The method for estimating carbon dioxide emissions from mobile sources requires total annual fuel consumption by fuel type then selects the appropriate CO2 emission factor from Appendix C, Table C.4; and then multiply in fuel consumed by the emission factor to calculate total CO2 emissions and convert kilograms to metric tons. The online reporting tool (CARROT) can also be used if you have fuel consumption information,	1	To calculate the emissions of non-CO2 gases (CH4 and N20) from off-road vehicles/construction equipment, use fuel consumption data and the off-road vehicle/construction equipment emission factors in Appendix C, Table C.5.	1		
CCAR	The method for estimating emissions of methane and nitrous oxide from mobile sources requires identification of the vehicle types, fuel, and model years of all the vehicles and the annual mileage by vehicle type. Appropriate emission factor for each vehicle and fuel type are provided (using Appendix C, Table C.5)	1				
MMS					Helicopter activity data was obtained from the "Helicopter Safety Advisory Conference's Gulf of Mexico Offshore Helicopter Operations Safety Review" report. Emissions were estimated assuming short landing and takeoff cycles. Emission factor were developed based on several test results from EPA, engine manufacturers and the Navy. Emissions from support vessels were estimated extrapolating activity data from the 1995 MMS study (data from 1992) and taking into account the increase in the number of platforms oprationg between 1992 and 2000. MMS 1992 data was developed by surveying industry players.	2

Table 15 Drilling and Exploration Sources.

Organization	Methodology					
	Drill Rigs	Rank	Workover Rigs	Rank	Explore Drill Test	Rank
IPCC	Apply default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a countries oil and natural gas industries (non-key sources). Tier 1 (general), Tier 2 (country specific) , Tier 3 (bottoms up Approach)	1	Apply default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a countries oil and natural gas industries (non-key sources). Tier 1 (general), Tier 2 (country specific) , Tier 3 (bottoms up Approach)	1	Apply default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a countries oil and natural gas industries (non-key sources). Tier 1 (general), Tier 2 (country specific) , Tier 3 (bottoms up Approach)	1
WRAP Method 1	Where available, use information on individual rig configurations including the numbers of each engine type, model years of each engine type, load factors of each engine type, usage of each engine type and BSFC (brake specific fuel consumption)	1	Where available, use information on individual rig configurations including the numbers of each engine type, model years of each engine type, load factors of each engine type, usage of each engine type and BSFC (brake specific fuel consumption)	1		
WRAP Method 2	Where detail information not available, use average depth of drilling in each production basin to derive total rig horsepower by scaling the average total rig horsepower from the WRAP Phase III work and scale the data to a particular depth by the ratio of the depth of wells in other basins.	2				
API	General emission estimate approaches for fuel combustion, combined with site-specific data and/or engineering judgment, are recommended.	2	General emission estimate approaches for fuel combustion, combined with site-specific data and/or engineering judgment, are recommended.	2	Use of CH_4 or natural gas rather than compressed air at CBM wells may be used (if available) as a motive force to drill the well which is then vented or flared. Use a material balance based on gas consumption and composition of gas.	2
MMS	AP-42 Emission factors and diesel, gasoline and natural gas fuel usage, are used to estimate emissions. Total emissions equal the sum of emissions from usage of each type of fuel	1				

Table 16 Sources of Venting Emissions: Glycol Dehydrators and Amine Units.

	Methodology							
	Glycol Dehydrators				Amine Units			
Organization	Methodology for Glycol Dehydrators	Rank	Methodology for Glycol Pumps	Rank	Acid Gas Removal	Rank	Gas Venting	Rank
API	AP-1 Measured test data of the glycol dehydrator vent is the preferred approach for determining venting emission.	1	AP-5 Assuming the pump is a Kimray or similar type, Table 5-3 provides an appropriate emission factor. The CH4 emissions are calculated by multiplying this emission factor by the annual gas throughput and adjusting for the facility CH4 concentration	2	Two CH4 emission factors for AGR vents were developed as part of the 1996 GRI/EPA CH4 emissions study (Volume 14, page A-13) based on process simulation results for typical unit operations (Myers, 1996). Table 5-4 provides the AGR CH4 emission factor on both a throughput basis and unit basis. The throughput basis should be used preferentially over the unit basis factor if the volume of gas treated is known.	2	Sour gas processing can directly vent the CO2 removed from the sour gas stream to the atmosphere or capture the CO2 for other uses, such as enhanced oil recovery. For systems that vent the waste CO2, emissions can be estimated by material balance using the known throughput and CO2 concentrations of the inlet and outlet gas streams (CAPP, 2003). Methane emissions from sour gas processing are assumed to be insignificant, but can also be estimated by material balance.	1
API	AP-2 If detailed information about the site-specific glycol dehydrator unit is known (volume of gas treated, and CH4, CO2 content), then a process simulator or other computer software such as GRI-GLYCalc (GRI, 2000) can be used to estimate the emissions. Detailed information to run the GRI-GLYCalc computer simulation includes the wet gas flow rate, wet gas temperature and pressure, existence of a gas-driven glycol pump, wet and dry gas water contents, glycol flow rate, use of stripping gas in the regenerator, and the temperature and pressure of the flash tank, if applicable.	1					For systems that send the acid gas to an incinerator. In this case, the CO2 emissions vented from the incinerator can be calculated based on the volume of acid gas to the incinerator and the mole fraction of CO2 in the acid gas.	1

Organization	Methodology							
	Glycol Dehydrators				Amine Units			
	Methodology for Glycol Dehydrators	Rank	Methodology for Glycol Pumps	Rank	Acid Gas Removal	Rank	Gas Venting	Rank
API	AP-3 If information about the site-specific glycol dehydrator is not readily available, then simplified emission factors can be used. These emission factors, provided in Table 5-11, were developed using both site data and computer simulations (Myers, 1996). Table 5-1 also lists the default CH4 content of the natural gas for the different industry segments that may use glycol dehydration. Does not include gas-assisted glycol pumps.	2						
API	AP-4 As an alternative to the industry specific emission factors given above, Table 5-2 provides general glycol dehydrator emission factors developed using GRI-GLYCalc (Texaco, 1999). Unlike the GRI/EPA emission factors, these factors include the emissions contribution from the gas-assisted glycol pump, if present. The emission factors are developed assuming typical operating parameters for a glycol unit with no vent condenser, as a vent condenser does not appreciably affect the CH4 emissions.	2						
IPCC	AP-Apply default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a countries oil and natural gas industries (non-key sources). Tier 1 (general), Tier 2 (country specific) , Tier 3 (bottoms up Approach)	1			Apply default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a countries oil and natural gas industries (non-key sources). Tier 1 (general), Tier 2 (country specific) , Tier 3 (bottoms up Approach)	1	Apply default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a countries oil and natural gas industries (non-key sources). Tier 1 (general), Tier 2 (country specific) , Tier 3 (bottoms up Approach)	1

Organization	Methodology							
	Glycol Dehydrators				Amine Units			
	Methodology for Glycol Dehydrators	Rank	Methodology for Glycol Pumps	Rank	Acid Gas Removal	Rank	Gas Venting	Rank
WRAP	Dehydrator emissions are calculated from two distinct sources: still vent emissions and reboiler emissions. Reboiler emissions are calculated on the basis of the emissions factor of the reboiler, and the annual flow rate of gas to the reboiler. The annual gas flow rate was calculated from the BTU rating of the reboiler and the local BTU content of the gas. It isassumed that reboiler was running 100 % the time. AP-42 emission factors for an uncontrolled small boiler were utilized as the basis of emission estimates. GRI-GLYCalc (GRI, 2000) used to estimate the emissions which indicate the tons of CO2 per year emitted for each dehydrator.	1						
WRAP	Where insufficient information is available to generate per-dehydrator or per-unit production emissions factors for dehydrator still vents and reboilers, apply broad regional emissions factors per unit production from the IPAMS/WRAP Phase III work	1						

Organization	Methodology							
	Glycol Dehydrators				Amine Units			
	Methodology for Glycol Dehydrators	Rank	Methodology for Glycol Pumps	Rank	Acid Gas Removal	Rank	Gas Venting	Rank
CAPP	Recommends use of the simulation program GRI-GLYCalc (Thompson et al., 1994). GRI-GLYCalc is primarily presented as a tool for estimating the amount benzene, toluene, ethyl benzene and xylene (BTEX) emitted by a glycol dehydrator (significant amounts of this material may be preferentially absorbed by the glycol and released off the flash tank and still column). However, in performing a rigorous simulation of the dehydration process, the program also provides information on the amount of methane and other organic emissions. The required input data includes: gas composition and flow rate, - glycol circulation rate, - temperature and pressure in the absorber column, - type of glycol pump, - operating pressure of the flash tank (if one is used) - amount of flash gas used by the process (if at all), - type of glycol (TEG or DEG), and - stripping gas usage.	1						
MMS	If detailed information about the site-specific glycol dehydrator unit is known, emission factor estimates can be calculated by using regression equations from GRI-GLYCalc version 4 (GTI 2000). This computer program runs for different combinations of gas pressure and temperature.	1			CH_4 emissions are estimated using AMINECalc (GTI 2001). Emissions are adjusted for any reported control devices using an efficiency factor. If the data is not readily available, operators have the option to use generic inputs to estimate emissions.	1		

Table 17 Sources of Venting/Fugitive Emissions: Blowdowns/ Start ups and Chemical Injection Pumps and Fugitives.

	Methodology				Methodology			
	Blowdowns, Start –Ups, Chemical Injection Pumps, Vents, Mud Degassing						Fugitives	
Organization	Methodology for Gas Wells	Rank	Methodology for Processing Plants	Rank	Chemical Injection Pumps	Rank	Fugitives	Rank
API	Determine the volume released based on documentation of the non-routine release events, and the concentration of CH4 (and CO2, if significant) in the gas stream.	1	Maintenance blowdowns at gas plants include compressor blowdowns, compressor starts, and other miscellaneous sources. The processing plant blowdown emission factor is presented in Table 5-23. This emission factor can be adjusted based on the CH_4 content of the site-specific gas if the natural gas has a significantly different CH_4 content from the default basis. Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.	1	The preferred approach for estimating GHG emissions from CIPs is to use site specific gas usage measurements or manufacturer's data. Alternatively, the simplified emission factors in Table 5-16 can be used to estimate CH_4 emissions from gas-driven CIPs (piston and diaphragm and specified pressures). The factors are given for piston and diaphragm type pumps, and an average emission factor is given if the type of pump is unknown.	2	Where LDAR program not used (typically only at processing plants) use facility-wide average emission factors. Separate fugitive emission factors for CH_4 for oil and gas production operations are provided (Table 6-1). For facilities that produce any natural gas, the gas production emission factors should be used. For facilities that do not market the associated gas or only produce crude, the oil production emission factors should be used.	2
API	Use simplified emission factors developed from an inventory of company practices or from specific measurement programs. The emission factors for these sources tend to be segment specific, so each industry segment is discussed separately (See Sections 5.7.2 through 5.7.5). Includes vessel blowdowns, Compressor starts, workovers, water removal, well clean-ups and pipeline blowdowns	2					Use equipment level average emission factors. Emission factors are provided (Tables 6-2 and 6-3) for equipment associated with oil and gas exploration and production operations. For facilities where oil and gas are produced from the same well, emission factors are provided by equipment type (Table 6-2) and should be applied to counts of equipment associated with crude production, while emission factors for natural gas production equipment are provided in Table 6-3. Gas processing equipment emission factors (compressors) are provided in Table 6-4	1

	Methodology				Methodology			
	Blowdowns, Start –Ups, Chemical Injection Pumps, Vents, Mud Degassing						Fugitives	
Organization	Methodology for Gas Wells	Rank	Methodology for Processing Plants	Rank	Chemical Injection Pumps	Rank	Fugitives	Rank
API	For several production activities and process turnarounds, use CH_4 emissions factors in Table 5-21, Processes include Vessel Blowdowns, Compressor starts and blowndowns, gas and oil well workovers, gas well removal, well cleanups and pipeline blowndowns	2					Apply default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a countries oil and natural gas industries (non-key sources). Tier 1 (general), Tier 2 (country specific) , Tier 3 (bottoms up Approach)	1
IPCC	Apply default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a countries oil and natural gas industries (non-key sources). Tier 1 (general), Tier 2 (country specific) , Tier 3 (bottoms up Approach)	2					Fugitive emissions from wellheads are estimated using AP-42 emissions factors (EPA, 1995) and component counts for typical well setups. The well setup is typically characterized by the type of equipment installed and by the type of service to which the equipment applies – gas, light liquid, heavy liquid, or water.	1

	Methodology				Methodology			
	Blowdowns, Start –Ups, Chemical Injection Pumps, Vents, Mud Degassing						Fugitives	
Organization	**Methodology for Gas Wells**	**Rank**	**Methodology for Processing Plants**	**Rank**	**Chemical Injection Pumps**	**Rank**	**Fugitives**	**Rank**
WRAP	Emissions from well completions are estimated on the basis of the volume of gas vented during completion, the number of completions and the CH_4 and CO_2 content of that gas, obtained from gas composition analyses. Flaring and/or green completion practices may be used to control emissions from the completion process. Flaring typically has 98% control efficiency for VOC emissions, and green completion practices have a range of control efficiencies depending on the amount of vented gas that is captured during the process.	1			The annual gas consumption rate per gallon of chemical pumped was multiplied by the total volume of chemical pumped to derive total gas consumption from gas-actuated pumps. If the gas consumption rate is not available, then use the average gas consumption rate from other producers (Likely from API methodology) Pneumatic pumps are assumed to operate exclusively at conventional gas wells. CH_4 emissions are estimated similarly to pneumatic devices	2	Use equipment level average emission factors. Emission factors for THC are provided (Table 19) for equipment associated with oil and gas exploration and production operations. Fractional control efficiencies for various equipment (pumps, compressors, valves) are provided in Table 20	2
WRAP	Emissions from blowdowns are estimated on the basis of the volume of gas vented during a blowdown and the average pollutant content of that gas, obtained from gas composition analyses and the frequency of blowdown events. This methodology is very similar to that of completion venting. Flaring and/or green practices may be used to control emissions from the blowdown process. Flaring typically has a 98% control efficiency for VOC emissions, and green practices have a range of control efficiencies depending on the amount of vented gas that is captured during the process.	1						

Organization	Methodology				Methodology			
	Blowdowns, Start –Ups, Chemical Injection Pumps, Vents, Mud Degassing						Fugitives	
	Methodology for Gas Wells	**Rank**	**Methodology for Processing Plants**	**Rank**	**Chemical Injection Pumps**	**Rank**	**Fugitives**	**Rank**
CAPP	Provides potential waste gas volumes and frequencies for blowdowns, purges and other venting activities (Table 16)	3			The amount of gas consumption is determined by the change in pressure of this gas in passing through the gas motor, the pumping rate and the required chemical injection pressure. As much as 7.5 m^3 of gas may be required to pump each liter of liquid; however, most applications will require much less gas than this (i.e., typically only half as much).	2		
	Methodology for Vents	**Rank**	**Methodology for Mud Degassing**	**Rank**			**Fugitives**	**Rank**
MMS	Vents receive emissions from miscellaneous sources as well as from manifold equipments such as glycol dehydrators, storage tanks, amine units, etc. Emissions are calculated based on the volume of gas vented from miscellaneous equipment and the chemical composition of the gas. (approach similar to API-1)	1	For water-based and oil-based muds, emissions are calculated using emission factors provided in the EPA 1977 report (Atmospheric Emissions from Offshore Oil and Gas Development and Production). There is no information available on how to calculate emissions from synthetic based mud.	3			Operators are required to specify the stream type and average VOC weight percent of fugitives, and provide an equipment inventory. THC emission factors (API 1996) for oil and gas equipment operations are used to estimate emissions.	1

Table 18 Source of Venting Emissions: Pneumatics, Gas Casing, and Truck loading.

Org	Methodology							
	Pneumatics		Gas Casing				Trucks	
	Pneumatics	Rank	Casing Gas	Rank	Casing Gas	Rank	Truck Loading	Rank
API	The preferred approach for estimating CH_4 emissions (and CO_2 emissions if CO_2 is present in the gas stream) from gas-driven pneumatic devices is to use site-specific device measurements or manufacturer's data. Alternatively, simplified CH_4 emission factors are provided in Table 5-15 for each industry sector. Table 5-15 also presents the corresponding CH_4 content of the gas used as the basis for the emission factors. The emission factors can be adjusted based on the CH_4 content of the site specific gas used to drive the devices if the natural gas is significantly different from the default basis. Also, if the pneumatic devices are driven with gas that contains significant quantities of CO_2, the CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.	2	Site-specific volumetric flow rate and CH_4 (and CO_2 if present) concentration data should be used to estimate these emissions. If production flow rate is know the simplified casing gas vented emission factors presented in Tables 5-17	2	Casing gas migration emissions should be estimated from site-specific measurements. In the absence of site-specific data, the following emission factor from page 3-25 of the CAPP document, Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, can be used (CAPP, 2002):	2	Simplified emission factors for truck loading of crude oil are provided (Table 5-10) such as submerged loading, and splash loading. The CH_4 content of crude is assumed to be 15 wt%, if site-specific data are not available (EPA, AP-42 Section 5.2, 1995). For petroleum liquids other than crude, the CH_4 content is generally insignificant and is assumed negligible if measured data are not available.	2
API			If the oil production throughput is not known, simplified casing gas vented THC emission factors (Table 5-18) for active and suspended wells based on data in Alberta (CAPP, 2002). The casing gas CH_4 emission factors can be adjusted based on the CH_4 content of the site-specific gas if the natural gas has a significantly different CH_4 content from the default basis. Also, if the gas at the site contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.	2				

Org	Methodology							
	Pneumatics		Gas Casing				Trucks	
	Pneumatics	Rank	Casing Gas	Rank	Casing Gas	Rank	Truck Loading	Rank
WRAP	Like fugitive emissions, the emissions from these devices are typically estimated by obtaining a configuration of a typical well, including the count of devices by type at the typical well. Emissions rates of gas from these pneumatic devices have been studied extensively by the EPA as part of the Natural Gas Star program (EPA, 2004), which are used as the source of quantitative emissions factors for pneumatic devices.	2					Oil and gas well and gas plant truck loading emissions are estimated based on loading losses per EPA AP-42, Section 5.2 methodology combined with data provided on oil product volume loaded. The surveyed producer loading loss rate is estimated based on EPA AP-42, Section 5.2 methodology using default values based on operating mode, the true vapor pressure of the liquid, the MW of the vapor and the temperature of the bulk liquid.	2
CAPP	Provides gas consumption rates for a variety of standard and low-bleed types of pneumatic instruments	3					Provides methodology for losses from rail tank cars and trucks during transport. Classified into high vapor pressure carriers and low vapor pressure carriers using default emission factors.	2
MMS	Emissions are estimated using equation 10.4-3 from EIIP 1999 (Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations. Chapter 10). The operating time, fuel usage rate and molecular weight of the gas are needed for the calculations.	2					Provides calculations to estimate emissions from offshore loading operations assuming that ships arrive uncleaned, ballasted condition and that the previous load was crude oil. Uses AP-42 marine loading approach	2

Table 19 Sources of Venting Emissions: Tanks.

Organization	Methodology							
	TANKS							
	Methodology for Flashing Losses	Rank	Methodology for Working/Breathing Losses	Rank	Methodology for Produced Water Tanks	Rank	Methodology for Natural Gas Blanketed Tanks	Rank
API	Direct measurements - Tank vent emissions can be measured directly, providing accurate emissions estimates for the measured tanks, but this approach is generally expensive and time consuming for large numbers of tanks.	1	Use AP-42 for estimating tank hydrocarbon working and standing loss emissions (EPA, Supplement D, 1997). Since Chapter 7 of AP-42 and the TANKS program are primarily directed at estimating THC or VOC emissions, need to multiply the total emissions by the concentration of CH_4 and/or CO_2 in the tank vent stream. The CH_4 and/or CO_2 concentrations should be based on site test data if they are available (otherwise the site will have to use engineering judgment).	1	Use of general industry emissions factors from produced (salt) water tanks. (Factors shown in Table 9-8)	2	Emissions are based on vapor displacement when liquid fills the tank The vent rate (VR) (See Equation 5-9) is assumed to be the vapor displacement due to filling the tank with liquid. Using the liquid throughput rate to estimate the vapor displacement should provide conservatively high emission estimates since it does not take into account the liquid level affects due to emptying the tank at the same time as filling.	2
API	Specific computer programs - API's E&P TANKS program (API, 1997) can be used to estimate flashing losses. However, this model works best when the low-pressure oil analysis (between the separator and storage tank) is known. Other input parameters include: separator pressure and temperature, atmospheric pressure, API gravity and Reid Vapor Pressure of the crude, composition of the crude, and production rate. If these conditions are unknown, assumptions can be made to run the program. Note that the EPA TANKS Program does not account for flashing loss emissions (EPA, 1999).	1						
API	Correlation equations – The Vasquez-Beggs Equation (VBE), standing correlation, and the Alberta Energy Utility Board (EUB) rule-of-thumb methods provide computational approaches for estimating tank flashing losses when limited input data are available.	2						

Organization	Methodology							
	TANKS							
	Methodology for Flashing Losses	Rank	Methodology for Working/Breathing Losses	Rank	Methodology for Produced Water Tanks	Rank	Methodology for Natural Gas Blanketed Tanks	Rank
API	Emission factors – Measured emissions from a variety of E&P tanks have been used to develop simple emission factors based on tank throughput. Emission factors developed by API/GRI and Canadian Petroleum Association (See Table 5-6)	3						
WRAP	For the condensate tank emission factors, use operator's supplied emission data from EP Tank model runs to calculate the representative weighted average emissions per for a throughput of 1 barrel/day condensate production. For oil tank emissions, the TANKS model was run with an average RVP of 5 and emissions for an average throughput of 1 bbl per day production was used to obtained emissions. The emissions factors for oil and condensate production are derived from running a process modeling software that predicts the volume of flash gas or working and breathing losses from the tank per unit of production.	1						
CAPP	The Canadian Association of Petroleum Producers (CAPP) document, Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, includes a standing correlation to estimate flashing losses (CAPP, 2002).	2						

Organization	Methodology							
	TANKS							
	Methodology for Flashing Losses	Rank	Methodology for Working/Breathing Losses	Rank	Methodology for Produced Water Tanks	Rank	Methodology for Natural Gas Blanketed Tanks	Rank
CAPP	The Canadian Association of Petroleum Producers (CAPP) document, Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, includes the EUB (Energy and Utilities Board) rule-of-thumb approach to estimate flashing losses (CAPP, 2002). CAPP reports that this approach tends to yield conservatively high flashing loss estimates and is recommended for facilities with low oil volumes, established pools, mature pools with declining GOR's, and some heavy oil production facilities (CAPP, 2002).	3						
MMS	Emissions are estimated using Vasquez-Beggs correlation equations and speciation profiles from API (Publication no. 4638)	2	THC emissions are calculated using AP-42 equations	1				

Table 20 Oil Sands Operation Sources

Organization	Methodology							
	Hydrogen Plant	Rank	Upgrading Coker Unit	Rank	Mine Surface	Rank	Pond Surface	Rank
CARB	Operators are required to report the total volume of hydrogen produced per year and the amount of hydrogen used as a transportation fuel. Methane and N2O emissions are fuel specific and based on fuel HHV. There are three calculation methods: (1) Source Testing Method: the operator conducts Source Testing to determine fuel and combustion specific emissions factors. The source test plan must be approved by ARB, must be performed at least once per year and under the supervision of ARB or the local air district. The fuel HHV should be measured too.	1	Calculation method based on hourly coke burn rate U.S. EPA 40 CFR Part 63). The required data is: number of days of operation, daily average coke burn rate and the carbon fraction in coke burned (section 95113). Calculation method based on hourly coke burn rate U.S. EPA 40 CFR Part 63). The required data is: number of days of operation, daily average coke burn rate and the carbon fraction in coke burned (section 95113).	2				
	(2) The operator can measure HHV content and use the default emission factors specified in Appendix A (Table 4 of the Regulation, section 95125)	2						
	(3) In the case where the HHV factor is not measured, default HHV and efficiency factor values can be used (Table 4 of the Regulation, section 95125)	3						
API	The are three calculation methods: (1) Known feedstock composition: uses the feedstock rate and the carbon content to estimate CO_2 emissions	2	Calculation method based on coke burned. The required data is: coke burn rate per year, the fraction of carbon in the coke and the molecular weight of both carbon and carbon dioxide. The methodology is based on the assumption that all the carbon in the coke is combusted into CO_2, it is recommended to use a site-specific carbon fraction of coke data in order to get more accurate estimates.	3				

Organization	Methodology							
	Hydrogen Plant	Rank	Upgrading Coker Unit	Rank	Mine Surface	Rank	Pond Surface	Rank
	(2) Known hydrogen rate: this approach uses the hydrogen production rate and the stoichiometric ratio of H_2 formed to CO_2 formed to estimate CO_2 emissions.	2						
	(3) When the feed gas composition is similar to natural gas, an emissions factor assuming an average natural gas composition (Table 5.5) can be used.	3						
CAPP	The emissions are estimated using an extrapolation model created by Clearstone Engineering Ltd. for Environment Canada's Bitumen-Oilsands Extrapolation Model - Rev 3 in 2007. This model uses results from the bitumen report (CAPP 2006) as its basis, along with annual production data as reported by the AEUB and the NEB. The emissions are divided into fugitive emissions (American Petroleum Institute (API) Separator, Equipment Leaks, Exposed Oil Sands, Ponds, Storage Tanks and others) and venting process emissions (FGD, Formation CO_2 from Acid Gas, Hydrogen Plant and Non-Combustion Point Sources). The extrapolation methodology uses activity data from the AEUB's ST-43: Mineable Alberta Oil Sands Annual Statistics, which is published annually, and the amount of heavy oil production in Saskatchewan as reported by the National Energy Board (NEB) and an emission factor. Source-specific factors* were developed for each facility by correlating the most recent 3 or 4 years of emission data for the facility, from the bitumen report (CAPP 2006), with available site-specific production accounting data.							2
OS/HOU Industry	The calculation method for the Catacarb process is based on the volume of gas, a hydrogen conversion efficiency factor and an emissions factor. The emissions factor is calculated from an average delivered natural gas composition using CAPP guide equation 3 (amended), API guide section 4.1.1 (amended) or the Alberta guide equation 7 (amended)	3	The methodology developed by Suncor is based on steam production, boiler efficiency, enthalpy of 790# steam and boiler feed water, heating value and carbon content of coke.	2	Emissions calculations depend on the type of mine surface, surface area, ore quality, length of time the surface has been exposed and the ambient temperature. Using emission flux measurements, Syncrude and Suncor have developed site-specific emission factors. Operators can decide to use Suncor and Syncrude historical data or to developed their own emission factors	2	Emissions calculations depend on the age of the pond, the surface area of the pond and the degree of microbial action. Using emission flux measurements, Syncrude and Suncor have developed site-specific emission factors.	2

Organization	Flue Gas Desulphurization	Rank
OS/HOU Industry	This is a mass balance approach and the overall accuracy depends on the degree to which the input materials are measured. Calculation method is based on mass of limestone, limestone %CaCO3, and conversion factor for CO2 equivalency.	2