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National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage - Background Information for Proposed Standards

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This background information document provides the basic information which was used as background in the development of the two standards 1) National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities and 2) National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. A description of the industries, control technologies available, cost of controls, modeling used in the estimation of national emission estimates and costs are included.

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Emission Standards Division

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
April 1997

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1.0 INTRODUCTION

1.1 PURPOSE OF DOCUMENT

National emission standards for hazardous air pollutants (NESHAP) are being developed for the oil and natural gas production source category and the natural gas transmission and storage source category by the U.S. Environmental Protection Agency (EPA). This background information document (BID) describes technical information and analyses supporting development of the NESHAPs for proposal in the Federal Register.

1.2 STATUTORY BASIS OF RULE

The NESHAPs for the oil and natural gas and natural gas transmission and storage source categories are being developed under the authority of §112(d) of the Clean Air Act as amended in 1990 (CAA).[1] Section 112(d) of the CAA directs the EPA Administrator to promulgate regulations establishing hazardous air pollutant (HAP) emission standards for each category of major and area sources of HAP that has been listed by the EPA for regulation under §112(c). The 188 pollutants that are designated as HAP are listed in §112(b).

A major source is defined as a stationary source or group of stationary sources located within a contiguous area and under common control that emits, or has the potential-to-emit (PTE) considering controls, 10 tons per year (tpy) or greater of any one HAP or 25 tpy or greater of any combination of HAP. An area source is any stationary source that is not a major source. Special provisions in §112(n)(4) for oil and gas wells and pipeline compressor and pump station facilities affect major source determinations for these facilities and also indicate under what circumstances the EPA may regulate oil and natural gas production wells as an area source category.

The CAA prescribes the minimum degree of emission reduction that must be required by standards developed under §112(d) for existing and new major sources of HAP. Standards for existing major sources may not be less stringent than the average emission limitation achieved by the best performing 12 percent of the existing sources for which the Administrator has emissions information. Standards that are established for major sources are referred to as maximum achievable control technology (MACT) standards. Standards for new major sources must reflect the maximum degree of emission reduction achieved in practice by the best controlled similar source (best of the best).

For source categories with fewer than 30 sources, standards may not be less stringent than the average emission limitation achieved by the best performing five sources. Standards for existing major sources may be more stringent than these minimums, but must consider cost, non-air quality health and environmental impacts, and energy requirements.

The CAA gives discretion to the Administrator when setting standards under §112(d) for area sources of HAP. Standards for area sources may either be based on MACT, as for major sources, or on generally available control technology (GACT).

1.3 SCOPE OF THE SOURCE CATEGORIES

The oil and natural gas production source category includes the processing and upgrading of crude oil prior to the point of custody transfer and natural gas prior to entering the pipeline systems associated with the natural gas transmission and storage source category. Included in this source category are offshore production platforms located in State waters. Facilities that handle hydrocarbon liquids from the point of custody transfer are in the organic liquids distribution (non-gasoline) source category.

For natural gas streams, the natural gas transmission and storage source category includes the pipeline transport, storage, and processing of natural gas prior to entering the final pipeline of the local distribution company (LDC) that delivers natural gas to the final end user. The scopes of these source categories are illustrated in Figure 1-1.

1.4 DOCUMENT CONTENTS

This BID is intended to provide (1) basic information on the process operations and HAP emission points associated with oil and natural gas production and natural gas transmission and storage and (2) information on controls and the impacts of controls available to reduce HAP emissions from identified HAP emission points. The description and analysis of regulatory alternatives will be presented in other EPA documents.

Chapter 2.0 presents an overview of the source categories. Chapter 3.0 identifies control options for HAPs that are applicable to identified HAP emission points in the source categories. Chapter 4.0 presents the model plants developed for use in estimating the impacts of applying the control options. Chapter 5.0 addresses the environmental and other impacts resulting from applying control options to identified HAP emission points in the source categories. Chapter 6.0 presents the costs and cost-effectiveness of the control options.

Additional information is presented in three appendices to this document. The appendices include (1) Appendix A - Evolution of the BID, (2) Appendix B - National Impacts Methodology, and (3) Appendix C - Monitoring, Inspections, Recordkeeping, and Reporting Cost Methodology.

1.5 DOCKET REFERENCE

The docket for these regulatory actions is designated as Docket No. A-94-04. The docket is an organized and complete file of the information submitted to or otherwise considered by the EPA in the development of this proposed rulemaking. The principal purposes of the docket are (1) to allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process and (2) to

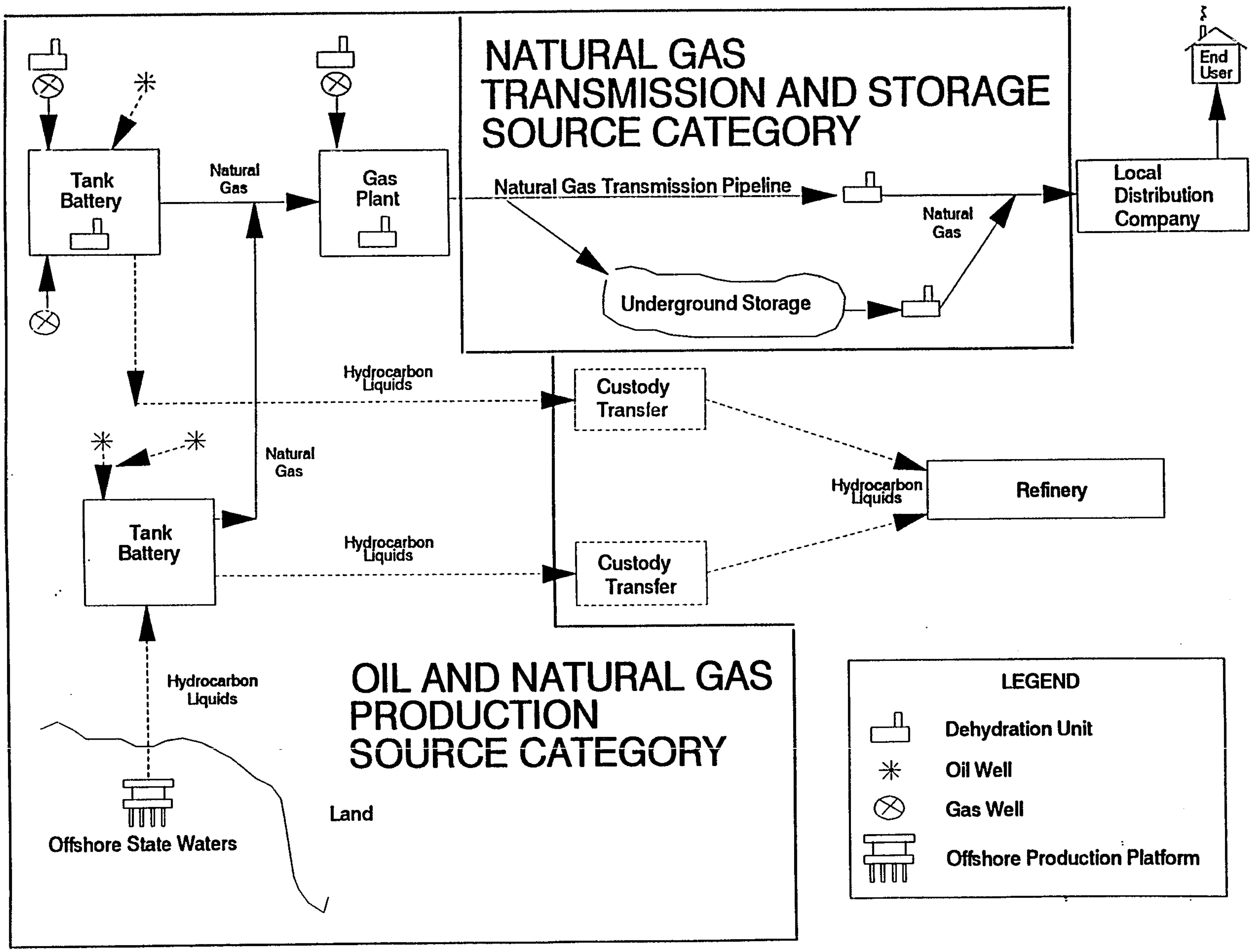

Figure 1-1. Oil and Natural Gas Industry

serve as the record in case of judicial review (except for interagency review materials) (§307(d)(7)(A) of the CAA).

The docket is available for public inspection and copying between 8:30 a.m. and 4:30 p.m., Monday through Friday, at the EPA's Air and Radiation Docket, Room M1500, U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460. A reasonable fee may be charged for copying.

1.6 REFERENCES

1. United States Congress. Clean Air Act as amended November 1990. 42 U.S.C. 7401, et seq. Washington, DC. U.S. Government Printing Office. November 1990.

2.0 THE OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS TRANSMISSION AND STORAGE SOURCE CATEGORIES

2.1 INTRODUCTION

The oil and natural gas production and natural gas transmission and storage source categories include the separation, upgrading, storage, and transfer of extracted streams (primarily hydrocarbons) that are recovered from production wells.[1] This chapter includes a summary characterization of these source categories, along with descriptions of extracted streams and recovered products, and the basic processes and operations involved with oil and natural gas production and natural gas transmission and storage. This chapter also presents descriptions of identified hazardous air pollutant (HAP) emission points associated with the processing, storing, and general handling of these materials and products.

The extracted streams and recovered products for these source categories include crude oil, condensate, natural gas, and produced water. The types of processes and operations in these source categories include production wells, dehydration units, tank batteries, natural gas processing plants, offshore production platforms, and pipeline transmission facilities, including underground storage operations. The primary HAP emission points associated with these source categories that are being evaluated include process vents, storage vessels, and equipment leaks.

Extracted streams and recovered products, processes and operations, and HAP emission points are described below. This chapter also addresses HAPs associated with these streams and products, facilities, and emission points, and includes baseline HAP emission estimates.

2.2 SOURCE CATEGORY CHARACTERIZATION

The oil and natural gas production source category includes the processing and upgrading of crude oil prior to the point of custody transfer and natural gas prior to entering the pipeline systems associated with the natural gas transmission and storage source category. This source category includes offshore production platforms located in State waters. Facilities that handle hydrocarbon liquids after the point of custody transfer are included as part of the organic liquids distribution (non-gasoline) source category. For natural gas streams, the natural gas transmission and storage source category includes the pipeline transport, storage, and processing of natural gas prior to entering the final pipeline of the local distribution company (LDC) that delivers natural gas to the final end user. The scope of these source categories are illustrated in Figure 1-1 of Chapter 1.0 of this background information document (BID).

2.2.1 Production Wells

In 1992, there were an estimated 590,000 crude oil and condensate production wells in the U.S., with a total annual production of over 2.6 billion barrels and approximately 3 trillion cubic feet of co-produced natural gas. This was a decrease of 3 percent in both the number of wells and in crude oil production as compared with 1991 levels.[2]

Of this total number of crude oil and condensate production wells, over 70 percent are classified as stripper wells, which are production wells that are (1) nearing depletion or (2) have a production rate of less than 10 barrels of oil per day (BOPD). Stripper well production accounts for approximately 14 percent of total domestic crude oil production.

In addition, for 1992, there were an estimated 280,000 natural gas production wells in the U.S., with a total estimated annual production of over 18 trillion cubic feet. This estimate represents a 3 percent increase in the number of wells and 1 percent increase in natural gas production as compared with 1991 levels.[3]

2.2.2 Dehydration Units

Once the natural gas has been separated from any liquid materials or products (crude oil, condensate, or produced water), residual entrained water vapor is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, that are ice-like structures, that can (1) cause corrosion or (2) plug equipment lines.

The Gas Research Institute (GRI) estimates that there are over 44,000 dehydration units in the U.S. Triethylene glycol (TEG) dehydration units account for most of this estimated population of dehydration units, with ethylene glycol (EG), diethylene glycol (DEG), and solid desiccant dehydration units accounting for the remaining portion.[4]

TEG dehydration units may be (1) stand-alone units that dehydrate natural gas from an individual well or several wells or (2) one of various processing units at condensate tank batteries, natural gas processing plants, offshore production platforms, and transmission facilities, including underground storage sites. Available information indicates that, on average, there is one TEG dehydration unit per condensate tank battery[5] and two to four dehydration units (TEG, EG, or solid desiccant) per natural gas processing plant, depending upon throughput capacity and type of processing configuration.[6]

2.2.3 Tank Batteries

A tank battery refers to the collection of process equipment used to separate, treat, store, and transfer crude oil, condensate, natural gas, and produced water. These facilities typically handle crude oil, condensate, or natural gas prior to transfer to a refinery or natural gas processing plant.

Based on an analysis of two studies conducted for the American Petroleum Institute (API), the U.S. Environmental Protection Agency (EPA) estimates that there were approximately 94,000 tank batteries in 1989.[7,8,9] Over 85 percent of tank batteries,[10] or an estimated 81,000 facilities, are classified as black oil tank batteries. Black oil refers to crude oil that has little, if any, associated gas production.

The remainder, or an estimated 13,000 tank batteries, are classified as condensate tank batteries. Condensate, also referred to as retrograde gas, consists of hydrocarbons that are in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process.

2.2.4 Natural Gas Processing Plants

The main functions of natural gas processing plants include (1) conditioning the gas by separation of natural gas liquids (NGL) from field gas and (2) fractionation of NGL into separate components. As of January 1, 1993, there were approximately 700 natural gas processing plants.[11]

2.2.5 Offshore Production Platforms

Offshore production platforms are used to produce, treat, and separate crude oil, condensate, natural gas, and produced water from production fields in offshore areas. Processes and operations at offshore production platforms are similar to those located at onshore facilities except that (1) there is generally little or no storage capacity at offshore platforms and (2) these facilities have limited available space.

In 1993, the U.S. Department of Interior's Minerals Management Service (MMS) estimated that there were approximately 3,800 offshore production platforms and other structures in Federal waters.[12] The majority of these offshore production platforms and other structures are located in the Central and Western Gulf of Mexico, with a limited number located in other Federal waters. The offshore facilities located in Federal waters are under the jurisdiction of the MMS for air emissions regulation and not the EPA.[13] There are an estimated 300 offshore production platforms in State waters that are under the EPA's jurisdiction for air emissions regulation,[14] with the majority of these facilities located in the State waters offshore of Texas, Louisiana, and Alabama.

2.2.6 Natural Gas Transmission and Storage Facilities

The natural gas transmission and storage source category consists of gathering lines, compressor stations, and high-pressure transmission pipeline. It is estimated that there are approximately 1,900 compressor stations and over 480,000 kilometers (300,000 miles) of high-pressure transmission pipeline.[15,16] In addition, this sector includes over 300 underground storage sites.[17,18] These sites are typically used as temporary storage facilities to meet peak demand periods, particularly during colder weather months. Processes and operations that may occur at facilities in this source category include dehydration, storage, and pipeline pigging activities.

2.3 EXTRACTED STREAMS AND RECOVERED PRODUCTS

The extracted streams and recovered products from production wells have differing characteristics that can influence the level of HAP emissions generated by the emission points in the oil and natural gas production and natural gas transmission and storage source categories. This section (Section 2.3) describes the primary extracted streams and recovered products associated with the two source categories.

2.3.1 Crude Oil

Each producing crude oil and natural gas field has its own unique properties, in that the composition of the crude oil and the attendant natural gas and reservoir (field) characteristics are different from that of any other field.[19]

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene and have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons and may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.[20]

Another classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the API.[21] A heavy or paraffinic crude oil is typically one with an API gravity of 20° or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has an API gravity in the range of the high 30's to the low 40's.[22]

Crude oils recovered in the production phase of the petroleum industry may be referred to as live crudes. Live crudes contain entrained or dissolved gases which may be released during processing or storage, whereas dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.[23]

2.3.2 Condensates

Condensates (by standard industry definition) are hydrocarbons that are in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process.[24] Condensates, including volatile oils, typically have an API gravity in the 40 or greater degree range.[25] In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.3.3 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists in a gaseous phase or in solution with crude oil or other hydrocarbon liquids in natural underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), carbon dioxide (CO_2), mercaptans, and entrained solids.

Natural gas streams that contain threshold concentrations of H_2S are classified as sour gases and those with threshold concentrations of CO_2 are classified as acid gases. The processes by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating.

Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. Over 75 percent of total onshore natural gas production and nearly all of offshore natural gas production is classified as sweet.[26]

Natural gas may be classified as wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons.[27] Dry gas is (1) natural gas whose water content has been reduced through dehydration or (2) natural gas that contains little or no recoverable liquid hydrocarbons.[28]

2.3.4 Produced Water

Produced water is the water recovered from a production well.[29] Produced water is separated from the extracted hydrocarbon streams in the various production processes and operations described in this chapter.

2.3.5 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed NGL, natural gasoline, propane, butane, and liquefied petroleum gas (LPG). Definitions for these hydrocarbons can be found in Reference 27.

2.3.6 HAP Constituents

The primary identified HAP constituents associated with oil and natural gas production facilities include benzene, toluene, ethyl benzene, and mixed xylenes (collectively referred to as BTEX), and n-hexane.[30] In addition, reference has been made to the presence of 2,2,4-trimethylpentane (iso-octane), along with general reference to the presence of formaldehyde, acetaldehyde, and ethylene glycol in certain process and emission streams associated with oil and natural gas production.[31] Also, BTEX, carbon disulfide (CS_2), and carbonyl sulfide (COS) may be present in the tail gas streams associated with amine treating units and sulfur recovery units (SRUs).[32,33]

Table 2-1 lists HAP constituents and concentrations for extracted streams and recovered products for the two source categories. The primary sources of data used in the development of the listed HAP concentration estimates were (1) a summary of the industry responses to the EPA's Air Emission Survey Questionnaires,[34] (2) a data base, provided by GRI, of natural gas analyses from various source category operations,[35] and (3) a data base provided by API.[36]

2.4 DESCRIPTION OF INDUSTRY COMPONENTS

2.4.1 Production Wells

A well, as defined by API and used in this BID, is "... the hole-in-the-ground drilled from the point of entry at the earth's surface to the total depth of the hole ..." for the recovery of crude oil, condensate, and natural gas from formations below the earth's surface.[37] The recovered products and extracted streams from production wells are naturally or artificially brought to the surface where the hydrocarbon products (crude oil, condensate, and natural gas) are separated from produced water and other impurities, such as sand. Depending on the production characteristics of the well, and the recovery rates for crude oil, condensate, and natural gas, a well may or may not be put into production.

2.4.1.1 Wellhead Assembly. The wellhead assembly is the surface equipment used to control the production from a well and maintain production pressure. The wellhead assembly consists of the casinghead, tubing head, Christmas tree, and pressure gauges.[38] These components are described below.

The casinghead is the collection of fittings that support and hold the casing in place. The tubing head provides support for the tubing. The tubing head also seals off pressure between the casing and tubing, and provides connections for controlling the flow of produced fluids from the well. The Christmas tree is

TABLE 2-1. AVERAGE HAP COMPOSITION OF EXTRACTED STREAMS AND RECOVERED PRODUCTS

HAP	HAP composition of extracted stream or recovered product					
				Natural gas (ppmv)[b,c]		
	Crude oil (Weight %)	Condensate (Weight %)	Produced water (ppmw)[a]	Direct from wells	Wet	Other[d]
Benzene	0.25	0.99	10	104	88	5
Toluene	0.48	3.50	6	56	44	6
Ethyl benzene	0.12	0.48	6	6	4	1
Mixed xylenes	0.55	4.90	13	34	20	1
n-Hexane	1.50	2.80	4	420	410	66
BTEX[e]	1.40	9.90	35	200	160	13
BTEX and n-Hexane	2.90	13.00	39	620	570	79

a - Parts per million weight.

b - Based on a review of the data collected in the EPA's Air Emissions Survey Questionnaires and other references, the HAP content of the primary fractionated products recovered in natural gas processing operations (including propane, butane, and liquified petroleum gas) has been identified as insignificant.

c - Parts per million volume.

d - Natural gas processed and stored at natural gas transmission facilities and underground storage facilities.

e - Benzene, toluene, ethyl benzene, and mixed xylenes.

<u>Note</u>: Total BTEX and BTEX and n-hexane values have been rounded.

the collection of valves and fittings mounted on the casinghead and tubing head that controls the flow of product from the well.

2.4.1.2 Production Methods

2.4.1.2.1 Primary Recovery. Primary recovery of hydrocarbon streams and produced water from a production well occurs due to the natural pressures that exist in a production reservoir. After some period, the natural pressures within a reservoir will usually decline to a point where other secondary or enhanced recovery methods must be employed to maintain a well's production.

2.4.1.2.2 Secondary Recovery. When the natural pressure within a reservoir is not sufficient for production, secondary recovery methods or artificial lift methods (such as surface pumping units, gas lift, or subsurface pumping) are applied to increase the yield of recovered product. Waterflooding, pressure maintenance, sucker rod pumping, and gas lift are common methods of secondary recovery and artificial lift.[39]

2.4.1.2.3 Tertiary (Enhanced) Recovery. Tertiary, or enhanced, recovery methods are used to supplement natural reservoir forces when primary and secondary recovery of the product is no longer economical. These methods include chemical and thermal methods and gas injection.

2.4.2 Dehydration[40,41]

As stated above, once the natural gas has been separated from liquid materials and products, residual entrained water vapor is removed from the natural gas stream by dehydration in order to (1) meet contract sales specifications, (2) limit hydrate formation, or (3) improve fuel heating values.

The formation of hydrates within a natural gas stream is promoted by natural gas at or below its water dew point, with liquid water present. Temperatures below the hydrate formation temperature, high operating pressures, high velocity or agitation through piping or equipment, presence of a small seed crystal of hydrate, and presence of H_2S or CO_2 (which are more soluble in water than hydrocarbons) also influence the formation of hydrates in natural gas pipelines.[42] In addition, hydrate formation is more often encountered during extended periods of cold weather.

Dehydration of natural gas may occur several times prior to delivery to the final consumer. Locations where dehydration may occur include (1) the production well site, (2) the tank battery, (3) the natural gas processing plant, (4) removal from underground storage facilities, (5) transmission compressor stations, (6) industrial and utility customer meter stations, and (7) at or after the transmission to distribution custody transfer stations, which is the point where natural gas typically changes ownership from a transmission company to a distribution company for delivery to the final consumer. This final point of custody transfer is typically referred to as the city gate.

Prior to the dehydration process in selected cases, facilities may prevent hydrate formation by injecting ethylene glycol or methanol into the natural gas stream, or using line heaters to heat the process stream.

2.4.2.1 Glycol Dehydration. The most widely used natural gas dehydration process is the glycol dehydration process. Glycol dehydration is an absorption process in which a liquid absorbent, a glycol, directly contacts the natural gas stream, which is circulated counter current to the glycol flow, and absorbs water vapor in a contact tower or absorption column.

The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol separator (GCG separator or flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. If the system includes a flash tank, the gas separated from the rich glycol is typically either (1) recycled to the header system, (2) used for fuel, or (3) used as a stripping gas. Any hydrocarbons that condense can be removed as a separate stream from the glycol.

The regenerated or lean glycol is recirculated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler stack. A flow diagram of a basic glycol dehydration unit is presented in Figure 2-1.

2.4.2.2 Solid Desiccant Dehydration. Solid desiccant dehydration uses adsorption to remove water. Adsorption refers to the surface phenomena in which a gas or liquid is attracted to the surface of a solid. Solid desiccant dehydration is generally used when large dew-point depressions are required or when an extremely dry gas is desired.[43]

Common solid desiccants used for natural gas dehydration include silica-base beads, activated alumina, silica-gel, alumina-gel balls, activated bauxite, and molecular sieves.[44] Desiccant life ranges from one to five years before the desiccant must be replaced.

Solid desiccant dehydration requires two or more adsorption towers for continuous operation because the solid desiccant within a tower must be regenerated when desiccant saturation is reached. Therefore, when one tower is undergoing regeneration, the other is switched into operation.

Regeneration may be accomplished by lowering the pressure, or increasing the temperature of the tower or both. Hot regeneration gas is typically circulated through the towers, and then cooled through a heat exchanger that condenses water removed from the tower packing.

The condensed water proceeds through a scrubber to recover hydrocarbons. The remaining gas stream is recycled and mixed with the incoming wet natural gas stream.[45]

2.4.3 Tank Batteries[46,47]

A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from production wells enter the tank battery through the production header, which may collect product from many wells.

Process equipment at a tank battery may include separators, dehydrators, heater treaters, free water knockouts (FWKOs), gun

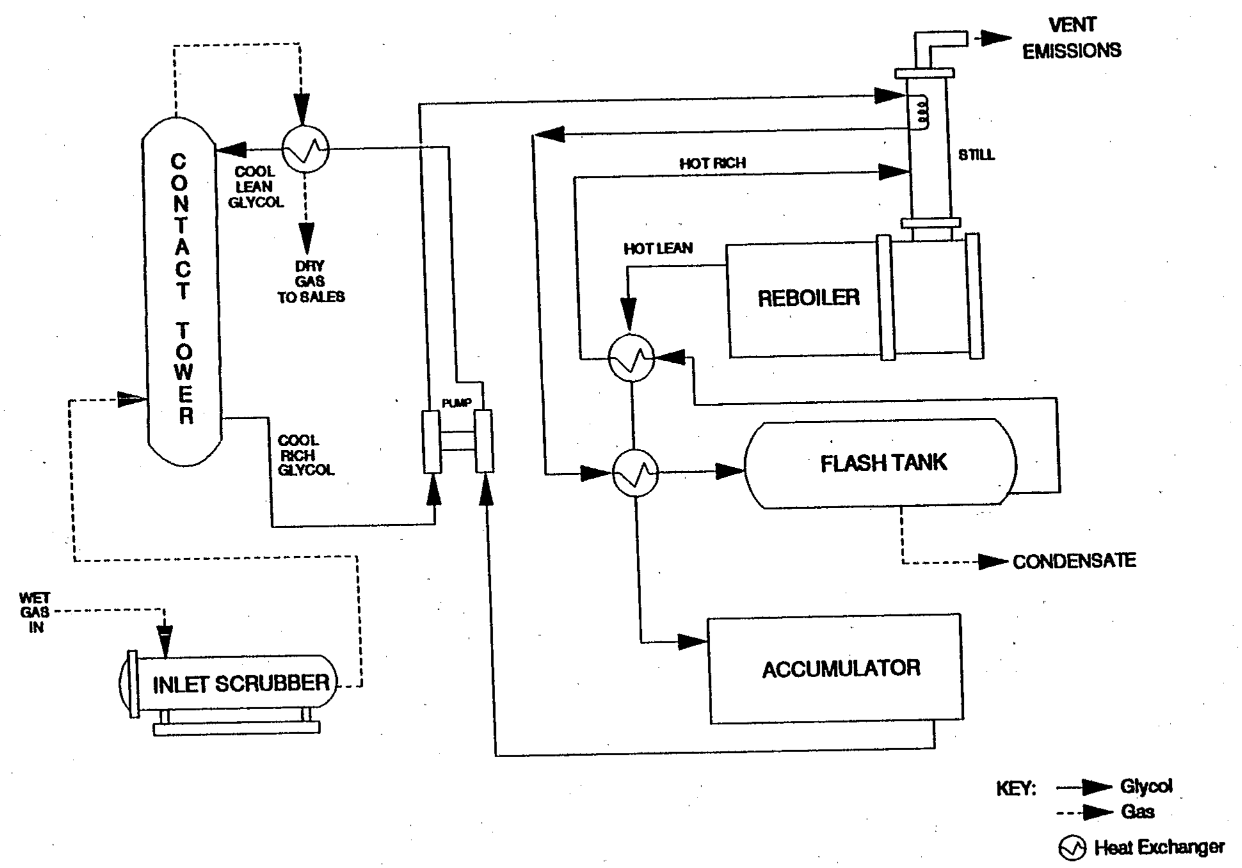

Figure 2-1. Flow Diagram of Basic Glycol Dehydration Unit

barrel separation tanks, storage tanks, and lease automatic custody transfer (LACT) units. Each piece of equipment is addressed below.

2.4.3.1 Separators. The separation of hydrocarbon products from basic sediment and water (BS&W) is accomplished by production separators. Basic sediment refers to the gas, sand, sediment, and other impurities mixed with the oil.

Depending on product characteristics, production separators may be two-phase or three-phase separators. Two-phase separators separate the product into liquid and gas streams. The liquid stream contains crude oil and produced water. Three-phase separators separate the product into crude oil or condensate, natural gas and other gas streams, and produced water.

Multi-well facilities may also include test separators, which operate in parallel to production separators, to determine the production rate, composition, quality, and production characteristics of individual wells.

2.4.3.2 Dehydration. The dehydration processes that may occur at tank batteries are the same as those discussed in detail in Section 2.4.2 of this BID.

2.4.3.3 Heater Treaters. Heater treaters are pressure vessels used to break tight emulsions and remove water and gases from crude oil. A heater treater is a combination of a heater, a free water knockout, and an oil and gas separator.

The inlet emulsion enters the heater treater at the top, which allows the release of gas entrained in the liquid to travel to the vapor space at the top of the column. The emulsion flows to the bottom of the vessel through a downcomer pipe. Heat is applied to the emulsion at the bottom of the vessel. Some facilities add a chemical demulsifier to the process stream to assist in the breaking of emulsions.

2.4.3.4 Free Water Knockouts (FWKOs). If large amounts of water are produced with the crude oil, additional separation may be accomplished by use of a FWKO. Removing the free water early in the separation process reduces the heating requirements and design throughput requirements of the subsequent field equipment.

FWKOs may incorporate two-phase (liquid/gas) or three-phase (crude oil/water/gas) separation. Heat or chemicals may be applied to the incoming stream prior to the FWKO to assist in the separation process.

2.4.3.5 Gun Barrel Separation Tanks. Gun barrel separation tanks, or wash tanks, are cylindrical vessels operating at atmospheric pressure that separate the production stream emulsion into crude and produced water. Gun barrels may be used for unstable emulsions that will naturally separate due to gravity, if adequate settling time is provided.

2.4.3.6 Storage Tanks and Other Vessels. Crude oil from the separation processes is typically directed to storage tanks (or other storage vessels) for temporary storage. The large majority of storage tanks used at crude oil production facilities are fixed-roof storage tanks. In addition, over 95 percent of the storage tanks used at tank batteries range in size from 200 to 1,000 barrel capacities.[48] Vapor losses from the storage tanks are either vented to the atmosphere or captured by a vapor recovery device.

Storage tanks are also used for temporary storage of produced water and slop oil. Produced water is typically disposed of in injection wells, where water is injected back into the producing formation for enhanced recovery applications, transferred off-site for treatment and disposal, or (in very limited cases) used for beneficial purposes.

Slop oil is oil that does not meet quality specifications. This oil is either (1) recycled into the separation and treatment process or (2) sold to an oil reclamation facility for treatment and recovery of residual crude oil product.

Tank batteries may have various types of surface impoundments (pits and sumps) located on-site. These pits and sumps are typically classified as emergency or production. Most pits and sumps are classified as emergency pits/sumps and are only used during process upset situations.[49]

However, production pits and sumps may also be used for separation processes at tank batteries. Most of production surface impoundments are located in selected heavy crude oil production areas of California.[50]

2.4.3.7 Custody Transfer. A LACT unit is usually used to meter the amount of crude oil or condensate produced at a tank battery. A LACT unit is an automated device that decreases the need for the presence of personnel to handle the transfer of crude oil or condensate. The unit records the amount of product transferred and product temperature. Automatic sampling can be incorporated into the LACT unit to determine product quality.[51,52,53]

Transfer of extracted streams or recovered products is usually accomplished in pipelines. However, transfer may also involve loading crude oil, condensate, or produced water into tank trucks, railcars, and barges through the use of splash loading or submerged fill techniques.

2.4.4 Natural Gas Processing Plants

Natural gas produced from the well is separated from hydrocarbon products (crude oil and condensate) and BS&W at tank batteries and then transferred, via pipeline, to a natural gas processing plant. Typical processes and operations at natural gas processing plants are described below. Detailed descriptions of processes and operations at natural gas processing plants are presented in References 41 and 42.

As stated above, the primary functions of a natural gas processing plant include (1) conditioning the natural gas by separation of NGL from the field gas and (2) fractionation of NGL into separate components. NGL may be fractionated into ethane, propane, butanes, and natural gasoline products. These products are then transported, primarily in pipeline systems, to refineries and other points of transfer or sale.

2.4.4.1 Dehydration. Generally, natural gas is dehydrated prior to the other processes at a natural gas processing plant. The natural gas dehydration process that may occur at a natural gas processing plant is the same as natural gas dehydration processes that may occur at other locations. Dehydration processes are discussed in Section 2.4.2 of this BID.

2.4.4.2 Sweetening and Sulfur Recovery Processes. As stated earlier in Section 2.3.3, some production fields produce sour or acid gases. Sour gas is natural gas that contains threshold concentrations of H_2S. Hydrogen sulfide is a toxic, corrosive substance which is usually removed by sweetening operations that occur immediately after the natural gas has been separated and dehydrated. Acid gases are those that contain threshold concentrations of CO_2.

The most widely used method of sweetening these gases is amine treating. Amine treating uses an amine/water solution to absorb the H_2S and CO_2 from the natural gas stream. The rich amine solution is then regenerated by steam stripping to remove the sour gas. The lean amine is recirculated to the absorber. The system is similar in design to a glycol dehydration unit.

Natural gas fields may produce enough H_2S so that it is beneficial to recover sulfur. Sulfur recovery may be used at natural gas processing facilities and offshore production platforms. After the H_2S is removed from the natural gas stream in the sweetening process, the gas is introduced into a SRU for further processing. At the sulfur recovery plant, the sulfur in the H_2S is converted to elemental sulfur. The recovered sulfur can be either sold commercially or disposed of properly. Any CO_2 contained in the gas stream will pass through the SRU unaltered and vented with the tail gas. Concentrated CO_2 streams from the sweetening process may be vented or flared to destroy any residual hydrocarbons.

2.4.4.3 Conditioning Processes. Natural gas processing plants may be characterized by the type of conditioning process used at the plant. The conditioning processes most often used for separation in natural gas processing plants include cryogenic-expansion, refrigeration, refrigerated absorption, cryogenic-Joule-Thomson, absorption, adsorption, and compression.

Each conditioning process recovers the NGLs for further treatment. Methane and other gases are removed from the NGL stream prior to the fractionation process.

2.4.4.4 Fractionation. After separating the NGL from the field gas, the NGL are separated into individual components, or desired products, by a process called fractionation. Fractionation uses the difference in volatility of the individual components to separate the mixture.

Depending on the composition of the NGL mixture, the fractionation system may include a deethanizer, depropanizer, and debutanizer in series. These units are named according to the desired product coming off the top of each fractionation unit. Primary products include ethane, propane, butane, LPG, mixed NGL, and natural gasoline.

2.4.4.5 Product Transfer and Metering. The primary method used for transfer of gaseous and liquid products from natural gas processing plants is by pipelines. However, transfer may include loading of condensate or natural gasoline into tank trucks, railcars, and barges through the use of splash loading or submerged fill techniques.

The most common device used for measuring natural gas is the orifice meter. A properly installed and maintained orifice meter will have an overall accuracy of plus or minus 2 percent.[54]

2.4.5 Offshore Production Platforms[55,56]

The processes and equipment at offshore production platforms that are used to produce, treat, and separate crude oil, natural gas, and produced water in offshore areas are basically identical to those at facilities located onshore, except that these operations take place within a confined space.[57] Offshore production platforms are constructed just large enough to accommodate the necessary equipment and support facilities to safely accomplish their tasks. This is done because the offshore production platforms are substantially more expensive to construct than onshore facilities. Most offshore production platforms have multiple deck areas stacked on top of each other to increase the amount of work space. Detailed descriptions of processes and operations at offshore production platforms are presented in References 47 and 55.

Offshore production platforms may be bottom supported, floating, or semi-submersible structures. They can be classified as either gathering platforms or central production platforms. Gathering platforms receive production from wells, separate the production into liquid and gas streams, and then transfer these streams by pipeline to a central production platform or an onshore production facility. At central production platforms, the liquid and gas streams undergo treatment, separation, and (sometimes) storage. Gas treatment may include dehydration prior to transfer to an onshore facility.

Produced water that is recovered from the production streams may be disposed of overboard if it meets or is below certain criteria of total oil and grease concentrations. In addition, it may also be reinjected into a producing zone within a reservoir for pressure maintenance and enhanced recovery operations.

2.4.6 Compressor Stations

Compressor stations are facilities that supply energy, in the form of increased pressure, to move natural gas in transmission pipelines or into underground storage.[58] Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion (IC) engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure.

2.4.7 Underground Storage

Underground storage facilities are subsurface facilities utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing. Load balancing is the process of equalizing the receipt and delivery of natural gas.[59] Processes and operations that may be located at underground storage facilities include, but are not limited to, compression and dehydration.

2.4.8 Other Processes and Operations

An operation that may occur throughout these source categories is pipeline pigging. Pipeline pigging involves inserting a pig, which is a cylindrical device made with pliable disks that fit the internal diameter of a pipeline, into a pipeline for the purpose of cleaning the line. Pipeline pressure moves the pig through the line. Water vapor and hydrocarbon liquids, such as condensate, may condense and restrict or block pipeline flow, thus, leading to the necessity of pigging.

As the pig approaches the receiving station of a pipeline, collected fluids (including hydrocarbon liquids) are drained to a sump or other storage vessel that is usually referred to as a slug catcher.[60] Pigging of pipelines is a common practice for pipelines from offshore production platforms because of the low seabed temperatures encountered by the offshore pipelines, which causes liquids to condense. Pigging of pipelines at onshore facilities may be utilized during seasons with lower ambient temperatures, such as fall and winter.

2.5 HAP EMISSION POINTS

2.5.1 HAP Emission Points

The three identified HAP emission points that may be associated with oil and natural gas production and natural gas transmission and storage include (1) process vents, (2) storage vessels, and (3) equipment leaks. Table 2-2 presents the basic facilities described above along with the identified HAP emission points.

2.5.1.1 Process Vents. A process vent is a vent from a process unit that discharges a gas stream into the atmosphere during operation. Gas streams from process vents may be discharged directly to the atmosphere or discharged through a product recovery device.

TABLE 2-2. BASIC FACILITY TYPES AND ASSOCIATED HAP EMISSION POINTS

Facility type	HAP emission points
Stand-alone glycol dehydration unit	Glycol dehydration unit reboiler vent and flash tank vent
Condensate tank battery	Glycol dehydration unit reboiler vent and flash tank vent Storage vessels
Natural gas processing plant	Glycol dehydration unit reboiler vent and flash tank vent Storage vessels Equipment leaks
Offshore production platform in State waters	Glycol dehydration unit reboiler vent and flash tank vent
Natural gas transmission and underground storage	Glycol dehydration unit reboiler vent and flash tank vent

The glycol dehydration unit reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water but also absorbs selected hydrocarbons, including BTEX and n-hexane. The water and hydrocarbons are boiled-off in the reboiler and, unless a control device is present, vented to the atmosphere.

The GCG separator or flash tank is also a potential HAP process vent emission point. HAP emissions will occur if the glycol dehydration unit includes a flash tank in the system design and any separated gases are vented to the atmosphere, instead of being either (1) recycled to the header system, (2) used for fuel, or (3) used as a stripping gas.

A process vent associated with natural gas sweetening operations is the acid gas vent. This stream may contain high concentrations of hydrogen sulfide and carbon dioxide. In addition, BTEX, CS_2, and COS may be present in this stream. If high concentrations of H_2S are present, a sulfur recovery plant is installed to produce elemental sulfur. Otherwise, the stream is flared.

Recent research conducted by GRI indicates the potential for significant HAP emissions (primarily BTEX) from amine-based gas sweetening processes.[61,62] The EPA is conducting followup to this research in an effort to determine emission levels of this potential HAP process vent emission point.

2.5.1.2 Storage Vessels. Crude oil and condensate are typically stored in fixed-roof storage tanks. Emissions are a result of working, breathing, and flash losses.

Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects.

Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production source category, flashing occurs when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emissions will occur in the storage stage.[63] Temperature of the liquid may also influence the amount of flash emissions.

In addition, HAP emissions may occur when hydrocarbon liquids, collected by slug catchers[64] during pipeline pigging (cleaning) operations, are transferred to storage tanks or other vessels.[65] HAP emissions may occur with the flashing of these hydrocarbon liquids due to a reduction in pressure as collected fluids are drained to a sump or other storage vessel.

2.5.1.3 Equipment Leaks. Equipment leaks (fugitive emissions) are emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. The amount of HAP emissions from equipment leaks is proportional to (1) the type and number of equipment components and (2) the concentration of HAP constituents of the stream in the components.

Since tank batteries are usually small facilities as compared with other industrial operations, they are generally characterized by a smaller number of components. Natural gas processing plants, especially those using refrigerated absorption, tend to have a large number of components.

2.6 BASELINE EMISSION ESTIMATES

2.6.1 Basic Methodology

Based on available information, estimates were developed for HAP, volatile organic compound (VOC), and methane[66] emissions from identified HAP emission points in the oil and natural gas production and natural gas transmission and storage source categories. Estimates of emissions before the implementation of a national emissions standard for hazardous air pollutants (NESHAP) are referred to as baseline emission estimates.

Table 2-3 presents baseline HAP, VOC, and methane national emission estimates for each facility type in the oil and natural

TABLE 2-3. BASELINE NATIONAL EMISSION ESTIMATES FOR ALL IDENTIFIED HAP EMISSION SOURCES IN THE OIL AND NATURAL GAS PRODUCTION SOURCE CATEGORY (MAJOR AND AREA HAP SOURCES)

Facility type	Baseline emission estimates (Megagrams per year)		
	HAP	VOC	Methane
Glycol dehydration units[a]	55,000	130,000	16,000
Storage tanks at condensate tank batteries	6,300	20,000	11,000
Natural gas processing plants[b]	3,200	10,000	7,000
Total	65,000	160,000	34,000

a - Includes estimated emissions from all glycol dehydration units, including stand alone units and those located at condensate tank batteries, natural gas processing plants, and offshore production platforms in State waters. Does not include those units in the natural gas transmission and storage source category.

b - Only includes emissions from storage tanks and equipment leaks.

<u>Note</u>: Numbers may vary due to rounding.

gas production source category. These estimates are based on model plant parameters that have been developed for the various types of facilities in this source category (see Chapter 4.0 of this BID). Tables 2-4 and 2-5 present a breakdown of these emissions based on potential major versus area source HAP emission designations for the oil and natural gas production source category.

Table 2-6 presents baseline HAP, VOC, and methane national emission estimates for each basic facility type in the natural gas transmission and storage source category. These estimates are based on model TEG dehydration unit parameters that have been developed for various facility types in this source category (see Chapter 4.0 of this BID). Tables 2-7 and 2-8 present a breakdown of these emissions based on potential major versus area source HAP emission designations for the natural gas transmission and storage source category.

These estimates were developed using a model plant approach. In this approach, emissions were first estimated for model plants selected to characterize the range of facilities in the source categories. National estimates were developed by extrapolating from model plant estimates. The methodology for developing nationwide emission estimates is further described in Chapter 5.0 and Appendix B of this BID.

2.6.2 Facility Emission Estimates

For glycol dehydration units, emissions are based on results generated from GRI-GLYCalc (Version 3.0).[67] This is a personal computer-based screening program developed by GRI for evaluating HAP and VOC emissions from TEG and EG dehydration units.

VOC emissions from production storage tanks have been evaluated previously and these factors have been applied to the estimated populations of these tanks in these source categories and used as the basis for estimating HAP and methane emissions from storage tanks.[68] Fugitive emissions from components are

TABLE 2-4. BASELINE NATIONAL EMISSION ESTIMATES FOR IDENTIFIED MAJOR HAP EMISSION SOURCES IN THE OIL AND NATURAL GAS PRODUCTION SOURCE CATEGORY

Facility type	Baseline emission estimates (Megagrams per year)		
	HAP	VOC	Methane
Glycol dehydration units[a]	36,000	85,000	6,200
Storage tanks at condensate tank batteries	1,800	5,900	3,200
Natural gas processing plants[b]	770	2,500	1,800
Total	39,000	94,000	11,000

a - Includes estimated emissions from all glycol dehydration units, including stand alone units and those located at condensate tank batteries, natural gas processing plants, and offshore production platforms in State waters designated as or located at major sources of HAP emissions. Does not include those units in the natural gas transmission and storage source category.

b - Only includes emissions from storage tanks and equipment leaks.

<u>Note</u>: Numbers may vary due to rounding.

TABLE 2-5. BASELINE NATIONAL EMISSION ESTIMATES FOR IDENTIFIED AREA HAP EMISSION SOURCES IN THE OIL AND NATURAL GAS PRODUCTION SOURCE CATEGORY

Facility type	Baseline emission estimates (Megagrams per year)		
	HAP	VOC	Methane
Glycol dehydration units[a]	19,000	43,000	9,600
Storage tanks at condensate tank batteries	4,500	14,000	8,100
Natural gas processing plants[b]	2,400	7,800	5,000
Total	26,000	65,000	23,000

a - Includes estimated emissions from all glycol dehydration units, including stand alone units and those located at condensate tank batteries, natural gas processing plants, and offshore production platforms in State waters that are not designated as potential major sources of HAP emissions. Does not include those units in the natural gas transmission and storage source category.

b - Only includes emissions from storage tanks and equipment leaks.

Note: Numbers may vary due to rounding.

TABLE 2-6. BASELINE NATIONAL EMISSION ESTIMATES FOR ALL IDENTIFIED HAP EMISSION SOURCES IN THE NATURAL GAS TRANSMISSION AND STORAGE SOURCE CATEGORY (MAJOR AND AREA HAP SOURCES)

Facility type	Baseline emission estimates (Megagrams per year)		
	HAP	VOC	Methane
Glycol dehydration units[a]	320	4,200	170

a - Includes estimated emissions from all glycol dehydration units in the natural gas transmission and storage source category.

Note: Numbers may vary due to rounding.

TABLE 2-7. BASELINE NATIONAL EMISSION ESTIMATES FOR IDENTIFIED MAJOR HAP EMISSION SOURCES IN THE NATURAL GAS TRANSMISSION AND STORAGE SOURCE CATEGORY

Facility type	Baseline emission estimates (Megagrams per year)		
	HAP	VOC	Methane
Glycol dehydration units[a]	120	1,500	59

a - Includes estimated emissions from all glycol dehydration units in the natural gas transmission and storage source category designated as or located at major sources of HAP emissions.

Note: Numbers may vary due to rounding.

TABLE 2-8. BASELINE NATIONAL EMISSION ESTIMATES FOR IDENTIFIED AREA HAP EMISSION SOURCES IN THE NATURAL GAS TRANSMISSION AND STORAGE SOURCE CATEGORY

Facility type	Baseline emission estimates (Megagrams per year)		
	HAP	VOC	Methane
Glycol dehydration units[a]	200	2,700	110

a - Includes estimated emissions from all glycol dehydration units in the natural gas transmission and storage source category that are not designated as potential major sources of HAP emissions.

Note: Numbers may vary due to rounding.

based on (1) standard equipment leak emission factors[69] and (2) estimated component count distributions.

HAP emissions associated with pipeline pigging operations were not estimated due to the lack of data on (1) how often this procedure occurs in this industry and (2) the quantity of hydrocarbons transferred from slug receivers to fixed-roof storage tanks or other storage vessels. As stated earlier, pipeline pigging will occur more often (1) at offshore production operations and (2) during the winter months.

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3.0 CONTROL OPTIONS AND PERFORMANCE OF CONTROLS

3.1 INTRODUCTION

This chapter addresses control options applicable to identified hazardous air pollutant (HAP) emission points in the oil and natural gas production and natural gas transmission and storage source categories. As discussed in Chapter 2.0, HAP emission points in these source categories include (1) process vents, (2) storage vessels, and (3) equipment leaks. Control options that may be applicable to each of these identified HAP emission points are described below.

In addition, performance (measured as control efficiency) of each control option was estimated based on best engineering judgement and referenced literature. Referenced control efficiencies of control options for volatile organic compounds (VOC) emission points were deemed applicable for these HAP emission points because of similar chemical properties of the HAP constituents and VOC. These control efficiencies are consistent with those demonstrated for similar applications.

3.2 PROCESS VENTS

As discussed in Chapter 2.0, the glycol dehydration unit reboiler vent is the primary identified process vent HAP emission point in these source categories. Several control techniques can be used to reduce emissions from this process vent emission point. These include vapor recovery (condensation), combustion, and pollution prevention.

3.2.1 <u>Vapor Recovery</u>

Condensation is the most common vapor recovery control technique used for glycol dehydration unit reboiler vents.

Condensers convert condensable components in the vapor phase to the liquid phase by reducing the temperature of the process vent stream. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that may increase hydrocarbon liquid production.

In addition, the dry non-condensable off-gas from the condenser may be used as fuel.[1] If the off-gas is not used as fuel, it may be recycled into the production process or directed to a flare, incinerator, or other combustion device. Since combustion devices are sensitive to the amount of water content in the process stream, condensers are typically installed prior to combustion processes.

The HAP emission reduction efficiency of condensers varies depending upon application.[2] Some glycol dehydration units use gas condensate glycol separators (GCG separators or flash tanks) prior to the reboiler to separate entrained gases, primarily methane and ethane, from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, this process vent may also be vented directly to the atmosphere.

Flash tanks typically enhance a condenser's emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream introduced to the condenser. Thus, condensers applied to those units with flash tanks typically achieve higher emission reduction efficiencies as compared to condensers used at glycol dehydration units that do not incorporate flash tanks in their system design.

Condensers, used in conjunction with flash tanks incorporated into the glycol circulation loop, typically achieve 95 percent HAP/VOC emission reduction.[3] Condensers used on glycol dehydration units without flash tanks incorporated into the glycol circulation loop may have HAP/VOC reduction efficiencies as low as 50 percent.[4]

3.2.2 Combustion

Destruction of the HAP components in a process stream may be accomplished by combustion. Combustion equipment includes flares, thermal incinerators, industrial boilers, and process heaters.

Flares are a common combustion device found at oil and natural gas production facilities and at some natural gas transmission operations. A flare is an open combustion device where the air around the flame provides the necessary oxygen for combustion. The flare combustion efficiency depends on vent gas flammability, auto-ignition temperature, heating value, density, and mixing of the components in the combustion zone.[5] Facilities that treat sour gas sometimes use flares to destroy hydrogen sulfide. The hydrogen sulfide is oxidized to form sulfur dioxide, a less toxic compound.

Flares were evaluated as a control option for glycol dehydration unit reboiler vents. Because large amounts of water are usually present in the glycol dehydration unit reboiler vent stream, problems with incomplete combustion may occur. Flares are most suitable when used in combination with condensers to combust the non-condensable stream, or when vapor collected from storage tanks must be destroyed.

Flares may achieve greater than a 98 percent HAP/VOC reduction efficiency.[6] Based on an emission reduction efficiency of 95 percent for a condenser and a 98 percent emission reduction efficiency for the combustion device, directing the non-condensable stream through a closed-vent system to a combustion device in conjunction with a condenser can achieve a HAP emission reduction of 99 percent or greater.

3.2.3 Pollution Prevention

System optimization is a pollution prevention technique that may be an applicable control option for some glycol dehydration units. System optimization involves the adjustment of glycol dehydration unit process variables to reduce emissions.

For example, glycol dehydration units may circulate more glycol than is necessary to meet contract specifications. Circulation rates of 2.0 to 3.0 gallons of glycol per pound of water removed are recommended rates that are usually adequate to meet typical contract pipeline specifications for water content in the natural gas stream.[7] Based on a recent report from the American Petroleum Institute (API), the national average glycol circulation rate for triethylene glycol (TEG) dehydration units is 5.9 gallons of glycol per pound of water removed.[8]

This control option can be applied to glycol dehydration units to improve process performance and reduce associated HAP emissions from glycol dehydration unit reboiler vents. High glycol circulation rates increase the amount of benzene, toluene, ethyl benzene, and mixed xylenes (collectively referred to as BTEX) and n-hexane absorbed from the natural gas stream. Therefore, more BTEX and n-hexane are released from the glycol dehydration unit reboiler vent during regeneration of the glycol from these units that over circulate glycol. Thus, optimizing the glycol dehydration process by adjusting the glycol circulation rate may reduce associated HAP emissions.[9]

3.3 STORAGE VESSELS

The majority of storage tanks and vessels used in these source categories are fixed-roof storage tanks. Most of the storage tanks used in the oil production segment (over 95 percent) have shell capacities in the range of 200 to 1,000 barrels.[10]

Internal floating roofs typically cannot be retrofitted to these tanks because internal friction between the interior of these small diameter tanks will inhibit proper operation of the floating roof. In addition, the small quantities of liquid stored in these tanks do not provide sufficient buoyancy to support floating roofs.[11]

Emissions from fixed-roof storage tanks may be reduced by using a vapor recovery unit (VRU) to capture escaping hydrocarbon vapors. Once the vapor from the tanks is captured, it may be returned to the natural gas line for processing or be routed to a control device.

Natural gas processing plants typically use pressurized storage tanks to store light natural gas liquids (ethane, propane, butane) and natural gasoline and to suppress evaporative losses.[12] However, hydrocarbons, including those collected in slug receivers during pipeline pigging operations, may be transferred to non-pressurized fixed-roof storage vessels.[13]

3.4 EQUIPMENT LEAKS

The primary control option used to reduce emissions from equipment leaks is a leak detection and repair (LDAR) program. A LDAR program includes equipment monitoring (usually with a leak detection instrument) on a prescribed schedule and the repairing of equipment in instances where a leak is detected. Aspects of a LDAR program are discussed below.

An alternative control option to a LDAR program is modifying or replacing existing equipment to reduce emissions. This option is also discussed below.

3.4.1 Leak Detection and Repair

LDAR programs involve regularly scheduled instrument monitoring of equipment to determine the presence of leaks. Once a leak is detected, the equipment is tagged and repaired on a prescribed schedule.

The major factors affecting the control efficiency of a LDAR program are (1) the frequency of equipment inspection and (2) the leak definition that triggers repair requirements. Another important component of a LDAR program is that it provides that accurate records be kept on leak frequencies and repairs.

LDAR programs may include performance specifications for individual equipment types. An example performance specification might state that "... if 2 percent or more of the valves in light liquid service leak more than 10,000 parts per million by volume (ppmv) of VOC, then more frequent inspection is required."

Three different levels of LDAR were evaluated as options for the oil and natural gas production source category. The three control options are summarized below. Detailed descriptions of the LDAR programs are provided in References 14 through 17.

3.4.1.1 Summary of Control Techniques Guideline. The Control Techniques Guideline (CTG) document, Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants[14] provides guidance for leak detection and repair at plants located in ozone non-attainment areas. The guideline includes quarterly monitoring of pressure relief valves, valves in light liquid and vapor service, pumps in light liquid service, and compressors. Pumps in light liquid service are to be visually inspected on a weekly basis. Caps are to be installed on open-ended lines when not in use. Equipment servicing process streams with a VOC concentration of 1.0 percent by weight or greater are subject to the requirements of the CTG.

3.4.1.2 Summary of New Source Performance Standards. The New Source Performance Standard (NSPS) for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants[15] applies to such plants with affected equipment constructed or modified after January 20, 1984. The NSPS leak detection and repair program requires monthly monitoring of pressure relief valves, valves in light liquid and vapor service, and pumps in light liquid service. Valves in gas/vapor service and light liquid service for which a leak is not detected for two consecutive months may be monitored quarterly.

Weekly visual inspection of pumps in light liquid service is also required. In addition to capping open-ended lines, capture and vent systems are to be installed on compressor seals. Equipment servicing process streams with a VOC concentration of 10 percent by weight or greater are subject to the requirements of the NSPS.

3.4.1.3 Summary of Equipment Leak Requirements Under the Hazardous Organic NESHAP Regulatory Negotiation. The Hazardous Organic NESHAP (HON) Regulatory Negotiation[16] was developed for the synthetic organic chemical manufacturing industry. The provisions of this regulation include monthly monitoring of valves in light liquid and vapor service and pumps in light liquid service. Pumps in light liquid service are to be visually inspected on a weekly basis.

The HON Regulatory Negotiation also phases-in more stringent requirements for valves and pumps by using a combination of LDAR programs and performance levels. In addition to capping open-ended lines and vent systems on compressor seals, pressure relief valves are to be equipped with rupture disk assemblies and sampling lines are to be equipped with closed-purge systems. Equipment servicing process streams with a HAP concentration greater than 5.0 percent by weight are subject to the requirements of the HON Regulatory Negotiation.

3.4.2 Equipment Modification

An equipment modification for reducing equipment leak emissions may include the installation of additional equipment, or the replacement of existing equipment. Equipment modification is an alternative to LDAR programs for reducing emissions from equipment leaks. Examples of equipment modification or replacement are described below. Control efficiencies are cited from the EPA's "Protocol for Equipment Leak Emission Estimates."[17]

3.4.2.1 Valves. Emissions from valves can be reduced by replacing old valves with bellows valves and diaphragm valves (sealless valves). The control efficiency for sealless valves is estimated to be 100-percent.

3.4.2.2 Pumps and Compressors. Emissions from pumps and compressors may be collected by a closed-vent system and routed to a control device. The control efficiency of this system depends on the percentage of vapors collected and the efficiency of the control device. Pumps and compressors may also be equipped with dual mechanical seals with barrier fluid at a higher pressure than the process stream. The control efficiency of the dual mechanical seal system is approximately 100-percent.

3.4.2.3 Sampling Connections. Emissions from sampling connections can be reduced by installing a closed-loop system, which has an estimated control efficiency of 100-percent. A closed-loop sampling system collects the purged process fluid and transfers it to a control device or directs it back into the process stream.

3.4.2.4 Pressure-Relief Devices. To reduce emissions from pressure-relief devices, rupture disks may be installed. Rupture disk systems are estimated to have a 100 percent control efficiency. Emissions from pressure-relief devices may also be collected by a closed-vent system and routed to a control device. The control efficiency of this option is dependent on the percentage of vapors collected and the efficiency of the control device.

3.4.2.5 Open-Ended Lines. Emissions from open-ended lines can be reduced 100 percent by installing a plug, cap, or second valve on the open end.

3.4.2.6 Connectors (Flanges). If allowable in the process, connectors may be welded together to obtain a 100-percent control efficiency.

3.5 CONTROL OPTIONS AND HAP EMISSION POINTS

A summary of control options applicable to the identified HAP emission points at facilities in the oil and natural gas production and natural gas transmission and storage source categories are identified in Table 3-1. This table includes estimated emission reduction efficiencies for each applicable control option. These reduction efficiencies are based on the control level achieved through reduction of VOC emissions, unless otherwise specified.

TABLE 3-1. SUMMARY OF CONTROL OPTIONS PER HAP EMISSION POINT

HAP emission point	Control options	Estimated control efficiency (%)[a]
Glycol reboiler vent	Condenser, with flash tank in dehydration system design	95
	Condenser without flash tank	50
	Combustion	98
	System optimization	Variable
Open-top storage tank	Cover plus vapor collection and redirect	99
Fixed-roof storage tank	Vapor collection and redirect	95[b]
Equipment leaks	CTG[c] NSPS[d] HON[e]	65 70 88

a - Estimates based on referenced literature and engineering judgement.

b - Vapor redirected to a control device operating at a 95 percent control efficiency.

c - Estimated level of control based on Reference 13.

d - Estimated level of control based on Reference 14.

e - Estimated level of control based on Reference 15.

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4.0 MODEL PLANTS

4.1 INTRODUCTION

Due to the large number of facilities in the oil and natural gas production and natural gas transmission and storage source categories, and the time and resources it would take to gather information on each facility, it was not possible to simulate the effects of applying control options at all potentially impacted facilities in these source categories. Therefore, an alternative approach involving the use of model plants was taken to estimate plant-level and nationwide impacts of control options. The model plants developed for these source categories are described in this chapter.

A model plant does not represent any single actual facility, but rather it represents a range of facilities with similar characteristics that may be impacted by a standard. Each model plant is characterized in terms of facility type, size, and other parameters that affect estimates of emissions, control costs, and secondary environmental impacts. Impacts of control options are estimated for each model plant and then extrapolated to estimate impacts on a nationwide level.

To span the range of types and sizes of facilities in these source categories, a number of model plants were developed. Model plants were developed for (1) glycol dehydration units, (2) condensate tank batteries, (3) natural gas processing plants, and (4) offshore production platforms in State waters.

These model plants were developed based on available information collected on processes, operations, and hazardous air pollutant (HAP) emission points in the oil and natural gas production and natural gas transmission and storage source categories. The information considered include (1) data from industry responses to the U.S. Environmental Protection Agency's (EPA's) Air Emissions Survey Questionnaires,[1] (2) observations made during four series of site visits to oil and natural gas production and natural gas transmission and storage facilities that were designed to collect information on processes and operations and HAP emission points,[2] (3) recommendations and comments received from members of the American Petroleum Institute (API) and its associated Clean Air Issues Group (CAIG),[3] (4) a data base of natural gas analyses for various industry operations provided by the Gas Research Institute (GRI),[4] and (5) data provided by API.[5]

4.2 DESCRIPTIONS OF MODEL PLANTS

4.2.1 Glycol Dehydration Units

4.2.1.1 Glycol Dehydration Units. The glycol dehydration unit reboiler vent has been identified as a significant source of HAP emissions in the oil and natural gas production and natural gas transmission and storage source categories. Glycol dehydration units may be (1) stand-alone facilities that dehydrate natural gas streams from an individual or series of production wells or (2) part of the overall production process located at condensate tank batteries, natural gas processing plants, offshore production platforms in State and Federal waters, and throughout the natural gas transmission source category, including underground storage facilities.

Triethylene glycol (TEG) dehydration units account for most of glycol dehydration units, with ethylene glycol (EG) and diethylene glycol (DEG) dehydration units accounting for the remaining estimated population of glycol dehydration units. Based on information received from API's CAIG and GRI, the EPA established an average number of (1) one TEG dehydration unit per condensate tank battery[6,7] and offshore production platform and (2) two to four dehydration units (TEG, EG, or solid desiccant) per natural gas processing plant, depending upon throughput capacity and type of processing configuration.[8]

Five separate model TEG dehydration units that represent the size range for these units within the oil and natural gas production and natural gas transmission and storage source categories (based on natural gas design and throughput capacities) were developed. The natural gas throughput capacity ranges of the five model TEG dehydration units are (1) ≤5 million standard cubic feet per day (MMSCF/D), (2) >5 to 20 MMSCF/D, (3) >20 to 50 MMSCF/D, (4) >50 to 500 MMSCF/D, and (5) >500 MMSCF/D.

In addition, four separate model EG dehydration units that represent the size range of these units within the oil and natural gas production source category (based on natural gas design and throughput capacities) were developed. The natural gas throughput capacity ranges of the four model EG dehydration units are (1) <20 MMSCF/D, (2) 20 to 100 MMSCF/D, (3) >100 to 500 MMSCF/D, and (4) >500 MMSCF/D.

Table 4-1 presents parameters for the five model TEG dehydration units and Table 4-2 presents parameters for the four model EG dehydration units. The parameters in this table are the basic inputs used in GRI-GLYCalc™ (Version 3.0),[9] a personal computer-based emissions screening program developed by GRI for evaluating HAP and volatile organic compound (VOC) emissions from TEG and EG dehydration units.

4.2.1.2 Distribution of Model Unit Populations. Tables 4-1 and 4-2 include the estimated number of glycol dehydration units based on application (stand-alone, condensate tank batteries, natural gas processing plants, offshore production platforms, and natural gas transmission and storage). Estimates of the total number of dehydration units in the U.S. range from 20,000[10] to recent projections of over 44,000.[11,12]

The EPA standardized the analysis for dehydration units in this regulatory development process by using a total national estimated dehydration unit population of approximately 40,000, which represents all dehydration units in every sector of

TABLE 4-1. MODEL TRIETHYLENE GLYCOL (TEG) DEHYDRATION UNITS

Parameter	Model TEG units				
	A	B	C	D	E
Natural gas					
Capacity (MMSCF/D)	≤5	>5 to 20	>20 to 50	>50 to 500	>500
Throughput (MMSCF/D)	0.28	10	35	100	500
Temperature (°F)	90	90	90	90	90
Pressure (psig)	700	700	700	700	700
Dry gas water content (Pounds of water per MMSCF/D)	7	7	7	7	7
Percent with flash tank in system design	10	40	55	100	100
Glycol circulation rate (Gallons of glycol per lbs of water removed)	5.9	5.9	5.9	5.9	5.9
Estimated population distribution of TEG units					
Stand-alone	24,000	200	25	20	---
Condensate tank battery	12,000	500	100	70	---
Natural gas processing plant[a]	---	66	110	54	---
Offshore production platform in State waters	---	260	40	---	---
Natural gas transmission and underground storage	200	125	25	10	10

MMSCF/D - Million of standard cubic feet per day

psig - Pounds per square inch gauge

a - Based on one of two parallel processing lines on-line at any one time for the small natural gas processing plant and two of three on-line for the larger model natural gas processing plants.

TABLE 4-2. MODEL ETHYLENE GLYCOL (EG) DEHYDRATION UNITS

Parameter	Model EG units			
	A	B	C	D
Natural gas				
Capacity (MMSCF/D)	<20	20 to 100	>100 to 500	>500
Throughput (MMSCF/D)	10	35	100	500
Inlet Temperature (°F)	75	75	75	75
Contactor Temperature (°F)	0	0	0	0
Pressure (psig)	1,000	1,000	1,000	1,000
Dry gas water content (Pounds of water per MMSCF/D)	5	5	5	5
Percent with flash tank in system design	100	100	100	100
Glycol circulation rate (Gallons of glycol per lbs of water removed)	0.5	0.5	0.5	0.5
Estimated population distribution of EG units				
Natural gas processing plant[a]	66	110	54	30

MMSCF/D - Million of standard cubic feet per day

psig - Pounds per square inch gauge

[a] - Based on one of two parallel processing lines on-line at any one time for the small natural gas processing plant and two of three on-line for the larger model natural gas processing plants.

both source categories, including the offshore production sector. Of this, approximately 38,000 are glycol dehydration units (primarily TEG and EG dehydration units) and 2,000 are solid desiccant dehydration units.

The model glycol dehydration unit distribution for natural gas processing plants reflects comments received from members of API's CAIG. These comments indicate that the majority of natural gas processing plants primarily employ non-glycol dehydration units (some form of solid desiccant system) within their processing stream, with the remaining natural gas processing plants using either TEG or EG dehydration units within their overall processing system design.[13]

4.2.1.3 Natural Gas Life Cycle. The number of times that natural gas is dehydrated by glycol dehydration units during its life cycle (life cycle being defined as from the point of production of natural gas at a well, through its various processing and storage stages, to the time when it is consumed by the end user) is one of the components in the overall methodology of determining model plant and nationwide impacts. In its initial analyses, the EPA selected two times (2x) as the number of times that natural gas is dehydrated by glycol dehydration units in its life cycle. This was based on information from GRI, which stated a lower limit of over 1x and an unknown upper estimate that natural gas is dehydrated several times with glycol systems in its life cycle.[14]

The EPA revised its estimate to approximately 1.6x for natural gas dehydrated through all forms of dehydration units (including solid desiccant units) located at all operational sectors throughout the oil and natural gas production and natural gas transmission and storage source categories. This revision was based on comments received from members of API's CAIG and through studies conducted by this group.[15,16,17] This total estimated life cycle factor includes accounting for offshore dehydration (approximately 0.2x) that is not under the EPA's air emissions regulatory jurisdiction.

A recent GRI report estimated the natural gas life cycle at between 2x and 3x. This report states "... In our discussions with the industry, it was stated that natural gas is frequently dried multiple times, usually during production, before gas processing, and in the transfer from underground storage."[18]

4.2.2 Condensate Tank Batteries

Four separate model condensate tank batteries that represent the size range of condensate tank batteries (based on condensate and natural gas design and throughput capacities) were developed. The natural gas throughput capacity ranges of the four condensate model batteries are (1) $\leq$5 MMSCF/D, (2) >5 to 20 MMSCF/D, (3) >20 to 50 MMSCF/D, and (4) >50 MMSCF/D.

Condensate tank batteries generally have a glycol dehydration unit as a process unit within the overall system design of the tank battery.[19] However, because glycol dehydration units are addressed as separate model plants, parameters for glycol dehydration units are not included with the model condensate tank battery parameters. The parameters (other than glycol dehydration unit parameters) for the model condensate tank batteries are presented in Table 4-3.

Approximately 15 percent of all tank batteries, or an estimated 13,000 tank batteries, are classified as condensate tank batteries.[20] A further breakdown of the number of condensate tank batteries in each model condensate tank battery size range is shown in Table 4-3. Parameters for model glycol dehydration units are presented in Section 4.2.1 and Tables 4-1 and 4-2 of this BID.

4.2.3 Natural Gas Processing Plants

Three separate model natural gas processing plants that represent different size ranges of natural gas processing plants (based on natural gas design and throughput capacities) were developed. The natural gas throughput capacity ranges of the three model processing plants are (1) <20 MMSCF/D, (2) 20 to 100 MMSCF/D, and (3) >100 MMSCF/D.

TABLE 4-3. MODEL CONDENSATE TANK BATTERIES

Parameter	Model condensate tank battery			
	E	F	G	H
Natural gas				
Capacity (MMSCF/D)	≤5	>5 to 20	>20 to 50	>50
Throughput (MMSCF/D)	0.28	10	35	100
Condensate throughput (BOPD)	15	100	1,000	5,000
Fixed-roof product storage tanks				
210 barrel capacity	4	2		
500 barrel capacity		2	2	
1,000 barrel capacity			2	4
Components				
Valves				
Gas/vapor	30	60	90	150
Light liquid	30	60	90	150
Heavy liquid	20	20	40	60
Pump seals				
Light liquid	2	4	6	10
Heavy liquid	2	2	4	6
Compressor seals	2	4	6	10
Pressure relief valves	6	10	16	26
Flanges and connections	170	290	460	750
Sampling connections	2	4	6	10
Open-ended lines	4	8	12	20
Total components	270	460	730	1,200
Estimated population	12,000	500	100	70

MMSCF/D - Million of standard cubic feet per day

BOPD - Barrels of oil per day

Parameters for the model natural gas processing plants are presented in Table 4-4. As with the model condensate tank batteries, parameters for model glycol dehydration units at natural gas processing plants are not presented in Table 4-5. Parameters for model glycol dehydration units are presented in Section 4.2.1 and Tables 4-1 and 4-2.

As of January 1, 1993, there were approximately 700 domestic natural gas processing plants.[21] The cited reference includes a listing of these natural gas processing plants by State, along with design capacities and estimated 1992 throughputs. Based on this annual survey, estimates of the number of natural gas processing plants corresponding to each model plant size range were made and are included in Table 4-4.

4.2.4 Offshore Production Platforms in State Waters

Two model offshore production platforms designed to be representative of a small and a medium offshore production platform that are typical of those located in State water areas were developed. The parameters and values selected to characterize these model offshore production platforms are presented in Table 4-5.

As with the model condensate tank batteries and natural gas processing plants, parameters for model glycol dehydration units at offshore production platforms are not presented in this table. Parameters for model glycol dehydration units are presented in Section 4.2.1 and Tables 4-1 and 4-2 of this BID.

There are approximately 300 offshore production platforms in State waters that are under the EPA's jurisdiction for air emissions regulation.[22] To characterize this segment of the oil and natural gas production source category, the EPA requested technical data from members of API's CAIG to assist in developing model offshore production platforms that would be representative of those located in State waters.[23]

TABLE 4-4. MODEL NATURAL GAS PROCESSING PLANTS

Parameter	Model natural gas processing plant A	B	C
Natural gas			
Capacity (MMSCF/D)	<20	20 to 100	>100
Throughput (MMSCF/D)	10	35	200
Fixed-roof product storage tanks			
1,000 barrel capacity	4	4	4
Components			
Valves			
Gas/vapor	300	750	1,800
Light liquid	60	150	360
Heavy liquid	20	40	60
Pump seals			
Light liquid	4	10	24
Heavy liquid	2	4	6
Compressor seals	4	10	24
Pressure relief valves	10	24	54
Flanges and connections	1,200	3,200	12,000
Sampling connections	4	10	24
Open-ended lines	8	10	48
Total components	1,600	4,200	14,000
Estimated population	260	300	140

MMSCF/D - Million of standard cubic feet per day

a - Primary products loaded are natural gasoline and condensate.

TABLE 4-5. MODEL OFFSHORE PRODUCTION PLATFORMS

Parameter	Small	Medium
Number of well slots	2	18
Production wells	1	8
Crude oil capacity (BOPD)	1,000	5,000
Crude oil production (BOPD)	200	2,000
Natural gas capacity (MMSCF/D)	10	20
Natural gas production (MMSCF/D)	5	10
Components		
Valves		
Gas/vapor	60	540
Light liquid	15	120
Heavy liquid	2	8
Pump seals		
Light liquid	1	1
Heavy liquid	1	3
Compressor seals	3	7
Pressure relief valves	2	16
Flanges and connections	500	4,000
Sampling connections	1	3
Open-ended lines	2	2
Total components	590	4,700
Estimated population	260	40

BOPD - Barrels of oil per day

MMSCF/D - Million of standard cubic feet per day

However, as of the date of this background information document (BID), the requested technical data on State water offshore production platforms have not been received from API's CAIG. Due to this, the EPA developed its characterization of offshore production platforms located in State waters and estimated model parameters based on data appearing in an U.S. Department of Interior's Minerals Management Service (MMS) report on Federal offshore statistics.[24]

4.2.5 Natural Gas Transmission and Storage

The only HAP emission point of concern for the national emission standards for hazardous air pollutants (NESHAP) for natural gas transmission and storage facilities is any process vent associated with a glycol dehydration unit at these facilities. According to industry representatives, 80 percent of dehydration units used in the natural gas transmission and storage source category are TEG dehydration units, with solid desiccant systems accounting for most of the remaining units.[25] There are few, if any, EG dehydration units in this source category.[26,27]

Thus, as with the model condensate tank batteries, natural gas processing plants, and offshore production platforms located in State waters, parameters for model TEG dehydration units at natural gas transmission and storage facilities are not presented in this section of the BID. The parameters for model TEG dehydration units are presented in Section 4.2.1 and Table 4-1 of this BID.

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27. Memorandum from Viconovic, G., EC/R Incorporated, to Smith, M.E., EPA/WCPG. December 7, 1995. Summary of November 9th, 1995, meeting with representatives of the natural gas transmission industry.

5.0 ENVIRONMENTAL AND ENERGY IMPACTS OF CONTROL OPTIONS

5.1 INTRODUCTION

This chapter provides a discussion of the environmental and energy impacts associated with the control options that have been identified as applicable to the identified hazardous air pollutant (HAP) emission points in the oil and natural gas production and natural gas transmission and storage source categories. The control options under evaluation for HAP emission points identified in these source categories are listed in Table 3-1 of Chapter 3.0 of this background information document (BID).

The control options applicable to the identified HAP emission points include a variety of emission reduction techniques. The control options include (1) the use of emissions control equipment (e.g., installation of a cover or fixed-roof for tanks) and (2) work standards (e.g., system optimization for glycol dehydration units and leak detection and repair (LDAR) programs for fugitive emission points).

Two control options being evaluated for HAP emission points in these source categories may have secondary environmental impacts or energy-use impacts. These control options include the use of (1) a combustion system (flare) for remotely located facilities and (2) a vapor collection and redirect system for fixed-roof storage tanks.

The impact analyses consider a facility's ability to handle collected vapors. Some remotely located facilities may not be able to use collected vapor for fuel or recycle it back into the process. In addition, it may not be technically feasible for some facilities to utilize the non-condensable vapor streams from condenser systems as an alternative fuel source safely. An option for these facilities is to combust these vapors by flaring.

These concerns are reflected in the analyses conducted by the EPA. In its analyses, the EPA estimated that (1) 45 percent of all impacted facilities will be able to use collected vapors as an alternative fuel source for an on-site combustion device such as a process heater or the glycol dehydration unit firebox, (2) 45 percent will be able recycle collected vapors into a low pressure header system for combination with other hydrocarbon streams handled at the facility, and (3) 10 percent will direct all collected vapor to an on-site flare.

5.2 AIR POLLUTANT IMPACTS

5.2.1 Primary Air Pollutant Impacts

The primary air pollutant impacts are based on the estimated control efficiency of the control options listed in Table 5-1. Emission reductions for control of the glycol dehydration unit reboiler vent are based on the application of (1) a condenser with a flash tank in the design of the glycol dehydration system or (2) an equivalent HAP control system.

The control options that are being evaluated for HAP emission points in these source categories are also effective in the control of volatile organic compound (VOC) and methane emissions from the same identified emission points. Thus, the primary air pollutant impacts associated with control of HAP emission points include reductions in associated VOC and methane emissions. The primary nationwide air pollutant impacts, which are reductions in HAP, VOC, and methane air emissions associated with major HAP emission points in these source categories, are presented in Tables 5-1 and 5-2. The primary nationwide air pollutant impacts associated with area source glycol dehydration units are presented in Table 5-3.

TABLE 5-1. EXAMPLE NATIONAL PRIMARY AIR POLLUTANT IMPACTS FOR MAJOR SOURCES IN THE OIL AND NATURAL GAS PRODUCTION SOURCE CATEGORY

Emission point	Emissions (Megagrams per year)		
	HAP	VOC	Methane
Baseline			
Process vents	36,000	85,000	6,200
Storage vessels	2,100	6,900	3,900
Equipment leaks	470	1,500	1,100
Total baseline	39,000	94,000	11,000
Reduction			
Process vents	28,000	55,000	3,800
Storage vessels	1,500	4,800	2,700
Equipment leaks	230	730	540
Total reduction	30,000	61,000	7,000
Controlled[a]			
Process vents	8,000	30,000	2,400
Storage vessels	640	2,100	1,200
Equipment leaks	240	770	560
Total controlled	8,900	33,000	4,200

a - Based on following control options:

Glycol dehydration unit - Condenser with flash tank in design
Storage tanks - Vent to 95% control device
Equipment leaks - 70% level of control

TABLE 5-2. EXAMPLE NATIONAL PRIMARY AIR POLLUTANT IMPACTS FOR MAJOR SOURCES IN THE NATURAL GAS TRANSMISSION AND STORAGE SOURCE CATEGORY

Emission point	Emissions (Megagrams per year)		
	HAP	VOC	Methane
Baseline			
Process vents	120	1,500	59
Reduction			
Process vents	110	1,400	54
Controlled[a]			
Process vents	10	100	5

a - Based on following control options:

Glycol dehydration unit - Condenser with flash tank in design

TABLE 5-3. EXAMPLE NATIONAL PRIMARY AIR POLLUTANT IMPACTS FOR AREA SOURCE GLYCOL DEHYDRATION UNITS IN THE OIL AND NATURAL GAS PRODUCTION SOURCE CATEGORY

	Emissions (Megagrams per year)		
Emission point	HAP	VOC	Methane
Baseline			
Process vents	19,000	43,000	9,600
Reduction			
Process vents	3,300	7,200	1,500
Controlled[a]			
Process vents	16,000	36,000	8,100

a - Based on the application of a condenser with flash tank in design to area source glycol dehydration units. Of the estimated total population of approximately 37,000 area source glycol dehydration units, approximately 520 units would be required to install controls.

5.2.2 Secondary Air Pollutant Impacts

Secondary emissions of air pollutants result from the operation of certain control devices (such as a flare) that may be used to comply with a standard. For condenser systems, it is estimated that 45 percent of impacted glycol dehydration units will use the non-condensable portion of the emission stream as a supplemental fuel source for the glycol reboiler. Thus, there is no net change in energy use associated with the application of this control option for those facilities that incorporate this design and no net change in combustion-related emissions.

A portion of impacted facilities (10 percent) are judged to be remotely located or technically unable to utilize collected vapors. These facilities flare collected emission streams. Thus, there will be an increase in sulfur dioxide (SO_X), nitrogen oxide (NO_X), and carbon monoxide (CO) emissions from this combustion. Table 5-4 presents the secondary air pollutant impacts on a national basis. The estimated national annual increase in secondary air emissions from flaring will be <1 megagram (Mg) of SO_X, 7 Mg of NO_X, and 1 Mg of CO.

5.3 WATER AND SOLID WASTE IMPACTS

The condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by reinjection. Thus, the water impact associated with installation of a condenser system for a glycol dehydration unit reboiler vent would be minimal.

Water vapor may be collected along with hydrocarbon vapors in the vapor collection and redirect system for fixed-roof storage tanks. The water vapor may condense in the control systems. A knockout designed into the system will collect any condensable product (water and hydrocarbons). As with the condenser system, this water can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by

TABLE 5-4. EXAMPLE NATIONAL SECONDARY AIR POLLUTANT IMPACTS DUE TO FLARING FOR MAJOR AND AREA SOURCES IN THE OIL AND NATURAL GAS PRODUCTION SOURCE CATEGORY[a]

Model plant and emission point	Estimated number installing flare	Estimated emissions per flare[b] (Kilograms per year)			Total (Megagrams per year)		
		SO_x	NO_x	CO	SO_x	NO_x	CO
Stand alone glycol units							
A	52	<1	48	10	<1	2	<1
B	34	<1	48	10	<1	2	<1
C	4	<1	48	10	<1	<1	<1
D	2	<1	52	11	<1	<1	<1
Tank battery							
F	6	<1	48	10	<1	<1	<1
G	4	<1	48	10	<1	<1	<1
H	2	<1	52	11	<1	<1	<1
Natural gas processing plants							
A	1	<1	48	10	<1	<1	<1
Total					<1	7	1

a - No major sources in the natural gas transmission and storage source category are anticipated to use flares.

b - SO_x - Sulfur dioxide
NO_x - Nitrogen oxides
CO - Carbon monoxide

reinjection. Thus, the water impact associated with installation of vapor control systems would be minimal.

There are no identified solid wastes that would be generated by installation of (1) a condenser system for the glycol dehydration unit reboiler vent or (2) a vapor collection and redirect system for fixed-roof storage tanks. Thus, no solid waste impacts are anticipated with the installation of these systems.

5.4 ENERGY IMPACTS

If vapor collection and redirect systems is used for the control of emissions from a fixed-roof storage tank, it would require electricity for operation of the primary components of the vapor collection/recovery system. These components include fans and blowers for proper operation of the system.

The annual estimated energy requirements for each vapor collection/recovery system is 300 kilowatt hours per year (kw-hr/yr). It is estimated that approximately 125 facilities would install one or more of these control options.

The national energy demand impact is presented in Table 5-5. The estimated national electrical demand that would result from the operation of all control options is 38,000 kw-hr/yr.

TABLE 5-5. EXAMPLE NATIONAL ENERGY REQUIREMENTSE

Emission point and model plant	Estimated number installing control option	Energy requirement (kw-hr/yr)	Total (kw-hr/yr)
Storage tanks			
Condensate tank batteries	100	300	30,000
Natural gas processing plants	25	300	7,500
Total			38,000

kw-hr/yr - Kilowatt hours per year

6.0 COSTS OF CONTROL OPTIONS

6.1 INTRODUCTION

This chapter presents the approach used to estimate the cost impacts of the control options presented in Chapter 3.0 to identified hazardous air pollutant (HAP) emission points in the oil and natural gas production and natural gas transmission and storage source categories. Cost impacts are based on the model plants presented in Chapter 4.0.

The model plant cost impacts were extrapolated to estimate the cost and cost-effectiveness of the control options on a national basis. The methodology used to estimate the cost impacts of applying control options[1] to identified HAP emission points in these source categories is described in Appendix B.

A detailed example is provided in this BID to demonstrate the methodology as applied on a model plant basis. The costs of the control options used in this example case are presented in Reference 1.

6.2 SUMMARY OF COST METHODOLOGY

6.2.1 General Approach

Cost estimates were developed for the following control options (1) condenser systems, with and without the installation of a gas condensate glycol separator (GCG separator or flash tank) in glycol dehydration system design, (2) vapor collection systems for fixed-roof storage tanks, and (3) a leak detection and repair (LDAR) program for fugitive emissions.

All costs were updated to July 1993 dollars using cost indices obtained from Chemical Engineering.[2] In selected cases, separate costs were estimated for applying control options to existing and new facilities.

The difference in costs between an existing facility and a new facility for the same control option is a retrofit factor that accounts for space limitations and additional engineering requirements. The retrofit factor is applied to the capital cost of control options installed at existing facilities. The retrofit cost adjustment factor is estimated to be 1.15, meaning that it was judged that it will cost (on average) 15 percent more to install a control option at an existing facility as compared with installation of the same control option at a similar size new facility.

6.2.2 Monitoring Equipment

Cost estimates for monitoring equipment associated with condenser systems and vapor collection devices were included in the capital cost estimates. In addition, the annualized capital costs of the monitoring equipment were included in the annual costs of these control options.

The cost of monitoring equipment consists of the installation of instrumentation to monitor the operation of the control device. For purposes of this analysis, the cost of monitoring was estimated to be equal to the capital cost instrumentation factor for each control option.

6.2.3 Product Recovery

Product recovery is presented as an annual credit in each cost table, where applicable. Product recovery credits were calculated by multiplying the mass of product recovered by the product value for each control option.

Recovered condensate and other liquid hydrocarbons were assigned a value of $18.00 per barrel, the average current price for crude oil.[3] For recovered gaseous products, different values were assigned depending on how the recovered gas are used. Recovered gaseous hydrocarbons recycled for processing were assigned a value of $2.00 per thousand standard cubic feet (mscf).[4] By assigning a value of 1,000 British thermal units

(BTUs)/mscf, recovered gaseous hydrocarbons used as supplemental fuel were valued at $1.30/mscf.[5] Gaseous hydrocarbons directed to an incinerator or flare have no value for product recovery.

6.2.4 Monitoring, Inspection, Recordkeeping, and Reporting

The annual costs associated with monitoring, inspection, recordkeeping, and reporting (MIRR) were included in the total annual costs, but are presented separately from the control option costs. Appendix C presents the methodology and estimated example MIRR costs for each major HAP emission point. Estimated example MIRR costs are also presented in Appendix C for glycol dehydration units that are classified as area sources.

6.2.5 Costs of HAP Emission Control Options

6.2.5.1 Process Vents. The glycol dehydration unit reboiler vent has been identified in this BID as the primary HAP emission process vent in the oil and natural gas production and natural gas transmission and storage source categories. The most effective control option identified for reducing the level of HAP emissions from the glycol dehydration unit reboiler vent is a condenser operated in conjunction with a flash tank in a glycol dehydration unit's system design.

Additional control can be achieved by recycling the non-condensable gas stream into the incoming natural gas line. The non-condensable gas stream may also be directed to a flare or incinerator or used as a supplemental fuel source. A condenser may be operated at a high enough efficiency such that the residual non-condensable gas stream may be vented to the atmosphere. Cost estimates were developed for a condenser system with a 95 percent HAP emission reduction efficiency. The necessary equipment for a condenser system includes a condenser, condensate storage vessel, and piping.

System optimization is another control option that may be applicable to this HAP emission point. Costs for system optimization are not presented due to the variability of effort associated with implementing this option. In addition, the HAP reduction and the costs of implementing this option may vary substantially among facilities based on site-specific factors.

6.2.5.2 Storage Tanks. Crude oil and condensate are typically stored in fixed-roof storage tanks. Since most of these tanks are too small to install an internal floating roof, the control options evaluated for fixed-roof storage tanks require collecting the vapor emitted with a closed-vent system.

The vapor collected by the closed-vent system may be processed for sale, used for fuel, or be directed to a control device. For this analysis, it was estimated that 45 percent of all facilities implementing controls for storage tanks will process the recovered gas for sale, 45 percent will use the recovered gas for fuel or fuel substitute, and 10 percent will install flares to destroy the collected gas stream.

The capital cost for each closed-vent system includes the cost of a fan, flame arrestor, and piping. The equipment was designed to recover vapor from four storage tanks. Total capital cost was estimated to be the same for all model plant configurations utilizing this control option.

Costs were also estimated for flares. Based on the recovered volumes of gas from the storage tanks, costs estimates were developed for two size flares. Capital costs for flares include the costs for a knockout drum, a flare, and piping.

6.2.5.3 Equipment Leaks. Control option costs for equipment leaks at natural gas processing plants are based on the model plant component counts for the facilities that are presented in Chapter 4.0 and the use of a LDAR program. Cost estimates were tabulated for a monthly LDAR program based on the New Source Performance Standards (NSPS) for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants (40 CFR, Part 60, Subpart KKK).[6]

6.3 MODEL PLANT BASED CONTROL COSTS

This section provides a general discussion of how control option costs were estimated for the model plants. More detailed information on the methodology and the algorithms used may be found in Reference 1.

6.3.1 Glycol Dehydration Units

The costs of applying a condenser to the reboiler vent of each model glycol dehydration unit described in Chapter 4.0 were estimated. For this analysis, it was estimated that all existing model triethylene glycol (TEG)-D and TEG-E dehydration units have flash tanks in their system designs (see Chapter 2.0 for discussion of flash tank use). It was also estimated that 90 percent of the model TEG-A dehydration units, 60 percent of model TEG-B dehydration units, and 45 percent of model TEG-C dehydration units do not have flash tanks in their system designs. Therefore, costs for flash tanks were added to the condenser cost estimates for those existing model glycol dehydration units not having flash tanks in the system design.

6.3.2 Condensate Tank Batteries

For condensate model tank batteries, control option costs were estimated for VRUs for fixed-roof storage tanks.

6.3.3 Natural Gas Processing Plants

Control option costs for model natural gas processing plants were developed for VRUs for fixed-roof storage tanks and a monthly LDAR program for control of equipment leaks.

6.4 EXAMPLE

The following example illustrates the approach used to estimate the cost impacts of control options on a model plant. The model plant selected for this example is model condensate tank battery G that has a model TEG-C unit co-located at the tank battery. The model plant characteristics of these facilities are presented in Tables 4-1 and 4-3 of Chapter 4.0.

The applicable control options for this model plant combination include (1) a condenser for the glycol dehydration unit reboiler vent and (2) a closed-vent system for the storage tanks. This example model plant combination has an on-site combustion device, so installation of a control device is not required for the vapor collected from storage tanks.

The size of the condenser is dependent on the flow rate of the glycol dehydration unit reboiler vent, which is the inlet stream to the condenser. The flow rate and HAP concentration of the glycol dehydration unit reboiler vent was estimated using the parameters presented in Table 4-1 in Chapter 4.0 of this BID and GRI-GLYCalc^{TM} (Version 3.0).[7] The reduction of HAP achieved by the condenser is based on a HAP emission reduction efficiency of 95 percent and an average inlet concentration of 200 parts per million by volume (ppmv) benzene, toluene, ethyl benzene, and mixed xylenes (collectively referred to as BTEX) in the wet natural gas entering the glycol dehydration process.

The design criteria and cost of the condenser system are presented in Table 6-1 and Table 6-2. As shown, the estimated total capital investment of the condenser is $11,000, while the total net annual cost is ($940).

A closed-vent system is the control option applied to the fixed-roof storage tanks at this facility. Emissions from the storage tanks are based on standing and working losses. For purposes of this example, flash emissions were not calculated. As shown in Table 6-3, the total capital investment is estimated as $3,600. The vapor collected is directed to the on-site combustion device (flare). Therefore, no product recovery credit is claimed in the total net annual cost shown in Table 6-4.

The total estimated annual costs for MIRR are approximately $5,700 for this model plant. The costs are added to the annual costs for the control options for this model plant. The summation of these annual costs divided by the annual HAP emission reduction is equal to the cost effectiveness for controlling the combination of HAP emission points at this model plant.

The cost impacts of implementing these control options to this model plant combination are summarized in Table 6-5. As shown, the total capital investment for this model plant combination is $14,600. Total net annual cost incurred by the

TABLE 6-1. EXAMPLE CONDENSER CAPITAL COSTS[a] FOR MODEL GLYCOL DEHYDRATION UNIT TEG-C

Equipment	Description	Size	Factor/ Reference	Cost
Condenser[b]	Condenser and piping	All	Ref. 8	$6,800
Condensate storage tank		50 gallons	2.72(V)+1,960 Ref. 9	2,100
Flash tank	Low pressure separator	125 psig	Ref. 10	N.A.
Purchased equipment costs (PEC)				$8,900
Enhanced monitoring equipment (EM)			0.10*PEC	890
Total capital cost (TCC) for existing unit[c]			1.15*(PEC+EM)	$11,000

a - July 1993 dollars.

b - Includes direct and indirect costs.

c - Retrofit factor of 1.15x for existing units.

N.A. - Not applicable to units with flash tank in existing system design.

<u>Note</u>: Numbers may vary due to rounding.

TABLE 6-2. EXAMPLE CONDENSER ANNUAL COSTS[a] FOR MODEL GLYCOL DEHYDRATION UNIT TEG-C

Cost category	Factor	Cost
Direct annual cost		
Operating labor	(0.5 hr/8 hr)*(2,080 hr/yr)*($13.20/hr)	$1,700
Supervising labor	0.15*(Operating labor)	260
Operating materials	None required	0
Maintenance		
Labor	(0.5 hr/8 hr)*(2,080 hr/yr)*($14.50/hr)	1,900
Material	0.5*(Maintenance labor)	950
Utilities	None required	0
Indirect annual costs		
Overhead	0.60*(Maintenance total)	2,300
Administrative	0.02*(TCC)	230
Property taxes	0.01*(TCC)	110
Insurance	0.01*(TCC)	110
Capital recovery[b]	0.1098*(TCC)	1,500
Recovery credit[c]/ condensate	(555 bbl/yr)*($18.00/bbl)	(10,000)
Total annual cost		($940)

a - July 1993 dollars.

b - Based on an equipment life of 15 years and an interest rate of 7 percent over the life of the equipment.

c - Number in parentheses indicate a savings.

<u>Note</u>: Numbers may vary due to rounding.

TABLE 6-3. EXAMPLE CLOSED VENT SYSTEM CAPITAL COSTS[a] FOR MODEL CONDENSATE TANK BATTERY TB-G

Equipment	Description	Size	Factor/ Reference	Cost
Fan	FRP, centrifugal	10.5" dia.	$42.3*(D)^{1.2}$ Ref. 11	$750
Motor	w/Belt & starter	7.5 hp	$235*(hp)^{0.256}$ Ref. 11	410
Piping	2" Galv. steel	200 ft	Ref. 12	830
Flame arrestor	2" dia.		Ref. 12	110
Equipment costs (EC)				$2,100
Enhanced monitoring equipment (EM)			0.10*(EC)	210
Purchased equipment cost (PEC)			1.08*(EC+EM)	2,500
Direct installation cost (DC)			Ref. 12	580
Indirect installation cost (IC)			0.20*(PEC)	500
Total capital cost (TCC)			(PEC+DC+IC)	$3,600

a - July 1993 dollars.

<u>Note</u>: Numbers may vary due to rounding.

TABLE 6-4. EXAMPLE CLOSED VENT SYSTEM ANNUAL COSTS[a] FOR MODEL CONDENSATE TANK BATTERY TB-G

Cost category	Factor	Cost
Direct annual cost		
Maintenance		
Labor[b]	(1 hr/yr)*($14.50/hr)	$15
Material	1.0*(Maintenance labor)	15
Utilities	$0.0509/kW-hr	20
Indirect annual costs		
Overhead	0.60*(Maintenance total)	18
Administrative	0.02*(TCC)	72
Property taxes	0.01*(TCC)	36
Insurance	0.01*(TCC)	36
Capital recovery[b,c]	0.1098*(TCC)	400
Total annual cost		$610

a - July 1993 dollars.

b - Reference 12.

c - Based on an equipment life of 15 years and an interest rate of 7 percent over the life of the equipment.

N.A. - Not applicable.

<u>Note</u>: Numbers may vary due to rounding.

TABLE 6-5. EXAMPLE MODEL PLANT COST IMPACTS[a]

HAP emission point	Control option	HAP reduction (Megagrams per year)	Total capital cost	Total net annual cost
Glycol reboiler vent	Condenser	60	$11,000	($940)[b]
Storage tanks	Closed vent system	0.2	3,600	610
MIRR costs[c]				5,700
Total		60	$14,600	$5,370

a - These cost impacts apply to an existing facility represented by model condensate tank battery G and model glycol dehydration unit TEG-C.

b - Parentheses represent a cost savings due to product recovery.

c - Monitoring, inspection, recordkeeping, and reporting (MIRR) costs includes $3,400 for glycol dehydration unit and $2,300 for storage tanks.

model plant combination is $5,370, which includes the cost of MIRR. Total annual reduction of hazardous air pollutants is 60 megagrams per year (Mg/yr). Therefore, the cost effectiveness of these control options on this model plant combination is $90 per megagram (Mg) of HAP reduced.

References used in the development of the tables in this chapter[8,9,10,11,12,13] are listed in Section 6.5 of this chapter.

6.5 REFERENCES

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10. Owens, A.S. BTEX Emissions from Gas/Glycol Dehydrators: Air Quality Case Histories. Proceedings of the 1994 GRI Glycol Dehydrator/Gas Processing Air Toxics Conference (June 1994). Gas Research Institute, Chicago, IL.

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APPENDIX A.

EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT

The primary objective of this project is to develop a basis for supporting proposed national emissions standards for hazardous air pollutants (NESHAP) for the oil and natural gas production and natural gas transmission and storage source categories. To accomplish this objective, technical data were acquired on the following aspects of these two source categories (1) process operations and equipment, (2) the characteristics of extracted and recovered products, (3) identified potential emission points where hazardous air pollutants (HAP) are released (including the magnitude and composition of HAP emissions), and (4) the types and costs of control options that may be applied to identified potential HAP emissions.

The bulk of the information was gathered from the following sources

1. Technical literature,
2. Federal, Regional, State, and local regulatory agencies,
3. Site visits,
4. Industry representatives, and
5. Equipment vendors.

Significant events relating to the evolution of the background information document (BID) for the oil and natural gas production and natural gas transmission and storage NESHAPs are itemized in Table A-1.

TABLE A-1. EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT

Date	Company, consultant, or agency/location	Nature of action
06/22/92	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
10/07/92	Amoco Production Co. ARCO Oil & Gas Co. Chevron U.S.A. Inc. Exxon Company, U.S.A. Conoco, Inc. Texaco Exploration and Producing Inc. Mobil Exploration & Producing U.S. Inc.	Section 114 information request letter for plant visits
10/12/92	Amoco Production Co., Zachary, LA	Plant visit to gather background information on the methods used to produce oil and natural gas
10/12/92	ARCO Oil & Gas Co., Lafayette, LA	Plant visit to gather background information on the methods used to produce oil and natural gas
10/13/92	Chevron, U.S.A. Inc., Thompson, TX	Plant visit to gather background information on the methods used to produce oil and natural gas
10/13/92	Exxon Company, U.S.A., Katy, TX	Plant visit to gather background information on the methods used to produce oil and natural gas
10/14/92	Conoco, Inc., Benavides, TX	Plant visit to gather background information on the methods used to produce oil and natural gas

TABLE A-1. EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT (Continued)

Date	Company, consultant, or agency/location	Nature of action
10/15/92	Texaco Exploration and Producing Inc., Midland, TX	Plant visit to gather background information on the methods used to produce oil and natural gas
03/17/93	U.S. Environmental Protection Agency and Gas Research Institute/RTP, NC	Industry meeting
04/06/93 & 04/07/93	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
04/29/93	U.S. Environmental Protection Agency/RTP, NC and Washington, DC	Work group meeting
05/27/93	Marathon Oil Co. Oxy USA Inc. Shell Oil Co. Lomack Petroleum, Inc. Maxus Energy Corp. Mitchell Energy Co. Phillips Petroleum Co. Amerada Hess Corp. Amoco Production Co. Conoco, Inc. Oryx Energy Co. Texaco, Inc. Unocal Mesa Petroleum Union Pacific Environmental Services Enron Corp. Atlantic Richfield Co. BP Exploration Alaska, Inc. Chevron USA Production Co. Exxon USA Production Dept. Mobil Oil Corp. Kerr McGee Pogo Production Co. Arch Petroleum	Air emissions survey questionnaires mailout

TABLE A-1. EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT (Continued)

Date	Company, consultant, or agency/location	Nature of action
07/27/93	Exxon Company U.S.A. Chevron U.S.A., Inc. Shell Western E&P Inc. Texaco USA	Section 114 information request letter for plant visits
08/03/93	Texaco Exploration and Production Inc., Offshore of Santa Barbara County, CA	Plant visit to gather background information on the methods used to produce oil and natural gas
08/04/93	Mobil Exploration and Producing U.S. Inc., Goleta, CA	Plant visit to gather background information on the methods used to produce oil and natural gas
08/04/93	Exxon Company, U.S.A., Offshore of Santa Barbara County, CA	Plant visit to gather background information on the methods used to produce oil and natural gas
08/03/93 & 08/05/93	Chevron U.S.A. Inc., Offshore of Santa Barbara County and Ventura County, CA	Plant visits to gather background information on the methods used to produce oil and natural gas
08/09/93 through 08/11/93	State of Kansas, Various sites	Plant visits to gather background information on the methods used to produce oil and natural gas

TABLE A-1. EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT (Continued)

Date	Company, consultant, or agency/location	Nature of action
08/10/93	Wallace Energy, Inc., Plainville, KS	Plant visit to gather background information on the methods used to produce oil and natural gas
08/10/93	Oil Reclaiming Company, Limited, Seward, KS	Plant visit to gather background information on the methods used to produce oil and natural gas
08/10/93	H&W Oil Company, Hays, KS	Plant visit to gather background information on the methods used to produce oil and natural gas
08/11/93	Trident NGL, Inc., Cheney, KS	Plant visit to gather background information on the methods used to produce oil and natural gas
09/15/93	CNG Transmission Corp.	Air emissions survey questionnaire mailout
02/01/94	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
02/01/94	Distribution of draft BID Chapters 2.0, 3.0, and 4.0 to industry	BID chapter distribution
04/12/94	U.S. Environmental Protection Agency/RTP, NC and Washington, DC	Work group meeting
04/26/94	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting

TABLE A-1. EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT (Continued)

Date	Company, consultant, or agency/location	Nature of action
04/26/94	Distribution of draft BID Chapters 2.0, 3.0, and 4.0 to industry	BID chapter distribution
05/17/94	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
05/23/94	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
08/26/94	Distribution of complete preliminary draft BID to interested parties	BID distribution
10/13/94	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry teleconference
12/08/94	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
04/26/95	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry teleconference
05/08/95	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
05/25/95	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry teleconference
11/02/95	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
11/09/95	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
12/14/95	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
03/21/96	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting

TABLE A-1. EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT (Continued)

Date	Company, consultant, or agency/location	Nature of action
04/04/96	Transcontinental Gas Pipe Line Corporation, Reidsville, NC	Plant visit to gather background information on the methods used in natural gas transmission
05/09/96	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting
07/30/96	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry teleconference
08/28/96	U.S. Environmental Protection Agency/RTP, NC and Washington, DC	Work group meeting
10/17/96	U.S. Environmental Protection Agency/RTP, NC and Washington, DC	Work group meeting
10/31/96	U.S. Environmental Protection Agency/RTP, NC and Washington, DC	Work group meeting
11/07/96	U.S. Environmental Protection Agency and industry representatives/RTP, NC	Industry meeting and teleconference

APPENDIX B.
NATIONAL IMPACTS METHODOLOGY

B.1 INTRODUCTION

This appendix describes the general methodology used to estimate the nationwide impacts of the proposed national emission standards for hazardous air pollutants (NESHAP) that are being developed for the oil and natural gas production and natural gas transmission and storage source categories. This methodology results in (1) estimates of baseline (i.e., before the implementation of NESHAP) and controlled hazardous air pollutant (HAP) emissions and (2) the impacts of control options. Impacts estimated include HAP emission reduction, total capital and net annual costs, and secondary environmental and energy impacts.

B.2 OVERVIEW OF METHODOLOGY

The basic elements of the methodology used in estimating impacts for the oil and natural gas production and natural gas transmission and storage NESHAPs are as follows (1) development of model plants, (2) identification of HAP emission points and control options, (3) application of HAP emission control options to identified emission points, (4) estimation of model plant impacts, and (5) extrapolation from model plant impacts to national impacts. Each of the above elements is discussed below.

B.3 MODEL PLANT DEVELOPMENT

Due to the large number of facilities in these source categories and the time and resources that would have been required, it was not feasible to simulate the impacts of standards on each actual impacted facility. Instead, a model plant approach was used.

First, distinct sectors of the source categories were identified in terms of operation, equipment, and emissions. Then a sufficient number of model plants were developed to represent each industry sector. The sectors identified include (1) glycol dehydration units, (2) condensate tank batteries, (3) natural gas processing plants, (4) offshore production platforms in State waters, and (5) natural gas transmission facilities, including underground storage operations. Since the primary identified HAP emission point of concern at natural gas transmission facilities is the co-location of any triethylene glycol (TEG) dehydration unit at these facilities, separate model plants were not developed for facilities in this sector of the oil and natural gas industry.

The primary information sources used to develop the model plants and model plant parameters included (1) responses to the U.S. Environmental Protection Agency's (EPA's) Air Emissions Survey Questionnaires,[1] (2) site visits to operating facilities, (3) discussions and meetings with industry and trade association representatives, and (4) available literature.

In addition, a data base from the Gas Research Institute (GRI) containing natural gas analyses[2] and a data base provided by the American Petroleum Institute (API)[3] were used, in conjunction with industry survey responses, to develop natural gas compositions. Composition of process streams, particularly HAP constituents, is a key parameter in the model plant analysis. The concentration of HAP constituents in these streams has a direct impact on estimated model plant HAP emissions.

The primary HAP constituents of the process streams associated with the oil and natural gas production and natural gas transmission and storage source categories include benzene toluene, ethyl benzene, and mixed xylenes (collectively referred to as BTEX), and n-hexane. Process stream concentrations of these HAP are listed in Table 2-1 of Chapter 2.0 of this BID.

As indicated in Table 2-1, the EPA estimated three national average BTEX concentrations for natural gas of 200, 160, and 13 parts per million volume (ppmv). These values are reflective of the three sectors in these source categories of (1) production, (2) processing, and (3) transmission and underground storage, which handle natural gas streams. The EPA has analyzed BTEX values within ranges of either side of these average values in an effort to better determine the impacts of the proposed NESHAPs.

Initially, the EPA estimated a production BTEX concentration of 550 ppmv based on the data received in company responses to the Air Emissions Survey Questionnaires (Reference 1). The EPA revised this estimate to 440 ppmv by incorporating BTEX data supplied by GRI (Reference 2). The EPA revised its estimate again (May 1996) to 200 ppmv after incorporating additional new BTEX data supplied by API (Reference 3).

The production estimate influences the calculation of HAP concentrations for the processing sector in the oil and natural gas production source category. The revision of the HAP concentration for the production sector has caused a 75 percent reduction in the EPA's initial (December 1993) estimate of nationwide HAP emissions from glycol dehydration units, the primary identified HAP emission point in these source categories.

Each model plant was characterized based on the specific parameters necessary to calculate impacts. Parameters include (1) product and other throughputs, (2) number and type of process vessels (i.e., storage tanks), and (3) number and type of process component equipment (i.e., valves). Chapter 4.0 of this BID provides detailed descriptions of the model plants.

B.4 CONTROL OPTIONS

Control options were identified that reduce HAP emissions from HAP emission points in the oil and natural gas production industry. These control options are discussed in detail in Chapter 3.0 of this BID.

Control options that are applicable to HAP emission points in the oil and natural gas production industry will also achieve co-control of volatile organic compound (VOC) and methane emissions. Due to similarities in the emission characteristics of HAP, VOC, and methane from the emission points in this industry, control options for HAP were judged to be equally effective, in terms of emission reduction efficiency, for HAP, VOC, and methane. The efficiencies used in the analysis for each control option can be found in Table 3-1 of this BID.

B.5 MODEL PLANT IMPACTS

Impacts of the control options were calculated for model plants using available information. Model plant impacts include (1) HAP emission reduction per model plant, (2) total capital and net annual costs and cost-effectiveness per megagram of annual HAP emission reduction, and (3) secondary environmental impacts and energy requirements.

B.5.1 Emissions

Emissions were estimated using emission factors and emission estimation tools. Emissions from glycol dehydration units were estimated using GRI-GLYCalc^{TM} (Version 3.0).[4] Emissions from storage tanks resulting from standing and working losses were estimated using the EPA's TANKS program.[5] Flash emissions from storage tanks were estimated using a separate algorithm specifically developed by the EPA for estimating flash emissions from storage tanks in the oil and natural gas production industry.[6] Emissions from components were estimated using emission factors developed for equipment leaks.[7]

Emissions based on the model plants were first estimated at baseline. Baseline was established by assigning an estimated level of control to each model plant category. Therefore, baseline estimates have taken into account those emission points already controlled.

Emissions were then estimated for each model plant with the application of controls, or after implementation of NESHAP. The difference of these estimates is the emissions reduction impact that the NESHAP would have on each model plant.

B.5.2 Costs

Capital costs and net annual costs were calculated for each control option. Capital costs include the cost of the control equipment and the costs associated with installing the equipment. Net annual costs account for the operation and maintenance costs and monitoring, inspection, recordkeeping, and recording (MIRR) costs.

Where available, standardized costing methodologies, such as presented in the OAQPS Control Cost Manual, were used to estimate capital and annual costs.[8] A product recovery credit was included in the annual costs, where judged appropriate. Example model plant control option costs are discussed in Chapter 6.0 and example MIRR costs are discussed in Appendix C of this BID.

The impact analyses consider a facility's ability to handle collected vapors. Some remotely located facilities may not be able to use collected vapor for fuel or recycle it back into the process. In addition, it may not be technically feasible for some facilities to utilize the non-condensable vapor streams from condenser systems as an alternative fuel source safely. An option for these facilities is to combust these vapors by flaring.

These concerns are reflected in the analyses conducted by the EPA. In its analyses, the EPA estimated that (1) 45 percent of all impacted facilities will be able to use collected vapors as an alternative fuel source for an on-site combustion device such as a process heater or the glycol dehydration unit firebox, (2) 45 percent will be able to recycle collected vapors into a low pressure header system for combination with other hydrocarbon streams handled at the facility, and (3) 10 percent will direct all collected vapor to an on-site flare.

B.5.3 Other Impacts

Other impacts associated with the implementation of standards include secondary environmental impacts and energy requirements. These impacts were also estimated using the model plant approach. Chapter 5.0 of this BID provides more discussion of these impacts.

B.6 NATIONAL IMPACTS ESTIMATES

To calculate national impacts, estimates were made of the total number of facilities nationwide corresponding to each model plant category. These estimates were based primarily on (1) production statistics, (2) responses to the Air Emissions Survey Questionnaires, and (3) estimated facility populations.[9] Estimated facility populations are at the bottom of each model plant table (Tables 4-1 to 4-5) in Chapter 4.0 of this BID.

From these distributions and associated model plant HAP emission estimates, projections were made of the number of facilities that would be designated as major and area sources of HAP emissions. The estimated number of major and area sources were then used as a basis for determining the national impacts of each control option.

Generally, it was judged that a TEG dehydration unit must be co-located at a facility in order for the facility to be designated as a major source. National impacts were calculated for major sources, area sources, and each source category as a whole.

B.7 REFERENCES

1. Responses to the U.S. Environmental Protection Agency's Air Emissions Survey Questionnaires for the Oil and Natural Gas Production Source Category (EPA Air Docket A-94-04, Items II-D-1 through II-D-25). 1993.

2. Letter and attachment from Evans, J.M., Gas Research Institute, to Viconovic, G., EC/R Incorporated. April 19, 1995. Natural gas BTEX content.

3. American Petroleum Institute. Triethylene Glycol Dehydrator Operating Parameters for Estimating BTEX Emissions (Prepublication Draft). Washington, DC. February 1996.

4. Gas Research Institute. Technical Reference Manual for GRI-GLYCalc^{TM}: A Program for Estimating Emissions from Glycol Dehydration of Natural Gas, Version 3.0 (GRI-96/0091). Chicago, IL. March 1996.

5. TANKS (Version 1.1). Downloaded from the U.S. Environmental Protection Agency's Technology Transfer Network.

6. Memorandum from Akin, T., and W.H. Battye, EC/R Incorporated, to Smith, M.E., EPA/CPB. October 18, 1994. Recommendation of an algorithm to estimate flash emissions from process vessels in the oil and natural gas production industry.

7. Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. Code of Federal Regulations, Title 40, Part 60, Subpart KKK. July 1, 1992. U.S. Government Printing Office, Washington, DC.

8. U.S. Environmental Protection Agency. OAQPS Control Cost Manual (Fourth Edition, EPA 450/3-90-006). Research Triangle Park, NC. January 1990.

9. Memorandum from Akin, T., EC/R Incorporated, to Smith, M.E., EPA/CPB. July 30, 1993. Revised preliminary estimate of the number and size ranges of tank batteries on a national basis.

APPENDIX C.

MONITORING, INSPECTION, RECORDKEEPING, AND REPORTING COST METHODOLOGY

C.1 INTRODUCTION

This appendix documents the methodology used to estimate costs associated with monitoring, inspection, recordkeeping, and reporting (MIRR) for the control options presented in Chapter 3.0 of this background information document (BID). The primary costs associated with MIRR are labor costs required to perform MIRR activities.[1] Labor costs are divided into three categories (1) technical, (2) managerial, and (3) clerical. An estimate of the number of technical labor hours required was made for each MIRR activity, and then managerial and clerical labor hours were estimated as a percentage of technical labor hours (5 and 10 percent of technical labor hours, respectively). Technical labor was costed at $44.00 per hour ($44/hr), managerial labor at $60/hr, and clerical labor at $25/hr.

The MIRR costs presented in this appendix should be considered example costs. Costs projected for the national emissions standards for hazardous air pollutants (NESHAP) will be finalized and documented when the specific requirements of the standards are determined. The capital and annual costs associated with control option monitoring equipment are included in the control option costs.

C.2 COST METHODOLOGY

C.2.1 Example Costs for Major Source MIRR

MIRR costs are different for each type of control. These costs are calculated on an emission point basis and applied to the model plants. For each emission point, the hours required to perform an associated MIRR item and the number of times per year the associated MIRR item is performed are estimated. By multiplying these two numbers, the estimated number of technical labor hours is calculated for each associated MIRR item on an annual basis.

As discussed above, the number of managerial and clerical labor hours are estimated as a percentage of each technical labor hour. The number of technical, managerial, and clerical labor hours are multiplied by the number of impacted facilities and wage per labor hour to obtain annual MIRR costs.

C.2.2 Number of Major Sources

After the initial step of estimating the costs associated with MIRR, the next step is to determine the number of facilities, on a model plant basis, that will be subject to MIRR requirements for major sources. Facilities classified as major sources (those emitting or having the potential-to-emit 10 tons per year (tpy) or greater of a single hazardous air pollutant (HAP) or 25 tpy or greater of any combination of HAP) are subject to the major source MIRR requirements in this section.

The number of facilities impacted within each model plant category is estimated to calculate annual MIRR costs on a national basis. The number of impacted facilities was estimated using model plants and model compositions of process streams presented in Chapter 4.0 of this BID.

In the oil and natural gas production source category, approximately 440 triethylene glycol (TEG) dehydration units are estimated to be major sources or co-located at major sources and, therefore, would be subject to MIRR requirements. In the natural gas transmission and storage source category, approximately 5 TEG dehydration units are estimated to be major sources and, therefore, would be subject to MIRR requirements. The estimated MIRR costs per TEG dehydration unit at major sources are presented in Table C-1.

It is estimated that approximately 120 facilities have storage vessels that are located at facilities that are major sources and would be impacted by the proposed regulation for the oil and natural gas production source category. Table C-2 presents estimated MIRR costs for these facilities. Storage tanks include the set of tanks at each facility.

In addition, approximately 12 facilities estimated to be major sources are projected to be impacted by leak detection and repair (LDAR) requirements in the proposed regulation for the oil and natural gas production source category. Except for additional reporting requirements, all other associated MIRR items for LDAR programs are accounted for in the net annual control costs for LDAR. The estimated costs per LDAR program at major sources for the reporting requirements are presented in Table C-3.

Total estimated MIRR costs for major sources are calculated by summing the MIRR costs associated with each emission point, which are presented in Tables C-1, C-2, and C-3. For the oil and natural gas production source category, total MIRR costs for major sources (based on the example cost methodology) is approximately $1.8 million per year in the third year after promulgation of the proposed oil and natural gas production NESHAP. The major source MIRR costs are summarized in Table C-4.

For the natural gas transmission and storage source category, total MIRR costs for major sources (based on the example cost methodology) is approximately $17,000 per year in the third year after promulgation of the proposed natural gas transmission and storage NESHAP.

TABLE C-1. EXAMPLE ANNUAL MIRR COSTS PER GLYCOL DEHYDRATION UNIT DESIGNATED AS OR LOCATED AT A MAJOR HAP EMISSION SOURCE

Activity	Activity cost parameters					
	Technical hours per activity (A)	Number of activities per year (B)	Technical hours per year (C)	Management hours per activity (D)	Clerical hours per activity (E)	Total annual costs in $ per year (F)
Read rule and instructions	3	2	6	0.30	0.60	300
Plan activities	5	1	5	0.25	0.50	250
Training	1	1	1	0.05	0.10	50
Testing/Development	20	1	20	1.00	2.00	1,000
Monitoring/Inspection	0.3	52	16	0.78	1.60	780
Process/Review	1.5	1	1.5	0.08	0.15	74
Complete reports	5	1	5	0.25	0.50	250
Record/Report	0.5	12	6	0.30	0.60	300
Store/Maintain data	0.5	12	6	0.30	0.60	300
Totals[a]			66	3	7	3,300

Activity cost parameters

C = A x B
D = 0.05 x C
E = 0.10 x C
F = ($44 x C) + ($60 x D) + ($25 x E)

[a] - Total hours are rounded to nearest hour and total dollars rounded to nearest $100.

TABLE C-2. EXAMPLE ANNUAL MIRR COSTS PER STORAGE VESSEL LOCATED AT A MAJOR HAP EMISSION SOURCE

Activity	Activity cost parameters					
	Technical hours per activity (A)	Number of activities per year (B)	Technical hours per year (C)	Management hours per activity (D)	Clerical hours per activity (E)	Total annual costs in $ per year (F)
Read rule and instructions	0	0	0	0	0	0
Plan activities	0	0	0	0	0	0
Training	0	0	0	0	0	0
Testing/Development	10	1	10	0.50	1.00	500
Monitoring/Inspection	0.05	365	18	0.91	1.83	900
Process/Review	2	4	8	0.40	0.80	400
Complete reports	1	4	4	0.20	0.40	200
Record/Report	0.05	52	3	0.13	0.26	130
Store/Maintain data	0.05	52	3	0.13	0.26	130
Totals[a]			45	2	5	2,300

Activity cost parameters

C = A x B
D = 0.05 x C
E = 0.10 x C
F = ($44 x C) + ($60 x D) + ($25 x E)

a - Total hours are rounded to nearest hour and total dollars rounded to nearest $100.

TABLE C-3. EXAMPLE ANNUAL MIRR COSTS PER LEAK DETECTION AND REPAIR LOCATED AT A MAJOR HAP EMISSION SOURCE

Activity	Activity cost parameters					
	Technical hours per activity (A)	Number of activities per year (B)	Technical hours per year (C)	Management hours per activity (D)	Clerical hours per activity (E)	Total annual costs in $ per year (F)
Read rule and instructions	0	0	0	0	0	0
Plan activities	0	0	0	0	0	0
Training	0	0	0	0	0	0
Testing/Development	0	0	0	0	0	0
Monitoring/ Inspection[a]	0	0	0	0	0	0
Process/Review	0	0	0	0	0	0
Complete reports	1	4	4	0.2	0.4	200
Record/Report	1	2	2	0.1	0.2	99
Store/Maintain data	1	2	2	0.1	0.2	99
Totals[b]			8	<1	1	400

Activity cost parameters

C = A x B
D = 0.05 x C
E = 0.10 x C
F = ($44 x C) + ($60 x D) + ($25 x E)

a - Monitoring and inspection costs included as part of leak detection and repair program.
b - Total hours are rounded to nearest hour and total dollars rounded to nearest $10.

TABLE C-4. TOTAL ESTIMATED EXAMPLE MIRR COSTS FOR MAJOR HAP EMISSION SOURCES IN THE OIL AND NATURAL GAS PRODUCTION SOURCE CATEGORY

HAP emission point category	Estimated number of major sources[a]	MIRR per HAP emission point ($)	Total MIRR ($1,000)
Glycol dehydration unit[b]	440	3,300	1,500
Tank battery			
Storage tank	120	2,300	280
Natural gas processing plant			
Storage tank	12	2,300	28
Equipment leaks	12	400	4.8
Total estimated example MIRR costs over 3 year compliance period			1,800[c]

a - Number of major sources for storage vessels represent the number of tank batteries and natural gas processing plants with an average of 4 storage tanks per tank battery.

b - Includes stand alone glycol dehydration units and those located at condensate tank batteries, and natural gas processing plants.

c - Rounded to nearest $100,000.

C.2.3 Example Costs for Area Source MIRR

If a standard is promulgated for area sources, it is anticipated that the MIRR requirements and the associated costs would be less as compared to those for major sources. The same general method followed for major sources (see Section C.2.1) is followed for calculating example area source MIRR costs, but with fewer requirements. As with all other control options, the capital costs associated with continuous monitoring for area sources are included as a component to the control option costs.

C.2.4 Number of Area Sources

After the initial step of estimating the costs associated with area source MIRR, the next step is to determine the number of facilities, on a model plant basis, that will be area sources and, thus, subject to area source MIRR. Only those TEG dehydration units classified as area sources (those not meeting the designation of major source) and meeting the applicability thresholds of the proposed area source standard are subject to area source MIRR requirements.

The number of facilities impacted within each model plant category is estimated to calculate annual MIRR costs on a national basis. The number of impacted facilities was estimated using model plants and model compositions of process streams (see Chapter 4.0 of this BID). Approximately 520 glycol dehydration units will be impacted and, thus, subject to MIRR requirements.

The estimated MIRR costs per glycol dehydration unit at area sources are presented in Table C-5. Total estimated MIRR costs for area sources (based on the example cost methodology) is approximately $1.2 million per year in the third year after promulgation of the proposed oil and natural gas production NESHAP. The area source MIRR costs are summarized in Table C-6.

C.2.5 Continuous Monitoring

Continuous monitoring requirements are included in standards for HAP emissions, promulgated under §112(d) of the Clean Air Act

TABLE C-5. EXAMPLE ANNUAL MIRR COSTS PER GLYCOL DEHYDRATION UNIT DESIGNATED AS AN AREA HAP EMISSION SOURCE

Activity	Activity cost parameters					
	Technical hours per activity (A)	Number of activities per year (B)	Technical hours per year (C)	Management hours per activity (D)	Clerical hours per activity (E)	Total annual costs in $ per year (F)
Read rule and instructions	1.5	2	3	0.15	0.30	150
Plan activities	3	1	3	0.15	0.30	150
Training	1	1	1	0.05	0.10	50
Testing/Development	20	1	20	1.00	2.00	990
Monitoring/Inspection	0.1	52	5.2	0.26	0.52	260
Process/Review	1.5	1	1.5	0.08	0.15	74
Complete reports	5	1	5	0.25	0.50	250
Record/Report	0.5	6	3	0.15	0.30	150
Store/Maintain data	0.5	12	6	0.30	0.60	300
Totals[a]			48	2	5	2,400

Activity cost parameters

C = A x B
D = 0.05 x C
E = 0.10 x C
F = ($44 x C) + ($60 x D) + ($25 x E)

a - Total hours are rounded to nearest hour and total dollars rounded to nearest $100.

TABLE C-6. TOTAL ESTIMATED EXAMPLE MIRR COSTS FOR GLYCOL DEHYDRATION UNITS IN THE OIL AND NATURAL GAS PRODUCTION SOURCE CATEGORY DESIGNATED AS AREA SOURCES

HAP emission point category	Estimated number of area sources	MIRR per HAP emission point ($)	Total MIRR ($1,000)[a]
Glycol dehydration units	520	2,400	1,200
Total estimated example MIRR costs over 3 year compliance period			1,200

a - Rounded to nearest $100,000.

as amended in 1990, to ensure continuous compliance. For standards developed for the oil and natural gas production and natural gas transmission and storage source categories, continuous monitoring requirements will be included for control options used to reduce HAP emissions from glycol dehydration units and storage vessels. Monitoring of control option parameters that are indicative of performance, such as temperature for condensers, will be required.

In developing example costs of control options, the capital costs of process instrumentation was doubled to account for the cost of continuous monitoring equipment. In addition, the labor costs for the operation and maintenance of equipment, recording monitoring data, and preparing reports associated with continuous monitoring are included in the example MIRR annual costs.

C.3 BASIS OF METHODOLOGY

The costs associated with MIRR for major sources are based on emission points. The following judgements were made for the emission points (1) one control device for all process vents associated with the glycol dehydration unit, (2) one control device for each set of storage tanks, (3) one parameter to monitor continuously for each control device, and (4) one facility-wide inventory of emission records is included with the reporting requirements for storage tanks. In addition, only reporting is required for LDAR programs, since the other MIRR cost components have been included in the annual control costs for the LDAR programs.

C.4 REFERENCES

1. U.S. Environmental Protection Agency. ESD Regulatory Procedures Manual (Continually Updated). Research Triangle Park, NC.