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ECONOMIC IMPACT ANALYSIS OF THE OIL AND NATURAL GAS PRODUCTION NESHAP AND THE NATURAL GAS TRANSMISSION AND STORAGE NESHAP

Final Report

Office of Air Quality
Clean Air
OAQPS
Planning and Standards

Economic Impact Analysis of the Oil and Natural Gas Production NESHAP and the Natural Gas Transmission and Storage NESHAP

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Air Quality Strategies and Standards Division
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This report is issued by the Air Quality Standards & Strategies Division of the Office of Air Quality Planning and Standards of the U.S. Environmental Protection Agency (EPA). It presents technical data on the National Emission Standard for Hazardous Air Pollutants (NESHAP), which is of interest to a limited number of readers. It should be read in conjunction with the Background Information Document (BID) for NESHAPs on the Oil and Natural Gas Production and Natural Gas Transmission and Storage source categories (April 1997). Both the Economic Impact Analysis and the BID are in the public docket for the NESHAP final rulemaking. Copies of these reports and other material supporting the rule are in Docket A-94-04 at EPA's Air and Radiation Docket and Information Center, Waterside Mall, Room M1500, Central Mall, 501 M Street, SW, Washington, DC 20460. The EPA may charge a reasonable fee for copying. Copies are also available through the National Technical Information Services, 5285 Port Royal Road, Springfield, VA 22161. Federal employees, current contractors and grantees, and nonprofit organizations may obtain copies from the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; phone (919) 541-2777.

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LIST OF ACRONYMS

API	American Petroleum Institute
ATAC	Average total (avoidable) cost
Bcf	Billion cubic feet
BID	Background information document
BOE	Barrels of oil equivalent
BOPD	Barrels of oil per day
bpd	Barrels per day
BTB	Black oil tank battery
Btu	British thermal unit
cf(d)	Cubic feet (per day)
CIS	Commonwealth of Independent States
CTB	Condensate tank battery
D&B	Dun and Bradstreet
DEG	Diethylene glycol
DOE	Department of Energy
EG	Ethylene glycol
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GRI	Gas Research Institute
HAPs	Hazardous air pollutants
IPAA	Independent Petroleum Association of America
ISEG	The Innovative Strategies and Economics Group
LDAR	Leak detection and repair

LPG	Liquid petroleum gas
MACT	Maximum achievable control technology
Mbpd	Thousand barrels per day
MC	Marginal cost
Mcf(d)	Thousand cubic feet (per day)
Mmbpd	Million barrels per day
MMBtu	Million British thermal units
MMcf(d)	Million cubic feet (per day)
MMS	Minerals Management Service
NAFTA	North American Free Trade Agreement
NESHAP	National Emission Standard for Hazardous Air Pollutants
NGL	Natural gas liquids
NGPA	Natural Gas Policy Act
NGPP	Natural gas processing plant
OGJ	Oil and Gas Journal
OPEC	Organization of Petroleum Exporting Countries
RCRA	Resource Conservation and Recovery Act
SBA	Small Business Administration
SIC	Standard Industrial Classification
TB	Tank battery
Tcf(d)	Trillion cubic feet (per day)
TEG	Triethylene glycol
TREG	Tetraethylene glycol

LIST OF DEFINITIONS

API Gravity--the gravity adopted by American Petroleum Institute for measuring the density of a liquid, expressed in degrees. It is converted from specific gravity by the following equation:

Degrees API gravity = 141.5/specific gravity - 131.5 *

Black Oil Tank Battery--the collection of process equipment used to separate, treat, store, and transfer streams from production wells primarily consisting of crude oil with little, if any, natural gas.

City Gate--the final destination of gas products prior to direct distribution to end users, such as homes, businesses, and industries.

Condensate Tank Battery--The collection of process equipment used to separate, treat, store, and transfer streams from production wells consisting of condensate and natural gas.

Condensates--hydrocarbons that are in a gaseous state under reservoir conditions (prior to production), but that become liquid during the production process.

Dry Gas--natural gas whose water content has been reduced through dehydration, or natural gas that contains little or no commercially recoverable liquid hydrocarbons.

End-user Price--the delivered price paid by residential, commercial, industrial, and electric utility consumers for natural gas.

Extracted Stream--the untreated mixture of gas, oil, condensate, water, and other liquids recovered at the wellhead.

Glycol Dehydration--absorption process in which a liquid absorbent, a glycol, directly contacts the natural gas stream and absorbs water vapor in a contact tower or absorption column. The glycol becomes saturated with water and is

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*Introduction to Oil and Gas Production. American Petroleum Institute. 1983.

circulated through a boiler where the water vapor is boiled off.

Gruy "Wellgroups"--Gruy Engineering Corp. developed "wellgroups," or model production wells, for both oil and gas wells in 37 areas across the U.S. For each geographic area, wellgroups are defined by well depth ranges and by production rate in each depth range.

Natural Gas Processing Plant--a facility designed to (1) achieve the recovery of natural gas liquids from the stream of natural gas, which may or may not have been processed through lease separators and field facilities, and (2) control the quality of the natural gas to be marketed.*

Natural Gas--a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist either in gaseous phase or in solution with crude oil from underground reservoirs.

Offshore Production Platforms--facilities used to produce, treat, and separate crude oil, natural gas, and produced water in offshore areas.

Producing Field--an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same geological structure feature and/or stratigraphic condition.*

Production Well--a hole drilled into the earth, usually cased with pipe for the recovery of crude oil, condensate, and natural gas.

Proved Crude Oil Reserves--the estimated amount of crude oil that can be found and developed in future years from known reservoirs under current prices and technology.

Proved Natural Gas Reserves--the estimated amount of gas that can be found and developed in future years from known reservoirs under current prices and technology.

Pump Stations--facilities designed to transport crude oil from tank batteries to refineries.

Stripper Wells--those production wells that produce less than 10 bpd or 60 Mcf per day.

Wellhead Price--represents the wellhead sales price, including charges for natural gas plant liquids subsequently removed from the gas, gathering and compression charges, and State production, severance, and/or similar charges.

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*Introduction to Oil and Gas Production. American Petroleum Institute. 1983.

Wet Gas--unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons.

EXECUTIVE SUMMARY

The petroleum industry is divided into five distinct sectors: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. The National Emission Standard for Hazardous Air Pollutants (NESHAP) establishes controls for the products and processes of the production and transportation sectors of the petroleum industry. Specifically, the oil and natural gas production and natural gas transmission and storage source categories include the separation, upgrading, storage, and transfer of extracted streams that are recovered from production wells. Thus, it includes the production and custody transfer up to the refinery stage for crude oil and up to the city gate for natural gas. This report evaluates the economic impacts of additional pollution control requirements for the oil and natural gas production and natural gas transmission and storage source categories that are designed to control releases of hazardous air pollutants (HAPs) to the atmosphere.

ES.1 INDUSTRY PROFILE

Production occurs within the contiguous 48 United States, Alaska, and at offshore facilities in Federal and State waters. In the production process, extracted streams from production wells are transported from the wellhead (through offshore production platforms in the case of offshore wells) to tank batteries for separation of crude oil, natural gas, condensates, and water from the product. Crude oil products are then transported to refineries, while natural gas products are directed to gas processing plants and then to final transmission lines at city gates. The equipment required in the production of crude oil and natural gas includes production wells (including offshore production platforms), dehydration units, tank batteries, natural gas processing plants, and transmission pipelines and underground storage facilities.

Because oil is an international commodity, the U.S. production of crude oil is affected by the world crude oil price, the price of alternative fuels, and existing regulations. Domestic oil production is currently in a state of decline that began in 1970. U.S. production in 1992 totaled only 7.2 million barrels per day (MMbpd)--the lowest level in 30 years.

Natural gas production trends are distinct from those of crude oil. Production has been increasing since 1986 mainly due to open access to pipeline transportation that has resulted in more marketing opportunities for producers and greater competition, leading to higher production. Also contributing to the increase in production are significant improvements in drilling productivity as well as more intensive utilization of existing fields since 1989. Natural gas consumers include residential and commercial customers, as well as industrial firms and electric utilities. Since 1986, natural gas consumption has shown relatively steady growth, which is projected to continue through the year 2010.

The oil and natural gas production industry is characterized by large (major) oil companies on one level and smaller independent producers on another level. Because of the existence of major oil companies, the industry possesses a wide dispersion of vertical and horizontal integration. Several oil companies achieve full vertical integration in that they own and operate facilities that are involved in each of the five sectors within the petroleum industry. Independent companies, by definition, are involved in only a subset of these five sectors. Horizontal integration also exists in that major and independent firms may own and operate several crude oil and natural gas production and processing facilities.

ES.2 REGULATORY CONTROL OPTIONS AND COSTS

The Background Information Document (BID) details the technology basis for the national emission standards on affected sources. Model plants were developed to evaluate the effects of various control options on the oil and natural gas production industry and the transmission and storage industry. Selection of control options was based on the application of presently available control equipment and technologies and varying levels of capture consistent with different levels of overall control. The BID presents a summary of the control options for each of the following model plants:

- triethylene glycol (TEG) dehydration units,
- condensate tank batteries (CTB)
- natural gas processing plants (NGPP), and
- offshore production platforms (OPP).

Table ES-1 summarizes the annual compliance costs associated with the regulatory requirements for each model plant by source category. Major sources of HAP emissions are controlled based on the MACT floor, as defined in the BID. The Agency has determined that a glycol dehydration unit must be collocated at a facility for that facility to be designated as a major source. Therefore, the MACT floor may apply to stand-alone TEG units, condensate tank batteries, and natural gas processing plants. Black oil tank batteries and offshore production platforms are not considered since TEG units are not typical of the operations at black oil tank batteries and are completely controlled at offshore production platforms. Based on public comments on the proposed rule, EPA re-evaluated the costs and affected units in the Natural Gas Transmission and Storage sector. A full evaluation is presented in the BID, but a summary of costs are also presented in Table ES-1. The final rule for this industry will control major sources only, whereas the proposal for this rule evaluated control

TABLE ES-1. SUMMARY OF ANNUAL CONTROL COSTS BY MODEL PLANT

Model Plant	Cost per model unit
TEG dehydration units	
TEG-A	—
TEG-B	$12,989
TEG-C	$12,937
TEG-D	$12,790
TEG-E	$12,790
Condensate tank batteries	
CTB-E	—
CTB-F	$19,660
CTB-G	$24,973
CTB-H	$25,071
Natural gas processing plants	
NGPP-A	$46,747
NGPP-B	$61,823
NGPP-C	$81,083
Natural gas transmission and storage units	
TEG-A	-
TEG-B	-
TEG-C	-
TEG-D	$49,787
TEG-E	$49,787

requirements for major and area sources. Therefore, this EIA for the final rule only presents impacts on major sources.

ES.3 ECONOMIC IMPACT ANALYSIS

This economic impact analysis assesses the market-, facility-, and industry-level impact of the final rule on the oil and natural gas production industry. According to the BID, black oil tank batteries will not incur control costs so that only condensates processed at condensate tank batteries will be directly affected by the regulation. Condensates represent less than 5 percent of total U.S. crude oil production.* Thus, this analysis does not include a model to assess the regulatory effects on the world crude oil market because the anticipated changes in the U.S. supply are not likely to influence world prices. Consequently, the economic analysis focuses on the regulatory effects on the U.S. natural gas market that is modeled as a national, perfectly competitive market for a homogeneous commodity. In addition to the analysis presented at proposal, this EIA also incorporates an evaluation of the impact on the transmission and storage sector of the natural gas industry.

To estimate the economic impacts of the regulation on the natural gas market, a multi-dimensional Lotus spreadsheet model was developed incorporating various data sources to provide an empirical characterization of the U.S. natural gas industry for a base year of 1993--the latest year for which supporting technical and economic data were available at proposal. The analysis for the final rule maintains this base year to provide consistent comparisons between the final rule and proposed rule. The exogenous shock to the economic model is the imposition of the regulations and the corresponding control costs.

A competitive market structure was incorporated to compute the equilibrium prices (wellhead and end user) at which the supply and demand balance for natural gas output. Domestic supply is represented by a detailed characterization of the production flow of natural gas through a network of production wells and processing facilities. Demand for natural gas by end-use sector is expressed in equation form, incorporating estimates of demand elasticities from the economic literature. Although the model includes a foreign component of U.S. natural gas supply (i.e., imports), it does

*Oil and Natural Gas Production: An Industry Profile. U.S. Environmental Protection Agency, OAQPS, Research Triangle Park, NC. October 1994. p. 4.

not incorporate U.S. exports of natural gas that are observed at insignificant levels. The model analyzes market adjustments associated with the imposition of the regulation by employing a process of _tatonnement_ whereby prices approach equilibrium through successive correction modeled as a Walrasian auctioneer.

As presented in Table ES-2, the major outputs of this model are market-level impacts, including price and quantity adjustments for natural gas and the impacts on foreign trade, and industry-level impacts, including the change in revenues and costs, adjustments in production, closures, and changes in employment. The market adjustments associated with the

TABLE ES-2. SUMMARY OF SELECTED ECONOMIC IMPACT RESULTS

Natural Gas Production	
Market-level impacts	
Prices(%)	0.0008%
Wellhead	0.0004%
End-user	
Domestic production (%)	-0.0003%
Industry-level impacts	
Change in revenues ($\$10^6$)	$3.0
Change in costs (10^6)	$7.4
Change in profits ($\$10^6$)	-$4.4
Closures	
Production wells	0
Natural gas processing plants	0
Employment losses	0
Economic welfare impacts ($\$10^6$)	
Change in consumer surplus	-$0.3
Change in producer surplus	-$4.6
Domestic	-$4.7
Foreign	$0.1
Change in economic welfare	-$4.9

regulation are negligible in percentage terms (less than 0.01 percent) as well as in comparison to the observed trends in the U.S. natural gas market. For example, between 1992 and 1993, the average annual wellhead price increased by 14 percent, while domestic production of natural gas rose by 3 percent.

For transmission and storage, a screening analysis of impacts at the firm level was conducted. If this indicated substantial impacts a full market model as utilized for natural gas production could have been developed. The screening analysis showed:

1) that only 7 firms are estimated to be impacted,
2) that total compliance costs on this industry ($300,000) represent only 2/100ths of one percent (0.02%) of industry revenues, and

3) that compliance costs for individuals firms are likely to represent less than one percent of firm revenues for the affected firms.

Furthermore, the market adjustments in price and quantity allow calculation of the economic welfare impacts (i.e., changes in the aggregate economic welfare as measured by consumer and producer surplus changes). These estimates represent the social cost of the regulation. For natural gas production, transmission, and storage, the annual social cost of the regulation is $4.9 million. This measure of social cost is preferred to the national cost estimates from the engineering analysis because it accounts for the market adjustments and the associated deadweight loss to society of the reallocation of resources.

ES.4 REGULATORY FLEXIBILITY ANALYSIS

Environmental regulations such as this final rule for the oil and natural gas production and the natural gas transmission and storage industry affect all businesses, large and small, but small businesses may have special problems in complying with such regulations. The Regulatory Flexibility Act (RFA) of 1980 requires that special consideration be given to small entities affected by Federal regulation. Under the 1992 revised EPA guidelines for implementing the Regulatory Flexibility Act, an initial regulatory flexibility analysis (IRFA) and a final regulatory flexibility analysis (FRFA) will be performed for every rule subject to the Act that will have any economic impact, however small, on any small entities that are subject to the rule, however few, even though EPA may not be legally required to do so. The Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996 further amended the RFA by expanding judicial and small business review of EPA rulemaking. Although small business impacts are expected to be minimal due to the size cutoff for TEG dehydration units, this firm-level analysis addresses the RFA requirements by measuring the impacts on small entities.

Potentially affected firms include entities that own production wells and/or processing plants and equipment involved in oil and natural gas production, transmission or storage. For the production sector, we use financial information from the Oil and Gas Journal(OGJ)and financial ratios from Dun and Bradstreet to characterize the financial status of a sample of 80 firms potentially affected by the regulation. Firms in this sample include major and independent producers of oil and natural gas in addition to interstate pipeline and local distribution companies primarily involved in natural gas. According to Small Business Administration general size standard definitions for SIC codes, a total of 39 firms included in this analysis, or 48.8 percent, are defined as small. For the natural gas transmission and storage sector, we use information from the OGJs special issue of "Pipeline Economics" to determine impacts on small businesses. With regulation, the change in measures of profitability for production firms are minimal with no overall disparity across small and large firms, while the likelihood of financial failure is unaffected for both small and large firms. Likewise, for the transmission and storage sector, impacts are minimal because the majority of firms included in our analysis have compliance cost-to-revenues ratios below one percent. Therefore, there is no evidence of any disproportionate impacts on small entities due to the final rule on the oil and natural gas production industry.

SECTION 1
INTRODUCTION

The U.S. Environmental Protection Agency (EPA or the Agency) is developing an air pollution regulation for reducing emissions generated by the oil and natural gas production and natural gas transmission and storage source categories. EPA has developed a National Emission Standard for Hazardous Air Pollutants (NESHAP) for each category of major sources under the authority of Section 112(d) of the Clean Air Act as amended in 1990. The Innovative Strategies and Economics Group (ISEG) of EPA contributes to this effort by providing analyses and supporting documents that describe the likely economic impacts of the standards on directly and indirectly affected entities.

1.1 SCOPE AND PURPOSE

This report evaluates the economic impacts of pollution control requirements for the oil and natural gas production and natural gas transmission and storage source categories that are designed to control releases of hazardous air pollutants (HAPs) to the atmosphere. The Clean Air Act's purpose is "to protect and enhance the quality of the Nation's air resources" (Section 101[b]). Section 112 of the Clean Air Act as amended in 1990 establishes the authority to set national emission standards for the 189 HAPs listed in this section of the Act.

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 considering control, 10 tons or more of any one HAP or 25 tons or more of any combination of HAPs. Special provisions in Section 112(n)(4) for oil and gas wells and pipeline facilities affect major source determinations for these facilities.

For HAPs, the Agency establishes Maximum Achievable Control Technology (MACT) standards. The term "MACT floor" refers to the minimum control technology on which MACT can be based. For existing major sources, the MACT floor is the average emissions limitation achieved by the best performing 12 percent of sources (if the category or subcategory includes 30 or more sources), or the best performing five sources (if the category or subcategory includes fewer than 30 sources). MACT can be more stringent than the floor, considering costs, nonair quality health and environmental impacts, and energy requirements.

1.2 ORGANIZATION OF THE REPORT

The remainder of this report is divided into four sections that support and provide details on the methodology and results of this analysis. The sections include the following:

- Section 2 introduces the reader to the oil and natural gas production and natural gas transmission and storage source categories. It begins with an overview of the oil and natural gas industry and presents data on products and markets, production units, and the companies that own and operate the production and storage units.

- Section 3 reviews the model plants, regulatory control options, and associated costs of compliance as detailed in the draft Background Information Document (BID) prepared in support of the regulations.

- Section 4 describes the methodology for assessing the economic impacts of the regulation and the analysis results.

- Section 5 explains the methodology for assessing the company-level impacts of the regulation including an initial regulatory flexibility analysis to evaluate the small business effects of the regulation.

SECTION 2
INDUSTRY PROFILE

The petroleum industry is divided into five distinct sectors: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. The NESHAP considers controls for the products and processes of the production and transportation sectors of the petroleum industry. Specifically, the oil and natural gas production and natural gas transmission and storage source categories include the separation, upgrading, storage, and transfer of extracted streams that are recovered from production wells. Thus, it includes the production and custody transfer up to the refining stage for crude oil and up to the city gate for natural gas.

Most crude oil and natural gas production facilities are classified under SIC code 1311--Crude Oil and Natural Gas Exploration and Production, while most natural gas transmission and storage facilities are classified under SIC 4923--Natural Gas Transmission and Distribution. The outputs of the oil and natural gas production industry--crude oil and natural gas--are the inputs for larger production processes of gas, energy, and petroleum products. In 1992, an estimated 594,189 crude oil wells and 280,899 natural gas production wells operated in the United States. U.S. natural gas production was 18.3 trillion cubic feet (Tcf) in 1993, continuing the upward trend since 1986, while U.S. crude oil production in 1992 was 7.2 million barrels per day (MMbpd), which is the lowest level in 30 years. The leading domestic oil and gas producing states are Alaska, Texas, Louisiana, California, Oklahoma, New Mexico, and Kansas.

The remainder of this section provides a brief introduction to the oil and natural gas production industry. The purpose is to give the reader a general understanding of the technical and economic aspects of the industry that must be addressed in the economic impact analysis. Section 2.1 provides an overview of the oil and natural gas production processes employed in the U.S. with an emphasis on those affected directly by the regulation. Section 2.2 presents historical data on crude oil and natural gas including reserves, production, consumption, and foreign trade. Section 2.3 summarizes the number of production facilities by type, location, and other parameters, while Section 2.4 provides general information on the potentially affected companies that own oil and natural gas production facilities.

2.1 PRODUCTION PROCESSES

Production occurs within the contiguous 48 United States, Alaska, and at offshore facilities in Federal and State waters. Figure 2-1 shows that, in the production process, extracted streams from production wells are transported from the wellhead (through offshore production platforms in the case of offshore wells) to tank batteries to separate crude oil, natural gas, condensates, and water from the product. Crude oil products are then transported through pump stations to a refinery, while natural gas products are directed to gas processing plants and then to final transmission lines at city gates. The equipment required in the production of crude oil and natural gas includes production wells (including offshore production platforms), separators, dehydration units, tank batteries, and natural gas processing plants.

2.1.1 Production Wells and Extracted Products

The type of production well used in the extraction process depends on the region of the country in which the well

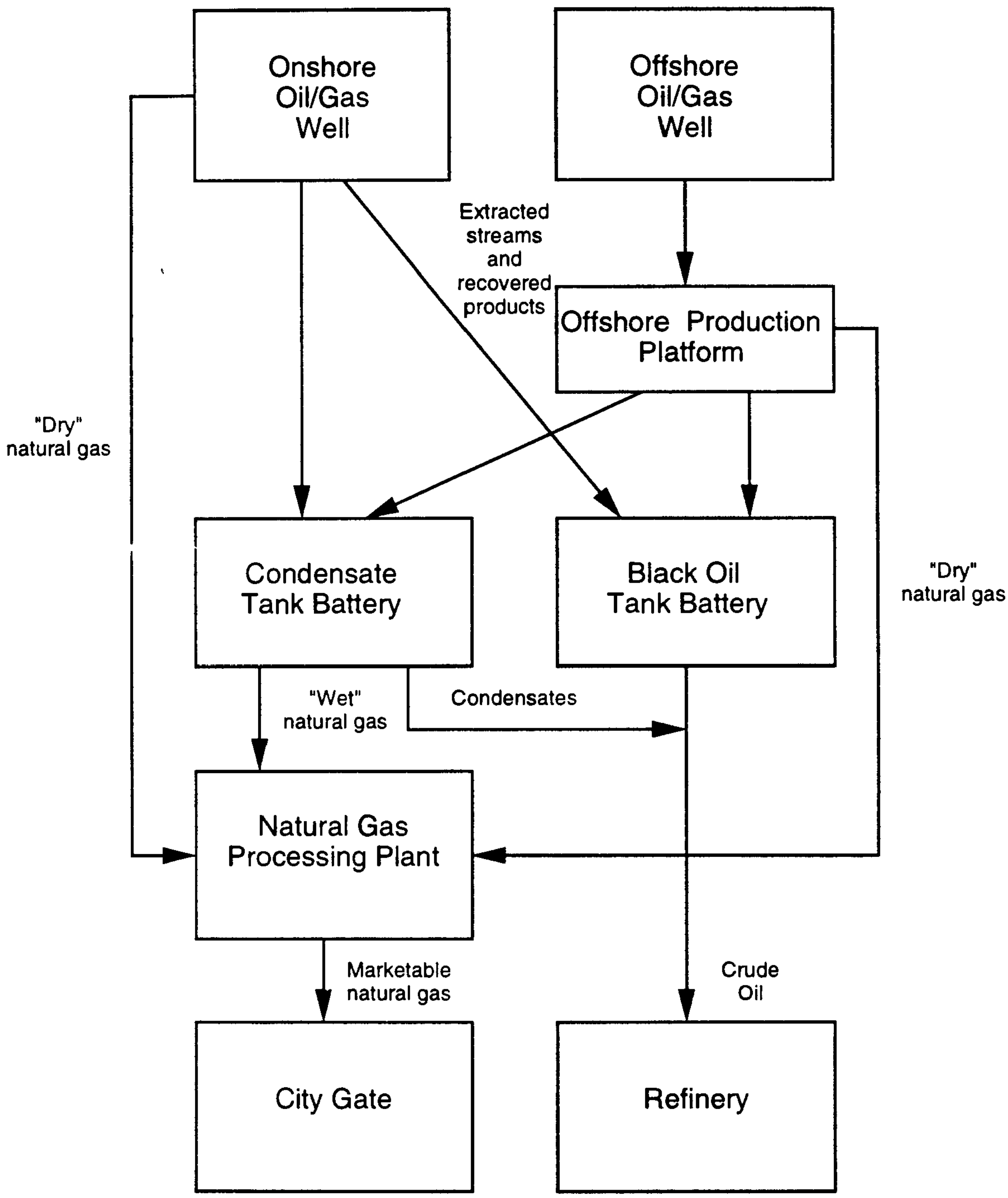

Figure 2-1. Crude oil and natural gas production flow diagram.

is drilled and the composition of the well stream. The recovered natural resources are naturally or artificially brought to the surface where the products (crude oil, condensate, and natural gas) are separated from produced water and other impurities. Offshore production platforms are used to extract, treat, and separate recovered products in offshore areas. Processes and operations at offshore production platforms are similar to those located at onshore facilities except that offshore platforms generally have little or no storage capacity because of the limited available space.[1]

Each producing well has its own unique properties in that the composition of the well stream (i.e., crude oil and the attendant gas) is different from that of any other well. As a result, most wells produce a combination of oil and gas; however, some wells can produce primarily crude oil and condensate with little natural gas, while others may produce only natural gas. The primary extracted streams and recovered products associated with the oil and natural gas industry include crude oil, natural gas, condensate, and produced water. These are briefly described below.

Crude oil can be broadly classified as paraffinic, naphthenic, or intermediate. Paraffinic (or heavy) crude is used as an input to the manufacture of lube oils and kerosene. Naphthenic (or light) crude is used as an input to the manufacture of gasolines and asphalt. Intermediate crudes are those that do not fit into either category. The classification of crude oil is determined by a gravity measure developed by the American Petroleum Institute (API). API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the API. A heavy or paraffinic crude is one with an API gravity of 20° or less, and a light or naphthenic crude, which flows freely at atmospheric temperatures, usually has an API gravity in the range of the high 30s to the low 40s.[2]

Natural gas is a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist either in gaseous phase or in solution with crude oil from underground reservoirs. Natural gas may be classified as wet or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is natural gas whose water content has been reduced through dehydration, or natural gas that contains little or no commercially recoverable liquid hydrocarbons.

Condensates are hydrocarbons that are in a gaseous state under reservoir conditions (prior to production), but which become liquid during the production process. Condensates have an API gravity in the 50° to 120° range.[3] According to historical data, condensates account for approximately 4.5 to 5 percent of total crude oil production.

Produced water is recovered from a production well or is separated from the extracted hydrocarbon streams. More than 90 percent of produced water is reinjected into the well for disposal and to enhance production by providing increased pressure during extraction. An additional 7 percent of produced water is released into surface water under provisions of the Clean Water Act. The remaining 3 percent of produced water extracted from production wells is disposed of as waste.

In addition to the products discussed above, other various hydrocarbons may be recovered through the processing of the extracted streams. These hydrocarbons include mixed natural gas liquids, natural gasoline, propane, butane, and liquefied petroleum gas.

2.1.2 Dehydration Units

Once the natural gas has been separated from the crude oil or condensate and water, residual water is removed from the natural gas by dehydration to meet sales contract specifications or to improve heating values for fuel consumption. Liquid desiccant dehydration is the most widespread technology used for natural gas with the most common process being a basic glycol system. Glycol dehydration is an absorption process in which a liquid absorbent, a glycol, directly contacts the natural gas stream and absorbs the water vapor that is later boiled off. Glycol units in operation today may use ethylene glycol (EG), diethylene glycol (DEG), triethylene glycol (TEG), and tetraethylene glycol (TREG).[4]

Dehydration units are used at several processing points in the process to remove water vapor from the gas once it has been separated from the crude oil or condensate and water. Locations where dehydration may occur include the production well site, the condensate tank battery, the natural gas processing plant, aboveground and underground storage facilities upon removal, and the city gate.

2.1.3 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. As shown in Figure 2-2, the extracted products enter the tank battery through the production header, which may collect the product from many production wells. Process equipment at a tank battery may include separators that separate the product from basic sediment and water; dehydration units; heater treaters, free water knockouts, and gunbarrel separation tanks that basically remove water and gas from crude oil; and storage tanks that temporarily store produced water and crude oil.[5]

Tank batteries are classified as black oil tank batteries if the extracted stream from the production wells primarily

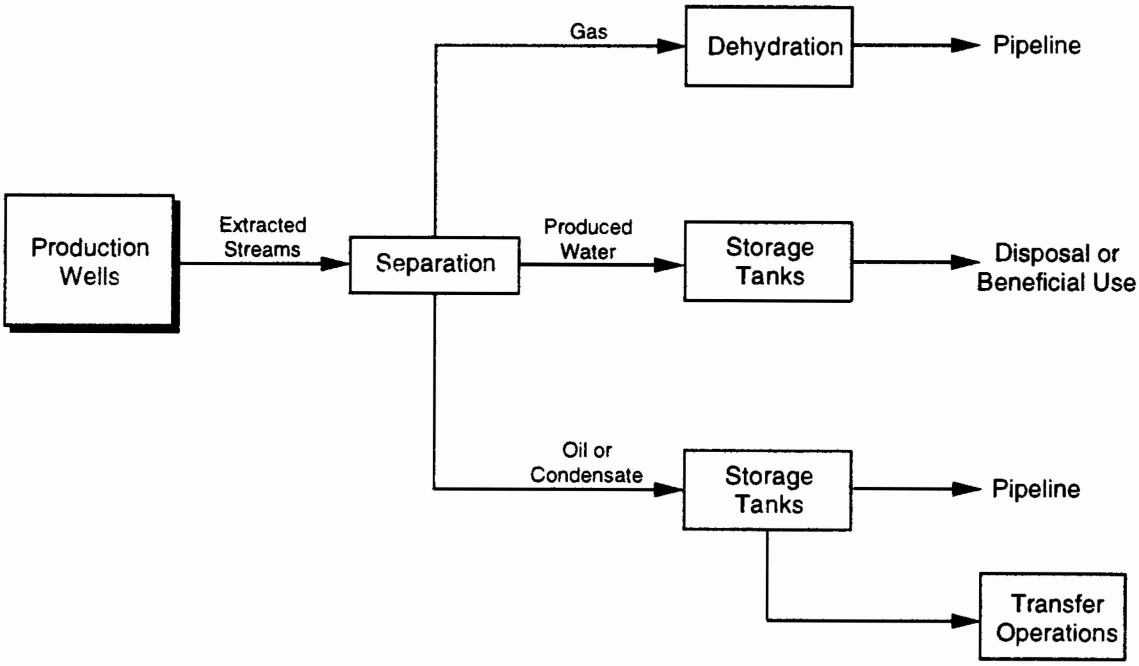

Figure 2-2. Summary of processes at a tank battery.

consists of crude oil that has little, if any, associated gas. In general, any associated gas recovered at a black oil tank battery is flared. Condensate tank batteries are those that process extracted streams from production wells consisting of condensate and natural gas. Dehydration units are part of the process equipment at condensate tank batteries but not at black oil tank batteries.

2.1.4 Natural Gas Processing Plants

Natural gas that is separated from other products of the extracted stream at the tank battery is then transferred via pipeline to a natural gas processing plant. As shown in Figure 2-3 the main functions of a natural gas processing plant include conditioning the gas by separation of natural gas liquids (NGL) from the gas and fractionation of NGLs into separate components, or desired products that include ethane, propane, butane, liquid petroleum gas, and natural gasoline. Generally, gas is dehydrated prior to other processes at a plant. Another function of these facilities is to control the quality of the processed natural gas stream. If the natural gas contains hydrogen sulfide and carbon dioxide, then

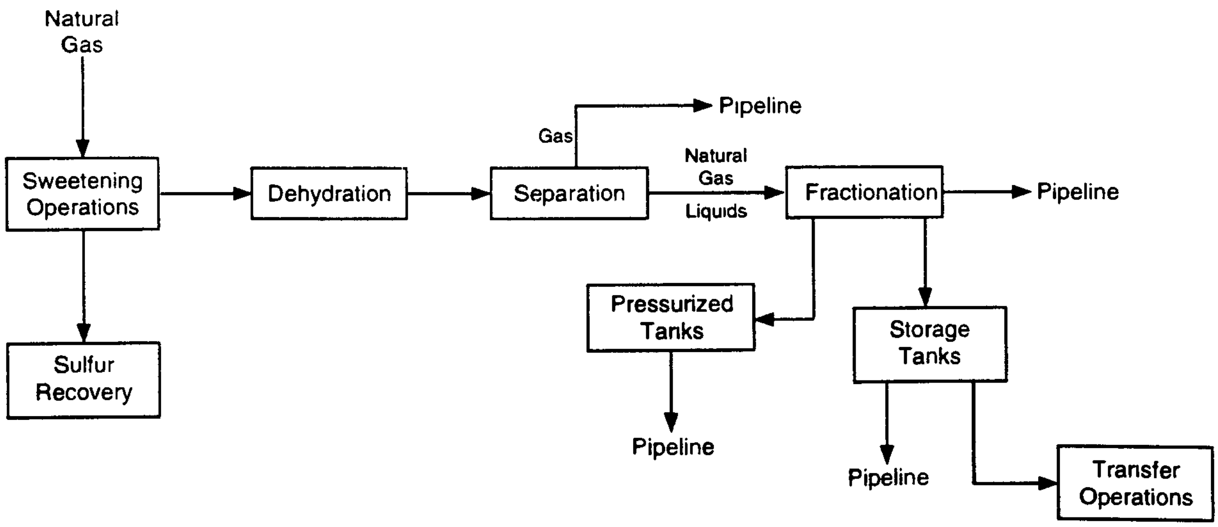

Figure 2-3. Summary of processes at natural gas processing plant.

sweetening operations are employed to remove these contaminants from the natural gas stream immediately after separation and dehydration.

2.1.5 Natural Gas Transmission and Storage Facilities

After processing, natural gas enters a network of pipelines and storage systems. The natural gas transmission and storage source category consists of gathering lines, compressor stations, high-pressure transmission pipeline, and underground storage sites.

Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. 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 engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure.

Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.2 PRODUCTS AND MARKETS

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, is typically consumed close to where it is produced. Final products of crude oil are used primarily as engine fuel for automobiles, airplanes, and other types of vehicles. Natural gas, on the other hand, is used primarily as boiler fuel for industrial, commercial, and residential applications.

2.2.1 Crude Oil

The following subsections provide historical data on the U.S. reserves, production, consumption, and foreign trade of crude oil.

2.2.1.1 Reserves. The Department of Energy defines oil reserves as "oil reserves that data demonstrate are capable of being recovered in the future given existing economic and operating conditions."[6] Table 2-1 provides total U.S. crude oil reserves for 1976 through 1993.[7] Crude oil reserves continued their decline for the sixth consecutive year in 1993, dropping by 788 million barrels (3.3 percent) to 2.3 billion barrels. Low oil prices and decreased drilling activity are the major factors for these recent declines.

Table 2-2 presents the U.S. proved reserves of crude oil as of December 31, 1993, by State or producing area.[8] As this table indicates, five areas currently account for 80 percent of the U.S. total proved reserves of crude oil with Texas leading all other areas, followed closely by Alaska, California, the Gulf of Mexico, and New Mexico. Texas, Alaska, and California accounted for roughly 82 percent of the overall decline in crude oil reserves from 1992 to 1993. Meanwhile, the Gulf of Mexico Federal Offshore had an oil reserve increase of 237 million barrels.

2.2.1.2 Domestic Production. Because oil is an international commodity, the U.S. production of crude oil is affected by the world crude oil price, the price of

TABLE 2-1. TOTAL U.S. PROVED RESERVES OF CRUDE OIL, 1976 THROUGH 1993
(million barrels of 42 U.S. gallons)

Year	Total discoveries	Production	Proved reserves
1976			33,502[a]
1977	794	2,862	31,780
1978	827	3,008	31,355
1979	636	2,955	29,810
1980	862	2,975	29,805
1981	1,161	2,949	29,426
1982	1,031	2,950	27,858
1983	924	3,020	27,735
1984	1,144	3,037	28,446
1985	995	3,052	28,416
1986	534	2,973	26,889
1987	691	2,873	27,256
1988	553	2,811	26,825
1989	716	2,586	26,501
1990	689	2,505	26,254
1991	554	2,512	24,682
1992	484	2,446	23,745
1993	785	2,339	22,957

[a]Based on following year data only.

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

alternative fuels, and existing regulations. Domestic oil production is currently in a state of decline that began in 1970. Table 2-3 shows U.S. production in 1992 at 7.2 MMbpd, which is the lowest level in 30 years.[9] Domestic production of crude oil has dropped by almost 2 MMbpd since 1985. This decline has been attributed to a transfer of U.S. investment from domestic sources to foreign production.*

*The investment in foreign ventures is spurred by low labor costs and less stringent regulatory environments abroad, as well as the increased likelihood of discovering larger fields in overseas activity.

TABLE 2-2. U.S. CRUDE OIL RESERVES BY STATE AND AREA, 1993
(million barrels)

State/area	Proved reserves 12/31/92	Total discoveries and adjustments	Production	Proved reserves 12/31/93
Alaska	6,022	332	579	5,775
Alabama	41	10	10	41
Arkansas	58	17	10	65
California	3,893	161	290	3,764
Colorado	304	10	30	284
Florida	36	10	6	40
Illinois	138	-7	15	116
Indiana	17	0	2	15
Kansas	310	9	48	271
Kentucky	34	-5	3	26
Louisiana	668	77	106	639
Michigan	102	0	12	90
Mississippi	165	-12	20	133
Montana	193	-6	16	171
Nebraska	26	-1	5	20
New Mexico	757	14	64	707
North Dakota	237	19	30	226
Ohio	58	4	8	54
Oklahoma	698	68	86	680
Pennsylvania	16	-1	1	14
Texas	6,441	309	579	6,171
Utah	217	31	20	228
West Virginia	27	-1	2	24
Wyoming	689	13	78	624
Federal offshore	2,569	492	316	2,745
Pacific (California)	734	-11	50	673
Gulf of Mexico (Louisiana)	1,643	489	252	1,880
Gulf of Mexico (Texas)	192	14	14	192
Miscellaneous	29	8	3	34
Total, lower 48 States	17,723	1,219	1,760	17,182
Total, U.S.	23,745	1,551	2,339	22,957

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

TABLE 2-3. U.S. CRUDE OIL PRODUCTION, 1982-1992

Year	Crude oil production (MMbpd)
1982	8.65
1983	8.69
1984	8.88
1985	9.00
1986	8.68
1987	8.35
1988	8.14
1989	7.61
1990	7.36
1991	7.42
1992	7.17

Source: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.

2.2.1.3 Domestic Consumption. Crude oil is the primary input to the production of several petroleum products. Consequently, the demand for crude oil is derived from the demand of these final products. Final petroleum products include motor gasoline, diesel fuel, jet fuel, and fuels for the industrial, residential, and commercial sectors as well as for electric utilities. Historical crude oil consumption trends for 1980 through 1992 are shown in Table 2-4.[10,11] As shown in this table, a slight upturn in demand occurred in 1988, and consumption then remained fairly constant through 1992.

2.2.1.4 Foreign Trade. The world oil market is unique in that it is dominated by the Organization of Petroleum Exporting Countries (OPEC), which applies the following

TABLE 2-4. TOTAL U.S. CRUDE OIL CONSUMPTION AND PRICE LEVELS, 1980-1992

Year	Domestic consumption (MMbpd)	Crude oil domestic wellhead price ($/barrel) Current dollars	Constant 1990 dollars
1980	17.06	21.6	34.2
1981	16.06	31.8	45.7
1982	15.30	28.5	38.6
1983	15.23	26.2	34.4
1984	15.73	25.9	32.6
1985	15.73	24.1	29.3
1986	16.28	12.5	14.9
1987	16.67	15.4	17.7
1988	17.28	12.6	13.9
1989	17.33	15.9	16.8
1990	16.99	20.0	20.0
1991	16.70	16.5	15.8
1992	17.00	16.0	14.7

Sources: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

economic principle: if supply is restricted, prices will rise. OPEC accounts for 38 percent of the world oil supply, while the U.S. accounts for 12 percent. Supplies from the OPEC exert a significant influence on domestic crude oil foreign trade levels. In February 1992, OPEC reimposed quotas on individual country output. The new quota signified a reduction in production intended to alter world oil prices. Any future additions to OPEC supply could reduce world crude oil prices. Additionally, if supplies to the world oil supply from the Commonwealth of Independent States (CIS) continue to decline, excess OPEC supplies can be absorbed without a significant crude oil price reduction.

As Table 2-5 demonstrates, U.S. imports of crude oil have increased steadily since 1983 at an average annual growth rate of 9.6 percent, while U.S. exports have steadily declined at an average of 4 percent annually.[12] This has resulted in a net import level in 1992 of 6 MMbpd. Oil imports are projected to exceed 8.2 MMbpd in 1993. This annual growth rate of 4.7 percent is measurably higher than the 2.9 percent rate registered in 1992.[13] Total oil imports are predicted to reach 10.1 MMbpd by the year 2000. This predicted rise in imports of crude oil corresponds to an average annual increase of 3.4 percent. The import dependency ratio is forecast to rise to 55 percent in 2000, compared to 48 percent in 1993.[14] As a result of the historical decline in domestic production and increases in demand levels, net imports of crude oil are expected to continue to increase.

TABLE 2-5. SUMMARY OF U.S. FOREIGN TRADE OF CRUDE OIL, 1983-1992

Year	Imports (MMbpd)	Domestic crude oil consumption (MMbpd)	Import percentage of domestic consumption	Exports (MMbpd)	Domestic crude oil output (MMbpd)	Export percentage of domestic output
1983	3.10	15.23	20.3	0.16	8.6	2.0
1984	3.23	15.73	20.5	0.18	8.9	2.0
1985	3.08	15.73	19.6	0.20	9.0	2.2
1986	4.13	16.28	25.4	0.15	8.7	1.7
1987	4.60	16.67	27.6	0.15	8.3	1.8
1988	5.06	17.28	29.3	0.15	8.1	1.9
1989	5.79	17.33	33.4	0.14	7.6	1.8
1990	5.87	16.99	34.5	0.11	7.4	1.5
1991	5.78	16.70	34.6	0.12	7.4	1.6
1992	6.07	17.00	35.7	0.09	7.2	1.3

Source: U.S. Department of Energy. Annual Energy Review 1991. DOE/EIA-0384(91). June 1992.

2.2.1.5 Future Trends. Table 2-6 presents the U.S. Department of Energy's annual projections of crude oil production, consumption, and world oil price from 1993 through 2010 based on two rates of economic growth and two possible oil price scenarios.[15] U.S. crude oil supply is predicted to continue to decline between 1993 and 2010, due to low levels of drilling activities in recent years. The range of projections for 2010 is from 6.2 to 3.6 MMbpd. According to the Independent Petroleum Association of America (IPAA), U.S. crude oil production is predicted to continue its decline from 7.0 MMbpd in 1993 to 6 MMbpd by 2000.[16] This will be the lowest oil output level since 1950.

TABLE 2-6. SUPPLY, DEMAND, AND PRICE PROJECTIONS FOR CRUDE OIL, 1993-2010

		Alternative projections to 2010			
Item	Actual 1993	High economic growth	Low economic growth	High oil price	Low oil price
Production (MMbpd)	6.85	5.57	5.23	6.20	3.58
Consumption[a] (MMbpd)	15.30	15.9	15.9	15.8	16.00
World oil price (1993 $/barrel)	16.12	24.99	23.29	28.99	14.65

[a]Consumption is measured by U.S. refinery capacity.

Source: U.S. Department of Energy. Annual Energy Outlook 1995. DOE/EIA-0383(95). January 1995.

2.2.2 Natural Gas

The following subsections provide historical data on the U.S. reserves, production, consumption, and foreign trade of natural gas.

2.2.2.1 Reserves. Proved reserves of natural gas are the estimated amount of gas that can be found and developed in future years from known reservoirs under current prices and technologies.[17] Table 2-7 provides total U.S. natural gas reserves for 1976 through 1993.[18] Although natural gas discoveries were up considerably in 1993, increased production along with lower revisions and adjustments (resulting from new information about known gas reservoirs) led to a decline in overall natural gas reserves of 2.6 Tcf to total 162.4 Tcf. This decline reflects a 1.6 percent change in reserves from the 1992 level.

TABLE 2-7. U.S. PROVED RESERVES OF DRY NATURAL GAS, 1976 THROUGH 1993
(billion cubic feet [Bcf] at 14.73 psia and 60° F)

Year	Total discoveries	Production	Proved reserves
1976			213,278[a]
1977	14,603	18,843	207,413
1978	18,021	18,805	208,033
1979	14,704	19,257	200,997
1980	14,473	18,699	199,021
1981	17,220	18,737	201,730
1982	14,455	17,506	201,512
1983	11,448	15,788	200,247
1984	13,521	17,193	197,463
1985	11,128	15,985	193,369
1986	8,935	15,610	191,586
1987	7,175	16,114	187,211
1988	10,350	16,670	168,024
1989	10,032	16,983	167,116
1990	12,368	17,233	169,346
1991	7,542	17,202	167,062
1992	7,048	17,423	165,015
1993	8,868	17,789	162,415

[a]Based on following year data only.

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

Table 2-8 presents the U.S. proved reserves of natural gas as of December 31, 1993, by State or producing area.[19,20] As indicated by this table, the five leading gas producing areas of Texas, the Gulf of Mexico, Oklahoma, Louisiana, and New Mexico all had declines in proved reserves from 1992 to 1993 totaling 2.6 Tcf. These declines were partially offset by substantial increases in Virginia and Colorado, where gas reserves increased by 942 Bcf over 1992.

2.2.2.2 Domestic Production. Natural gas production trends are distinct from those of crude oil. As shown in Table 2-9, production has been increasing since 1986.[21,22] This trend can be partially attributed to open access to pipeline transportation, which has resulted in more marketing opportunities for producers and greater competition, leading to higher production. Traditionally, most natural gas sold at the wellhead was sold under long-term, price-regulated contracts and purchased by pipeline companies. These pipeline companies in turn resold it to local distribution companies (from the "wellhead" to the "city gate"). Therefore, the pipelines transported natural gas as part of a larger package of "bundled" services that include acquisition and transportation. Local distribution companies then distribute gas to residential, commercial, and industrial customers and electric utilities (from the "city gate" to the "burner tip"). The end-user price thus reflected the cost of acquisition plus the cost of transport and other services along with the regulator-specified fair rate of return on investment.

The Natural Gas Policy Act (NGPA) of 1978 and subsequent Federal Energy Regulatory Commission (FERC) orders throughout the 1980s promoting open access transportation have dramatically altered the industry organization of the U.S.

TABLE 2-8. U.S. NATURAL GAS RESERVES BY STATE AND AREA, 1993
(Bcf)

State/area	Proved reserves 12/30/92	Total discoveries and adjustments	Production	Proved reserves 12/30/93
Alaska	9,725	657	396	9,986
Alabama	5,870	-371	287	5,212
Arkansas	1,752	-9	188	1,555
California	2,892	169	262	2,799
Colorado	6,463	922	406	6,979
Florida	55	12	8	59
Kansas	10,302	264	694	9,872
Kentucky	1,126	-22	68	1,036
Louisiana	10,227	830	1,516	9,541
Michigan	1,290	75	147	1,218
Mississippi	873	38	111	800
Montana	875	-141	50	684
New Mexico	20,339	1,019	1,419	19,939
New York	329	-43	22	264
North Dakota	567	75	57	585
Ohio	1,161	66	121	1,106
Oklahoma	14,732	1,246	1,879	14,099
Pennsylvania	1,533	328	139	1,722
Texas	38,141	4,736	5,030	37,847
Utah	2,018	358	178	2,198
Virginia	904	454	36	1,322
West Virginia	2,491	286	179	2,598
Wyoming	11,305	824	742	11,387
Federal offshore	28,186	4,096	4,696	27,586
Pacific (California)	1,136	32	45	1,123
Gulf of Mexico (Louisiana)	20,006	3,128	3,383	19,751
Gulf of Mexico (Texas)	7,044	936	1,268	6,712
Other states	93	13	10	96
Total, lower 48 States	163,584	15,165	18,245	160,504
Total, U.S.	173,309	15,822	18,641	170,490

Sources: U.S. Department of Energy, Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

TABLE 2-9. U.S. NATURAL GAS PRODUCTION AND WELLHEAD PRICE LEVELS, 1980-1992

Year	Domestic production (Tcf)	Average annual wellhead price ($/Mcf)	
		Current dollars	Constant 1990 dollars
1980	20.18	1.6	2.5
1981	19.96	2.0	2.9
1982	17.82	2.5	3.4
1983	16.09	2.6	3.4
1984	17.47	2.7	3.3
1985	16.45	2.5	3.0
1986	16.06	1.9	2.3
1987	16.62	1.7	2.0
1988	17.10	1.7	1.9
1989	17.31	1.7	1.8
1990	17.81	1.7	1.7
1991	17.87	1.6	1.5
1992	18.47	1.8	1.7

Sources: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

market for natural gas by separating the marketing and transport functions of interstate pipeline companies.* With the separation of transportation from production in the industry, much of the natural gas is purchased directly from producers, and the pipeline companies principally provide transportation services for their customers. Independent

*These Federal Energy Regulatory Commission orders include FERC Order No. 380, which effectively eliminated the requirement that customers of interstate pipelines purchase any minimum quantity of natural gas, and FERC Order No. 636, which mandates that pipelines must separate gas sales from transportation, thereby allowing open access to pipeline transportation for gas producers and customers.

brokers and other marketers service these transactions and bypass the traditional marketing structure.[*,23]

Also contributing to the increase in production shown in Table 2-9 are significant improvements in drilling productivity as well as more intensive utilization of existing fields since 1989. Because of lower prices in 1990 and 1991, however, producers have curtailed drilling programs and have sought ways to cut production costs, for example, by more intensive development of profitable onshore fields.

2.2.2.3 Domestic Consumption. Table 2-10 displays natural gas consumption by end user from 1980 to 1992, while Table 2-11 presents end-user prices for natural gas for the same time period.[24,25] Natural gas users include residential and commercial customers, as well as industrial firms and electric utilities. Since 1986, natural gas consumption has shown relatively steady growth, which is projected to continue through the year 2010. Because some consumers can substitute certain petroleum products for natural gas, prices of oil and gas often move in the same direction. Low crude oil prices after the 1986 price collapse, for example, effectively pushed competing gas prices lower.

2.2.2.4 Foreign Trade. On the international market, the U.S. and Canada are the world's leading producers of natural gas, accounting for more than 59 percent of the worldwide gas processing capacity (the U.S. accounts for nearly 42 percent alone) and more than 57 percent of world natural gas production. Table 2-12 displays the level of imports and exports of natural gas as well as the import share

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*Based on USDOE/EIA information for 1991, 84 percent of natural gas was transported to the market for marketers, local distribution companies (LDCs), and end users (45 percent for independent brokers and other marketers, 32 percent for local distribution companies, and 7 percent directly to end users) as compared with only 3 percent in 1982. The remaining 16 percent in 1991 was purchased at the wellhead by interstate pipeline companies for distribution.

TABLE 2-10. U.S. NATURAL GAS CONSUMPTION BY END-USE SECTOR, 1980-1992

	End-user consumption (Tcf)					
Year	Residential	Commercial	Industrial	Electric utilities	Other[a]	Total
1980	4.75	2.61	7.17	3.68	1.66	19.88
1981	4.55	2.52	7.13	3.64	1.57	19.40
1982	4.63	2.60	5.83	3.23	1.71	18.00
1983	4.38	2.43	5.64	2.91	1.47	16.84
1984	4.56	2.52	6.15	3.11	1.61	17.95
1985	4.43	2.43	5.90	3.04	1.47	17.28
1986	4.31	2.32	5.58	2.60	1.41	16.22
1987	4.31	2.43	5.95	2.84	1.67	17.21
1988	4.63	2.67	6.38	2.64	1.71	18.03
1989	4.78	2.71	6.82	2.79	1.70	18.80
1990	4.39	2.62	7.02	2.79	1.90	18.72
1991	4.56	2.73	7.23	2.79	1.75	19.05
1992	4.70	2.77	7.64	2.77	1.85	19.75

[a]Includes natural gas consumed as lease, plant, and pipeline fuel.

Source: Energy Statistics Sourcebook, 8th ed. PennWell Publishing Co. September 1993.

of U.S. domestic consumption and the export share of U.S. marketed production for the years 1973 through 1993. North American gas trade is a major factor in the competitive U.S. natural gas market. Natural gas imports no longer serve as a marginal source of supply but are actively competing for market share. As shown in Table 2-12, imports increased by 6 percent to 2.3 Tcf from 1992 to 1993 providing 11 percent of U.S. domestic consumption.[26] Canadian suppliers account for most of the natural gas imports to the United States. Although no significant changes in gas trade with Mexico are expected in the near future, the North American Free Trade Agreement (NAFTA) will assist in developing and integrating the Mexican gas industry.[27]

TABLE 2-11. U.S. NATURAL GAS PRICE BY END-USE SECTOR, 1980-1992

Year	End-use sector ($/Mcf) Residential	Commercial	Industrial	Electric utilities	Average
1980	$3.68	$3.39	$2.56	$2.27	$2.91
1981	$4.29	$4.00	$3.14	$2.89	$3.51
1982	$5.17	$4.82	$3.87	$3.48	$4.32
1983	$6.06	$5.59	$4.18	$3.58	$4.82
1984	$6.12	$5.55	$4.22	$3.70	$4.85
1985	$6.12	$5.50	$3.95	$3.55	$4.72
1986	$5.83	$5.00	$3.23	$2.43	$4.13
1987	$5.54	$4.77	$2.94	$2.32	$4.05
1988	$5.47	$4.63	$2.95	$2.33	$4.09
1989	$5.64	$4.74	$2.96	$2.43	$4.22
1990	$5.80	$4.83	$2.93	$2.39	$4.20
1991	$5.82	$4.81	$2.69	$2.18	NA
1992	$5.86	$4.87	$2.81	$2.37	NA

Source: Energy Statistics Sourcebook, 8th ed. Penn Well Publishing Co. September 1993.

Historically, imports of natural gas have increased at an average annual growth rate of 10.5 percent. Increases in natural gas imports have been driven by increased U.S. demand and additions to interstate pipeline capacity in 1991 and 1992. Exports have doubled since 1983 although yearly fluctuations have occurred. Net import levels have steadily increased over this time period to 1.79 Tcf in 1992. According to the IPAA, total gas imports, mainly from Canada, are èxpected to rise to 3.1 Tcf by 2000, up from 2.2 Tcf in 1992. This is an average increase of nearly 6 percent each year.

2.2.2.5 Future Trends. Currently, the domestic natural gas production industry is in transition from a period

TABLE 2-12. HISTORICAL SUMMARY OF U.S. NATURAL GAS FOREIGN TRADE, 1973-1993
(Bcf)

Year	Total imports	Total exports	Net imports	Total consumption	Net imports as a percentage of total consumption	Marketed production	Exports as a percentage of marketed production
1973	1,032.9	77.2	955.7	22,049.4	4.3	22,647.6	0.3
1974	959.2	76.8	882.5	21,223.1	4.2	21,600.5	0.4
1975	953.0	72.7	880.3	19,537.6	4.5	20,108.7	0.4
1976	963.8	64.7	899.1	19,946.5	4.5	19,952.4	0.3
1977	1,011.0	55.6	955.4	19,520.6	4.9	20,025.5	0.3
1978	965.5	52.5	913.0	19,627.5	4.7	19,974.0	0.3
1979	1,253.4	55.7	1,197.7	20,240.8	5.9	20,471.3	0.3
1980	984.8	48.7	936.0	19,877.3	4.7	20,379.7	0.2
1981	903.9	59.4	844.6	19,403.9	4.4	20,177.0	0.3
1982	933.3	51.7	881.6	18,001.1	4.9	18,519.7	0.3
1983	918.4	54.6	863.8	16,834.9	5.1	16,822.1	0.3
1984	843.0	54.8	788.3	17,950.5	4.4	18,229.6	0.3
1985	949.7	55.3	894.4	17,280.9	5.2	17,197.9	0.3
1986	750.5	61.3	689.2	16,221.3	4.2	16,858.7	0.4
1987	992.5	54.0	938.5	17,210.8	5.5	17,432.9	0.3
1988	1,293.8	73.6	1,220.2	18,029.6	6.8	17,918.5	0.4
1989	1,381.5	106.9	1,274.6	18,800.8	6.8	18,095.1	0.6
1990	1,532.3	85.6	1,446.7	18,716.3	7.7	18,593.8	0.5
1991	1,773.3	129.2	1,644.1	19,129.4	8.6	18,585.8	0.7
1992	2,137.5	216.3	1,921.2	19,726.2	9.7	18,616.9	1.2
1993	2,350.1	140.2	2,209.9	20,219.0[a]	10.9	19,251.0	0.7

[a]Preliminary data.

Notes: Totals may not equal sum of components due to independent rounding. Geographic coverage is the continental United States including Alaska.

Source: U.S. Department of Energy. Energy Information Administration. Natural Gas Monthly U.S. Natural Gas Imports and Exports--1993. August 1994.

of overcapacity to one near full capacity utilization. Since 1985, demand has grown in response to low prices while drilling activity remained depressed, lowering the gap that existed between demand and supply levels. While the U.S. has a relatively large potential gas reserve base available for development, current low market prices must increase to stimulate new drilling activity and meet projected demand growth. Natural gas supplies are expected to continue to increase through the 1990s, slowing near 2000 as deliverability through existing pipelines constrains the development of some gas markets.[28]

Table 2-13 presents the U.S. Department of Energy's annual projections of natural gas production, consumption, and wellhead prices from 1993 to 2010 based on three rates of economic growth. U.S. natural gas production and consumption are projected to increase steadily over the projection period.[29] The range of projections for 2010 is from 19.89 to 21.91 Tcf. According to the IPAA, natural gas production is expected to increase through the year 2000 at an average annual rate of 1.1 percent, reaching nearly 20 Tcf by the year 2000, up from an expected level of 18.3 Tcf in 1993.[30]

TABLE 2-13. SUPPLY, DEMAND, AND PRICE PROJECTIONS FOR NATURAL GAS, 1993-2010

		Alternative projections to 2010		
	Actual 1993	Base case economic growth	High economic growth	Low economic growth
Production (Tcf)	18.35	20.88	21.91	14.89
Consumption (Tcf)	20.21	24.59	25.85	23.18
Wellhead price (1993 $/Mcf)	2.02	3.39	3.74	3.01

Source: U.S. Department of Energy. Annual Energy Outlook 1995. DOE/EIA-0383(95). January 1995.

2.3 PRODUCTION FACILITIES

The following subsections provide details on the operating facilities of the oil and natural gas production industry including production wells, dehydration units, tank batteries, and natural gas processing plants.

2.3.1 Production Wells

Table 2-14 displays the number of crude oil and natural gas wells in operation from 1983 to 1992.[31] In 1992, an estimated 594,200 crude oil wells operated in the United States, and 280,900 natural gas production wells. For offshore production, an estimated 3,841 oil and gas production platforms operated in 1991 and were associated with a total of 33,000 wells. Natural gas production wells have increased in number steadily since 1983, while crude oil wells show more volatility.

TABLE 2-14. NUMBER OF CRUDE OIL AND NATURAL GAS WELLS, 1983-1992

Year	Natural gas producing wells	Crude oil producing wells
1983	170,300	603,300
1984	193,900	620,800
1985	214,100	646,600
1986	219,100	628,700
1987	214,600	621,200
1988	217,800	623,600
1989	232,100	606,900
1990	241,100	602,400
1991	265,100	610,200
1992	280,900	594,200

Source: U.S. Department of Energy. Natural Gas 1992: Issues and Trends. DOE/EIA-0560(92). Washington, DC. March 1993.

Table 2-15 details the distribution of oil and gas well capacity by production of barrels per month.[32] Small production wells dominate the industry. Stripper wells are defined as those production wells that produce less than 10 bpd or 60 Mcf per day. In 1989, over 80 percent of the oil wells produced less than 10 bpd or 0 to 300 barrels per month, and over 78 percent of the gas wells produced within the same range. The remaining production wells produce over a wide range, from levels of 301 barrels per month to over 5,000 barrels per month.

TABLE 2-15. U.S. ONSHORE OIL AND GAS WELL CAPACITY BY SIZE RANGE, 1989

Size range (barrels/ month)	Number of oil wells	Percentage of total	Number of gas wells	Percentage of total
0-60	306,032	49.5	135,231	51.8
61-100	67,150	10.9	24,049	9.2
101-200	76,926	12.4	28,144	10.8
201-300	47,263	7.6	17,765	6.8
301-400	20,631	3.3	10,859	4.2
401-500	21,433	3.5	6,957	2.7
501-600	13,044	2.1	5,442	2.0
601-1000	29,992	4.9	12,400	4.7
1001-2000	22,134	3.6	10,042	4.0
2001-5000	9,735	1.6	6,365	2.4
5001-Over	3,555	0.6	3,806	1.4
Total	617,895	100.0	261,060	100.0

Source: Gruy Engineering Corporation. Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry. Prepared for the American Petroleum Institute. July 20, 1991.

Table 2-16 presents the distribution of U.S. natural gas producing wells by state at the end of 1993.[33] According to World Oil, for 1993, a total of 286,168 natural gas producing wells operated at onshore and offshore locations in the

TABLE 2-16. DISTRIBUTION OF U.S. GAS WELLS BY STATE, 1993

State	1993 gas wells	Percentage of total (%)
Alabama	3,395	1.19
Alaska	157	0.05
Arkansas	2,914	1.02
California	1,072	0.37
Colorado	6,372	2.23
Federal OCS	3,532	1.23
Illinois	384	0.13
Indiana	1,327	0.46
Kansas	14,200	4.96
Kentucky	12,836	4.49
Louisiana	13,214	4.62
Michigan	3,174	1.11
Mississippi	552	0.19
Montana	2,900	1.01
Nebraska	60	0.02
New Mexico	27,832	9.73
New York	5,951	2.08
North Dakota	104	0.04
Ohio	34,581	12.08
Oklahoma	28,902	10.10
Pennsylvania	31,100	10.87
South Dakota	38	0.01
Tennessee	620	0.22
Texas	47,245	16.51
Utah	1,164	0.41
Virginia	1,340	0.47
West Virginia	38,280	13.38
Wyoming	2,880	1.01
Others	42	0.01
Total U.S.	286,168	100.00

Source: Producing Gas Well Numbers are up Once Again. World Oil. February 1993. Vol. 214, No.2.

continental U.S. and Alaska. As shown, Texas accounts for approximately 16.5 percent of U.S. natural gas wells with 47,245. A continued increase in U.S. natural gas wells is expected for 1994 based on increases in gas prices.

2.3.1.1 Gruy Engineering Corporation Database. Based on lease data, the Gruy Engineering Corporation developed "wellgroups" for both oil and gas wells in each of 37 different geographic areas across the United States.[34] For each geographic area, wellgroups are defined by well depth and then by production rate in each depth range. Four depth ranges were employed for oil wells: 0 to 2,000 feet; 2,001 to 6,000 feet; 6,001 to 10,000 feet; and deeper than 10,000 feet. Three depth ranges were developed for gas wells: 0 to 4,000 feet; 4,001 to 10,000 feet; and deeper than 10,000 feet. Furthermore, 11 production ranges were used for both oil and gas wells, expressed in barrels of oil equivalent (BOE), where one barrel of oil equals one BOE that equals 10 Mcf. The production rate ranges in BOE per month are 0 to 60; 61 to 100; 101 to 200; 201 to 300; 301 to 400; 401 to 500; 501 to 600; 601 to 1,000; 1,001 to 2,000; 2,001 to 5,000; and greater than 5,000. Therefore, each of the 37 geographic areas was divided into a possible 44 oil wellgroups and 33 gas wellgroups. The result of Gruy's analysis provides 1,004 oil wellgroups and 643 gas wellgroups (some regions had no wells of certain types). Appendix A provides data on the oil wellgroups developed by Gruy Engineering for each geographic area, and Appendix B provides data on the natural gas wellgroups.

2.3.2 Dehydration Units

The Gas Research Institute (GRI) estimates that the U.S. may have 40,000 or more glycol dehydration units. TEG and EG dehydration units account for approximately 95 percent of this total, with solid desiccant dehydration units accounting for the remaining 5 percent.[35] The primary application of solid desiccant dehydration units is to dehydrate natural gas streams at cryogenic natural gas processing plants.

For TEG dehydration units, stand-alone units dehydrate natural gas from an individual well or several wells, and units are collocated at condensate tank batteries and natural gas processing plants. Available information indicates that, on average, there is one TEG dehydration unit per condensate tank battery and two or four dehydration units (TEG, EG, or solid desiccant) per natural gas processing plant, depending on throughput capacity.[36,37]

2.3.3 Tank Batteries

According to the BID, approximately 94,000 tank batteries operated in the U.S. as of 1989.[38] Furthermore, over 85 percent of tank batteries, or an estimated 81,000 facilities, are classified as black oil tank batteries. The remaining 13,000 tank batteries are classified as condensate tank batteries.

2.3.4 Natural Gas Processing Plants

Table 2-17 shows the number of natural gas processing facilities in operation from 1987 to 1993 in the United States.[39] Over this time period the number of natural gas processing plants has declined by over 10 percent, or a total of 82 plants over 7 years. Table 2-18 provides the number of natural gas processing facilities as of January 1, 1994, the total processing capacity, and 1993 throughput level by State.[40] The States with the largest number of natural gas processing plants are Texas, Oklahoma, Louisiana, Colorado, and Wyoming, while the top states in terms of natural gas processing capacity are Texas, Louisiana, Alaska, Kansas, and Oklahoma.

TABLE 2-17. U.S. NATURAL GAS PROCESSING FACILITIES, 1987-1993

Year	Number of facilities
1987	810
1988	760
1989	745
1990	751
1991	748
1992	735
1993	728

Source: Gas Processing Report. Oil and Gas Journal. 92(24). June 1994.

2.3.5 Natural Gas Transmission and Storage Facilities

There are an estimated 300,000 miles of high-pressure transmission pipelines and approximately 1990 compressor stations in the U.S. In addition, the natural gas industry operates over 300 underground storage sites.

2.4 FIRM CHARACTERISTICS

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract and process extracted streams and recovered products to produce the raw materials crude oil and natural gas. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

TABLE 2-18. U.S. NATURAL GAS PROCESSING PLANTS, CAPACITY, AND THROUGHPUT AS OF JANUARY 1, 1994, BY STATE

		Natural gas (MMcfd)	
State	Number of plants	Capacity	1993 throughput
Alabama	9	785.0	700.7
Alaska	3	7,775.0	6,502.0
Arkansas	3	878.0	520.5
California	29	1,044.0	658.5
Colorado	50	1,596.5	1,128.6
Florida	2	890.0	622.0
Kansas	22	5,122.0	3,778.4
Kentucky	3	141.0	117.9
Louisiana	72	18,334.4	11,869.4
Michigan	28	4,731.9	858.6
Mississippi	6	884.2	209.5
Montana	6	19.5	6.8
New Mexico	34	2,889.0	2,122.2
North Dakota	6	122.9	83.2
Ohio	1	20.0	8.8
Oklahoma	94	4,656.8	2,857.5
Pennsylvania	2	14.0	8.3
Texas	293	17,259.5	12,002.5
Utah	14	624.9	416.2
West Virginia	7	398.9	337.9
Wyoming	41	3,783.7	2,973.6
Total U.S.	725	71,971.2	47,783.1

Source: "Worldwide Gas Processing Report." Oil & Gas Journal. 92(24):49110. June 13, 1994.

2.4.1 Ownership

The oil and natural gas industry may be divided into different segments that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry activities: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. Independent producers include smaller firms that are involved in some but not all of the five activities. Transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

During 1992, almost 7,700 companies owned the 9,391 establishments operating within SIC code 1311 (Crude Oil and Natural Gas).[41] For SIC 1311, the top 8 firms in 1992 accounted for 43.2 percent of the value of shipments, while the top 16 firms accounted for almost 60 percent. Furthermore, the top 8 firms accounted for 64 percent of industry crude oil production and 37 percent of industry natural gas production, while the top 16 firms accounted for 77.7 percent of industry crude oil production and 58.3 percent of industry natural gas production.[42]

Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. The Independent Petroleum Association of America reports that 70 percent of its members' income comes from natural gas production.[43] In 1993, gas production revenues exceeded oil production revenues for the first time, accounting for 56 percent ($38 billion) of total oil and gas industry production revenues. Higher wellhead prices for natural gas, increased efficiency, and lower production costs have all contributed to increased natural gas production and improvements in producer revenues.[44]

2.4.2 Size Distribution

The Small Business Administration (SBA) defines criteria for defining small businesses (firms) in each SIC. Table 2-19 lists the primary SICs to be affected by the proposed

TABLE 2-19. NUMBER AND PROPORTION OF FIRMS IN SMALL BUSINESS CATEGORY (BY SIC CODE)

SIC Code	SIC Description	SBA size standard in number of employees or annual sales	Number of firms	Number of firms meeting SBA standard	Percentage of firms meeting SBA standard
1311	Crude petroleum and natural gas	500	429	372	87%
1381	Drilling oil and gas wells	500	132	100	76%
1382	Oil and gas exploration services	$5 million	176	77	44%
2911	Petroleum refining	1,500	141	98	70%
4922	Natural gas transmission	$5 million	79	11	14%
4923	Gas transmission and distribution	$5 million	74	6	8%
4924	Natural gas distribution	500	121	71	59%

Source: Ward's Business Directory. Volume 2. Washington, DC. 1993.

regulations and their corresponding small business criteria. SICs 1311 and 1381 have the highest percentage of small businesses--87 percent and 76 percent respectively--and SICs 4922 and 4123 have the lowest percentage--8 percent and 14 percent respectively.[45]

2.4.3 Horizontal and Vertical Integration

Because of the existence of major oil companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one.

Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company owning oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosine. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons:

- A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation.
- A horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation.
- A horizontally integrated firm could be indirectly as well as directly affected by the regulation. For example, if a firm is diversified in manufacturing pollution control equipment (an unlikely scenario), the regulation could indirectly and favorably affect it.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of control of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is limited. Production, transmission, and local distribution of natural gas usually occur at individual firms. It is more likely that natural gas producers will sell their output either to a firm that will subject it to additional purification processes or directly to a pipeline for transport to an end user. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Of the independents' total revenues, 72 percent is derived from natural gas output, and the remaining 28 percent is from crude oil production. Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas. Overall, the independent producers sell their output to refineries or natural gas pipeline companies. They are typically not vertically integrated but may own one or two facilities, indicating limited horizontal integration.

2.4.4 Performance and Financial Status

In a special addition of the Oil and Gas Journal (OGJ), financial and operating results for the top 300 oil and natural gas companies are reported.[46] Table 2-20 lists selected statistics for the top 20 companies in 1993.[47] The results presented in the table reflect lower crude oil and petroleum prices in 1993, which suppressed revenues. However,

TABLE 2-20. TOP 20 OIL AND NATURAL GAS COMPANIES, 1993

Rank	Company	Total assets ($10^3)	Total revenue ($10^3)	Net income ($10^3)	Worldwide liquids production (Mil bbl)	Worldwide natural gas production (Bcf)	U.S. liquids production (Mil bbl)	U.S. natural gas production (Mil bbl)
1	Exxon Corp.	84,145,000	111,211,000	5,280,000	568.0	1,583.0	202.0	697.0
2	Mobil Corp.	40,585,000	63,975,000	2,084,000	285.0	1,665.0	111.0	558.0
3	Chevron Corp.	34,736,000	37,082,000	1,265,000	295.0	902.0	144.0	751.0
4	Amoco Corp.	28,486,000	28,617,000	1,820,000	236.0	1,487.0	100.0	867.0
5	Shell Oil Co.	26,851,000	21,092,000	781,000	170.0	553.0	147.0	539.0
6	Texaco Inc.	26,626,000	34,071,000	1,068,000	228.0	748.0	155.0	652.0
7	ARCO (Atlantic Richfield Corp.)	23,894,000	19,183,000	269,000	250.0	449.0	221.0	332.0
8	Occidental Petroleum Corp.	17,123,000	8,544,000	283,000	79.0	238.0	21.0	219.0
9	BP (USA)	14,864,000	15,714,000	1,461,000	--	--	228.9	33.6
10	Conoco Inc.	11,938,000	15,771,000	812,000	135.0	481.0	40.0	305.0
11	Enron Corp.	11,504,315	8,003,939	332,522	3.5	262.2	2.5	240.0
12	Phillips Petroleum Co.	10,868,000	12,545,000	243,000	89.0	509.0	47.0	345.0
13	USX-Marathon Group	10,806,000	11,962,000	-29,000	57.0	317.0	41.0	193.0
14	Coastal Corp.	10,277,100	10,136,100	115,800	4.9	122.0	4.9	122.0
15	Unocal Corp.	9,254,000	8,344,000	213,000	84.0	623.0	48.0	365.0
16	Amerada Hess Corp.	8,641,546	5,872,741	-268,203	79.0	323.0	26.0	183.0
17	Columbia Gas System	6,957,900	3,398,500	152,200	3.6	71.5	3.6	71.5
18	Ashland Oil Inc.	5,551,817	10,283,325	142,234	8.3	36.2	0.4	36.2
19	Consolidated Natural Gas Co.	5,409,586	3,194,616	205,916	3.9	124.0	3.9	124.0
20	Pennzoil Co.	4,886,203	2,782,397	141,856	24.0	223.0	24.0	220.0

Note: All values are in 1993 U.S. dollars.

Source: "Total Earnings Rose, Revenues Fell in 1993 for OGJ300 Companies." Oil and Gas Journal. 92(36):49-75. September 5, 1994.

higher natural gas prices, consumption, and production, as well as increased consumption of petroleum production, offset these trends. Total assets for the top 300 companies fell in 1993 for the third consecutive year, a reflection of continued industry restructuring and consolidation with mergers, acquisitions, and liquidations. As a result, the number of publicly held companies was slashed. The top 300 companies, however, represent a large portion of the U.S. oil and gas industry and indicate changes and trends in industry activity and operating performance.

Net income for OGJ's top 300 companies jumped 75.5 percent in 1993 to $18.3 billion, while total revenues fell 3.9 percent to $475.1 billion. Other measures of financial performance for the group showed improvement in 1993. Capital and exploration spending totaled $50.3 billion, up 1.8 percent from 1992. In addition, the number of U.S. net wells drilled rose 24.4 percent to 8,656. Table 2-21 provides 1993 performance highlights for the OGJ's group of 22 large U.S. oil companies.[48] Earnings for the group jumped sharply in 1993, increasing by 78.6 percent from 1992. Performance in 1993 restored group profits to the 1991 level even though total revenues for the group fell 3.8 percent to $436.3 billion in 1993. Lower crude oil and petroleum product prices were the main factors in the observed decline in revenues.

A more recent issue of OGJ reported on the economic status of all 110 major and nonmajor* natural gas pipeline companies in 1994.[49] Table 2-22 reports the sales volume, operating revenues, and net income for the top 10 U.S. natural gas pipeline companies in 1994. Operating revenues of the top

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*Major pipeline companies are those whose combined gas sold for resale and gas transported for a fee exceeded 50 bcf at 14.37 psi (60 degrees F) in each of the three previous calendar years. Nonmajors are natural gas pipeline companies not classified as majors and whose total gas sales of volume transactions exceeded 200 MMcf at 14.73 psi (60 degrees F) in each of the three previous calendar years.

TABLE 2-21. PERFORMANCE MEASURES FOR OGJ GROUP, 1993

Performance measure	1993 highlights
Total assets	$385.4 billion, down 1 percent
Net profits	$16.2 billion, up 78.6 percent
Return on equity	10.1 percent, up 4.8 points
Return on total assets	3.9 percent, up 1.9 points
Capital/exploration spending	$38.8 billion, down 5.8 percent
Net liquids production	8.4 million bpd, down 2 percent
Net natural gas production	30 bcfd, up 0.7 percent
Crude runs to stills	15.6 million bpd, up 1.2 percent
Liquid reserves	32 billion bbl, up 1.7 percent
Natural gas reserves	140.2 tcf, up 0.6 percent

Source: "Profits for OGJ Group Show Big Gain in 1993; Revenues Dip." Oil and Gas Journal. 92(24):25-30. June 13, 1994.

TABLE 2-22. PERFORMANCE OF TOP 10[a] GAS PIPELINE COMPANIES, 1994

Company	Net Income ($000)	Operating Revenues ($000)
Tennessee Gas Pipeline Co.	489,984	1,065,285
Natural Gas Pipeline of America	158,165	1,046,660
ANR Pipeline Co.	152,057	152,057
Texas Eastern Transmission Corp.	148,887	832,405
Panhandle Eastern Pipe Line Co.	112,910	384,771
Transcontinental Gas Pipe Line Corp.	110,726	1,590,962
Northern Natural Gas Co.	97,570	702,567
El Paso Natural Gas Co.	92,978	669,439
CNG Transmission Corp.	88,055	488,754
Florida Gas Transmission Co.	78,166	175,731
Total 1994	1,529,498	7,108,631
Total All Companies 1994	2,373,245	16,547,531
Total All Companies 1993	1,113,303	21,746,475

[a]Based on net income.

Source: "U.S. Interstate Pipelines Ran More Efficiently in 1994". Oil and Gas Journal, p. 39-58. November 27, 1995.

10 companies equaled $7,108,631 and represented 43 percent of the total operating revenues for major and nonmajor companies, which had declined by 24 percent from the previous year. Net income for the top 10 was over $1.5 billion and represented almost 65 percent of the total net income for all major and nonmajor companies. Despite the overall decline in operating revenues, the total net income for the 100 companies rose by 37 percent from 1993 to 1994.

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SECTION 3
REGULATORY CONTROL OPTIONS AND COSTS OF COMPLIANCE

The BID details the available technologies on which this NESHAP is based. Model plants were developed to evaluate the effects of various control options on the oil and natural gas production and natural gas transmission and storage source categories. Control options were selected based on the application of presently available control equipment and technologies and varying levels of capture consistent with different levels of overall control. Section 3.1 presents a brief description of the model plants. Section 3.2 provides an overview of the control options, and Section 3.3 summarizes the compliance costs associated with the regulatory control options.

3.1 MODEL PLANTS

The large number of production, processing, and storage facilities in the oil and natural gas industry necessitates using model plants to simulate the effects of applying the regulatory control options to this industry. A model plant does not represent any single actual facility; rather it represents a range of facilities with similar characteristics that may be affected by the regulation. Each model plant is characterized by facility type, size, and other parameters that influence the estimates of emissions and control costs. Model plants developed for the oil and natural gas production and natural gas transmission and storage source categories are

- TEG dehydration units,
- tank batteries that handle condensate (CTB),

- natural gas processing plants (NGPP), and
- offshore production platforms (OPP).

The following subsections identify these model plants and provide the estimated capacity, throughput, and population for each unit.*

3.1.1 TEG Dehydration Units

As shown in Table 3-1, the engineering analysis establishes five model TEG dehydration units based on natural gas throughput capacity.[50] These model units are defined in the following manner:

- TEG unit A: ≤5 MMcfd,
- TEG unit B: >5 MMcfd and ≤20 MMcfd,
- TEG unit C: >20 MMcfd and ≤50 MMcfd,
- TEG unit D: >50 to 500 Mmcfd, and
- TEG unit E: >500 Mmcfd.

The total estimated number of TEG dehydration units is just below 30,000 units. In addition, Table 3-1 includes the number of TEG dehydration units by application (i.e., stand-alone, condensate tank battery, natural gas processing plant, offshore production platform, and natural gas transmission and storage facilities). The estimated number of TEG dehydration units by application is assumed to be one TEG dehydration unit per condensate tank battery and offshore production platform used in the separation of the well stream and two to four dehydration units (TEG, EG, or solid desiccant) per natural gas processing plant, depending on throughput capacity and type of processing configuration, to dry the gas to required specifications. In addition, model TEG units were distributed within the natural gas transmission and storage source category consistent with their natural gas design and throughput capacities.

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*No model plants are developed for natural gas transmission and storage facilities because the only HAP emission point of concern for these facilities is a process vent at an associated TEG dehydration unit.

TABLE 3-1. MODEL TEG DEHYDRATION UNITS

	Model plant					
	A	B	C	D	E	Total
Capacity (MMcfd)	<5	5 to 20	20 to 50	>50 to 500	>500	
Throughput (MMcfd)	0.3	10	35	100	500	
Estimated population						
Stand-alone	24,000	200	25	20		24,245
@ Condensate tank battery	12,000	500	100	70		12,670
@ Natural gas processing plant		66	110	54		230
@ Offshore production platform		260	40			300
@ Natural gas transmission and underground storage	200	125	35	10	10	370
TOTAL	36,200	1,151	300	154	10	37,815

Source: National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage --Background Information Document. U.S. Environmental Protection Agency. Research Triangle Park, NC. April 1997.

Note: MMcfd = million cubic feet per day.

3.1.2 Condensate Tank Batteries

As shown in Table 3-2, the engineering analysis establishes four model condensate tank batteries based on natural gas throughput capacity. These model units are defined as follows:

- CTB E: ≤5 MMcfd,
- CTB F: >5 MMcfd and ≤20 MMcfd,
- CTB G: >20 MMcfd and ≤50 MMcfd, and
- CTB H: >50 MMcfd.

TABLE 3-2. MODEL CONDENSATE TANK BATTERIES

	Model plant				
	E	F	G	H	Total
Capacity (MMcfd)	≤5	5 to 20	20 to 50	>50	
Throughput (MMcfd)	1	10	35	100	
Estimated population	12,000	500	100	70	12,670

Source: National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage --Background Information Document. U.S. Environmental Protection Agency. Research Triangle Park, NC. April 1997.

Note: Mmcfd = million cubic feet per day.

Condensate tank batteries generally have a TEG dehydration unit as a process unit within the overall system design of the tank battery. The estimated number of condensate tank batteries operating in the U.S. is close to 13,000, or 15 percent of all tank batteries.[51]

3.1.3 Natural Gas Processing Plants

As shown in Table 3-3, the engineering analysis establishes three model natural gas processing plants based on natural gas throughput capacity. These model units are defined as follows:

- NGPP A: ≤20 MMcfd,
- NGPP B: >20 MMcfd and ≤100 MMcfd,
- NGPP C: >100 MMcfd.

Although the population of TEGs and tank batteries must be estimated, the OGJ provides detailed information on U.S. natural gas processing plants. As of January 1, 1994, the U.S. had approximately 700 natural gas processing plants. The OGJ's annual survey of natural gas processing plants

TABLE 3-3. MODEL NATURAL GAS PROCESSING PLANTS

	Model plant			
	A	B	C	Total
Capacity (MMcfd)	≤20	20 to 100	>100	
Throughput (Mmcfd)	10	70	200	
Estimated population	260	300	140	700

Source: U.S. Environmental Protection Agency. National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage—Background Information Document. Office of Air Quality Planning and Standards. Research Triangle Park, NC. April 1997.

Note: MMcfd = million cubic feet per day.

identifies each plant by State, design capacities, and estimated 1993 throughput.[52] The estimates of the number of natural gas processing plants corresponding to each size range shown in Table 3-3 are based on this annual survey.

3.1.4 Offshore Production Platforms

As shown in Table 3-4, the engineering analysis establishes two model offshore production platforms based on crude oil productive capacity of those located in state water areas. These model units are defined in the following manner:

- OPP A: State water areas with 1,000 bpd capacity, and
- OPP B: State water areas with 5,000 bpd capacity.

As discussed in the BID, approximately 300 offshore production platforms are located in State water and therefore subject to EPA's jurisdiction for air emissions regulations. The model characterization of these platforms is based on data from the Minerals Management Service (MMS) of the U.S. Department of Interior.[53]

TABLE 3-4. MODEL OFFSHORE PRODUCTION PLATFORMS

	Model plant		
	Small	Medium	Total
Location	State waters	State waters	
Capacity (BOPD)	1,000	5,000	
Throughput (BOPD)	200	2,000	
Estimated population	260	40	300

Source: National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage --Background Information Document. U.S. Environmental Protection Agency. Research Triangle Park, NC. April 1997.

Note: BOPD = barrels of oil per day.

3.2 CONTROL OPTIONS

Sources of HAP emissions in oil and natural gas production include the glycol dehydration unit process vents, storage vessels, and equipment leaks. Table 3-5 summarizes the control options under evaluation for HAP emission points within the model units in the oil and natural gas production and natural gas transmission and storage source categories.[54] The control options include the use of certain equipment (e.g., installation of a cover or fixed roof for tanks) and work standards (e.g., leak detection and repair [LDAR] programs for fugitive emission sources). Control options that are applicable to each potential HAP emission point at model plants are fully detailed in the BID.

Major sources of HAP emissions are controlled based on the MACT floor, as defined by the control options in Table 3-6. The Agency has determined that a glycol dehydration unit must be collocated at a facility for the facility to be designated as a major source. Therefore, the MACT floor may apply to stand-alone TEG units, condensate tank

TABLE 3-5. SUMMARY OF CONTROL OPTIONS BY MODEL PLANT AND HAP EMISSION POINT

Model plant/unit	HAP emission point	Control option	Control efficiency (%)
TEG dehydration unit	Reboiler vent	Condenser with flash tank in design	95
		Condenser without flash tank	50
		Combustion	98
		System optimization	Variable
Tank battery	Open-top storage tank	Cover and vent to 95% control device or redirect	99
	Fixed roof storage tank	Vent to 95% control device or redirect	95
	Equipment leaks	LDAR[a]	70
Natural gas processing plant	Fixed roof storage tank	Vapor collection and redirect	95
	Equipment leaks	LDAR	70
Offshore production platforms	Equipment leaks	LDAR	70

[a] Leak detection and repair program based on one of the following:
- Control Techniques Guideline (CTG) document applicable to natural gas/gasoline processing plants,
- New Source Performance Standard (NSPS) applicable to onshore natural gas processing plants constructed or modified after 1/20/84, or
- Hazardous Organic NESHAP (HON) regulatory negotiation applicable to synthetic organic chemical manufacturing facilities.

Source: National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage —Background Information Document. U.S. Environmental Protection Agency. Research Triangle Park, NC. April 1997.

batteries, natural gas processing plants, and storage facilities. Black oil tank batteries and offshore production platforms are not considered since TEG units are not typical of the operations at black oil tank batteries and are completely controlled at offshore production platforms.

The engineering analysis contained in the BID document projects the number of major sources of HAP emissions by model plant. Tables 3-6, 3-7, and 3-8 provide the percentage and number of affected units by model type--TEG dehydration unit, condensate tank battery, and natural gas processing plant.

TABLE 3-6. TOTAL AND AFFECTED POPULATION OF TEG UNITS BY MODEL TYPE

	Model TEG Unit					
Item	A	B	C	D	E	Total
Total population	36,200	1,151	300	154	10	37,615
Percent affected	0.0%	22.7%	50.3%	18.2%	50.0%	445
Affected units						
Stand-alone	0	138	25	20	0	183
@ Condensate TB	0	109	100	5	0	214
@ NGPP	0	14	26	3	0	43
@ transmission and storage facility	0	0	0	4	3	5
Total	0	261	151	32	3	445

3.3 COSTS OF CONTROLS

The BID describes in detail the cost estimates for control options that are applicable to each potential HAP emission point at model plants. Cost estimates are expressed

TABLE 3-7. TOTAL AND AFFECTED POPULATION OF CONDENSATE TANK BATTERIES BY MODEL TYPE

	Model condensate tank battery				
Item	E	F	G	H	Total
Total population	12,000	500	100	70	12,670
Percent affected	0%	21.8%	10.0%	7.1%	1.0%
Affected units	0	109	10	5	124

TABLE 3-8. TOTAL AND AFFECTED POPULATION OF NATURAL GAS PROCESSING PLANTS BY MODEL TYPE

	Model NGPP			
Item	A	B	C	Total
Total population	260	300	140	700
Percent affected	2.7%	1.3%	0.7%	1.7%
Affected units	7	4	1	12

in July 1993 dollars. Table 3-9 summarizes the total and annualized capital costs; operating expenses; monitoring, inspection, recordkeeping, and reporting costs (maintenance costs); and total annual cost for each control option by model plant. The annualized capital cost is calculated using a capital recovery factor of 0.1098 based on an equipment life

TABLE 3-9. REGULATORY CONTROL COSTS PER UNIT FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY BY MODEL PLANT

Control option/model plant[a]	Number of Affected Units	Total capital cost	Annualized capital cost	Operating and maintenance cost[b]	Total annual cost	Product recovery credit
Condenser control systems[c]						
TEG-B	157	$13,620	$1,495	$11,626	$13,121	$2,825
TEG-B′	104	$11,400	$1,252	$11,538	$12,790	$2,825
TEG-C	67	$13,620	$1,495	$11,626	$13,121	$9,789
TEG-C′	84	$11,400	$1,252	$11,538	$12,790	$9,789
TEG-D	28	$11,400	$1,252	$11,538	$12,790	$23,783
TEG-E	5	$11,400	$1,252	$11,538	$12,790	$3,580
Storage tank controls/recycle						
CTB-F	50	$3,590	$394	$2,511	$2,905	$71
CTB-G	4	$3,590	$394	$2,511	$2,905	$93
CTB-H	2	$3,590	$394	$2,511	$2,905	$115
NGPP-A	3	$3,590	$394	$2,511	$2,905	$115
NGPP-B	2	$3,590	$394	$2,511	$2,905	$115
NGPP-C	0	$3,590	$394	$2,511	$2,905	$115
Storage tank controls/fuel substitute						
CTB-F	50	$3,590	$394	$2,511	$2,905	$46
CTB-G	4	$3,590	$394	$2,511	$2,905	$60
CTB-H	2	$3,590	$394	$2,511	$2,905	$75
NGPP-A	3	$3,590	$394	$2,511	$2,905	$75
NGPP-B	2	$3,590	$394	$2,511	$2,905	$75
NGPP-C	1	$3,590	$394	$2,511	$2,905	$75

(continued)

TABLE 3-9. REGULATORY CONTROL COSTS PER UNIT FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY BY MODEL PLANT (CONTINUED)

Control option/model plant[a]	Number of Affected Units	Total capital cost	Annualized capital cost	Operating and maintenance cost[b]	Total annual cost	Product recovery credit
Storage tank controls/flare						
TB-F	9	$37,080	$4,071	$44,490	$48,561	$0
TB-G	2	$37,080	$4,071	$44,490	$48,561	$0
TB-H	1	$45,260	$4,970	$44,817	$49,787	$0
NGPP-A	1	$37,080	$4,071	$44,490	$48,561	$0
NGPP-B	0	$37,080	$4,071	$44,490	$48,561	$0
NGPP-C	0	$45,260	$4,970	$44,817	$49,787	$0
Leak detection and repair						
NGPP-A	7	$1,378	$6,564	$10,543	$11,921	$135
NGPP-B	4	$1,378	$6,564	$19,479	$20,857	$340
NGPP-C	1	$1,378	$6,564	$40,331	$41,709	$815

[a] Abbreviations are TEG for triethylene glycol dehydration units, CTB for condensate tank batteries, and NGPP for natural gas processing plants. The letter following the hyphen designates the model plant.

[b] Included in this cost category are operating and maintenance costs, other annual costs (i.e., administrative, taxes, insurance, etc.), and monitoring, inspection, recordkeeping, and reporting costs.

[c] Model condensate tank battery E is not listed since it does not incur control costs. Also the presence of a flash tank at glycol dehydration units affects the compliance costs. Thus, model TEG-B represents a glycol dehydration unit without a flash tank, white model TEG-B' has a flash tank.

of 15 years and a 7 percent discount rate.[55] The total annual cost is calculated as the sum of the annualized capital cost; operating expenses; and the monitoring, inspection, recordkeeping, and reporting costs.

In addition, product recovery is presented in Table 3-9 as an annual cost credit where applicable. Product recovery credits were calculated by multiplying the mass of product recovered by the product value. Recovered liquid, condensate, and crude oil were assigned a value of $18 per barrel, while recovered gas product was assigned different dollar amounts depending on its use. Recycled product for further processing and sale was valued at $2 per Mcf, recovered gas hydrocarbons for use as a fuel supplement were valued at $1.30 per Mcf, and gas hydrocarbons directed to an incinerator or flare were assigned no value.[56]

Table 3-10 summarizes the annual control costs for major sources expressed per model plant. The annual costs for model condensate tank batteries and natural gas processing plants are appropriately weighted given the percentage of affected units subject to the various control options and include the costs of TEG dehydration units present at each model type. One TEG unit is assigned to each model CTB based on throughput capacity so that a TEG unit A is assigned to each CTB E, a TEG unit B is assigned to each CTB F, a TEG unit C is assigned to each CTB G, and a TEG unit D is assigned to each CTB H. The allocation of TEG units to model NGPPs is such that a model NGPP A is assigned two TEG B units, a model NGPP B is assigned three model TEG C units, and a model NGPP C is assigned three model TEG D units.

TABLE 3-10. SUMMARY OF ANNUAL CONTROL COSTS BY MODEL PLANT

Model Plant	Cost per model unit
TEG dehydration units	
TEG-A	–
TEG-B	$12,989
TEG-C	$12,937
TEG-D	$12,790
TEG-E	$12,790
Condensate tank batteries	
CTB-E	–
CTB-F	$19,660
CTB-G	$24,973
CTB-H	$25,071
Natural gas processing plants	
NGPP-A	$46,747
NGPP-B	$61,823
NGPP-C	$81,083
Natural gas transmission and storage	
TEG-A	-
TEG-B	-
TEG-C	-
TEG-D	$49,787*
TEG-E	$49,787

* Three of the four affected TEGs of this size are assumed to have control costs of $49,787, while the fourth TEG is assumed to have control costs of $4,315.

References:

1. Ref. 1, Chapter 4.

2. Ref. 1, p. 2-4.

3. Ref. 39.

4. U.S. Department of the Interior/Minerals Management Service. Federal Offshore Statistics: 1993 (OCS Report MMS 94-0060). Herndon, VA. 1994.

5. Ref. 1, Table 3-1.

6. Ref. 1.

7. Ref. 1.

SECTION 4
ECONOMIC IMPACT ANALYSIS

Implementing the controls will directly affect the costs of production in the oil and natural gas production industry. However, these initial effects will be felt throughout the economy--downstream by consumers of refined petroleum products and natural gas and upstream by suppliers of inputs to the industry. As demonstrated in Section 3, facilities in this industry will be affected by the regulation differently, depending on the products (crude oil, condensates, natural gas) they process, the processing equipment they currently employ, and the level of throughput. Facility-level production responses to the additional regulatory costs will determine the market-level impacts of the regulation. Specifically, the cost of the air pollution controls may force the premature closing of some facilities or may cause facilities to alter current production levels.

Section 3 indicates that black oil tank batteries will not incur control costs as a result of the regulation. Thus, only condensates processed at condensate tank batteries will be directly affected by the regulation, which represents less than 5 percent of total U.S. crude oil production.[1] Crude oil is an international commodity, transported and consumed throughout the world. Most economic models of world crude oil markets consider the OPEC as a price-setting residual supplier, facing a net demand for crude oil that is the difference between the world demand and the non-OPEC supply of crude oil.[2,3] Accordingly, the U.S. may be seen as a price taker on the world oil market with no power to influence the world price in any significant way. This analysis does not include a model to assess the regulatory effects on the world crude oil market because not only will less than 5 percent of U.S. crude oil production be affected but changes in the U.S. supply are not likely to influence world prices. Therefore, this analysis focuses on the regulatory effects on the U.S. natural gas market.

As discussed in Section 2, the natural gas industry has undergone fundamental changes in recent years including a restructuring of the interstate pipeline industry and a diminishing of excess productive capacity. These changes have resulted in increased competition within the natural gas industry. Accordingly, producers of natural gas can respond to changes in demand and price levels fairly easily because their product is often sold directly to the end user.

Open access to pipeline transportation created regional spot markets for natural gas through local and regional competition between pipelines for gas supplies and between producers for gas sales. Doane and Spulber find that open access, or the "unbundling" of pipeline services, has integrated regional wellhead markets into a national market for natural gas.[4] The regional wellhead markets are linked by the action of buyers, who are interested in the delivered price of natural gas (i.e., the sum of the wellhead price and the transportation and transaction costs of obtaining gas). Buyers have the opportunity to evaluate costs of purchasing gas from different regions and transporting it along different pipeline systems. To the extent that natural gas producers compete across regions to supply the same customers, the regional wellhead markets combine to form a national market.[5] Based on this research, the U.S. market for natural gas was modeled as a national, perfectly competitive market for a homogeneous commodity.

Sections 4.1 through 4.3.2.2 assesses the market-,and industry-level impact of the regulation on the natural gas production industry. These sections provide a conceptual overview of the production relationships involving the natural gas industry, the details of an operational market model to assess the regulation, and the results of the economic analysis. Section 4.3.2.2 presents a screening analysis of impacts on the natural gas transmission and storage industry. Section 4.4 provides conclusions for the impacts on society from these regulations.

4.1 MODELING MARKET ADJUSTMENTS

Standard concepts in microeconomics are employed to model the supply of natural gas and the impacts of the regulation on production costs and output decisions. The following subsections examine the impact of the regulations that affect operating costs for producing wells in the U.S. natural gas industry. Together they provide an overview of the basic economic theory of the effect that regulations have on production decisions and of the concomitant effect on natural gas prices. The three main elements are the regulatory effects on the production well or "facility," market response, and facility-market interactions.

4.1.1 Facility-Level Effects

At any point in time, the costs that a firm faces can be classified as either unavoidable (sunk) or avoidable. In the former category, we include costs to which the firm is committed and that must be paid regardless of any future actions of the firm.* The second category, avoidable costs, describes any costs that would be foregone by ceasing production. Avoidable costs can also be viewed as the full opportunity costs of operating the facility. These costs can

*For instance, debt incurred to construct a production well or processing facility must be repaid regardless of the production plan and even if the well or facility ceases operation prior to full repayment.

be further refined to distinguish between costs that vary with the level of production and those that are independent of the production level.* The determination of both the avoidability and the variability of firms' costs is essential to analyzing economic responses to the regulation.

Figure 4-1 illustrates the classical U-shaped structure of production costs with respect to natural gas production. Let ATAC be the average total (avoidable) cost curve and MC the marginal cost of producing natural gas, which intersects ATAC at its minimum point. All these curves are drawn conditional on input prices and the technology in place at the production well. Thus, all firms have some flexibility via their decision to operate, at a given output rate, or to close the well. But they do not have the full flexibility to vary the size and composition of their existing capital stock at the production well or processing facility (i.e., to change technology beyond that needed to comply with the regulatory alternative).

The well's supply function for natural gas is that section of the marginal cost curve bounded by the quantities Q_{min} and Q_{max}. Q_{max} is the largest feasible production rate that can be sustained at the facility given the technology and other fixed factors in place, regardless of the output price. Q_{min} is the minimum economically feasible production rate, which is determined by the minimum of the ATAC curve, which coincides with the price P_{min}. Suppose the market price of

*For example, production factors such as labor, materials, and capital (except in the short run) vary with the level of output, whereas expenditures for facility security and administration may be independent of production levels but avoidable if the well or processing facility closes down.

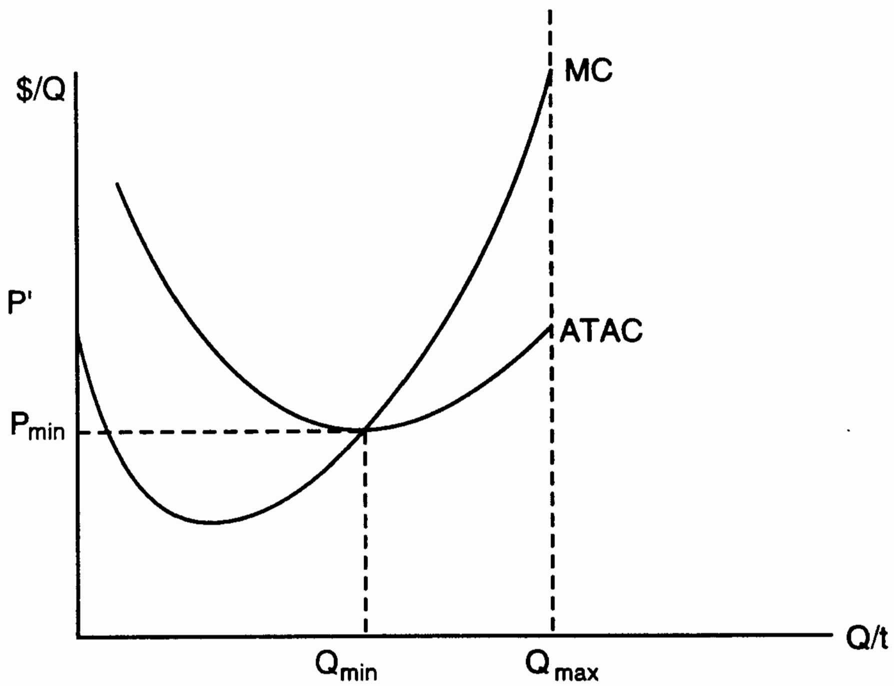

Figure 4-1. Facility unit cost functions.

natural gas is less than P_{min}. In this case, the firm's best response is to close the well and not produce natural gas because P < ATAC implies that total revenue would be less than total avoidable costs if the well operated at the associated output levels below Q_{min}.*

Now consider the effect of the regulatory control costs. These costs are all avoidable because a firm can choose to cease operation of the facility and thus avoid incurring the costs of compliance. These costs of compliance include the variable component consisting of the operating and maintenance costs and the nonvariable component consisting of the compliance capital equipment acquired for the regulatory option. Incorporating the regulatory control costs will

*This characterization of the economics regarding the operating decision agrees with that described in Reference 6.

involve shifting upward the ATAC and MC curves as shown in Figure 4-2 by the per-unit compliance cost (operating and

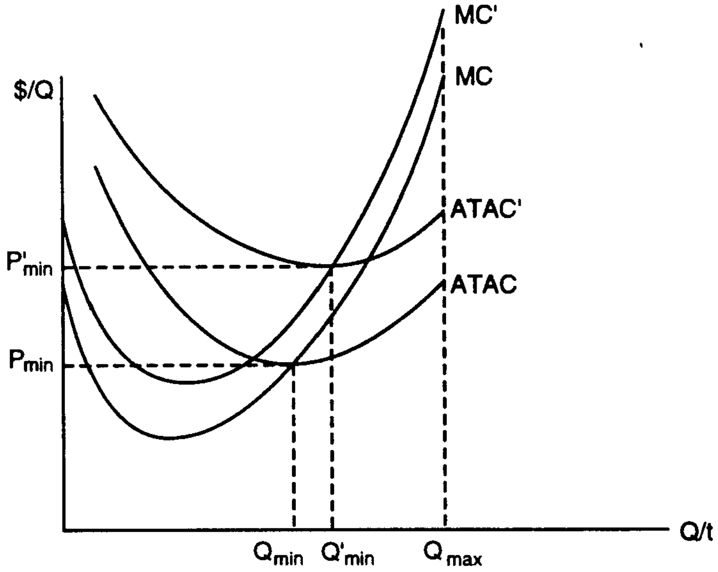

Figure 4-2. Effect of compliance costs on facility cost functions.

maintenance plus annualized capital). Therefore, the supply curve for each production well shifts upward with marginal costs, and a new (higher) minimum operating level (Q'_{min}) is determined by a new (higher) P'_{min}.

4.1.2 Market-Level Effects

The competitive structure of the market is an important determinant of the regulation's effect on market price and quantity. As discussed above, it was assumed that natural gas prices are determined in perfectly competitive markets. As illustrated in Figure 4-3, without the regulation, the market quantity and price of natural gas (Q_0, P_0) are determined by the intersection of the market demand curve (D) and the market supply curve (S). The market supply curve is determined by the horizontal summation of the individual facility supply curves. Imposing the regulation increases the costs of producing natural gas for individual suppliers and, thus, shifts the market supply function upward to S' (see Figure 4-3). The supply shifts for natural gas cause the

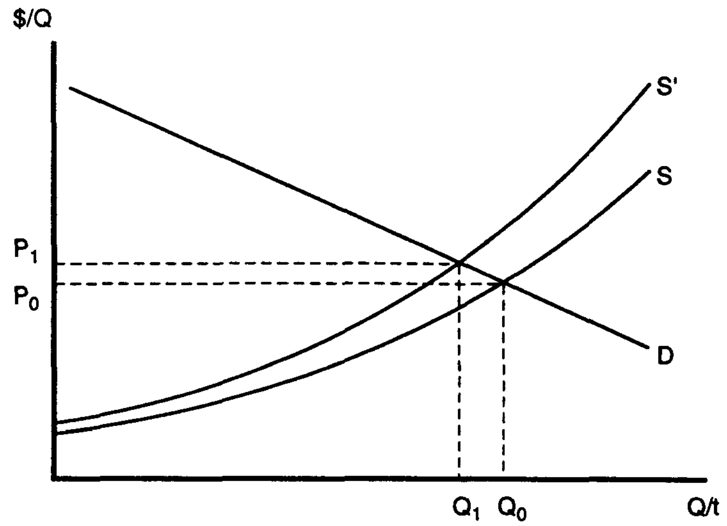

Figure 4-3. Natural gas market equilibria with and without compliance costs.

market price to rise and market quantity to fall at the new with-regulation equilibrium.

4.1.3 Facility-Level Response to Control Costs and New Market Prices

In evaluating the market effects for natural gas, the analysis must distinguish between the initial effect of the regulation and the net effect after the market has adjusted. Initially, the cost curves at all affected wells producing natural gas shift upward by the amount of the appropriate unit costs of the regulation. However, the combined effect across these producers causes an upward shift in the market supply curve for natural gas, which pushes up the price. Determining which shift dominates for a particular production well depends on the relative magnitude of the well-specific unit control costs of the regulation and the change in market price.

Given changes in market prices and costs, operators of production wells will elect to either

- continue to operate, adjusting production and input use based on new prices and costs, or
- close the production well if revenues do not exceed operating costs.

The standard closure evaluation is based on the comparison of revenues to the opportunity costs of production. If operators of production wells anticipate that these costs with the controls will exceed revenues, they will close the well.

Production well closures directly translate into quantity reductions. However, these quantity reductions will not be the only source of output change in response to the regulation. The output of production wells that continue operating with regulation will also change as will the quantity supplied from foreign sources. Affected facilities that continue to produce may increase or decrease their output levels depending on the relative magnitude of their unit control costs and the changes in market prices. Unaffected U.S. producers will not face an increase in compliance costs, so their response to higher product prices is to increase production. Foreign producers, who do not incur higher production costs because of the regulation, will respond in the same manner as the unaffected U.S. facilities.

The approach described above provides a realistic and comprehensive view of the regulation's effect on responses at the facility-level as well as the corresponding effect on market prices and quantities for natural gas. The next section describes the specifics of the operational market model.[6]

4.2 OPERATIONAL MARKET MODEL

To estimate the economic impacts of the regulation, the competitive market paradigm outlined above was operationalized. The purpose of the model is to provide a structure for analyzing the market adjustments associated with regulations to control air pollution from the oil and natural gas production industry. The model is a multi-dimensional Lotus spreadsheet incorporating various data sources to provide an empirical characterization of the U.S. natural gas industry for a base year of 1993--the latest year for which supporting technical and economic data were available at proposal. The analysis for the final rule maintains this same base year for consistency.

To implement this model, the production wells and natural gas production facilities to be included in the analysis were identified and characterized, the supply and demand sides of the U.S. natural gas market were specified, supply and demand specifications were incorporated into a market model framework, and market adjustments due to imposing regulatory compliance costs were estimated.

4.2.1 Network of Natural Gas Production Wells and Facilities

Because of the large number of producing wells, operating units, and processing plants in the oil and natural gas production industry, it is not possible to simulate the effects of imposing the regulatory control costs at each and every facility in the industry. The following section describes the methods employed in linking the EPA engineering model plants (as described in Section 2) with the wellgroups developed by Gruy Engineering Corporation (as discussed in Section 2.3.1.1 and provided in Appendixes A and B) to construct the model units of analysis that constitute the "facilities" for use in the economic model of the U.S. natural gas industry.

To apply the Gruy Engineering Corporation data to the economic analysis, it was necessary to make appropriate adjustments to those databases. First, to ensure consistent units of measure between Gruy and supporting data sources, all units of natural gas production were converted to thousands of cubic feet per day (Mcfd). Next, because the Gruy report reflects 1989 data, it was necessary to adjust the number of gas wells to reflect 1993 data, the base year of this analysis. The 1993 gas wells, as shown in Table 2-16, were allocated across the Gruy well cohorts in each state in the same proportion as their distribution in the Gruy database. Gas well production rates (Mcfd/well) were calculated based on the Gruy data. These rates were not altered for the analysis because no evidence suggested that production rates have changed since 1989. Natural gas production was recalculated by multiplying the production rates per well by the 1993 number of producing wells in each cohort. These adjustments are reflected in Appendix B.

To facilitate the analysis, the producing field was determined to be the relevant unit of production. Thus, the individual Gruy gas wells were integrated into producing fields of homogeneous well types rather than employing units of production at the individual well level. The number of wells in each wellgroup, or cohort, was distributed as evenly as possible to each of the fields. Rather than allocate parts of a well, the number of wells was distributed as integer values so that some like fields have an additional well. The oil wells, however, were included in the analysis at the wellgroup level as a single cohort, thereby representing one or more fields.

4.2.1.1 Allocation of Production Fields to Natural Gas Processing Plants. Once the production fields for each state were established, each field needed to be assigned to one of the 720 U.S. natural gas processing plants listed in the OGJ.[7] Oil and gas production fields were randomly allocated to the natural gas processing plants within a State given the plant-level natural gas processing throughput for 1993 as provided in the OGJ survey. However, in many cases, natural gas that is extracted in one State is processed in another State. Table 4-1 shows which states produce more gas than they process (excess suppliers), process more than they produce (excess demanders), or process exactly what they produce. Because of this interstate flow of natural gas, it was necessary to allocate the production fields of States with excess supply to the processing plants within that State first and then assign the unallocated fields to States with excess demand. The step-by-step allocation process was as follows:

1) Assign uniform random numbers between 0 and 1 to each production field using the @RAND function in Lotus 1-2-3.

2) Sort the production fields by their random number.

3) Allocate production fields to a processing plant until the 1993 processing level at that plant is matched (exactly or as close as possible).

4) Continue to the next processing plant within that state repeating Step 3 until the 1993 processing levels at all processing plants within the State are satisfied.

Those states with excess supply were assumed to only process gas extracted from fields within that State. Production fields that were not allocated to a processing plant within their State are then assigned to the next closest State with excess demand based on the location of existing pipelines. The steps outlined above were repeated for the excess demand states until all production fields had been allocated to processing plants.

After allocating the production fields to the processing plants, like field types that were assigned to the same processing plant were combined by summing the number of wells across these fields. This further aggregation is justified since baseline and with-regulation costs per unit are the same within wellgroups, natural gas processing plants, and their combination. After this adjustment was completed, just over

TABLE 4-1. LIST OF STATES BY EXCHANGE STATUS OF NATURAL GAS, 1993

Export	Import	No exchange
Alabama	Arkansas	Alaska
Arizona	Colorado	
California	Florida	
Illinois	Kansas	
Indiana	Louisiana	
Kentucky	Wyoming	
Michigan		
Mississippi		
Montana		
Nebraska		
New Mexico		
New York		
North Dakota		
Oklahoma		
Ohio		
Oregon		
Pennsylvania		
South Dakota		
Tennessee		
Texas--North		
Texas--Gulf Coast		
Texas--West		
Utah		
Virginia		
West Virginia		

Note: Exporting States produced more natural gas in 1993 than that processed within the State, importing States processed more natural gas in 1993 than that produced within the State, while States with no exchange processed and produced an equal amount of natural gas in 1993.

8,000 production field groupings supplied the 691 processing plants.*

4.2.1.2 Assignment of Model Units. Once production fields had been assigned to natural gas processing plants, it became necessary to assign natural gas processing equipment to the production fields and natural gas processing plants. Processing equipment includes TEG dehydration units and condensate tank batteries (CTB). TEG units may be stand-alone units or they may exist at condensate tank batteries or natural gas processing plants. The following sections discuss the model units defined in the engineering analysis and the methods employed in allocating these units to the production fields and natural gas processing plants for the economic analysis.

Stand-alone TEG units. For this analysis, a stand-alone TEG unit was assigned to gas production fields that are deeper than 4,000 feet. This assignment was based on the assumption that wells that are less than 4,000 feet deep produce "dry gas" and do not need a stand-alone TEG unit. Data supporting this assumption are found in the U.S. Department of Energy report entitled, "Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations: 1990-1993." This report provides cost information for natural gas lease equipment by type of well, and dehydrators and their corresponding cost estimates are only listed for well types greater than 4,000 feet deep.[8]

For gas production fields with well depth greater than 4,000 feet, stand-alone TEG units were assigned based on the throughput of each field (i.e., a production field producing 25 MMcfd is assigned a model TEG unit C). To approximate the

*Total does not sum to the 720 as reported in the industry profile (section 2)because plants in OGJ processing survey that indicated no throughput for 1993 were excluded from the analysis.

engineering estimates of the number of model units, it was necessary to convert some model C and D units initially assigned to production fields into multiple model A and B units. Thus, randomly selected model C and D units were converted to model A and B units according to the ratio of average throughput per unit (as expressed in MMcfd) (i.e., one model C unit is equivalent to 125 model A units, one model D is equivalent to 350 model A units, and one model D unit is equivalent to 10 model B units).[9]

Condensate tank batteries and associated TEG units. Model condensate tank batteries were assigned to production fields based on the throughput of each field (i.e., if a field produces 2 MMcfd of natural gas, it was assigned a model CTB E). One TEG unit was assigned to each condensate tank battery based on throughput capacity so that a TEG unit A was assigned to each CTB E, a TEG unit B was assigned to each CTB F, a TEG unit C was assigned to each CTB G, and a TEG unit D was assigned to each CTB H. To approximate the engineering estimates of the number of model units, it was necessary to convert some model CTB F, G, and H units initially assigned to production fields into multiple model E units. Thus, randomly selected model F, G, and H units were converted to model E units according to the ratio of average throughput per unit (as expressed in MMcfd) (i.e., one model F unit is equivalent to 10 model E units, one model G is equivalent to 35 model E units, and one model H unit is equivalent to 100 model E units).[10]

TEG units at natural gas processing plants. TEG dehydration units are also employed at NGPPs. For this analysis, the allocation of model TEG units to model NGPPs was based on the engineering analysis so that a model NGPP A is assigned two model TEG B units, a model NGPP B was assigned three model TEG C units, and a model NGPP C was assigned three model TEG D units.

After completing the assignment of model units, every "facility" began with a model production well and ended with a model natural gas processing plant (e.g., model production well 1 → TEG dehydration unit A at CTB E → Natural gas processing plant A). As a result, the level of domestic production is equal to the level of natural gas processed at natural gas processing plants during 1993 as provided by the OGJ processing survey. Table 4-2 provides a summary of the network of production wells and production facilities by State for 1993. Because of the uncertainty related to the actual combinations of production well and processing plants, the production well-processing facility combinations developed for this analysis to reflect the base year data of 1993 will not be unique--there are likely other possible combinations of production wells and processing facilities that are consistent with the base year data.

4.2.2 Supply of Natural Gas

Producers of natural gas have the ability to vary output in the face of production cost changes. Production well-specific upward sloping supply curves for natural gas are developed to allow domestic producers to vary output in the face of regulatory control costs. The following sections provide a description of the production technology characterizing production at U.S. natural gas fields and the corresponding supply functions, as well as the foreign component of U.S. natural gas supply (i.e., imports).

4.2.2.1 Domestic Supply. For this analysis, the generalized Leontief technology was assumed to characterize natural gas production at all producing fields. This formulation allows for projection of supply curves for natural gas at the field level. In general, the supply function of a

TABLE 4-2. SUMMARY OF ALLOCATION OF PRODUCTION WELLS, PROCESSING PLANTS, AND MODEL UNITS FOR 1993 BY STATE

	Wells providing natural gas to plants within that State				Stand-alone TEG				
State	Oil wells	Gas wells	Total	Natural gas processed (Mmcfd)	A	B	C	D	Total
Alaska	1,541	157	1,698	6,499.2	286	1	1	1	289
Alabama	0	2,274	2,274	701.9	339	2	1	1	343
Arkansas	12,726	2,974	15,700	520.3	206	3	1	2	212
California	40,482	1,018	41,500	659.4	577	2	0	0	579
Colorado	8,306	7,157	15,463	1,129.6	781	4	0	4	789
Florida	2,779	1,395	4,174	621.3	369	2	1	0	372
Kansas	33,967	26,850	60,817	3,776.5	2,747	13	3	4	2,767
Kentucky	0	7,842	7,842	118.0	0	0	0	0	0
Louisiana	71,049	131,256	202,305	11,865.5	5,973	62	4	5	6,044
Michigan	2,099	2,196	4,295	859.0	69	1	0	0	70
Mississippi	1,811	278	2,089	209.6	92	1	0	1	94
Montana	0	83	83	7.1	1	0	0	0	1
North Dakota	2,101	80	2,181	83.2	9	0	0	0	9
New Mexico	5,606	17,596	23,202	2,122.2	1,205	10	1	0	1,216
Oklahoma	59,564	12,472	72,036	2,863.4	1,834	21	2	0	1,857
Pennsylvania	0	258	258	8.2	0	0	0	0	0
Ohio	0	609	609	8.8	0	0	0	0	0
West Virginia	0	24,154	24,154	337.8	0	0	0	0	0
Texas-Gulf Coast	56,558	17,647	74,205	7,037.9	5,119	47	4	2	5,172
Texas-North	50,502	14,521	65,023	1,679.7	882	7	1	0	890
Texas-West	61,913	7,750	69,663	3,284.0	1,778	6	3	0	1,787

TABLE 4-2. SUMMARY OF ALLOCATION OF PRODUCTION WELLS, PROCESSING PLANTS, AND MODEL UNITS FOR 1993 BY STATE (CONTINUED)

	Condensate tank batteries					Natural gas processing plants			
State	E	F	G	H	Total	A	B	C	Total[a]
Alaska	27	2	3	4	36	0	0	3	3
Alabama	79	4	1	2	86	2	4	3	9
Arkansas	60	3	3	2	68	1	1	1	3
California	281	6	3	0	290	15	11	2	28
Colorado	326	6	0	4	336	27	14	4	45
Florida	84	4	2	2	92	0	1	1	2
Kansas	555	32	15	6	608	6	4	11	21
Kentucky	0	0	0	0	0	0	3	0	3
Louisiana	2,765	162	32	25	2,984	14	22	32	68
Michigan	86	4	1	0	91	7	9	11	27
Mississippi	54	3	0	1	58	3	2	1	6
Montana	1	0	0	0	1	6	0	0	6
North Dakota	27	1	1	0	29	5	1	0	6
New Mexico	571	40	7	0	618	6	20	7	33
Oklahoma	1,175	53	1	4	1,233	34	48	10	92
Pennsylvania	0	0	0	0	0	1	0	0	1
Ohio	0	0	0	0	0	0	1	0	1
West Virginia	0	0	0	0	0	3	2	2	7
Texas-Gulf Coast	2,220	99	11	15	2,345	22	69	21	112
Texas-North	665	32	4	0	701	42	27	7	76
Texas-West	1,418	15	10	1	1,444	34	44	10	88
Utah	137	8	1	2	148	7	5	2	14
Wyoming	918	26	5	2	951	15	16	9	40

natural gas producing field resulting from the generalized Leontief technology is:

$$q_j = \gamma_j + \frac{\beta}{2}\left[\frac{1}{r}\right]^{1/2} \tag{4.1}$$

where

q_j = annual production of natural gas (Mcf) for field $j = 1$ to n,

r = national wellhead price of natural gas,

β = negative supply parameter (i.e., $\beta < 0$), and

γ_j = productive capacity of field j.

Figure 4-4 illustrates the theoretical supply function of Equation (4.1). As shown, the upward-sloping supply curve is specified over a productive range with a lower bound of zero that corresponds with a shutdown price equal to $\frac{\beta^2}{4\gamma_j^2}$ and an upper bound given by the productive capacity of q_j^M that is approximated by the supply parameter γ_j. The curvature of the supply function is determined by the β parameter (see Appendix C for a discussion of the derivation and interpretation of this parameter).

To specify the supply function of Eq. (4-1) for this analysis, the β parameter is computed by substituting the market supply elasticity for natural gas (ξ), the wellhead price of natural gas (r), and the production-weighted average annual production level of natural gas per well (q) into the following equation:

$$\beta = -\xi 4q\left[\frac{1}{r}\right]^{-1/2}. \tag{4.2}$$

The market-level supply elasticity for natural gas is assumed to be 0.2624, which reflects the production-weighted average

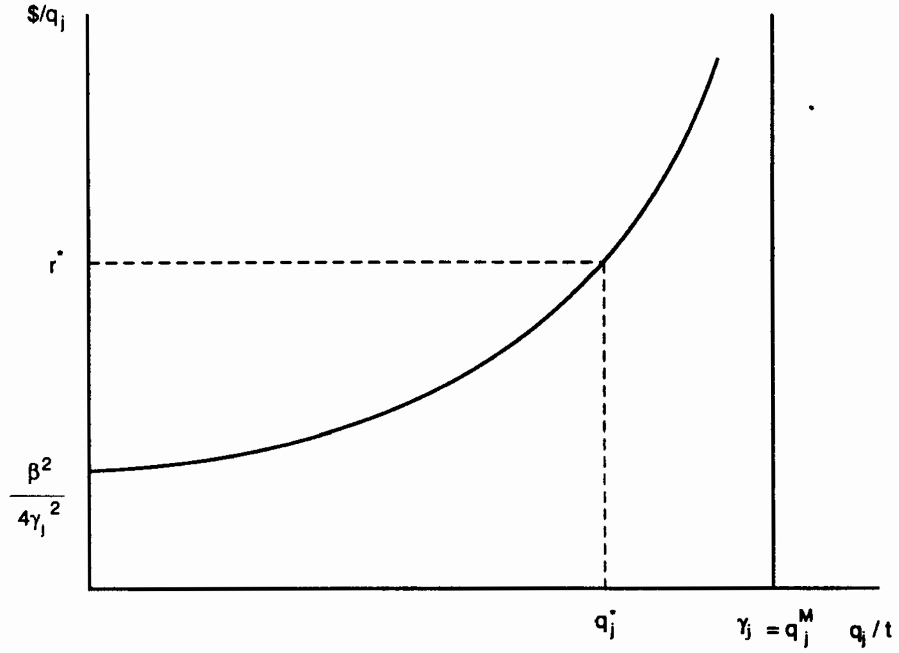

Figure 4-4. Theoretical supply function of natural gas producing well.

supply elasticity estimated across EPA regions as shown in Table 4-3.[11] The 1993 wellhead price of natural gas is $2.01 per Mcf and the production-weighted average annual level of natural gas production per well based on the Gruy database is 131,496 Mcf. The β parameter is calculated by incorporating these values into Equation (4.2) resulting in an estimate of the β parameter equal to -195,674.

Unlike the product-specific β, the individual supplier-level elasticity of supply is not constant, but varies across each producing field with the level of production, q_j. For high production fields, the elasticity of supply will be low reflecting the low responsiveness to price changes of large wells due to high overhead expenses and low extraction costs as described in the literature. For low production fields, the elasticity of supply will be high reflecting the high responsiveness to price changes of "stripper" wells. Since stripper wells produce a small product volume and have low

TABLE 4-3. SHORT-RUN SUPPLY ELASTICITY ESTIMATES FOR NATURAL GAS BY EPA REGION

EPA Region	Estimates of short-run elasticities
1	0.852
2	0.263
3	0.207
4	0.122
5	0.118
6	0.463
Weighted average	0.2624

Source: U.S. Department of Energy. Documentation of the Oil and Gas Supply Module. DOE/EIA-M063. Energy Information Administration, Oil and Gas Analysis Branch. Washington, DC. March 1994.

overhead expenses, producers usually respond to fluctuations in price of oil or gas by ceasing production when revenues fall below operating costs, and possibly resuming production when it is profitable.[12] As a result, domestic capacity utilization fluctuates mainly as stripper wells are changed from idle to production status.

The intercept of the supply function, γ_j, approximates productive capacity and varies across producing fields. This parameter does not influence the field's production responsiveness to price changes as does the β parameter. Thus, the parameter γ_j is used to calibrate the model so that each field's supply equation is exact using the Gruy data.

4.2.2.2 Foreign. The importance of including foreign imports in the economic model is highlighted by the significant level of U.S. importation of natural gas that currently reflects over 10 percent of U.S. domestic consumption. Thus, the model specifies a general formula for the foreign supply for natural gas that is:

$$q^I = A^I [r]^{\xi^I} \tag{4.3}$$

where

q_I = foreign supply of natural gas (Mcf),

A^I = positive constant, and

ξ^I = foreign supply elasticity for natural gas.

Difficulty in estimating foreign trade elasticities has long been recognized and precludes inclusion of econometric estimates (new or existing). International trade theory suggests that foreign trade elasticities are larger than domestic elasticities. In fact, at the limit, the foreign trade elasticities are infinite, reflecting the textbook case of price-taking in world markets by small open economy producers and consumers. For this analysis, a value of 0.852 is assumed for the import supply elasticity, which is the highest domestic supply elasticity estimate from Table 4-3. The multiplicative foreign supply parameter, A^I, is determined by backsolving given estimates of the import supply elasticities, 1993 wellhead price, and the quantities of U.S. imports 1993.

4.2.2.3 Market Supply. The market supply of natural gas (Q^S) is the sum of supply from all natural gas producers, i.e.,

$$Q^S = q^I + \sum_j q_j^s \tag{4.4}$$

where q^I is foreign supply of natural gas and $\sum_j q_j^s$ is the domestic supply of natural gas, which is the sum of natural gas production across all U.S. producing fields (j).

4.2.3 Demand for Natural Gas

Natural gas end users include residential and commercial customers, as well as industrial firms and electric utilities. These customer groups have very different energy requirements and thus quite different service needs. Therefore, the model specifies a general formula for the demand of natural gas by end-use sector (q_i^d), that is,

$$q_i^d = B_i^d \, [p_i]^{\eta_i^d} \tag{4.5}$$

where

p_i = the end-user price for sector I,

η_i^d = the demand elasticity for end-use sector I,

B_i^d = a positive constant

The multiplicative demand parameter, B_i^d, calibrates the demand equation so that each end-use sector replicates its observed 1993 level of consumption given data on price and the demand elasticity.

Table 4-4 provides the estimates of the demand elasticity by end-use sector that are employed in the model.[13] In a survey of price elasticities of demand for natural gas, Al-Sahlawi found that short-run elasticities of demand range from -0.035 to -0.686 in the residential sector and -0.161 to -0.366 in the commercial sector.[14] As shown in Table 4-4, this analysis employs the mid-point of the range for each of these end-use sectors. Industrial demand for natural gas is a derived demand resulting from producers optimizing the relative use of fuels that comprise the energy input to the production function. Based on time-series data across 9 U.S. states, Beierlin, Dunn, and McConnor used a combination of error components and seemingly unrelated regression to

TABLE 4-4. SHORT-RUN DEMAND ELASTICITY ESTIMATES FOR NATURAL GAS BY END-USER SECTOR

End-use sector	Estimate of the short-run demand elasticity
Residential	-0.3605
Commercial	-0.2635
Industrial	-0.6100
Electric utility[a]	-1.0000

[a] Value is assumed due to lack of literature estimates of this parameter for electric utilities. Higher absolute value than other sectors because of greater fuel-switching capabilities.

Source: Al-Sahlawi, Mohammed A. "The Demand for Natural Gas: A Survey of Price and Income Elasticities," Energy Journal Vol. 10, No. 1, January 1989.

estimate a short-run elasticity of -0.61 for natural gas.[15] To the best of our knowledge there exist no studies that estimate short-run demand elasticities for electric utilities. Because electric utilities have greater fuel switching capabilities than other end-users, we assume a more responsive short-run elasticity of -1 for this group in the model.

The total market demand for natural gas (Q^D) is the sum across all consuming end-use sectors, i.e.,

$$Q^D = \sum_i q_i^d \ . \tag{4.6}$$

An additional component of natural gas consumption is that used as lease, plant, and pipeline fuel. This consumption is fairly constant over time varying only with fluctuations of natural gas production. For the purposes of this analysis, this component is treated as an additional end-use sector consuming at a constant amount without and with the regulation.

4.2.4 Incorporating Regulatory Control Costs

The starting point for assessing the market impact of the regulations is to incorporate the regulatory control costs into the natural gas production decision. The regulatory control costs for each model unit are presented in Table 3-9 of Section 3. An additional aspect of the regulation is the product recovery credit received by natural gas producers as a result of adding the controls. These credits do not directly affect the production decisions as do the costs of adding the pollution controls. Rather these credits are added revenues that each producer gains after complying with the regulation.

The focus of incorporating regulatory control costs into the model structure is to appropriately assign the costs to the natural gas flows directly affected by the imposition of HAP emission controls. This assignment includes the identification of affected entities and determination of their control costs and the inclusion of these costs in the production decision of each affected entity.

4.2.4.1 Affected Entities. For this analysis, affected units were randomly selected given the percentages provided in Tables 3-7 through 3-9 of Section 3 and then assigned the appropriate compliance costs. Specifically, the following steps were undertaken:

- Each production field was assigned a uniform random value between 0 and 1 using the @RAND function in Lotus 1-2-3.
- Affected units were determined to be those with a random value below the percentage affected as given in Tables 3-7 through 3-9 for each model type.
- Total annual compliance costs, as shown in Table 3-9, were assigned to affected units and aggregated across model units for each "facility," or production field-processing plant combination.

The total annual compliance costs are expressed at the model unit level and must be converted to a per Mcf basis for inclusion in the model, i.e., application to affected product flows. To avoid double counting, compliance costs assigned to natural gas processing plants are further allocated to the multiple production fields providing natural gas according to their share of total natural gas processed at the plant. The total annual compliance costs per Mcf (c_j) for each affected production field j are computed as the sum of total annual compliance costs for affected TEG unit(s), condensate tank battery, and natural gas processing plant divided by the annual production level of the field.

4.2.4.2 Natural Gas Supply Decisions. The production decisions at the individual producing fields are affected by the total annual compliance costs, c_j, which reflect the shift in marginal cost and are expressed per Mcf of natural gas. If the producing field serves an affected stand-alone TEG unit, condensate tank battery, or natural gas processing plant, then its supply equation will be directly affected by the regulatory control costs, which enter as a net price change, i.e., r_j - c_j. Thus, the supply function for producing fields, assuming the generalized Leontief production technology becomes:

$$q_j = \gamma_j + \frac{\beta}{2}\left[\frac{1}{r_j - c_j}\right]^{1/2} \qquad (4.7)$$

The discussion above assumes that producing natural gas is profitable. However, in confronting the decision to comply with the regulation, a producer's optimal choice could be to produce zero output (i.e., close the production field). As shown in Figure 4-4, if the net wellhead price (r_j -c_j) falls below the shutdown price of $\frac{\beta^2}{4\gamma_j^2}$, then the producing field's production response for the supply equation given the regulatory control costs will be less than or equal to zero (i.e., $q_j \leq 0$).

4.2.5 Model Baseline Values and Data Sources

Table 4-5 provides the 1993 baseline equilibrium values for wellhead and end-user prices, domestic and foreign production, and consumption by end-use sector.[16] The level of domestic production is equivalent to the level of natural gas processed at natural gas processing plants during 1993 as obtained from the OGJ processing survey.[17] The consumption level for lease, plant, and pipeline fuel was adjusted to ensure that national production and consumption levels were exact for the model's 1993 characterization of the U.S. natural gas market.

4.2.6 Computing Market Equilibria

This section provides a summary of the model structure and a description of the equilibria computations of the model. A complete list of exogenous and endogenous variables, as well as the model equations, is given in Appendix D.

Producers' responses and market adjustments can be conceptualized as an interactive feedback process. Producers

TABLE 4-5. BASELINE EQUILIBRIUM VALUES FOR ECONOMIC MODEL: 1993

Item	Price[a] ($/Mcf)	Quantity (MMcf)
Producers		
Domestic	$2.01	17,440,586
Foreign	$2.01	2,350,115
Total	$2.01	19,790,701
Consumers		
Residential	$6.15	4,956,000
Commercial	$5.16	2,906,000
Industrial	$3.07	7,936,000
Electric utility	$2.61	2,682,000
Other	N/A	1,310,701
Average/total	$4.16	19,790,701

[a] For producers, price reflects the national wellhead price. For consumers, price reflects the appropriate national end-user price.

[b] For producers, quantity reflects the total production level. For consumers, quantity reflects the appropriate level of consumption.

Source: Department of Energy. Natural Gas Monthly. Energy Information Administration, Washington, DC. October 1994.

face increased production costs due to compliance, which causes individual production responses; the cumulative effect, which leads to a change in the wellhead price that all producers (affected and unaffected) face; and the end-user price that all consumers face, which leads to further responses by producers (affected and unaffected) as well as consumers and thus new market prices, and so on.* The new equilibria after imposition of these regulatory control costs is the result of a series of iterations between producer and consumer responses and market adjustments until a stable

*End-user prices are determined by adding the new wellhead price to the absolute markup for each end-user.

market price arises where total market supply equals total market demand, i.e.,

$$Q^S = Q^D \quad .$$

This process is simulated given the producer and consumer response functions and market adjustment mechanisms to arrive at the post-compliance equilibria.

The process for determining equilibrium prices (and outputs) with the increased production cost is modeled as a Walrasian auctioneer. The auctioneer calls out a wellhead price for natural gas (indirectly yielding end-user prices) and evaluates the reactions by all participants (producers and consumers, both foreign and domestic) comparing quantities supplied and demanded to determine the next price that will guide the market closer to equilibrium, i.e., market supply equal to market demand. An algorithm is developed to simulate the auctioneer process and find a new equilibrium price and quantity for natural gas. Decision rules are established to ensure that the process will converge to an equilibrium, in addition to specifying the conditions for equilibrium. The result of this approach is a combination of wellhead price and end-user prices with the regulation that equilibrates supply and demand for the U.S. natural gas market.

The algorithm for deriving the with-regulation equilibrium can be generalized to five recursive steps:

1) Impose the control cost on the production wells, thereby affecting their supply decisions.

2) Recalculate the market supply of natural gas.

3) Determine the new wellhead price via the price revision rule and add appropriate markups to arrive at end-user prices.

4) Recalculate the supply function of producing fields and foreign suppliers with the new wellhead price, resulting in a new market supply of natural gas. Evaluate end-use consumption levels at the new end-

user prices, resulting in a new market demand for natural gas.

5) Return to Step 3, and repeat steps until equilibrium conditions are satisfied (i.e., the ratio of market supply to market demand is equal to 1).

4.3 REGULATORY IMPACT ESTIMATES

The model results can be summarized as market- and industry- and societal-level impacts due to the regulation.

4.3.1 Market-Level Results

Market-level impacts include the market adjustments in price (wellhead and end-user) and quantity for natural gas, including the changes in international trade flows. Table 4-6 provides the market adjustments for each regulatory scenario. As shown, the changes in wellhead and end-use prices for each regulatory scenario are all nearly zero (less than 0.0005 percent change). The market adjustments associated with the regulation are also negligible in comparison to the observed trends in the U.S. natural gas market. For example, between 1992 and 1993, the average annual wellhead price increased by 14 percent, while domestic production of natural gas rose by 3 percent.[18] The increase in foreign imports of natural gas is also inconsequential (totaling less than 0.0004 percent) for each regulatory scenario.

4.3.2 Industry-Level Results

Industry-level impacts include an evaluation of the changes in revenue, costs, and profits; the post-regulatory compliance cost; production well and natural gas processing plant closures; and the change in employment attributable to

TABLE 4-6. SUMMARY OF NATURAL GAS MARKET ADJUSTMENTS FOR MAJOR SOURCES

	Major sources			
Item	Price ($/Mcf)	Percent change (%)	Quantity (MMcf)	Percent change (%)
Producers				
Domestic	$2.01	0.00044%	17,440,551	-0.00020%
Foreign	$2.01	0.00044%	2,350,123	0.00035%
Total			19,790,674	-0.00014%
Consumers				
Residential	$6.15	0.00014%	4,955,997	-0.00005%
Commercial	$5.16	0.00017%	2,905,999	-0.00005%
Industrial	$3.07	0.00029%	7,935,986	-0.00018%
Electric utility	$2.61	0.00034%	2,681,991	-0.00034%
Other	N/A	N/A	1,310,701	0.00000%
Total	$4.16	0.00021%	19,790,674	-0.00014%

(continued)

the change in industry output. Workers' dislocation costs associated with industry-wide job losses are also computed. Table 4-7 summarizes these industry-level impacts by regulatory scenario.

TABLE 4-7. INDUSTRY-LEVEL IMPACTS

Oil and Natural Gas Production Category	
Change in revenues ($\$10^6$)	\$3.1
Market adjustments	\$0.2
Product recovery	\$2.9
Change in costs ($\$10^6$)	\$7.4
Post-regulatory control costs	\$7.5
Costs of production adjustment	-\$0.1
Change in profits ($\$10^6$)	-\$4.3
Closures	
Production wells	0
Natural gas processing plants	0
Employment loss	0
Natural Gas Transmission and Storage Category	
Compliance Costs ($\$10^6$)	\$0.3

4.3.2.1 Post-Regulatory Compliance Cost. The post-regulatory compliance cost at each facility can be calculated as the product of the total annual compliance cost per unit (c_j) and the new output rate ($q^{*\prime}$). At the industry-level, the post-regulatory compliance cost for major sources is roughly $7.5 million for production facilities and reflects the sum of the total annual compliance cost across all facilities continuing to operate in the post-compliance equilibrium. Thus, the post-compliance cost is not necessarily equal to the estimated compliance costs before accounting for market adjustments. They differ because producing wells output rates may change at affected producing wells.

4.3.2.2 Revenue, Production Cost, and Profit Impacts. The economic model generates information on the change in individual and market quantities and market price in the oil and natural gas production industry. This allows computation of the change in total revenue and total cost at the industry level. For major sources, the total increase in revenue is $3 million and includes the change in product revenue associated with market adjustments ($0.2 million), which is the difference between baseline product revenue and post-compliance product revenue, and the added revenue associated with the product recovery credits ($2.9 million). The total increase in production cost is $7.4 million and reflects the post-compliance costs of production minus the baseline costs of production, which will account for the increase in costs due to the regulation ($7.5 million) and the decrease in costs due to the lower output rate ($0.1 million). These costs amount to just C.004 percent of the total revenues in 1993 of the 300 largest publicly traded oil and natural gas producing companies in the U.S.[19,20] The changes in total revenue and total cost are used to measure the profitability impact of the regulations which indicates a loss of $4.3 million at the industry level due to regulation.

The economic model also uses changes in industry revenues and costs to project closures of producing wells and natural gas processing plants and to assess employment impacts in the industry. No closure or employment effects are estimated to occur.

4.3.2.3 Screening Analysis for Natural Gas Transmission and Storage

The cost estimates for the 7 major sources in the natural gas transmission and storage category were not included in the market model reported above. Between proposal and promulgation of this rule, data was collected through surveys and site visits for 81 facilities, however, only one facility in EPA's database, KN Interstate Gas Transmission Company, is known to be affected by the standard. We do not have information on the other six facilities estimated to be affected by the rule. Below is a screening analysis of impacts on the natural gas transmission and storage industry, the calculated impact for KN Interstate Gas Transmission Company, and an approach to characterize potential impacts for other affected facilities.

First, to screen the potential impacts on the market for natural gas transmission and storage, we calculate the ratio of total compliance costs with industry revenues. This calculation can give some insight into potential price increases and the level of potential impacts on the transmission and storage market. Information on pipeline economics from the OGJ[21] indicates total 1997 revenues of $16.1 billion for all pipeline firms listed. A total regulatory cost of $300,000 would represent 0.02% of market revenues. This level of impact is unlikely to be enough of a shock to production costs throughout the market to cause the supply curve to shift upward, so market price would not be expected to increase as a result of the regulation. This impact is also overstated to the extent that the table of firms from the OGJ does not list all of the firms in the industry. The table includes all "major" and "non-major" firms (as defined by the FERC), which are required to report pipeline company statistics. The overstatement of impacts will be minimal if the firms reported in the OGJ table constitute a large majority of the industry.

To screen for impacts of the rule on individual firms, we calculate the ratio of firm compliance cost to firm revenues[*]. If the ratio is greater that one percent for a substantial number of firms this screening would indicate a need for

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[*] It should be noted that while the estimated regulatory impact of $300,000 is based on seven facilities, this analysis is based on firm-level impacts. A firm may own one facility or several facilities - a portion of which might be affected by the final rule.

further evaluation, especially for small businesses in accordance with requirements of the Regulatory Flexibility Act and the Small Business Regulatory Enforcement and Fairness Act. Using the information provided by the OGJ, we selected data for 42 pipeline companies that transferred greater than 100 Mmscf of natural gas per year corresponding to the throughput of EPA's model TEG-D units and larger. It is assumed that companies listed in this table with less than 100 Mmscf would not be affected by the rule because they may not be a major source (as defined by the Clean Air Act), or they may be major but excluded from this regulation due to the 85 Mmscf cut-off for control requirements. From the information given in the table, we obtained the total volume of gas sold and transferred, and operating revenues to calculate the cost-to-revenues ratios for each company. The firms were then divided into two categories: (1) those with throughput of 100 but less than 500 Mmscf (i.e., model TEG-D size category), and (2) those with throughput greater than or equal to 500 Mmscf (i.e. model TEG-E facilities). Table 4-8 below displays the firm information for the two TEG size categories. We then calculate the cost-to-revenue ratios assuming one TEG transfers all of the throughput indicated for the firm (i.e. a TEG-D can transfer as little as 100 Mmscf , or as much as 499 Mmscf). The cost associated with controlling a single TEG is $49,787, which is used in the numerator of the ratio.

As Table 4-8 demonstrates, this rule will have a minimal impact on affected firms. All but one of the 42 companies in the analysis had a cost-to-revenue ratio well below 1%, including KN Interstate Gas with a ratio of 0.06%. The range of ratios for the listed firms is from 0.003% to 1.32%. The average firm ratio is 0.09%, which indicates that the impacts are typically well below 1/10th of one percent.

It is also possible for a firm to transfer it's volume through multiple TEGs of various sizes. As is previously mentioned, TEGs with throughputs below 85 Mmscf do not have control requirements resulting from this rule. Therefore, firms that utilize multiple TEG units will have a portion of those controlled by the rule. Again, we do not have information on the number of affected TEG units operated at the listed firms. Alternatively, we calculate the number of TEGs it would take to equate to 1% of a firm's revenues. Table 4-8 shows that on average, it would require 57 TEGs to be controlled for compliance costs to reach 1% of firm revenues.

In summary, the screening of compliance costs on market and firm revenues shows minimal impacts on the natural gas transmission and storage industry. Nearly all of the firms have impacts below 1%, and it would require the control of 57 TEGs on average for greater impacts to be realized. With this information, it is not likely that small businesses will be significantly impacted and the further evaluation of the industry is not warranted.

TABLE 4-8. IMPACTS ON SELECTED NATURAL GAS TRANSMISSION AND STORAGE FIRMS

(See Excel file: Trans1)

4.4 Economic Welfare Impacts

The value of a regulatory policy is traditionally measured by the change in economic welfare that it generates. Welfare impacts resulting from the regulatory controls on the oil and natural gas production industry will extend to the many consumers and producers of natural gas. Consumers of natural gas will experience welfare impacts due to the adjustments in price and output of natural gas caused by the imposition of the regulations. Producer welfare impacts result from the changes in product revenues to all producers associated with the additional costs of production and the corresponding market adjustments. The theoretical approach used in applied welfare economics to evaluate policies is presented in Appendix E and indicates our approach to estimation of the changes in economic welfare.

The market adjustments in price and quantity in the oil and natural gas production industry were used to calculate the changes in aggregate economic welfare using applied welfare economics principles. Table 4-9 shows the estimated economic welfare change. These estimates represent the social cost of the regulation. For major sources, the social cost of the regulation is $4.9 million with producers of natural gas incurring over 95 percent of the total burden. An alternative measure of the social cost is the total annual compliance cost as estimated by the engineering analysis. However, that measure fails to account for market adjustments and the fact that units may close and not incur the regulatory costs. Thus, the difference between the engineering estimate of social cost and that derived through economic welfare analysis is the deadweight loss to society of the reallocation of resources.

TABLE 4-9. ECONOMIC WELFARE IMPACTS ($\$10^6$)

Change in consumer surplus	-$0.32
Change in producer surplus	-$4.33
Domestic	-$4.36
Foreign	$0.04
Change in surplus for transmission and storage	-$0.30
Change in economic welfare	-$4.94

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10. Ref. 1, Table 4-1.

11. U.S. Department of Energy. Documentation of the Oil and Gas Supply Module (OGSM) DOE/EIA-M063. Energy Information Administration, Oil and Gas Analysis Branch, Washington, DC. March 1994.

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13. Al-Sahlawi, Mohammed A. "The Demand for Natural Gas: A Survey of Price and Income Elasticities," Energy Journal 10(1) January 1989.

14. Ref. 69.

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17. Ref. 39, p. 63.

18. Ref. 72, Table 4.

19. Ref. 46.

20. Dun's Analytical Services. Industry Norms and Key Business Ratios. Dun and Bradstreet, Inc. 1994.

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SECTION 5
FIRM-LEVEL ANALYSIS

A regulatory action to reduce air emissions from the oil and natural gas production industry will potentially affect owners of the regulated entities. Firms or individuals that own the production wells and processing facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility. The legal and financial responsibility for compliance with a regulatory action ultimately rests with these owners who must bear the financial consequences of their decisions. Thus, an analysis of the firm-level impacts of the EPA regulation involves identifying and characterizing affected entities, assessing their response options by modeling or characterizing the decision-making process, projecting how different parties will respond to a regulation, and analyzing the consequences of those decisions. Analyzing firm-level impacts is important for two reasons:

- Even though a production well or processing facility is projected to be profitable with the regulation in place, financial constraints affecting the firm owning the facility may mean that the plant changes ownership.
- The Regulatory Flexibility Act (RFA) requires that the impact of regulations on all small entities, including small companies, be assessed.

Environmental regulations such as the NESHAP for the oil and natural gas production industry affect all businesses, large and small, but small businesses may have special problems in complying with such regulations. The RFA of 1980 requires that special consideration be given to small entities affected by Federal regulation. Under the 1992 revised EPA guidelines for implementing the RFA, an initial regulatory flexibility analysis (IRFA) and a final regulatory flexibility analysis (FRFA) will be performed for every rule subject to the Act that will have any economic impact, however small, on any small entities that are subject to the rule, however few, even though EPA may not be legally required to do so. In 1996, the Small Business Regulatory Enforcement Fairness Act (SBREFA) was passed, which further amended the RFA by expanding judicial review of agencies' compliance with the RFA and by expanding small business review of EPA rulemaking.

Although small business impacts are expected to be minimal due to the size cutoffs for TEG dehydration units,[1] this firm-level analysis addresses the RFA requirements by measuring the impacts on small entities in the oil and natural gas production source category. In addition, the screening analysis presented in section 4.3.2.3 provides an indication that small transmission and storage firms are also not likely to experience significant impacts.

Small entities include small businesses, small organizations, and small governmental jurisdictions and may be defined using the criteria prescribed in the RFA or other criteria identified by EPA. Small businesses are typically defined using Small Business Association (SBA) general size standard definitions for Standard Industrial Classification (SIC) codes. Firms involved in the oil and natural gas production industry include producers (majors and independents), transporters (pipeline companies), and distributors (local distribution companies) that are covered by various SIC codes. The relevant industries include SICs 1311 (Crude Petroleum and Natural Gas), 1381 (Drilling Oil and Gas Wells), 1382 (Oil and Gas Exploration Services), 2911

[1]TEG dehydration units that process less than 3 MMcfd are not expected to be affected by the regulation. It follows that the smaller owners would likely own only units of this type.

(Petroleum Refining), 4922 (Natural Gas Transmission), 4923 (Gas Transmission and Distribution) and 4924 (Natural Gas Distribution). The SBA size standards for these industries are shown in Table 5-1.

TABLE 5-1. SBA SIZE STANDARDS BY SIC CODE FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY

SIC code	Description	SBA size standard in number of employees/annual sales
1311	Crude Petroleum and Natural Gas	500
1381	Drilling Oil and Gas Wells	500
1382	Oil and Gas Exploration Services	$5 million
2911	Petroleum Refining	1,500
4922	Natural Gas Transmission	$5 million
4923	Natural Gas Transmission and Distribution	$5 million
4924	Natural Gas Distribution	500

The general steps involved in analyzing company-level impacts include identifying and analyzing the possible options facing owners of affected facilities and analyzing the impacts of the regulation including impacts on small companies and comparing them to impacts on other companies.

5.1 ANALYZE OWNERS' RESPONSE OPTIONS

In reality, owners' response options to the impending regulation potentially include the following:

- installing and operating pollution control equipment,
- closing or selling the facility, and
- complying with the regulation via process and/or input substitution (versus control equipment installation).

This analysis assumes that the owners of an affected facility will pursue a course of action that maximizes the value of the company, subject to uncertainties about actual costs of compliance and the behavior of other companies.

The market model presented in Section 4 models the facility- and market-level impacts for natural gas producing wells and processing facilities under the owners' first two options listed above. Evaluating facility and market impacts under the third option listed above requires detailed data on production costs and input prices; costs and revenues associated with alternative services/products; and other owner motivations, such as legal and financial liability concerns, and is beyond the scope of this analysis. Consequently, this analysis is based on the assumption that owners of oil and natural gas production facilities respond to the regulation by installing and operating pollution control equipment or discontinuing operations at production wells or process facilities that they own. The facility- and market-level impacts, presented in Section 4, were used to assess the financial impacts to the ultimate corporate owners of oil and natural gas production facilities.

As a result of the regulations, companies will potentially experience changes in the costs of oil and natural gas production as well as changes in the revenues generated by providing these products. Both cost and revenue impacts may be either positive or negative. The cost and revenue changes projected to result from regulating each source category occur at the facility level as a result of market adjustments. Net changes in company profitability are derived by summing facility cost and revenue changes across all facilities owned by each affected company. The net impact on a company's profitability may be negative (cost increases exceed revenue increases) or positive (revenue increases exceed cost increases).

Figure 5-1 characterizes owners' potential responses to regulatory actions. The shaded areas represent decisions made at the facility level that are used as inputs to the company-level analysis. For this analysis, companies are projected to implement the cost-minimizing compliance option and continue to operate their facilities. As long as the company continues to meet its debt obligations, operations will continue. Realistically, if the company cannot meet its interest payments or is in violation of its debt covenants, the company's creditors may take control of the exit decision and forced exit may occur. If the market value of debt (DM) under continued operations is greater than the liquidation value of debt (DL), creditors would probably allow the facility to continue to operate. Under these conditions, creditors may renegotiate the terms of debt. If, however, the DM under continued operations is less than DL, involuntary exit will result and the facility will discontinue operations. Exit will likely take the form of liquidation of assets or distressed sale of the facility. These decisions are modeled in terms of their financial impact to parent companies. The decision to continue to operate may be accompanied by a change in the financial viability of the company.

5.2 FINANCIAL IMPACTS OF THE REGULATION

This analysis evaluates the change in financial status by computing the with-regulation financial ratios of potentially affected firms and comparing them to the corresponding baseline ratios. These financial ratios may include indicators of liquidity, asset management, debt management, and profitability. Although a variety of possible financial ratios provide individual indicators of a firm's health, they may not all give the same signals. Therefore, this analysis focuses on changes in key measures of profitability (return on sales, the return on assets, and the return on equity).

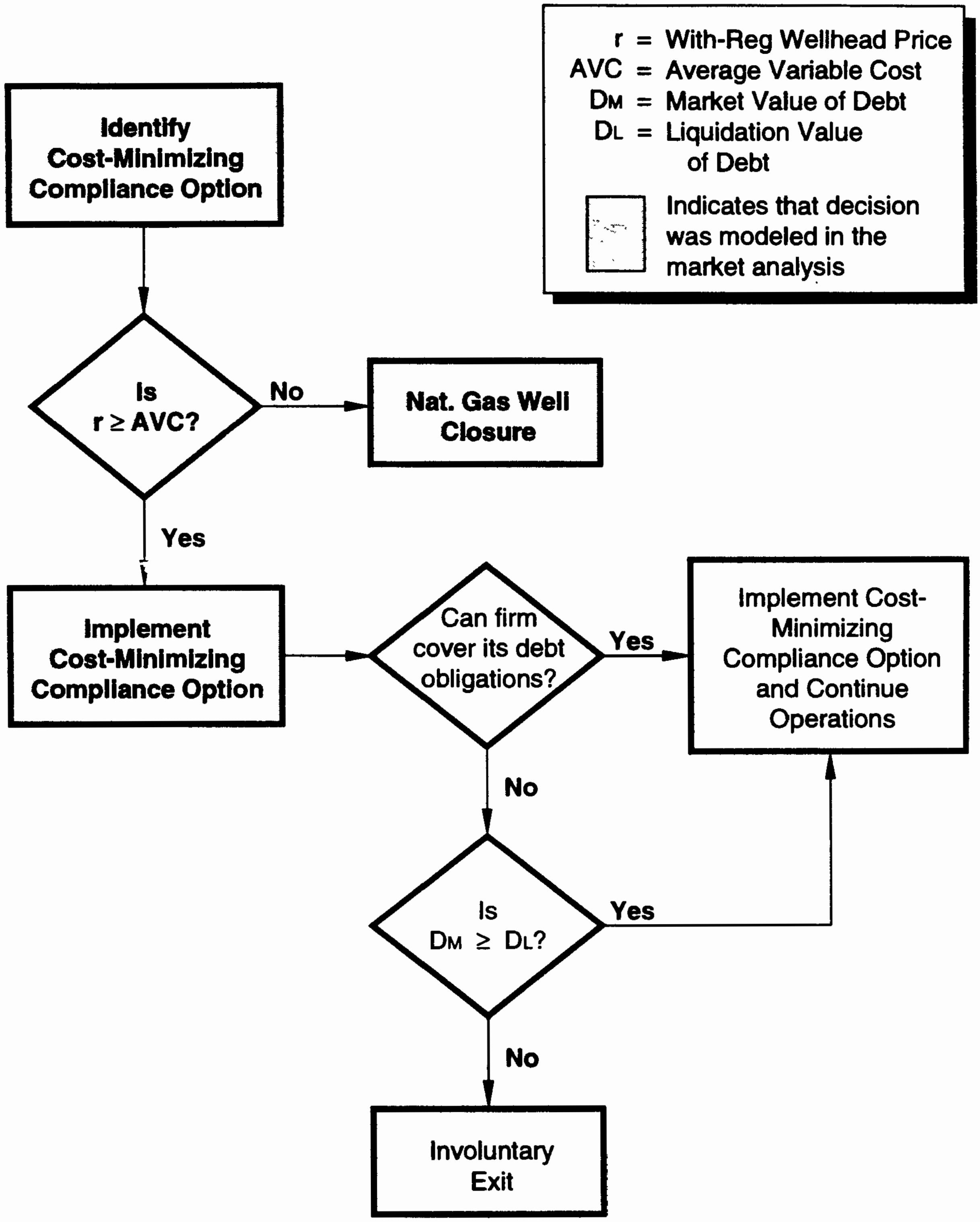

Figure 5-1. Characterization of owner responses to regulatory action.

To assess the financial impacts on the oil and natural gas production source category, this analysis characterizes the financial status of a sample of 80 public firms potentially affected by the regulation. Based on SBA size standards from Table 5-1, a total of 39 firms in this sample are defined as small, or 48.8 percent. Baseline financial statements are developed based on financial information reported in the OGJ and industry-level financial ratios from Dun and Bradstreet (D&B). To compute the with-regulation financial ratios, pro-forma income statements and balance sheets reflecting the with-regulation condition of potentially affected firms were developed based on projected with-regulation costs (including compliance costs) and revenues (including product recovery credits and the with-regulation price and quantity changes projected using a market model).

The financial impacts on the natural gas transmission source category are not assessed because no small entities are expected to be affected. Only operations with throughput of 500 MMcfd or more will be affected by the rule.[2] Information reported in OGJ for the 110 largest gas pipeline companies indicates that none of the companies with volumes in the 500 MMcfd range would have qualified as small businesses (less than $5 million in revenues) in 1994.[1] For the 34 companies that did transmit volumes in that range in 1994, even if all 5 of the TEG units expected to be affected by the rule were operated by the firm with the smallest revenues, the annual compliance costs would only represent 0.34 percent of its revenues.

5.2.1 Baseline Financial Statements

Pro-forma income statements and balance sheets reflecting the 1993 baseline condition of 80 potentially affected firms

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[2]Based on model TEG units in Class E.

were developed based on financial information reported in the OGJ and industry-level financial ratios from D&B.[2,3] This analysis includes 49 firms that listed 1311 as their primary SIC code, 8 firms under SIC 1382, 14 firms under SIC 2911, 8 firms under SIC 4922, and 1 firm under SIC 4924. Each of these firms is publicly traded and listed in the OGJ300, which includes estimates of total revenue, net income, total assets, and shareholder equity. The remaining financial variables needed to complete each firm's income statement and balance sheet were computed using financial ratios computed from the OGJ data and from the D&B benchmark financial ratios shown in Table 5-2. Appendix F provides more detailed firm-by-firm financial data for the 80 sample firms.

This analysis employed probability distributions of the D&B benchmark ratios rather than point estimates to compute the remaining financial variables. The probability distributions for each financial ratio listed in Table 5-2 were generated using @RISK, a risk analysis software add-on for Lotus 1-2-3. In projecting the baseline financial statements, the D&B benchmark ratios were modeled as a triangular distribution with the median value reflecting the most likely value of the distribution and the lower and upper quartile values reflecting the 25th and 75th percentile values of the distribution. @RISK randomly selected a value from the probability distribution of each financial ratio and combined these values with the OGJ data to project the baseline income statement and balance sheet for each firm.

5.2.2 With-Regulation Financial Statements

Before adjusting the baseline financial statements, the regulatory control costs must be mapped from processing facilities to the firms that own them. Mapping the regulatory costs to firms requires knowledge of the number of processing facilities owned by each firm and the extent that they are

TABLE 5-2. DUN AND BRADSTREET'S BENCHMARK FINANCIAL RATIOS BY SIC CODE FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY

SIC code/financial ratio	Lower quartile	Median	Upper quartile
1311-Crude Petroleum and Natural Gas			
Quick ratio (times)	0.6	1.1	2.3
Current ratio (times)	0.8	1.5	3.5
Current liab. to net worth (%)	84.0	30.9	9.7
Fixed assets to net worth (%)	133.5	64.0	22.2
1381-Drilling Oil and Gas Wells			
Quick ratio (times)	0.8	1.3	2.7
Current ratio (times)	1.0	1.7	4.2
Current liab. to net worth (%)	92.8	37.1	11.2
Fixed assets to net worth (%)	123.5	74.6	27.5
1382-Oil and Gas Exploration Services			
Quick ratio (times)	0.5	1.0	1.9
Current ratio (times)	0.8	1.3	3.4
Current liab. to net worth (%)	77.3	33.4	10.0
Fixed assets to net worth (%)	129.9	70.0	22.3
2911-Petroleum Refining			
Quick ratio (times)	0.5	0.7	0.9
Current ratio (times)	1.1	1.3	1.9
Current liab. to net worth (%)	97.9	68.3	37.7
Fixed assets to net worth (%)	220.1	169.9	103.8
4922-Natural Gas Transmission			
Quick ratio (times)	0.3	0.7	1.0
Current ratio (times)	0.8	1.0	1.5
Current liab. to net worth (%)	105.9	50.7	29.4
Fixed assets to net worth (%)	264.7	175.7	111.4

(continued)

TABLE 5-2. DUN AND BRADSTREET'S BENCHMARK FINANCIAL RATIOS BY SIC CODE FOR THE OIL AND NATURAL GAS PRODUCTION INDUSTRY (CONTINUED)

SIC code/financial ratio	Lower quartile	Median	Upper quartile
4923-Gas Transmission and Distribution			
Quick ratio (times)	0.3	0.7	1.1
Current ratio (times)	0.7	1.0	1.4
Current liab. to net worth (%)	127.6	65.6	30.4
Fixed assets to net worth (%)	229.3	144.3	104.8
4924-Natural Gas Distribution			
Quick ratio (times)	0.4	0.7	1.1
Current ratio (times)	0.8	1.0	1.4
Current liab. to net worth (%)	99.2	57.9	35.4
Fixed assets to net worth (%)	225.0	176.9	86.8

Source: Dun's Analytical Services. Industry Norms and Key Business Ratios. Dun and Bradstreet, Inc. 1994.

affected by the regulation. The market model did not explicitly link firms to their respective processing facilities. Thus, this analysis relies on firm responses to EPA's Air Emissions Survey Questionnaires to determine ownership of TEG dehydration units and condensate tank batteries and the OGJ's Special Report, "Worldwide Gas Processing," to determine ownership of natural gas processing plants operating in the U.S. as of January 1994.[4]

Table 5-3 provides the ratio of model TEG units to total assets as computed from the EPA survey data. These ratios reflect the average of firms within the natural gas production groups as defined in the table. To estimate the number of model TEG units for each firm, the total assets of the firm were multiplied by the appropriate ratios. The number of model CTBs for each firm was estimated according to the ratio of CTBs to TEG units by model type. In addition, the number

TABLE 5-3. DISTRIBUTION OF MODEL TEG UNITS BY FIRM'S LEVEL OF NATURAL GAS PRODUCTION

	Model TEG units per ($$10^6$) of assets			
Natural gas production	A	B	C	D
>500 Bcf	0.30259	0.05663	0.00890	0.00405
175 to 500 Bcf	0.40071	0.07447	0.00355	0.00532
100 to 175 Bcf	0.36200	0.09000	0.00600	0.01800
10 to 100 Bcf	0.41223	0.02660	0.00000	0.00665
<10 Bcf	1.15830	0.00000	0.00000	0.00000

of model natural gas processing plants owned by each firm was estimated given the company name and 1993 throughput of natural gas as provided in the OGJ.

In the absencc of information on the number of affected units owned by each firm, this analysis assumed that each TEG unit, CTB, and processing plant owned by each firm is expected to be affected by the regulation--the worst-case scenario for each firm. Affected firms typically incur three types of costs because of regulation: capital, operating, and administrative. The capital cost is an initial lump sum associated with purchasing and installing pollution control equipment. Operating costs are the annually recurring costs associated with operation and maintenance of control equipment, while administrative costs are annually recurring costs associated with emission monitoring, reporting, and recordkeeping. Figure 5-2 provides an indication of the burden of the regulatory costs on sample firms in the oil and natural gas production source category by size. This figure shows the distribution of total annual compliance cost (annualized capital plus the annual operating and administrative cost) as a percentage of baseline sales across sample firms by size. As shown, the mean level of regulatory burden for small firms in the sample if 0.09 percent of sales

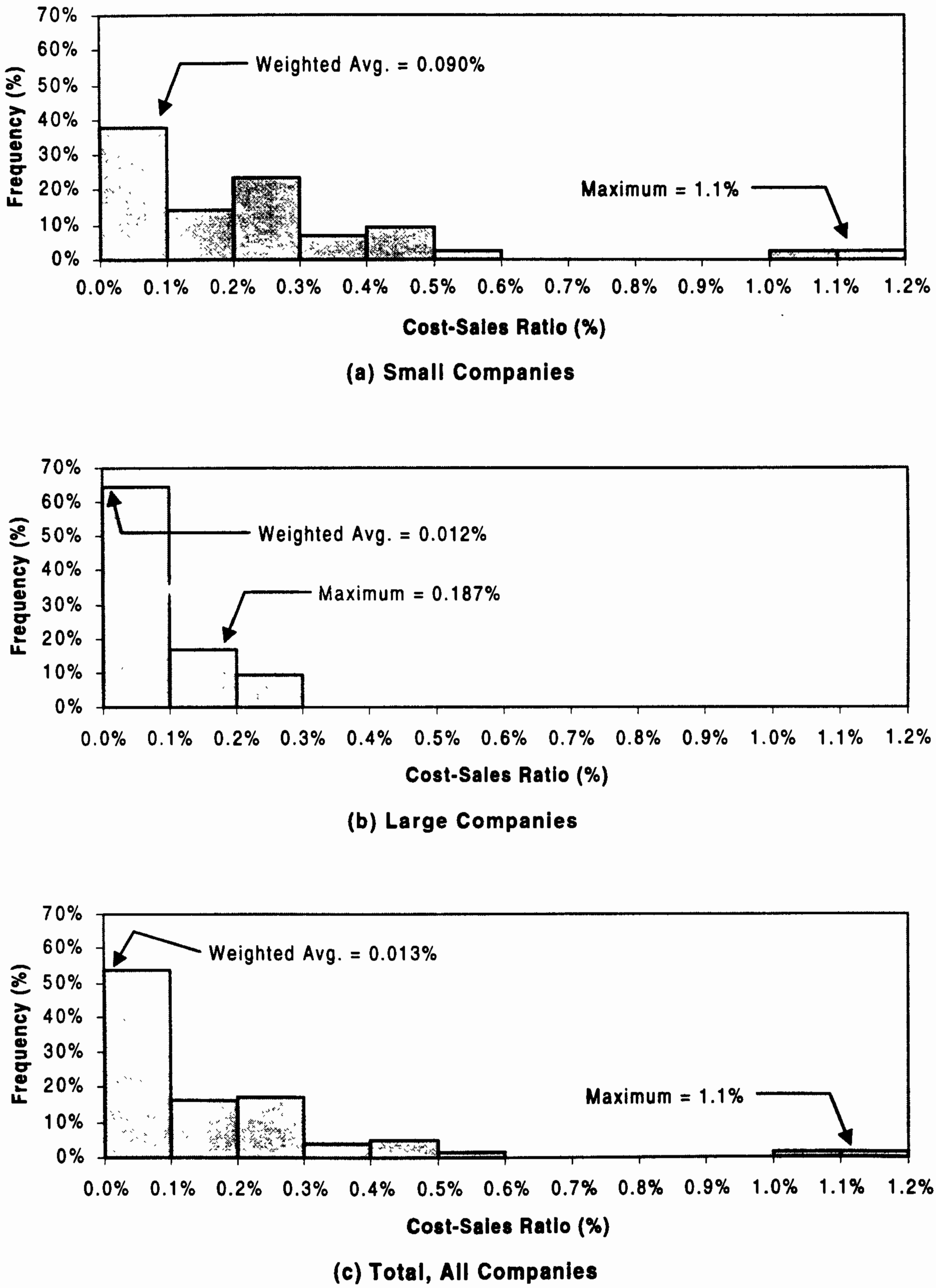

Figure 5-2. Distribution of total annual compliance cost to sales ratio for sample companies.

with a maximum level of 1.1 percent of sales. Alternatively, the mean level of regulatory burden for large firms in the sample is 0.01 percent of sales with a maximum level of 0.19 percent.

Several adjustments were made to the baseline financial statements of each firm to account for the regulation-induced changes at all facilities owned by the firm. Table 5-4 shows the adjustments made to the baseline financial statements to develop the with-regulation financial statements that form the basis of this analysis.

In the annual income statement, the baseline annual revenues are increased by the projected product recovery credits earned by each firm and by the expected change in operating revenues of less than 0.01 percent based on the regulation induced market adjustments. Furthermore, the baseline operating expenses are increased by the estimated change in operating and maintenance costs across TEG units and NGPPs owned by the firm, while the firms' other expenses also increase due to the interest charges and depreciation associated with the acquired pollution control equipment.

In the balance sheet, changes occur to only those firms that incur capital control costs and are determined by the manner in which firms acquire the pollution control equipment. These firms face three choices in funding the acquisition of capital equipment required to comply with the regulation. These choices are

- debt financing,
- equity financing, or
- a mixture of debt and equity financing.

Debt financing involves obtaining additional funds from lenders who are not owners of the firm: they include buyers of bonds, banks, or other lending institutions. Compliance

TABLE 5-4. CALCULATIONS REQUIRED TO SET UP WITH-REGULATION FINANCIAL STATEMENTS

Financial statement category	Calculations
Income statement	
Annual revenues	Baseline annual revenues + product recovery credits + projected revenue change due to market adjustments.
Cost of sales	Baseline cost of sales + operating and maintenance cost of regulation.
Gross profit	Annual revenues - cost of sales.
Expenses due to regulation	Interest: Projected share of capital costs financed through debt times the debt interest rate (7%). Depreciation: 7.5% times the annualized capital costs.
Other expenses and taxes	(Gross profit - estimated expense due to regulation) times the baseline ratio of other expenses and taxes to gross profit.
Net income	Gross profit - estimated expense due to regulation - other expenses and taxes.
Balance sheet	
Current assets	Baseline current assets - [(1 - debt ratio) times total capital cost].
Fixed assets	Baseline fixed assets + total capital cost.
Other noncurrent assets	No change from baseline.
Total assets	Current assets + fixed assets + other noncurrent assets.
Current liabilities	Baseline current liabilities + amortized compliance cost financed through debt - estimated interest expense.
Noncurrent liabilities	Baseline noncurrent liabilities + (debt ratio times total capital cost) - current portion of debt.
Total liabilities	Current liabilities + noncurrent liabilities.
Net worth	Total assets - total liabilities.

Note: Depreciation expense is based on the first year's allowable deduction for industrial equipment under the modified accelerated cost recovery system.

costs not financed through debt are financed using internal or external equity. Internal equity includes the current portion of the company's retained earnings that are not distributed in the form of dividends to the owners (shareholders) of the company, while external equity refers to newly issued equity shares. Each source differs in its exposure to risk, its taxation, and its costs. In general, debt financing is more risky for the firm than equity financing because of the legal obligation of repayment, while borrowing debt can allow a firm to reduce its weighted average cost of capital because of the deductibility of interest on debt for State and Federal income tax purposes. The outcome is that a tradeoff associated with debt financing for each firm exists and it depends on the firm's tax rates, its asset structures, and their inherent riskiness.

Leverage indicates the degree to which a firm's assets have been supplied by, and hence are owned by, creditors versus owners. Leverage should be in an acceptable range, indicating that the firm is using enough debt financing to take advantage of the low cost of debt, but not so much that current or potential creditors are uneasy about the ability of the firm to repay its debt. The debt ratio (d) is a common measure of leverage that divides all debt, long and short term, by total assets. Empirical evidence shows that capital structure can vary widely from the theoretical optimum and yet have little impact on the value of the firm.[5] Consequently, it was assumed that the current capital structure, as measured by the debt ratio, reflects the optimal capital structure for each firm. Thus, for this analysis, each firm's debt ratio for 1993 determines the amount of capital expenditures on pollution control technology that will be debt financed. That portion not debt financed is assumed to be financed using internal equity.

Thus, on the assets side of the balance sheet of affected firms, current assets decline by (1-d) times the total capital cost (E^K), while the value of property, plant, and equipment (fixed assets) increases by the total capital cost (i.e., the value of the pollution control equipment). Thus, the overall increase in a firm's total assets is equal to that fraction of the total capital cost that is not paid out of current assets (i.e., $d*E^K$).

The liabilities side of the balance sheet is affected because firms enter new legal obligations to repay that fraction of the total capital cost that is assumed to be debt financed (i.e., $d*E^K$). Long-term debt, and thus total liabilities, of the firm is increased by this dollar amount less the interest expense paid during the year. Owner's equity, or net worth at these firms, is increased by only the amount of interest expense paid during the year due to the offsetting increases in both total assets and total liabilities regarding the acquisition of the pollution control equipment. Moreover, working capital at each affected firm, defined as current assets minus current liabilities, unambiguously falls because of the decline in current assets and the increase in current liabilities.

Comparison of the baseline and with-regulation financial statements of firms in the U.S. oil and natural gas production industry provides indicators of the potential disparity of economic impacts across small and large firms. These indicators include the key measures of profitability (return on sales, return on assets, and return on equity) and changes in the likelihood of financial failure or bankruptcy (as measured by Altman's Z-score).

5.2.3 Profitability Analysis

Financial ratios may be categorized as one of five fundamental types:

- liquidity or solvency
- asset management
- debt management
- profitability
- market value[6]

Profitability is the most comprehensive measure of the firm's performance because it measures the combined effects of liquidity, asset management, and debt management. Analyzing profitability is useful because it helps evaluate both the incentive and ability of firms in the oil and natural gas production industry to incur the capital and operating costs required for compliance. More profitable firms have more incentive than less profitable firms to comply because the annual returns to doing business are greater. In the extreme, a single-facility firm earning zero profit has no incentive to comply with a regulation imposing positive costs unless the entire burden of the regulation can be passed along to consumers. This same firm may also be less able to comply because its poor financial position makes it difficult to obtain funds through either debt or equity financing.

As shown in Table 5-5, three ratios are commonly used to measure profitability: return on sales, return on assets, and return on equity. For all these measures, higher values are unambiguously preferred over lower values. Negative values result if the firm experiences a loss.

TABLE 5-5. KEY MEASURES OF PROFITABILITY

Measure of profitability	Formula for calculation
Return on sales	$\frac{\text{Net income}}{\text{Sales}}$
Return on assets	$\frac{\text{Net income}}{\text{Total assets}}$
Return on equity	$\frac{\text{Net income}}{\text{Owner's equity}}$

Table 5-6 provides the summary statistics for each of the measures of profitability. The summary statistics include the mean, minimum, and maximum values for each measure in the baseline and with-regulation conditions across small, large, and all firms included in this analysis. A comparison of the values in baseline and after imposition of the regulation provides much detail on the distributional changes in these profitability measures across firms.

TABLE 5-6. SUMMARY STATISTICS FOR KEY MEASURES OF PROFITABILITY IN BASELINE AND WITH-REGULATION BY FIRM SIZE CATEGORY

Measure of profitability/summary statistics	Baseline			With regulation		
	Small firms	Large firms	All firms	Small firms	Large firms	All firms
Return on sales						
Mean	8.05	3.71	5.82	7.87	3.66	5.71
Minimum	-43.99	-17.29		-44.30	-17.33	
Maximum	70.15	29.47		69.82	29.30	
Return on assets						
Mean	5.83	2.72	4.24	5.76	2.70	4.19
Minimum	-10.34	-7.16		-10.42	-7.18	
Maximum	62.22	16.59		62.22	16.49	
Return on equity						
Mean	9.00	6.16	7.54	8.80	6.10	7.41
Minimum	-91.37	-33.40		-91.78	-33.64	
Maximum	90.35	26.43		89.85	26.26	

As Table 5-6 illustrates, the mean return on sales slightly declines for all firms after imposition of the regulation from 5.82 percent to 5.71 percent. This slight decline is shared across small and large firms. Further, the mean return on assets declines to some extent for all firms with regulation from 4.24 percent to 4.19 percent. This inconsiderable decline in the mean return on assets is found for small and large firms alike. As measured across all firms, the with-regulation mean return on equity declines slightly from 7.54 percent to 7.41 percent. As a group, the financial impacts associated with the regulation are negligible and show no overall disproportionate impact across small and large firms.

The screening analysis of the transmission and storage firms in section 4.3.2.2 shows that the cost-to-revenues ratios of the selected firms is 0.09% on average, which indicates that impacts are typically well below 1/10th of one percent for these firms.

Therefore, this information presented in this section of the EIA along with the screening analysis of the transmission and storage firms in section 4.3.2.2 clearly indicates that there will not be a significant impact on a substantial number of small entities in the natural gas production, and transmission and storage industries.

References:

1. Ref. 49.

2. Ref. 46.

3. Ref. 76.

4. Ref. 39.

5. Brigham, Eugene F., and Louis C. Gapenski. Financial Management: Theory and Practice. 6th Ed. Orlando, FL, The Dryden Press. 1991.

6. Ref. 82.

APPENDIX A

GRUY ENGINEERING CORPORATION'S
OIL WELLGROUPS BY STATE

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
Alaska						
AKOIL 1	0-2	0- 60	4	3	12.43	1.33
AKOIL 2	0-2	61- 100	2	2	31.33	0.17
AKOIL 3	0-2	201- 300	2	2	91.17	0.70
AKOIL 4	0-2	401- 500	1	1	42.80	14.27
AKOIL 5	0-2	601-1,000	1	1	54.17	17.53
AKOIL 6	0-2	1,0001-2,000	6	4	610.07	187.30
AKOIL 7	0-2	2,001-5,000	23	7	2,233.33	2,142.23
AKOIL 8	0-2	5,001-over	67	10	176,855.57	37,691.77
AKOIL 9	2-6	1,001-2,000	1	1	100.50	50.27
AKOIL 10	2-6	5,001- Over	2	1	32,719.13	6,184.60
AKOIL 11	6-10	0- 60	1	1	2.20	0.27
AKOIL 12	6-10	61- 100	5	1	1.93	3.57
AKOIL 13	6-10	101- 200	2	2	3.33	4.97
AKOIL 14	6-10	201- 300	3	1	16.30	15.40
AKOIL 15	6-10	301- 400	1	1	14.10	8.90
AKOIL 16	6-10	401- 500	1	1	34.97	10.97
AKOIL 17	6-10	501- 600	2	3	60.73	29.93
AKOIL 18	6-10	601-1,000	5	3	160.77	94.03
AKOIL 19	6-10	1,001-2,000	14	5	546.37	463.40
AKOIL 20	6-10	2,001-5,000	27	6	2,778.30	2,250.57
AKOIL 21	6-10	5,001- Over	613	7	1,732,915.13	808,289.93
AKOIL 22	10+	61- 100	2	2	26.10	0.33
AKOIL 23	10+	101- 200	2	2	50.03	0.67
AKOIL 24	10+	301- 400	1	1	22.93	10.13
AKOIL 25	10+	501- 600	1	1	2.03	18.10
AKOIL 26	10+	601-1,000	6	6	161.20	57.43
AKOIL 27	10+	1,001-2,000	11	6	472.47	348.40
AKOIL 28	10+	2,001-5,000	31	9	5,214.00	2,726.60
AKOIL 29	10+	5,001- Over	704	10	2,990,463.67	1,039,351.67

(continued)

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
Alabama						
ALOIL 1	0-2	0- 60	2	3	0.00	1.90
ALOIL 2	0-2	61- 100	4	3	5.13	7.73
ALOIL 3	0-2	101- 200	11	6	6.13	43.53
ALOIL 4	0-2	201- 300	443	4	324.13	3,587.97
ALOIL 5	0-2	301- 400	50	4	0.00	505.47
ALOIL 6	0-2	501- 600	54	3	188.63	762.30
ALOIL 7	0-2	601-1,000	36	5	138.47	665.37
ALOIL 8	0-2	1,001-2,000	8	3	107.40	362.10
ALOIL 9	0-2	2,001-5,000	20	6	2,093.50	1,755.03
ALOIL 10	0-2	5,001- Over	7	4	1,808.80	2,062.70
ALOIL 11	2-6	0- 60	18	6	3.07	6.20
ALOIL 12	2-6	61- 100	15	7	61.97	22.30
ALOIL 13	2-6	101- 200	49	11	148.47	185.97
ALOIL 14	2-6	201- 300	38	10	103.07	254.83
ALOIL 15	2-6	301- 400	23	7	124.03	191.57
ALOIL 16	2-6	401- 500	13	4	4.90	148.47
ALOIL 17	2-6	501- 600	11	7	214.97	129.83
ALOIL 18	2-6	601-1,000	8	4	19.50	138.43
ALOIL 19	2-6	1,001-2,000	4	4	156.30	57.00
ALOIL 20	2-6	2,001-5,000	1	1	162.50	57.20
ALOIL 21	6-10	0- 60	2	3	0.00	1.43
ALOIL 22	6-10	201- 300	1	1	0.00	9.00
ALOIL 23	6-10	401- 500	1	1	0.40	16.27
ALOIL 24	6-10	601-1,000	4	3	1.07	49.10
ALOIL 25	6-10	1,001-2,000	6	4	5.53	231.03
ALOIL 26	6-10	2,001-5,000	11	4	37.53	680.23
ALOIL 27	6-10	5,001- Over	1	1	13.03	202.33
ALOIL 28	10+	0- 60	7	1	0.10	2.03
ALOIL 29	10+	101- 200	1	1	0.00	5.53
ALOIL 30	10+	201- 300	2	3	0.17	10.17
ALOIL 31	10+	301- 400	7	4	31.53	66.90
ALOIL 32	10+	401- 500	2	3	6.30	30.17

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
ALOIL 33	10+	501- 600	2	3	8.33	28.90
						(continued)
ALOIL 34	10+	601-1,000	7	7	113.43	130.43
ALOIL 35	10+	1,001-2,000	12	10	382.23	381.27
ALOIL 36	10+	2,001-5,000	25	18	1,557.57	2,214.33
ALOIL 37	10+	5,001- Over	33	17	4,389.67	6,605.90
Arkansas						
AROIL 1	0-2	0- 60	1484	48	28.77	1,176.03
AROIL 2	0-2	61- 100	704	47	7.93	1,722.60
AROIL 3	0-2	101- 200	560	56	26.17	2,474.17
AROIL 4	0-2	201- 300	156	33	138.67	1,186.97
AROIL 5	0-2	301- 400	231	21	32.70	2,793.13
AROIL 6	0-2	401- 500	31	15	38.27	421.93
AROIL 7	0-2	501- 600	47	8	227.73	790.53
AROIL 8	0-2	601-1,000	41	13	3,222.50	871.00
AROIL 9	0-2	1,001-2,000	109	12	0.00	4,341.50
AROIL 10	0-2	2,001-5,000	4	4	178.27	339.43
AROIL 11	0-2	5,001- Over	5	6	912.30	1,529.90
AROIL 12	2-6	0- 60	694	51	1.97	672.57
AROIL 13	2-6	61- 100	320	60	9.87	798.87
AROIL 14	2-6	101- 200	399	98	46.00	1,883.33
AROIL 15	2-6	201- 300	148	55	119.83	1,150.90
AROIL 16	2-6	301- 400	69	41	11.33	782.20
AROIL 17	2-6	401- 500	31	24	70.40	435.47
AROIL 18	2-6	501- 600	16	14	3.70	272.23
AROIL 19	2-6	601-1,000	45	27	410.07	1,049.20
AROIL 20	2-6	1,001-2,000	26	19	106.53	1,022.90
AROIL 21	2-6	2,001-5,000	7	6	159.07	577.90
AROIL 22	6-10	0- 60	18	11	55.43	16.10
AROIL 23	6-10	61- 100	14	10	61.17	17.60
AROIL 24	6-10	101- 200	88	40	213.93	295.27
AROIL 25	6-10	201- 300	64	25	284.63	460.67
AROIL 26	6-10	301- 400	43	21	581.80	403.17

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
AROIL 27	6-10	401- 500	20	12	179.23	264.17
AROIL 28	6-10	501- 600	12	7	343.30	167.93
AROIL 29	6-10	601-1,000	50	20	1,652.83	1,033.10

(continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
AROIL 30	6-10	1,001-2,000	26	10	2,247.10	904.40
AROIL 31	6-10	2,001-5,000	10	8	3,947.77	561.43
AROIL 32	6-10	5,001- Over	1	1	1,600.67	70.67
AROIL 33	10+	0- 60	1	1	3.37	0.33
AROIL 34	10+	61- 100	1	1	8.30	1.57
AROIL 35	10+	201- 300	2	3	7.50	12.27
AROIL 36	10+	401- 500	1	1	94.53	7.17
AROIL 37	10+	501- 600	1	1	5.63	16.57
AROIL 38	10+	601-1,000	4	5	245.33	85.77
AROIL 39	10+	1,001-2,000	7	6	1,394.40	178.70
AROIL 40	10+	2,001-5,000	2	3	1,465.73	54.17
AROIL 41	10+	5,001- Over	2	2	2,320.40	135.63
Arizona						
AZOIL 1	0-2	101- 200	1	1	4.17	4.20
AZOIL 2	0-2	301- 400	1	1	7.83	9.47
AZOIL 3	0-2	401- 500	1	1	44.47	9.97
AZOIL 4	0-2	601-1,000	3	1	56.30	42.47
AZOIL 5	0-2	2,001-5,000	4	1	4.40	121.90
AZOIL 6	2-6	0- 60	1	1	0.00	0.83
AZOIL 7	2-6	101- 200	1	1	5.77	4.27
AZOIL 8	2-6	201- 300	5	1	94.73	31.37
AZOIL 9	2-6	301- 400	2	1	34.83	18.50
AZOIL 10	2-6	401- 500	1	1	0.00	16.20
AZOIL 11	2-6	501- 600	1	1	69.10	12.60
AZOIL 12	2-6	601-1,000	2	1	55.03	40.63
AZOIL 13	2-6	2,001-5,000	2	1	0.00	71.33
California-Coastal and Northern						
CACNOIL 1	0-2	0- 60	322	59	131.83	229.57
CACNOIL 2	0-2	61- 100	169	44	395.40	324.37

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
CACNOIL 3	0-2	101- 200	292	58	1,228.53	1,066.93
CACNOIL 4	0-2	201- 300	160	36	1,031.03	1,022.10
CACNOIL 5	0-2	301- 400	119	39	1,348.27	1,085.70
CACNOIL 6	0-2	401- 500	68	29	567.50	836.27
CACNOIL 7	0-2	501- 600	47	23	522.53	744.30
						(continued)
CACNOIL 8	0-2	601-1,000	113	27	2,038.60	2,436.70
CACNOIL 9	0-2	1,001-2,000	94	19	3,100.00	3,650.87
CACNOIL 10	0-2	2,001-5,000	31	6	1,615.53	2,699.20
CACNOIL 11	0-2	5,001- Over	8	5	2,942.90	792.70
CACNOIL 12	2-6	0- 60	279	50	443.53	156.53
CACNOIL 13	2-6	61- 100	221	38	900.30	418.27
CACNOIL [illegible]	2-6	101- 200	569	52	4,091.27	2,135.80
CACNOIL 15	2-6	201- 300	357	47	3,096.80	2,382.10
CACNOIL 16	2-6	301- 400	234	36	3,086.40	2,245.27
CACNOIL 17	2-6	401- 500	204	36	2,938.60	2,612.60
CACNOIL 18	2-6	501- 600	115	34	2,217.93	1,808.53
CACNOIL 19	2-6	601-1,000	301	41	5,214.47	6,883.57
CACNOIL 20	2-6	1,001-2,000	141	33	3,367.53	5,908.23
CACNOIL 21	2-6	2,001-5,000	59	16	2,295.00	5,474.37
CACNOIL 22	2-6	5,001- Over	3	4	280.53	594.67
CACNOIL 23	6-10	0- 60	49	21	36.93	29.83
CACNOIL 24	6-10	61- 100	33	15	124.63	44.20
CACNOIL 25	6-10	101- 200	118	24	814.27	406.80
CACNOIL 26	6-10	201- 300	86	29	880.03	509.93
CACNOIL 27	6-10	301- 400	71	21	874.43	624.00
CACNOIL 28	6-10	401- 500	61	21	883.33	718.00
CACNOIL 29	6-10	501- 600	51	21	961.67	699.07
CACNOIL 30	6-10	601-1,000	106	24	3,073.13	2,277.73
CACNOIL 31	6-10	1,001-2,000	117	23	4,871.77	4,637.63
CACNOIL 32	6-10	2,001-5,000	67	17	7,494.27	5,325.87
CACNOIL 33	6-10	5,001- Over	13	7	2,657.97	1,990.10
CACNOIL 34	10+	0- 60	6	5	2.50	2.50

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
CACNOIL 35	10+	61- 100	8	4	16.20	13.77
CACNOIL 36	10+	101- 200	17	5	64.67	71.73
CACNOIL 37	10+	201- 300	23	8	111.93	156.40
CACNOIL 38	10+	301- 400	38	7	373.03	363.70
CACNOIL 39	10+	401- 500	31	8	643.10	357.33
CACNOIL 40	10+	501- 600	24	8	574.00	310.73
CACNOIL 41	10+	601-1,000	60	11	1,507.80	1,263.60

(continued)

CACNOIL 42	10+	1,001-2,000	63	10	1,683.30	2,602.90
CACNOIL 43	10+	2,001-5,000	36	7	3,053.70	3,251.53
CACNOIL 44	10+	5,001- Over	3	1	350.20	565.37
California-Los Angeles Basin						
CALAOIL 1	0-2	0- 60	382	29	191.60	319.37
CALAOIL 2	0-2	61- 100	291	24	505.17	631.47
CALAOIL 3	0-2	101- 200	591	37	1,261.77	2,516.60
CALAOIL 4	0-2	201- 300	396	40	1,408.10	2,896.70
CALAOIL 5	0-2	301- 400	232	32	1,037.03	2,493.33
CALAOIL 6	0-2	401- 500	177	30	1,001.27	2,395.53
CALAOIL 7	0-2	501- 600	111	24	673.20	1,881.97
CALAOIL 8	0-2	601-1,000	273	37	2,385.63	6,438.13
CALAOIL 9	0-2	1,001-2,000	174	30	2,376.10	7,559.20
CALAOIL 10	0-2	2,001-5,000	48	20	1,258.47	4,424.30
CALAOIL 11	0-2	5,001- Over	1	1	15.00	192.43
CALAOIL 12	2-6	0- 60	189	30	124.23	128.73
CALAOIL 13	2-6	61- 100	176	30	195.30	377.67
CALAOIL 14	2-6	101- 200	493	39	1,136.43	2,154.20
CALAOIL 15	2-6	201- 300	415	38	1,342.37	3,011.63
CALAOIL 16	2-6	301- 400	282	37	1,398.13	2,921.70
CALAOIL 17	2-6	401- 500	230	34	1,290.00	3,135.20
CALAOIL 18	2-6	501- 600	176	29	954.37	3,027.90
CALAOIL 19	2-6	601-1,000	396	44	3,133.57	9,435.87
CALAOIL 20	2-6	1,001-2,000	239	32	3,014.03	9,753.57
CALAOIL 21	2-6	2,001-5,000	59	19	2,009.57	4,674.80

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
CALAOIL 22	2-6	5,001- Over	1	1	40.20	168.53
CALAOIL 23	6-10	0- 60	60	19	19.93	36.80
CALAOIL 24	6-10	61- 100	35	21	102.77	67.87
CALAOIL 25	6-10	101- 200	112	22	470.30	451.67
CALAOIL 26	6-10	201- 300	83	29	754.53	540.47
CALAOIL 27	6-10	301- 400	75	28	1,036.40	706.13
CALAOIL 28	6-10	401- 500	67	24	1,073.30	812.03
CALAOIL 29	6-10	501- 600	32	24	564.90	490.37
CALAOIL 30	6-10	601-1,000	86	29	1,894.23	1,951.50
						(continued)
CALAOIL 31	6-10	1,001-2,000	75	21	2,006.37	3,183.70
CALAOIL 32	6-10	2,001-5,000	46	11	2,038.97	4,551.50
CALAOIL 33	6-10	5,001- Over	10	5	449.97	1,982.90
CALAOIL 34	10+	0- 60	3	1	11.50	1.00
CALAOIL 35	10+	61- 100	1	1	2.40	2.40
CALAOIL 36	10+	101- 200	6	6	4.67	30.67
CALAOIL 37	10+	201- 300	4	4	9.43	22.40
CALAOIL 38	10+	301- 400	9	6	138.80	74.40
CALAOIL 39	10+	401- 500	5	5	111.77	62.10
CALAOIL 40	10+	501- 600	5	4	59.23	67.57
CALAOIL 41	10+	601-1,000	7	5	202.73	138.60
CALAOIL 42	10+	1,001-2,000	7	6	226.40	339.47
CALAOIL 43	10+	2,001-5,000	8	4	417.00	749.67
CALAOIL 44	10+	5,001- Over	1	1	255.63	225.73
California-San Jose Basin						
CASJOIL 1	0-2	0- 60	3812	77	520.23	2,968.03
CASJOIL 2	0-2	61- 100	2369	56	743.10	5,237.23
CASJOIL 3	0-2	101- 200	4493	54	1,963.40	19,634.90
CASJOIL 4	0-2	201- 300	3091	45	1,703.93	23,541.70
CASJOIL 5	0-2	301- 400	2474	32	1,770.13	26,934.10
CASJOIL 6	0-2	401- 500	2050	34	1,639.00	28,980.40
CASJOIL 7	0-2	501- 600	1541	24	1,715.33	26,846.50
CASJOIL 8	0-2	601-1,000	3920	31	4,760.87	96,300.23

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
CASJOIL 9	0-2	1,001-2,000	2971	24	9,799.00	127,933.63
CASJOIL 10	0-2	2,001-5,000	1137	20	21,738.57	102,768.57
CASJOIL 11	0-2	5,001- Over	266	9	110,704.47	61,404.97
CASJOIL 12	2-6	0- 60	1280	57	985.90	999.33
CASJOIL 13	2-6	61- 100	865	52	1,736.33	1,862.63
CASJOIL 14	2-6	101- 200	1400	55	7,310.10	5,482.23
CASJOIL 15	2-6	201- 300	830	53	8,410.87	5,453.63
CASJOIL 16	2-6	301- 400	447	40	6,593.17	4,038.97
CASJOIL 17	2-6	401- 500	303	31	6,641.60	3,468.57
CASJOIL 18	2-6	501- 600	254	26	6,752.80	3,595.77
CASJOIL 19	2-6	601-1,000	660	27	29,171.67	12,579.37
CASJOIL [illegible]	2-6	1,001-2,000	520	24	35,959.97	16,932.00
CASJOIL 21	2-6	2,001-5,000	295	14	28,730.93	18,800.80
CASJOIL 22	2-6	5,001- Over	38	7	18,777.40	6,337.57
CASJOIL 23	6-10	0- 60	74	37	29.10	47.93
CASJOIL 24	6-10	61- 100	49	20	183.33	82.57
CASJOIL 25	6-10	101- 200	144	39	796.57	476.60
CASJOIL 26	6-10	201- 300	97	39	1,487.23	529.43
CASJOIL 27	6-10	301- 400	69	27	1,363.60	548.13
CASJOIL 28	6-10	401- 500	53	26	1,669.13	557.60
CASJOIL 29	6-10	501- 600	40	21	1,499.47	469.27
CASJOIL 30	6-10	601-1,000	112	18	9,722.03	1,802.73
CASJOIL 31	6-10	1,001-2,000	132	20	24,153.97	3,472.83
CASJOIL 32	6-10	2,001-5,000	143	17	71,093.53	8,207.40
CASJOIL 33	6-10	5,001- Over	147	6	195,646.73	46,313.93
CASJOIL 34	10+	0- 60	21	15	8.97	5.90
CASJOIL 35	10+	61- 100	10	10	21.43	16.10
CASJOIL 36	10+	101- 200	16	9	88.87	58.83
CASJOIL 37	10+	201- 300	29	15	317.80	160.43
CASJOIL 38	10+	301- 400	16	11	111.03	124.33
CASJOIL 39	10+	401- 500	10	9	367.57	84.97
CASJOIL 40	10+	501- 600	17	11	398.53	261.17

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APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
CASJOIL 41	10+	601-1,000	38	18	968.70	786.50
CASJOIL 42	10+	1,001-2,000	34	15	2,484.67	1,253.27
CASJOIL 43	10+	2,001-5,000	44	12	3,552.93	4,144.37
CASJOIL 44	10+	5,001- Over	36	5	7,009.67	17,150.97
Colorado						
COOIL 1	0-2	0- 60	129	16	27.93	84.53
COOIL 2	0-2	61- 100	22	13	42.17	49.13
COOIL 3	0-2	101- 200	81	23	53.87	356.40
COOIL 4	0-2	201- 300	27	14	68.73	190.63
COOIL 5	0-2	301- 400	28	4	17.73	333.57
COOIL 6	0-2	401- 500	16	7	103.70	206.53
COOIL 7	0-2	501- 600	7	1	0.07	114.30
COOIL 8	0-2	601-1,000	7	4	22.87	148.73

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COOIL 9	0-2	1,001-2,000	4	3	36.73	184.17
COOIL 10	0-2	2,001-5,000	3	3	262.47	203.23
COOIL 11	2-6	0- 60	429	73	1,499.50	371.27
COOIL 12	2-6	61- 100	840	88	6,572.43	1,406.80
COOIL 13	2-6	101- 200	857	162	9,468.53	2,660.30
COOIL 14	2-6	201- 300	230	92	2,074.53	1,502.47
COOIL 15	2-6	301- 400	148	67	2,344.77	1,347.50
COOIL 16	2-6	401- 500	88	47	391.80	1,141.10
COOIL 17	2-6	501- 600	56	35	756.70	831.57
COOIL 18	2-6	601-1,000	121	52	3,415.87	2,443.47
COOIL 19	2-6	1,001-2,000	129	30	1,656.30	2,591.00
COOIL 20	2-6	2,001-5,000	127	17	5,416.67	10,206.50
COOIL 21	2-6	5,001- Over	39	6	8,031.40	6,169.97
COOIL 22	6-10	0- 60	270	93	919.70	170.40
COOIL 23	6-10	61- 100	407	89	3,349.77	649.10
COOIL 24	6-10	101- 200	975	129	18,818.13	2,432.77
COOIL 25	6-10	201- 300	418	85	14,182.10	1,634.30
COOIL 26	6-10	301- 400	146	51	6,468.87	852.53
COOIL 27	6-10	401- 500	101	39	5,963.23	761.77

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
COOIL 28	6-10	501- 600	44	25	2,357.63	388.53
COOIL 29	6-10	601-1,000	98	45	6,765.77	1,559.50
COOIL 30	6-10	1,001-2,000	76	23	7,984.73	2,289.20
COOIL 31	6-10	2,001-5,000	430	13	16,352.83	33,830.30
COOIL 32	6-10	5,001- Over	10	5	1,247.17	2,107.37
Florida						
FLOIL 1	0-2	601-1,000	1	1	3.07	25.43
FLOIL 2	0-2	1,001-2,000	1	2	65.40	58.17
FLOIL 3	0-2	2,001-5,000	1	1	9.80	103.03
FLOIL 4	0-2	5,001- Over	1	1	834.57	704.90
FLOIL 5	10+	61- 100	1	1	32.17	3.33
FLOIL 6	10+	101- 200	1	1	42.17	6.67
FLOIL 7	10+	201- 300	3	1	22.20	22.20
FLOIL 8	10+	301- 400	4	4	65.47	16.67
FLOIL 9	10+	501- 600	2	3	34.43	32.80

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FLOIL 10	10+	601-1,000	7	4	107.20	89.23
FLOIL 11	10+	1,001-2,000	19	10	550.03	693.73
FLOIL 12	10+	2,001-5,000	39	13	1,984.73	3,422.67
FLOIL 13	10+	5,001- Over	44	8	20,896.33	15,087.57
Illinois						
ILOIL 1	0-2	0- 60	5424	132	0.00	937.07
ILOIL 2	0-2	61- 100	5421	250	0.00	2,275.20
ILOIL 3	0-2	101- 200	14865	433	0.00	12,122.03
ILOIL 4	0-2	201- 300	3006	217	0.00	6,760.17
ILOIL 5	0-2	301- 400	1146	127	0.00	3,960.70
ILOIL 6	0-2	401- 500	630	88	0.00	2,966.17
ILOIL 7	0-2	501- 600	426	59	0.00	2,504.30
ILOIL 8	0-2	601-1,000	708	91	0.00	5,807.33
ILOIL 9	0-2	1,001-2,000	462	57	0.00	6,916.80
ILOIL 10	0-2	2,001-5,000	210	25	0.00	6,499.63
ILOIL 11	0-2	5,001- Over	51	12	0.00	5,835.70
Indiana						

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
INOIL 1	0-2	0- 60	1205	70	0.00	202.17
INOIL 2	0-2	61- 100	1894	135	0.00	683.73
INOIL 3	0-2	101- 200	3062	188	0.00	2,394.47
INOIL 4	0-2	201- 300	677	88	0.00	1,402.87
INOIL 5	0-2	301- 400	274	45	0.00	851.43
INOIL 6	0-2	401- 500	155	31	0.00	658.17
INOIL 7	0-2	501- 600	73	16	0.00	387.33
INOIL 8	0-2	601-1,000	119	26	0.00	901.87
INOIL 9	0-2	1,001-2,000	66	14	0.00	874.80
INOIL 10	0-2	2,001-5,000	17	6	0.00	486.60
INOIL 11	0-2	5,001- Over	7	3	0.00	350.93
Kansas						
KSOIL 1	0-2	0- 60	11041	385	0.00	6,667.47
KSOIL 2	0-2	61- 100	2824	385	0.00	5,559.90
KSOIL 3	0-2	101- 200	2204	691	0.00	8,269.37
KSOIL 4	0-2	201- 300	833	249	0.00	5,269.77
KSOIL 5	0-2	301- 400	219	103	0.00	1,873.87

(continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
KSOIL 6	0-2	401- 500	125	67	0.00	1,430.70
KSOIL 7	0-2	501- 600	74	40	0.00	1,025.37
KSOIL 8	0-2	601-1,000	93	56	0.00	1,761.77
KSOIL 9	0-2	1,001-2,000	69	44	0.00	2,517.87
KSOIL 10	0-2	2,001-5,000	11	10	0.00	637.70
KSOIL 11	0-2	5,001- Over	4	3	0.00	1,053.67
KSOIL 12	2-6	0- 60	7001	565	0.00	7,051.93
KSOIL 13	2-6	61- 100	6754	989	0.00	13,896.93
KSOIL 14	2-6	101- 200	8015		0.00	29,623.00
KSOIL 15	2-6	201- 300	2524	893	0.00	15,720.63
KSOIL 16	2-6	301- 400	955	373	0.00	8,413.90
KSOIL 17	2-6	401- 500	508	206	0.00	5,930.70
KSOIL 18	2-6	501- 600	292	147	0.00	4,034.57
KSOIL 19	2-6	601-1,000	556	234	0.00	10,691.93
KSOIL 20	2-6	1,001-2,000	320	153	0.00	10,400.10

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
KSOIL 21	2-6	2,001-5,000	107	69	0.00	7,183.67
KSOIL 22	2-6	5,001- Over	21	12	0.00	4,623.77
KSOIL 23	6-10	0- 60	15	10	0.00	2.43
KSOIL 24	6-10	61- 100	10	8	0.00	4.97
KSOIL 25	6-10	101- 200	137	45	0.00	285.50
KSOIL 26	6-10	201- 300	66	30	0.00	327.23
KSOIL 27	6-10	301- 400	25	18	0.00	197.07
KSOIL 28	6-10	401- 500	15	11	0.00	175.30
KSOIL 29	6-10	501- 600	6	5	0.00	74.93
KSOIL 30	6-10	601-1,000	21	10	0.00	397.93
KSOIL 31	6-10	1,001-2,000	16	7	0.00	545.40
KSOIL 32	6-10	2,001-5,000	10	6	0.00	704.97
KSOIL 33	10+	61- 100	5	1	0.00	10.87
Kentucky						
KYOIL 1	0-2	0- 60	4495	95	0.00	328.67
KYOIL 2	0-2	61- 100	8494	243	0.00	1,605.87
KYOIL 3	0-2	101- 200	5828	227	0.00	3,071.80
KYOIL 4	0-2	201- 300	1181	83	0.00	1,592.67
KYOIL 5	0-2	301- 400	502	38	0.00	1,047.70

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State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
KYOIL 6	0-2	401- 500	185	20	0.00	512.77
KYOIL 7	0-2	501- 600	119	17	0.00	402.67
KYOIL 8	0-2	601-1,000	264	26	0.00	1,183.43
KYOIL 9	0-2	1,001-2,000	231	23	0.00	1,876.80
KYOIL 10	0-2	2,001-5,000	86	7	0.00	1,772.30
KYOIL 11	0-2	5,001- Over	33	3	0.00	1,646.60
Louisiana-North						
LANOIL 1	0-2	0- 60	9725	37	516.63	5,964.77
LANOIL 2	0-2	61- 100	531	23	115.93	1,310.47
LANOIL 3	0-2	101- 200	455	32	118.50	1,838.93
LANOIL 4	0-2	201- 300	101	15	13.77	646.73
LANOIL 5	0-2	301- 400	40	14	31.33	396.87
LANOIL 6	0-2	401- 500	14	8	0.87	159.30

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
LANOIL 7	0-2	501- 600	16	8	23.33	215.53
LANOIL 8	0-2	601-1,000	27	12	30.10	481.80
LANOIL 9	0-2	1,001-2,000	17	15	70.90	442.43
LANOIL 10	0-2	2,001-5,000	6	6	64.30	265.43
LANOIL 11	0-2	5,001- Over	3	4	888.80	699.23
LANOIL 12	2-6	0- 60	2117	90	537.87	1,542.00
LANOIL 13	2-6	61- 100	452	74	656.03	1,121.57
LANOIL 14	2-6	101- 200	588	111	2,103.80	2,486.03
LANOIL 15	2-6	201- 300	341	86	1,784.33	2,321.10
LANOIL 16	2-6	301- 400	231	66	1,837.90	2,469.70
LANOIL 17	2-6	401- 500	153	60	2,503.53	1,954.60
LANOIL 18	2-6	501- 600	116	41	1,327.70	1,885.20
LANOIL 19	2-6	601-1,000	267	59	4,715.50	5,932.00
LANOIL 20	2-6	1,001-2,000	234	54	5,698.23	9,625.67
LANOIL 21	2-6	2,001-5,000	81	25	4,699.90	6,000.83
LANOIL 22	2-6	5,001- Over	2	1	88.30	346.13
LANOIL 23	6-10	0- 60	66	40	45.07	38.07
LANOIL 24	6-10	61- 100	41	26	87.20	85.70
LANOIL 25	6-10	101- 200	117	50	634.50	446.53
LANOIL 26	6-10	201- 300	76	44	772.63	521.50
LANOIL 27	6-10	301- 400	60	43	580.60	584.83
LANOIL 28	6-10	401- 500	57	37	1,113.20	656.93
LANOIL 29	6-10	501- 600	30	21	1,476.00	376.60
LANOIL 30	6-10	601-1,000	55	33	1,860.83	1,192.63
LANOIL 31	6-10	1,001-2,000	69	40	4,107.27	2,346.67
LANOIL 32	6-10	2,001-5,000	31	14	7,121.90	2,093.67
LANOIL 33	6-10	5,001- Over	19	1	55,878.43	514.30
LANOIL 34	10+	0- 60	8	7	15.20	3.87
LANOIL 35	10+	61- 100	4	5	24.37	7.33
LANOIL 36	10+	101- 200	15	12	57.97	51.20
LANOIL 37	10+	201- 300	11	6	341.80	58.20
LANOIL 38	10+	301- 400	17	11	230.17	143.23

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APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
LANOIL 39	10+	401- 500	13	9	505.57	132.07
Louisiana-South						
LASOIL 1	0-2	0- 60	169	20	23.47	223.20
LASOIL 2	0-2	61- 100	90	20	1.47	197.10
LASOIL 3	0-2	101- 200	110	27	61.70	416.33
LASOIL 4	0-2	201- 300	44	18	100.60	270.30
LASOIL 5	0-2	301- 400	36	14	129.80	303.57
LASOIL 6	0-2	401- 500	37	14	114.00	393.67
LASOIL 7	0-2	501- 600	25	11	130.93	322.70
LASOIL 8	0-2	601-1,000	42	17	433.73	729.10
LASOIL 9	0-2	1,001-2,000	68	23	1,268.17	2,184.70
LASOIL 10	0-2	2,001-5,000	21	13	970.87	1,504.47
LASOIL 11	0-2	5,001- Over	12	11	1,562.90	1,753.50
LASOIL 12	2-6	0- 60	187	36	10.47	147.77
LASOIL 13	2-6	61- 100	121	35	74.13	240.20
LASOIL 14	2-6	101- 200	223	50	206.97	850.83
LASOIL 15	2-6	201- 300	164	47	412.33	1,029.73
LASOIL 16	2-6	301- 400	149	50	750.87	1,294.03
LASOIL 17	2-6	401- 500	107	42	714.43	1,339.40
LASOIL 18	2-6	501- 600	94	38	715.17	1,466.40
LASOIL 19	2-6	601-1,000	220	67	2,529.87	4,642.33
LASOIL 20	2-6	1,001-2,000	191	60	3,652.63	7,010.57
LASOIL 21	2-6	2,001-5,000	115	41	3,577.70	8,723.50
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LASOIL 22	2-6	5,001- Over	26	16	1,775.90	3,741.90
LASOIL 23	6-10	0- 60	100	57	49.03	69.30
LASOIL 24	6-10	61- 100	60	42	76.13	96.33
LASOIL 25	6-10	101- 200	158	96	562.07	546.40
LASOIL 26	6-10	201- 300	186	106	1,023.73	1,140.93
LASOIL 27	6-10	301- 400	179	93	1,738.53	1,585.57
LASOIL 28	6-10	401- 500	176	92	2,176.73	2,056.20
LASOIL 29	6-10	501- 600	177	96	2,670.77	2,628.87
LASOIL 30	6-10	601-1,000	526	157	12,262.53	10,709.57

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
LASOIL 31	6-10	1,001-2,000	574	154	25,215.57	22,136.90
LASOIL 32	6-10	2,001-5,000	376	123	35,752.47	29,837.23
LASOIL 33	6-10	5,001- Over	122	55	26,934.57	23,851.47
LASOIL 34	10+	0- 60	52	37	22.57	21.20
LASOIL 35	10+	61- 100	21	18	65.30	32.27
LASOIL 36	10+	101- 200	98	60	503.93	335.57
LASOIL 37	10+	201- 300	84	51	892.90	546.63
LASOIL 38	10+	301- 400	85	57	1,173.73	711.20
LASOIL 39	10+	401- 500	66	47	1,135.70	673.80
LASOIL 40	10+	501- 600	72	48	1,707.90	1,101.23
LASOIL 41	10+	601-1,000	198	94	5,890.77	4,294.00
LASOIL 42	10+	1,001-2,000	294	121	18,507.50	11,376.27
LASOIL 43	10+	2,001-5,000	284	132	44,269.97	22,691.10
LASOIL 44	10+	5,001- Over	137	58	63,689.80	39,835.23
Michigan						
MIOIL 1	0-2	0- 60	5	1	33.33	22.77
MIOIL 2	0-2	101- 200	5	1	51.30	52.07
MIOIL 3	0-2	301- 400	6	2	50.00	28.93
MIOIL 4	0-2	401- 500	3	1	51.20	13.13
MIOIL 5	0-2	501- 600	3	1	129.37	8.70
MIOIL 6	0-2	601-1,000	17	7	462.50	106.93
MIOIL 7	0-2	1,001-2,000	6	3	603.33	30.63
MIOIL 8	0-2	2,001-5,000	3	2	200.00	123.43
MIOIL 9	2-6	0- 60	1763	21	9,849.33	337.93
MIOIL 10	2-6	61- 100	302	22	4,107.30	520.93
MIOIL 11	2-6	101- 200	411	35	8,838.43	2,433.10
MIOIL 12	2-6	201- 300	400	33	8,329.53	5,354.17
MIOIL 13	2-6	301- 400	203	32	2,121.93	747.43
MIOIL 14	2-6	401- 500	84	20	1,004.13	385.77
MIOIL 15	2-6	501- 600	122	19	2,047.67	632.13
MIOIL 16	2-6	601-1,000	238	38	7,649.03	1,712.43
MIOIL 17	2-6	1,001-2,000	377	38	26,107.70	4,454.93

(continued)

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
MIOIL 18	2-6	2,001-5,000	418	34	47,635.77	13,091.47
MIOIL 19	2-6	5,001- Over	99	19	8,042.33	8,148.80
MIOIL 20	6-10	0- 60	31	4	115.80	13.83
MIOIL 21	6-10	61- 100	31	6	217.70	83.37
MIOIL 22	6-10	101- 200	99	15	1,838.03	563.63
MIOIL 23	6-10	201- 300	99	12	2,286.97	1,339.97
MIOIL 24	6-10	301- 400	81	18	1,229.37	235.00
MIOIL 25	6-10	401- 500	41	12	953.27	141.57
MIOIL 26	6-10	501- 600	26	10	524.90	138.07
MIOIL 27	6-10	601-1,000	128	24	5,591.67	745.27
MIOIL 28	6-10	1,001-2,000	305	24	23,546.63	3,598.10
MIOIL 29	6-10	2,001-5,000	229	21	34,071.67	6,265.53
MIOIL 30	6-10	5,001- Over	41	13	8,594.57	2,886.23
MIOIL 31	10+	2,001-5,000	3	2	666.67	173.77
MIOIL 32	10+	5,001- Over	6	2	871.00	356.00
Missouri						
MOOIL 1	0-2	0- 60	807	0	11.10	377.77
Mississippi						
MSOIL 1	0-2	0- 60	18	8	0.67	2.37
MSOIL 2	0-2	61- 100	14	9	24.80	8.87
MSOIL 3	0-2	101- 200	18	10	2.47	47.00
MSOIL 4	0-2	201- 300	46	18	18.30	217.37
MSOIL 5	0-2	301- 400	18	11	4.73	121.07
MSOIL 6	0-2	401- 500	37	13	145.27	279.60
MSOIL 7	0-2	501- 600	27	12	57.40	237.07
MSOIL 8	0-2	601-1,000	50	18	505.67	705.60
MSOIL 9	0-2	1,001-2,000	73	22	1,933.57	1,847.80

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MSOIL 10	0-2	2,001-5,000	38	12	1,888.70	2,209.67
MSOIL 11	0-2	5,001- Over	5	3	0.00	549.00
MSOIL 12	2-6	0- 60	66	19	9.67	19.13
MSOIL 13	2-6	61- 100	55	22	32.37	57.27
MSOIL 14	2-6	101- 200	146	47	77.83	359.63

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
MSOIL 15	2-6	201- 300	142	40	118.77	663.40
MSOIL 16	2-6	301- 400	111	32	185.40	792.13
MSOIL 17	2-6	401- 500	98	24	333.20	845.27
MSOIL 18	2-6	501- 600	62	22	36.03	701.63
MSOIL 19	2-6	601-1,000	157	44	947.90	2,389.70
MSOIL 20	2-6	1,001-2,000	131	34	873.07	3,681.27
MSOIL 21	2-6	2,001-5,000	50	9	731.87	3,069.73
MSOIL 22	6-10	0- 60	47	30	1.70	11.60
MSOIL 23	6-10	61- 100	35	18	18.80	32.17
MSOIL 24	6-10	101- 200	128	58	40.33	308.53
MSOIL 25	6-10	201- 300	117	53	107.23	531.87
MSOIL 26	6-10	301- 400	120	46	222.80	780.57
MSOIL 27	6-10	401- 500	93	31	323.60	811.40
MSOIL 28	6-10	501- 600	72	28	306.10	780.20
MSOIL 29	6-10	601-1,000	250	53	1,555.03	3,823.10
MSOIL 30	6-10	1,001-2,000	181	42	1,844.03	4,905.97
MSOIL 31	6-10	2,001-5,000	133	25	3,086.10	7,858.73
MSOIL 32	6-10	5,001- Over	6	3	232.97	523.00
MSOIL 33	10+	0- 60	58	27	5.87	15.23
MSOIL 34	10+	61- 100	18	13	12.13	16.53
MSOIL 35	10+	101- 200	43	24	46.93	100.63
MSOIL 36	10+	201- 300	49	26	73.70	187.67
MSOIL 37	10+	301- 400	67	34	146.30	373.13
MSOIL 38	10+	401- 500	76	42	377.77	608.43
MSOIL 39	10+	501- 600	61	33	139.87	651.90
MSOIL 40	10+	601-1,000	175	65	1,139.97	2,591.03
MSOIL 41	10+	1,001-2,000	198	60	2,805.10	5,534.23
MSOIL 42	10+	2,001-5,000	194	56	11,177.97	11,524.77
MSOIL 43	10+	5,001- Over	105	34	12,424.30	14,861.27

(continued)

Montana						
MTOIL 1	0-2	0- 60	1070	17	89.67	740.17
MTOIL 2	0-2	61- 100	227	14	72.40	462.83

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
MTOIL 3	0-2	101- 200	142	16	235.43	496.00
MTOIL 4	0-2	201- 300	28	9	87.10	131.97
MTOIL 5	0-2	301- 400	8	5	116.83	78.70
MTOIL 6	0-2	501- 600	1	1	0.00	17.93
MTOIL 7	0-2	601-1,000	5	4	82.73	105.17
MTOIL 8	0-2	1,001-2,000	2	3	207.57	56.33
MTOIL 9	0-2	2,001-5,000	1	1	76.73	108.00
MTOIL 10	2-6	0- 60	550	53	41.13	488.37
MTOIL 11	2-6	61- 100	281	36	34.93	639.40
MTOIL 12	2-6	101- 200	364	61	355.47	1,496.57
MTOIL 13	2-6	201- 300	174	46	404.77	1,262.20
MTOIL 14	2-6	301- 400	87	28	155.80	922.97
MTOIL 15	2-6	401- 500	72	26	292.87	1,015.67
MTOIL 16	2-6	501- 600	39	20	74.37	686.73
MTOIL 17	2-6	601-1,000	89	29	531.53	2,236.70
MTOIL 18	2-6	1,001-2,000	58	21	395.07	2,538.87
MTOIL 19	2-6	2,001-5,000	25	12	616.93	2,341.37
MTOIL 20	2-6	5,001- Over	1	1	68.77	164.90
MTOIL 21	6-10	0- 60	19	15	1.60	6.23
MTOIL 22	6-10	61- 100	19	16	11.27	32.67
MTOIL 23	6-10	101- 200	70	35	86.47	260.13
MTOIL 24	6-10	201- 300	85	44	212.27	609.87
MTOIL 25	6-10	301- 400	104	41	534.00	1,106.80
MTOIL 26	6-10	401- 500	71	39	294.97	1,003.30
MTOIL 27	6-10	501- 600	70	40	426.33	1,203.27
MTOIL 28	6-10	601-1,000	209	54	2,031.60	5,159.87
MTOIL 29	6-10	1,001-2,000	222	38	3,230.10	9,870.70
MTOIL 30	6-10	2,001-5,000	88	23	2,631.17	7,623.70
MTOIL 31	6-10	5,001- Over	7	6	293.17	1,284.30
MTOIL 32	10+	0- 60	9	10	1.13	4.63
MTOIL 33	10+	61- 100	3	3	6.87	4.37

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MTOIL 34	10+	101- 200	12	12	21.73	46.00

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
MTOIL 35	10+	201- 300	14	15	40.23	95.47
MTOIL 36	10+	301- 400	18	18	98.13	173.70
MTOIL 37	10+	401- 500	30	27	293.27	376.60
MTOIL 38	10+	501- 600	24	22	331.50	399.70
MTOIL 39	10+	601-1,000	76	46	1,745.60	1,815.37
MTOIL 40	10+	1,001-2,000	106	66	3,837.77	4,466.73
MTOIL 41	10+	2,001-5,000	50	32	3,428.10	4,451.70
MTOIL 42	10+	5,001- Over	14	10	3,231.80	2,217.27
North Dakota						
NDOIL 1	0-2	0- 60	2	2	0.00	0.37
NDOIL 2	0-2	101- 200	4	4	2.10	10.93
NDOIL 3	0-2	201- 300	9	5	117.07	62.27
NDOIL 4	0-2	301- 400	2	1	3.60	22.93
NDOIL 5	0-2	401- 500	2	2	38.57	18.83
NDOIL 6	0-2	501- 600	2	2	22.97	16.60
NDOIL 7	0-2	601-1,000	3	2	11.43	60.67
NDOIL 8	0-2	1,001-2,000	5	6	20.30	66.33
NDOIL 9	0-2	2,001-5,000	6	6	196.10	520.43
NDOIL 10	0-2	5,001- Over	6	6	640.97	995.60
NDOIL 11	2-6	0- 60	84	46	44.27	78.13
NDOIL 12	2-6	61- 100	103	43	74.23	241.23
NDOIL 13	2-6	101- 200	289	65	436.33	1,299.13
NDOIL 14	2-6	201- 300	207	55	705.17	1,566.60
NDOIL 15	2-6	301- 400	95	32	354.37	1,056.33
NDOIL 16	2-6	401- 500	54	24	113.10	759.73
NDOIL 17	2-6	501- 600	53	23	310.57	916.17
NDOIL 18	2-6	601-1,000	72	24	255.67	1,692.87
NDOIL 19	2-6	1,001-2,000	46	15	109.10	1,992.97
NDOIL 20	2-6	2,001-5,000	19	9	314.10	1,657.00
NDOIL 21	2-6	5,001- Over	6	5	184.33	1,108.50
NDOIL 22	6-10	0- 60	73	37	39.97	23.00
NDOIL 23	6-10	61- 100	51	25	202.33	59.63
NDOIL 24	6-10	101- 200	133	51	1,221.03	409.23

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
						(continued)
NDOIL 25	6-10	201- 300	194	73	2,323.43	1,253.23
NDOIL 26	6-10	301- 400	177	75	2,444.53	1,643.23
NDOIL 27	6-10	401- 500	136	70	2,133.83	1,743.80
NDOIL 28	6-10	501- 600	115	65	2,069.53	1,839.37
NDOIL 29	6-10	601-1,000	322	98	8,519.37	7,351.93
NDOIL 30	6-10	1,001-2,000	321	81	14,738.37	13,123.53
NDOIL 31	6-10	2,001-5,000	163	50	15,897.07	14,098.87
NDOIL 32	6-10	5,001- Over	46	18	20,293.10	9,926.43
NDOIL 33	10+	0- 60	30	24	30.53	7.00
NDOIL 34	10+	61- 100	12	13	27.70	17.20
NDOIL 35	10+	101- 200	34	28	163.93	113.83
NDOIL 36	10+	201- 300	33	26	234.57	193.37
NDOIL 37	10+	301- 400	38	32	518.90	349.50
NDOIL 38	10+	401- 500	42	36	695.93	500.90
NDOIL 39	10+	501- 600	36	32	923.30	499.33
NDOIL 40	10+	601-1,000	115	67	4,398.97	2,523.60
NDOIL 41	10+	1,001-2,000	193	83	13,360.37	7,596.97
NDOIL 42	10+	2,001-5,000	156	58	21,523.03	12,330.33
NDOIL 43	10+	5,001- Over	69	29	46,475.90	11,876.00
Nebraska						
NEOIL 1	0-2	0- 60	25	12	0.50	32.13
NEOIL 2	0-2	61- 100	49	14	6.30	134.93
NEOIL 3	0-2	101- 200	84	28	165.90	364.97
NEOIL 4	0-2	201- 300	13	7	13.93	104.47
NEOIL 5	0-2	301- 400	10	4	0.00	116.57
NEOIL 6	0-2	501- 600	3	4	0.00	39.63
NEOIL 7	0-2	601-1,000	57	1	0.00	1,843.13
NEOIL 8	0-2	2,001-5,000	1	2	39.67	145.13
NEOIL 9	2-6	0- 60	104	67	24.77	131.30
NEOIL 10	2-6	61- 100	180	77	76.43	486.47
NEOIL 11	2-6	101- 200	380	135	381.53	1,903.60
NEOIL 12	2-6	201- 300	286	74	193.17	2,310.43

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
NEOIL 13	2-6	301- 400	121	36	361.10	1,281.07
NEOIL 14	2-6	401- 500	25	16	84.60	357.93

(continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
NEOIL 15	2-6	501- 600	54	12	68.87	1,020.33
NEOIL 16	2-6	601-1,000	23	16	48.60	572.77
NEOIL 17	2-6	1,001-2,000	77	12	65.23	3,384.70
NEOIL 18	2-6	2,001-5,000	5	4	0.00	318.83
NEOIL 19	6-10	0- 60	35	26	10.77	50.43
NEOIL 20	6-10	61- 100	45	29	23.10	117.37
NEOIL 21	6-10	101- 200	97	67	45.17	454.63
NEOIL 22	6-10	201- 300	38	31	88.50	303.37
NEOIL 23	6-10	301- 400	15	14	60.00	162.27
NEOIL 24	6-10	401- 500	9	9	6.87	118.20
NEOIL 25	6-10	501- 600	9	9	5.27	159.90
NEOIL 26	6-10	601-1,000	10	11	49.77	243.00
NEOIL 27	6-10	1,001-2,000	7	7	51.20	273.40
NEOIL 28	6-10	2,001-5,000	8	4	189.77	736.47
NEOIL 29	6-10	5,001- Over	1	1	72.80	221.67
New Mexico						
NMOIL 1	0-2	0- 60	881	93	778.37	594.57
NMOIL 2	0-2	61- 100	240	52	605.93	513.63
NMOIL 3	0-2	101- 200	276	52	1,065.80	1,144.77
NMOIL 4	0-2	201- 300	102	34	305.63	734.53
NMOIL 5	0-2	301- 400	52	24	274.10	518.43
NMOIL 6	0-2	401- 500	35	24	739.93	395.40
NMOIL 7	0-2	501- 600	14	13	565.67	146.40
NMOIL 8	0-2	601-1,000	24	22	965.97	301.53
NMOIL 9	0-2	1,001-2,000	13	13	702.10	209.93
NMOIL 10	0-2	2,001-5,000	11	12	693.97	655.70
NMOIL 11	0-2	5,001- Over	2	2	1,138.83	192.80
NMOIL 12	2-6	0- 60	2424	186	4,115.77	1,877.23
NMOIL 13	2-6	61- 100	1550	173	8,030.80	3,055.83
NMOIL 14	2-6	101- 200	2409	179	27,423.43	8,415.50

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
NMOIL 15	2-6	201- 300	1256	145	26,772.07	7,168.60
NMOIL 16	2-6	301- 400	729	117	22,602.07	5,874.97
NMOIL 17	2-6	401- 500	456	101	18,856.53	4,615.13
NMOIL 18	2-6	501- 600	302	68	15,637.30	3,662.23
NMOIL 19	2-6	601-1,000	655	98	42,880.60	11,097.90
NMOIL 20	2-6	1,001-2,000	417	67	39,434.20	14,102.07
NMOIL 21	2-6	2,001-5,000	213	34	20,413.93	17,644.83
NMOIL 22	2-6	5,001- Over	51	3	5,310.07	11,350.73
NMOIL 23	6-10	0- 60	479	113	1,945.70	221.73
NMOIL 24	6-10	61- 100	321	87	3,058.47	479.63
NMOIL 25	6-10	101- 200	845	120	14,319.67	2,556.23
NMOIL 26	6-10	201- 300	631	111	21,075.57	2,863.57
NMOIL 27	6-10	301- 400	487	98	21,493.30	3,276.43
NMOIL 28	6-10	401- 500	342	88	18,712.67	2,998.77
NMOIL 29	6-10	501- 600	222	72	13,888.27	2,526.53
NMOIL 30	6-10	601-1,000	510	95	47,243.90	7,780.37
NMOIL 31	6-10	1,001-2,000	382	83	46,788.27	12,054.23
NMOIL 32	6-10	2,001-5,000	231	59	38,694.57	16,448.33
NMOIL 33	6-10	5,001- Over	73	17	20,120.20	13,884.27
NMOIL 34	10+	0- 60	76	49	151.23	39.47
NMOIL 35	10+	61- 100	46	31	264.43	79.50
NMOIL 36	10+	101- 200	109	61	1,048.77	364.03
NMOIL 37	10+	201- 300	117	51	2,157.83	666.10
NMOIL 38	10+	301- 400	89	49	2,121.67	756.00
NMOIL 39	10+	401- 500	53	30	1,079.30	626.93
NMOIL 40	10+	501- 600	59	41	1,895.20	798.20
NMOIL 41	10+	601-1,000	138	64	6,001.57	2,738.20
NMOIL 42	10+	1,001-2,000	118	50	6,715.53	4,376.93
NMOIL 43	10+	2,001-5,000	60	33	8,737.60	4,465.53
NMOIL 44	10+	5,001- Over	30	11	8,444.53	6,760.47
Nevada						
NVOIL 1	2-6	101- 200	2	3	0.00	4.57

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APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
NVOIL 2	2-6	201- 300	4	3	0.00	33.87
NVOIL 3	2-6	301- 400	6	4	0.00	60.63
NVOIL 4	2-6	401- 500	3	1	0.00	26.07
NVOIL 5	2-6	501- 600	1	1	0.00	19.43
NVOIL 6	2-6	601-1,000	6	3	0.00	155.27
NVOIL 7	2-6	1,001-2,000	5	4	0.00	235.40

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NVOIL 8	2-6	2,001-5,000	11	4	0.00	1,135.23
NVOIL 9	2-6	5,001- Over	9	5	0.00	7,267.77
New York						
NYOIL 1	0-2	0- 60	3805	N/A	0.00	863.97
NYOIL 2	0-2	61- 100	70	N/A	0.00	146.13
NYOIL 3	0-2	101- 200	49	N/A	0.00	179.00
NYOIL 4	0-2	201- 300	20	N/A	0.00	162.17
NYOIL 5	0-2	601-1,000	6	N/A	0.00	145.03
Ohio						
OHOIL 1	0-2	0- 60	27356	N/A	0.00	11,722.67
OHOIL 2	2-6	61- 100	1424	N/A	0.00	3,511.13
OHOIL 3	2-6	101- 200	841	N/A	0.00	3,929.10
OHOIL 4	2-6	201- 300	374	N/A	0.00	3,395.77
OHOIL 5	2-6	501- 600	154	N/A	0.00	3,076.20
OHOIL 6	2-6	1,001-2,000	45	N/A	0.00	2,751.20
Oklahoma						
OKOIL 1	0-2	0- 60	28981	514	6,130.10	14,132.57
OKOIL 2	0-2	61- 100	5990	453	7,604.33	8,905.77
OKOIL 3	0-2	101- 200	6742	694	15,807.97	18,709.37
OKOIL 4	0-2	201- 300	2612	271	27,232.40	10,845.10
OKOIL 5	0-2	301- 400	928	157	10,788.30	5,708.53
OKOIL 6	0-2	401- 500	356	104	6,913.07	2,696.67
OKOIL 7	0-2	501- 600	215	63	5,101.77	1,984.67
OKOIL 8	0-2	601-1,000	401	80	14,083.57	5,176.33
OKOIL 9	0-2	1,001-2,000	171	43	8,669.53	3,734.70
OKOIL 10	0-2	2,001-5,000	65	17	8,480.77	3,967.63

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
OKOIL 11	2-6	0- 60	7618	480	7,213.00	4,620.70
OKOIL 12	2-6	61- 100	5631	529	10,941.07	8,228.37
OKOIL 13	2-6	101- 200	7341	884	27,160.73	19,611.37
OKOIL 14	2-6	201- 300	2763	461	21,579.57	12,102.60
OKOIL 15	2-6	301- 400	2058	265	13,968.10	13,669.33
OKOIL 16	2-6	401- 500	2179	173	9,767.73	20,633.57
OKOIL 17	2-6	501- 600	401	109	6,176.83	3,962.33
OKOIL 18	2-6	601-1,000	1135	151	25,833.57	15,867.40
OKOIL 19	2-6	1,001-2,000	411	110	13,864.33	10,290.30
OKOIL 20	2-6	2,001-5,000	151	45	19,590.67	7,389.10
OKOIL 21	2-6	5,001- Over	34	13	4,423.87	3,720.73
OKOIL 22	6-10	0- 60	1744	147	7,406.00	551.53
OKOIL 23	6-10	61- 100	1978	153	18,072.63	1,541.33
OKOIL 24	6-10	101- 200	5442	352	84,083.67	8,815.57
OKOIL 25	6-10	201- 300	3076	267	83,240.47	7,986.80
OKOIL 26	6-10	301- 400	1756	181	61,732.17	6,832.63
OKOIL 27	6-10	401- 500	1045	138	45,540.30	5,628.17
OKOIL 28	6-10	501- 600	704	109	39,961.50	4,238.90
OKOIL 29	6-10	601-1,000	1330	149	90,218.90	12,456.63
OKOIL 30	6-10	1,001-2,000	934	91	84,621.93	17,596.13
OKOIL 31	6-10	2,001-5,000	294	57	58,906.73	9,896.50
OKOIL 32	6-10	5,001- Over	50	16	21,552.97	5,527.10
OKOIL 33	10+	0- 60	47	25	215.63	9.87
OKOIL 34	10+	61- 100	87	31	616.90	62.17
OKOIL 35	10+	101- 200	355	90	3,088.33	524.63
OKOIL 36	10+	201- 300	247	75	4,626.53	759.97
OKOIL 37	10+	301- 400	196	54	5,262.33	932.07
OKOIL 38	10+	401- 500	145	39	5,375.67	823.00
OKOIL 39	10+	501- 600	113	34	6,301.57	697.07
OKOIL 40	10+	601-1,000	282	56	18,881.97	2,791.87
OKOIL 41	10+	1,001-2,000	271	44	21,834.70	5,614.13
OKOIL 42	10+	2,001-5,000	79	24	19,129.67	2,313.10

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
OKOIL 43	10+	5,001- Over	44	12	35,422.70	4,368.17
Pennsylvania						
PAOIL 1	0-2	0- 60	26702	N/A	0.00	5,066.90
PAOIL 2	0-2	61- 100	337	N/A	0.00	897.87
PAOIL 3	0-2	101- 200	139	N/A	0.00	813.37
PAOIL 4	0-2	501- 600	40	N/A	0.00	727.43
South Dakota						
SDOIL 1	0-2	101- 200	2	1	0.00	8.73
SDOIL 2	0-2	201- 300	2	1	0.00	14.90
SDOIL 3	0-2	1,001-2,000	2	2	0.00	44.50

(continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
SDOIL 4	0-2	2,001-5,000	1	1	0.00	116.57
SDOIL 5	2-6	101- 200	3	4	16.27	14.30
SDOIL 6	2-6	201- 300	2	3	3.40	16.03
SDOIL 7	2-6	401- 500	2	3	22.20	28.93
SDOIL 8	2-6	501- 600	6	6	24.80	104.87
SDOIL 9	2-6	601-1,000	3	4	20.70	89.80
SDOIL 10	2-6	1,001-2,000	1	1	17.83	35.10
SDOIL 11	2-6	2,001-5,000	4	3	871.77	322.33
SDOIL 12	2-6	5,001- Over	1	1	226.63	175.07
SDOIL 13	6-10	0- 60	1	1	0.27	0.23
SDOIL 14	6-10	61- 100	1	1	0.00	2.50
SDOIL 15	6-10	101- 200	2	3	0.50	7.87
SDOIL 16	6-10	201- 300	16	7	10.03	124.50
SDOIL 17	6-10	301- 400	14	8	20.43	158.63
SDOIL 18	6-10	401- 500	4	3	0.00	59.30
SDOIL 19	6-10	501- 600	12	4	12.67	217.23
SDOIL 20	6-10	601-1,000	37	8	50.43	989.17
SDOIL 21	6-10	1,001-2,000	42	5	1.60	1,893.77
SDOIL 22	6-10	2,001-5,000	3	1	0.00	167.00
Tennessee						
TNOIL 1	0-2	0- 60	489	N/A	0.00	431.90
TNOIL 2	0-2	61- 100	57	N/A	0.00	178.37

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
TNOIL 3	0-2	101- 200	22	N/A	0.00	107.13
TNOIL 4	0-2	201- 300	18	N/A	0.00	135.87
TNOIL 5	0-2	301- 400	13	N/A	0.00	144.30
TNOIL 6	0-2	501- 600	9	N/A	0.00	176.77
TNOIL 7	0-2	1,001-2,000	4	N/A	0.00	160.13
TNOIL 8	0-2	2,001-5,000	1	N/A	0.00	143.23
Texas-Gulf Coast						
TXGCOIL 1	0-2	0- 60	14856	227	810.87	6,062.03
TXGCOIL 2	0-2	61- 100	839	101	657.50	2,147.73
TXGCOIL 3	0-2	101- 200	1328	83	2,008.73	6,604.17
TXGCOIL 4	0-2	201- 300	474	53	789.90	3,690.67
TXGCOIL 5	0-2	301- 400	165	27	644.27	1,910.50

(continued)

TXGCOIL 6	0-2	401- 500	163	7	1,233.37	2,285.90
TXGCOIL 7	0-2	501- 600	837	11	4,776.50	15,001.83
TXGCOIL 8	0-2	601-1,000	609	18	4,698.57	13,453.53
TXGCOIL 9	0-2	1,001-2,000	17	11	404.37	635.57
TXGCOIL 10	0-2	2,001-5,000	1	1	373.03	77.30
TXGCOIL 11	2-6	0- 60	9344	571	6,719.93	7,805.00
TXGCOIL 12	2-6	61- 100	2451	358	6,473.43	6,073.80
TXGCOIL 13	2-6	101- 200	4857	569	15,404.20	22,642.10
TXGCOIL 14	2-6	201- 300	2319	416	16,282.30	18,119.00
TXGCOIL 15	2-6	301- 400	1487	300	14,038.17	16,581.17
TXGCOIL 16	2-6	401- 500	1326	205	16,091.33	18,698.47
TXGCOIL 17	2-6	501- 600	1330	142	15,457.40	23,455.53
TXGCOIL 18	2-6	601-1,000	2470	261	40,689.43	57,393.60
TXGCOIL 19	2-6	1,001-2,000	1991	182	233,150.53	78,840.43
TXGCOIL 20	2-6	2,001-5,000	379	64	134,278.20	27,913.43
TXGCOIL 21	2-6	5,001- Over	11	7	742.10	2,130.30
TXGCOIL 22	6-10	0- 60	920	336	1,149.20	711.90
TXGCOIL 23	6-10	61- 100	612	235	2,712.43	1,307.17
TXGCOIL 24	6-10	101- 200	1535	434	14,052.73	6,124.43
TXGCOIL 25	6-10	201- 300	1162	341	20,082.63	7,667.80

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
TXGCOIL 26	6-10	301- 400	946	308	22,867.23	9,031.33
TXGCOIL 27	6-10	401- 500	843	249	28,478.20	10,079.70
TXGCOIL 28	6-10	501- 600	617	191	26,189.63	9,045.90
TXGCOIL 29	6-10	601-1,000	1249	322	78,855.30	25,064.70
TXGCOIL 30	6-10	1,001-2,000	1080	264	116,647.70	37,938.33
TXGCOIL 31	6-10	2,001-5,000	492	145	139,729.73	34,415.50
TXGCOIL 32	6-10	5,001- Over	115	28	39,580.93	30,841.67
TXGCOIL 33	10+	0- 60	137	35	378.97	76.37
TXGCOIL 34	10+	61- 100	84	29	686.53	148.03
TXGCOIL 35	10+	101- 200	149	51	2,438.03	463.57
TXGCOIL 36	10+	201- 300	95	34	2,703.63	482.67
TXGCOIL 37	10+	301- 400	86	34	3,562.97	620.87
TXGCOIL 38	10+	401- 500	43	23	2,244.47	413.23
TXGCOIL 39	10+	501- 600	35	14	2,716.13	349.27

(continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
TXGCOIL 40	10+	601-1,000	115	34	11,308.83	1,889.13
TXGCOIL 41	10+	1,001-2,000	99	35	17,638.00	2,495.93
TXGCOIL 42	10+	2,001-5,000	44	18	14,699.93	2,330.40
TXGCOIL 43	10+	5,001- Over	5	5	4,752.83	333.73
Texas-North						
TXNOIL 1	0-2	0- 60	24154	324	8,155.87	14,697.57
TXNOIL 2	0-2	61- 100	2170	129	3,361.73	5,213.67
TXNOIL 3	0-2	101- 200	1406	119	3,867.60	6,088.77
TXNOIL 4	0-2	201- 300	474	57	3,124.40	3,125.57
TXNOIL 5	0-2	301- 400	93	31	125.13	996.13
TXNOIL 6	0-2	401- 500	39	15	330.57	516.03
TXNOIL 7	0-2	501- 600	15	8	134.07	252.17
TXNOIL 8	0-2	601-1,000	10	7	117.27	233.10
TXNOIL 9	0-2	1,001-2,000	2	3	3.87	72.27
TXNOIL 10	2-6	0- 60	11809		29,635.17	9,019.07
TXNOIL 11	2-6	61- 100	5331	913	35,910.47	10,659.43
TXNOIL 12	2-6	101- 200	5523		71,697.70	19,463.37
TXNOIL 13	2-6	201- 300	2233	559	41,825.13	14,511.50

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
TXNOIL 14	2-6	301- 400	901	313	28,284.77	7,728.80
TXNOIL 15	2-6	401- 500	593	207	17,502.63	7,173.20
TXNOIL 16	2-6	501- 600	436	149	15,842.00	6,238.23
TXNOIL 17	2-6	601-1,000	1057	266	19,382.53	24,238.00
TXNOIL 18	2-6	1,001-2,000	313	147	15,852.10	11,729.73
TXNOIL 19	2-6	2,001-5,000	125	24	10,560.43	9,402.20
TXNOIL 20	2-6	5,001- Over	6	5	856.03	1,463.87
TXNOIL 21	6-10	0- 60	661	211	1,349.63	527.43
TXNOIL 22	6-10	61- 100	520	195	3,892.13	981.37
TXNOIL 23	6-10	101- 200	955	265	16,088.27	2,969.90
TXNOIL 24	6-10	201- 300	583	187	14,460.37	3,401.93
TXNOIL 25	6-10	301- 400	280	114	9,370.90	2,259.77
TXNOIL 26	6-10	401- 500	250	78	8,494.97	2,868.47
TXNOIL 27	6-10	501- 600	152	56	7,490.80	2,010.53
TXNOIL 28	6-10	601-1,000	248	87	16,191.23	4,645.23
TXNOIL 29	6-10	1,001-2,000	168	60	8,557.73	6,135.67
						(continued)
TXNOIL 30	6-10	2,001-5,000	72	34	8,883.70	6,281.37
TXNOIL 31	6-10	5,001- Over	12	9	2,064.57	2,584.10
TXNOIL 32	10+	0- 60	10	8	13.27	4.53
TXNOIL 33	10+	61- 100	8	8	60.07	15.40
TXNOIL 34	10+	101- 200	23	14	468.20	55.37
TXNOIL 35	10+	201- 300	13	11	439.27	63.30
TXNOIL 36	10+	301- 400	11	11	604.30	64.73
TXNOIL 37	10+	401- 500	10	5	903.00	60.23
TXNOIL 38	10+	501- 600	4	4	530.90	22.07
TXNOIL 39	10+	601-1,000	26	9	3,824.97	261.87
TXNOIL 40	10+	1,001-2,000	9	8	2,029.30	142.53
TXNOIL 41	10+	2,001-5,000	11	6	5,321.30	308.77
TXNOIL 42	10+	5,001- Over	5	3	3,799.30	436.40
Texas-West						
TXWOIL 1	0-2	0- 60	3101	158	1,419.17	2,687.60
TXWOIL 2	0-2	61- 100	760	71	343.87	1,820.10

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
TXWOIL 3	0-2	101- 200	862	57	131.33	3,461.20
TXWOIL 4	0-2	201- 300	172	28	121.50	1,354.40
TXWOIL 5	0-2	301- 400	114	8	30.10	1,270.93
TXWOIL 6	0-2	401- 500	48	7	23.57	632.70
TXWOIL 7	0-2	501- 600	16	5	177.63	277.27
TXWOIL 8	0-2	601-1,000	40	8	159.97	869.87
TXWOIL 9	0-2	1,001-2,000	5	2	88.43	198.63
TXWOIL 10	0-2	2,001-5,000	1270	0	155,889.60	75,763.03
TXWOIL 11	2-6	0- 60	9224	709	24,699.93	8,859.80
TXWOIL 12	2-6	61- 100	5740	462	32,416.13	14,223.07
TXWOIL 13	2-6	101- 200	9670	575	73,291.37	44,562.07
TXWOIL 14	2-6	201- 300	5497	363	43,473.13	41,345.07
TXWOIL 15	2-6	301- 400	4518	251	34,413.57	49,462.13
TXWOIL 16	2-6	401- 500	4577	180	33,966.47	62,441.07
TXWOIL 17	2-6	501- 600	2114	130	35,221.13	35,724.10
TXWOIL 18	2-6	601-1,000	4219	180	58,625.27	104,599.53
TXWOIL 19	2-6	1,001-2,000	3829	120	304,490.43	163,734.80
TXWOIL 20	2-6	2,001-5,000	676	39	125,260.03	64,493.47

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State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
TXWOIL 21	2-6	5,001- Over	37	10	950.93	7,396.70
TXWOIL 22	6-10	0- 60	2295	391	44,810.03	2,599.13
TXWOIL 23	6-10	61- 100	2327	262	69,747.03	5,760.10
TXWOIL 24	6-10	101- 200	5183	413	144,652.73	23,487.93
TXWOIL 25	6-10	201- 300	2971	325	73,143.27	22,330.23
TXWOIL 26	6-10	301- 400	1704	237	55,556.17	18,207.17
TXWOIL 27	6-10	401- 500	1281	176	44,735.23	17,521.67
TXWOIL 28	6-10	501- 600	1150	153	33,130.67	19,941.33
TXWOIL 29	6-10	601-1,000	3356	239	103,708.00	86,184.10
TXWOIL 30	6-10	1,001-2,000	2540	173	457,137.57	106,421.63
TXWOIL 31	6-10	2,001-5,000	254	80	23,383.30	20,483.23
TXWOIL 32	6-10	5,001- Over	240	19	33,489.57	39,435.57
TXWOIL 33	10+	0- 60	222	121	5,372.10	169.10
TXWOIL 34	10+	61- 100	147	53	7,753.40	346.50

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
TXWOIL 35	10+	101- 200	324	120	20,292.60	1,449.77
TXWOIL 36	10+	201- 300	320	111	18,342.00	2,464.13
TXWOIL 37	10+	301- 400	180	81	13,626.33	1,996.57
TXWOIL 38	10+	401- 500	156	71	10,720.30	2,099.13
TXWOIL 39	10+	501- 600	131	64	4,706.33	2,127.53
TXWOIL 40	10+	601-1,000	362	112	20,884.23	8,595.03
TXWOIL 41	10+	1,001-2,000	342	104	52,246.17	14,177.37
TXWOIL 42	10+	2,001-5,000	144	68	8,611.00	12,583.97
TXWOIL 43	10+	5,001- Over	32	14	760.50	7,439.07
Utah						
UTOIL 1	0-2	0- 60	76	6	8.57	33.53
UTOIL 2	0-2	61- 100	6	1	4.47	13.80
UTOIL 3	0-2	101- 200	8	4	7.93	25.27
UTOIL 4	0-2	201- 300	3	3	21.63	25.90
UTOIL 5	0-2	301- 400	2	1	0.00	23.73
UTOIL 6	0-2	401- 500	1	2	36.63	12.67
UTOIL 7	0-2	501- 600	1	1	51.53	13.33
UTOIL 8	0-2	601-1,000	4	5	152.93	83.00
UTOIL 9	0-2	1,001-2,000	3	3	31.83	139.90
UTOIL 10	0-2	2,001-5,000	2	3	856.60	122.70
UTOIL 11	2-6	0- 60	45	23	38.93	18.90
UTOIL 12	2-6	61- 100	49	22	200.50	88.87
UTOIL 13	2-6	101- 200	130	27	860.10	483.90
UTOIL 14	2-6	201- 300	140	34	1,836.57	884.27
UTOIL 15	2-6	301- 400	127	26	1,956.00	1,217.83
UTOIL 16	2-6	401- 500	88	22	1,629.30	1,086.27
UTOIL 17	2-6	501- 600	94	20	2,320.70	1,369.40
UTOIL 18	2-6	601-1,000	228	31	6,241.50	5,098.07
UTOIL 19	2-6	1,001-2,000	213	22	7,149.07	8,791.70
UTOIL 20	2-6	2,001-5,000	76	12	4,250.83	6,305.30
UTOIL 21	2-6	5,001- Over	15	8	3,792.40	2,614.57
UTOIL 22	6-10	0- 60	7	7	0.83	3.47

(continued)

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
UTOIL 23	6-10	61- 100	5	6	19.47	7.30
UTOIL 24	6-10	101- 200	20	13	130.77	80.20
UTOIL 25	6-10	201- 300	33	19	594.30	199.27
UTOIL 26	6-10	301- 400	21	12	466.60	151.20
UTOIL 27	6-10	401- 500	20	11	477.30	211.10
UTOIL 28	6-10	501- 600	13	10	387.30	193.13
UTOIL 29	6-10	601-1,000	45	17	1,936.40	934.83
UTOIL 30	6-10	1,001-2,000	38	18	3,565.70	1,251.67
UTOIL 31	6-10	2,001-5,000	22	12	4,507.50	1,680.30
UTOIL 32	6-10	5,001- Over	16	7	50,086.47	2,283.70
UTOIL 33	10+	0- 60	31	4	24.50	11.40
UTOIL 34	10+	61- 100	14	3	29.23	21.93
UTOIL 35	10+	101- 200	21	4	112.43	63.33
UTOIL 36	10+	201- 300	25	6	176.07	155.47
UTOIL 37	10+	301- 400	17	6	183.67	146.27
UTOIL 38	10+	401- 500	22	5	384.73	226.67
UTOIL 39	10+	501- 600	18	5	284.90	254.27
UTOIL 40	10+	601-1,000	73	6	2,551.87	1,522.87
UTOIL 41	10+	1,001-2,000	153	7	12,665.57	5,726.77
UTOIL 42	10+	2,001-5,000	95	6	16,031.90	6,857.97
UTOIL 43	10+	5,001- Over	17	6	18,867.27	3,842.27

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APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
Virginia						
VAOIL 1	0-2	0- 60	50	N/A	0.00	58.33
West Virginia						
WVOIL 1	0-3	0- 60	15356	N/A	0.00	3,597.67
WVOIL 2	0-3	61- 100	284	N/A	0.00	608.47
WVOIL 3	0-3	101- 200	197	N/A	0.00	745.33
WVOIL 4	0-3	201- 300	81	N/A	0.00	675.20
WVOIL 5	0-3	601-1,000	24	N/A	0.00	603.87
Wyoming						
WYOIL 1	0-2	0- 60	1340	79	22.63	973.87
WYOIL 2	0-2	61- 100	393	46	53.20	951.70
WYOIL 3	0-2	101- 200	556	62	559.63	2,515.70
WYOIL 4	0-2	201- 300	326	45	414.17	2,501.33
WYOIL 5	0-2	301- 400	230	38	376.90	2,512.87
WYOIL 6	0-2	401- 500	140	34	290.60	1,993.60
WYOIL 7	0-2	501- 600	90	27	651.97	1,488.63
WYOIL 8	0-2	601-1,000	185	33	1,302.50	4,203.27
WYOIL 9	0-2	1,001-2,000	92	31	2,266.40	3,379.23
WYOIL 10	0-2	2,001-5,000	27	20	2,092.27	2,075.90
WYOIL 11	0-2	5,001- Over	5	5	4,559.67	1,201.67
WYOIL 12	2-6	0- 60	475	94	183.53	385.07
WYOIL 13	2-6	61- 100	466	92	546.40	1,025.17
WYOIL 14	2-6	101- 200	905	126	2,781.33	3,772.33
WYOIL 15	2-6	201- 300	537	121	2,149.97	3,880.47
WYOIL 16	2-6	301- 400	350	86	1,518.33	3,697.97
WYOIL 17	2-6	401- 500	266	75	1,132.67	3,576.10
WYOIL 18	2-6	501- 600	230	79	1,623.37	3,746.03
WYOIL 19	2-6	601-1,000	591	81	4,498.17	14,127.73
WYOIL 20	2-6	1,001-2,000	621	71	7,025.33	26,723.37
WYOIL 21	2-6	2,001-5,000	330	37	9,170.40	29,795.47
WYOIL 22	2-6	5,001- Over	46	15	4,628.70	9,108.30
WYOIL 23	6-10	0- 60	192	93	296.03	120.90
WYOIL 24	6-10	61- 100	201	90	822.40	398.10

APPENDIX A: GRUY ENGINEERING CORPORATION'S OIL WELLGROUPS BY STATE (Continued)

State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
WYOIL 25	6-10	101- 200	622	158	6,137.53	2,263.97

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State/ wellgroup	Depth range (Mft)	BOE range (BOE/mo)	Number of wells	Number of fields	Gas rate per well (Mcfd)	Oil rate per well (Bd)
WYOIL 26	6-10	201- 300	587	158	9,181.17	3,611.30
WYOIL 27	6-10	301- 400	457	133	9,092.83	4,035.30
WYOIL 28	6-10	401- 500	247	118	6,283.80	2,891.83
WYOIL 29	6-10	501- 600	175	93	4,791.50	2,550.97
WYOIL 30	6-10	601-1,000	416	166	10,529.70	9,063.23
WYOIL 31	6-10	1,001-2,000	348	147	10,470.40	14,483.13
WYOIL 32	6-10	2,001-5,000	300	125	23,030.37	27,171.90
WYOIL 33	6-10	5,001- Over	174	54	146,148.00	38,210.57
WYOIL 34	10+	0- 60	20	19	25.57	11.00
WYOIL 35	10+	61- 100	27	22	136.23	35.03
WYOIL 36	10+	101- 200	55	35	532.17	179.33
WYOIL 37	10+	201- 300	73	32	997.00	475.10
WYOIL 38	10+	301- 400	59	36	1,009.13	536.90
WYOIL 39	10+	401- 500	38	20	462.60	486.70
WYOIL 40	10+	501- 600	44	32	1,500.23	611.80
WYOIL 41	10+	601-1,000	117	53	5,375.20	2,355.20
WYOIL 42	10+	1,001-2,000	121	58	13,329.90	4,241.20
WYOIL 43	10+	2,001-5,000	95	49	21,076.03	6,666.07
WYOIL 44	10+	5,001- Over	103	26	223,460.00	34,896.93

APPENDIX B

GRUY ENGINEERING CORPORATION'S
GAS WELLGROUPS BY STATE

APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
Alaska									
AKGAS1	0-4	34	67	40.07	1	1	1	1	40.07
AKGAS2	0-4	100	133	121.90	2	3	3	5	365.70
AKGAS3	0-4	167	200	182.55	2	3	3	5	547.65
AKGAS4	0-4	200	333	224.61	5	4	7	6	1,572.29
AKGAS5	0-4	334	667	335.07	3	1	4	1	1,340.27
AKGAS6	0-4	667	1,667	902.83	1	1	1	1	902.83
AKGAS7	0-4	1,667		4,719.79	4	3	5	4	23,598.96
AKGAS8	4-10	134	167	68.23	2	3	3	5	204.70
AKGAS9	4-10	200	333	299.97	1	1	1	1	299.97
AKGAS10	4-10	334	667	229.31	3	3	4	4	917.24
AKGAS11	4-10	667	1,667	1,031.92	7	4	9	5	9,287.27
AKGAS12	4-10	1,667	0	5,981.88	72	8	95	11	568,278.30
AKGAS13	10+	334	667	494.77	2	3	3	5	1,484.30
AKGAS14	10+	667	1,667	1,568.63	1	1	1	1	1,468.63
AKGAS15	10+	1,667		6,108.00	13	5	17	7	103,836.04
Alabama									
ALGAS 1	0-4	0.0	20	5.16	203	31	452	69	2,333.70
ALGAS 2	0-4	20	33	18.12	148	30	329	67	5,962.46
ALGAS 3	0-4	34	67	34.87	275	37	611	82	21,304.13
ALGAS 4	0-4	67	100	74.30	191	40	425	89	31,578.46

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

					Gruy		Revised 1993		
State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)
ALGAS 5	0-4	100	133	94.52	95	37	211	82	19,943.42
ALGAS 6	0-4	134	167	141.98	95	31	211	69	29,957.19
ALGAS 7	0-4	167	200	174.39	42	23	93	51	16,218.68
ALGAS 8	0-4	200	333	256.60	115	32	259	71	66,458.72
ALGAS 9	0-4	334	667	444.45	79	27	174	60	77,333.60
ALGAS 10	0-4	667	1,667	740.36	20	15	37	33	27,393.26
ALGAS 11	0-4	1,667	0.00	2,231.05	60	9	126	20	281,112.23
ALGAS 12	4-10	0.0	20	0.93	4	5	26	11	24.27
ALGAS 13	4-10	20	33	13.23	5	6	11	13	145.57
ALGAS 14	4-10	34	67	42.09	9	7	20	16	841.70
ALGAS 15	4-10	67	100	71.10	14	9	31	20	2,204.10
ALGAS 16	4-10	100	133	99.15	12	11	27	25	2,677.13
ALGAS 17	4-10	134	167	136.09	11	9	24	20	3,266.11
ALGAS 18	4-10	167	200	170.26	6	5	13	11	2,213.39
ALGAS 19	4-10	200	333	233.31	25	13	56	29	13,065.10
ALGAS 20	4-10	334	667	456.88	27	13	60	29	27,412.52
ALGAS 21	4-10	667	1,667	847.83	19	12	42	27	35,608.71
ALGAS 22	4-10	1,667	0.00	1,799.49	5	5	11	11	19,794.35
ALGAS 23	10+	34	67	45.43	1	1	2	2	90.87
ALGAS 24	10+	134	167	17.90	1	2	2	4	35.80
ALGAS 25	10+	200	333	74.53	4	5	9	11	670.73

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
ALGAS 26	10+	334	667	176.07	1	1	2	2	352.13
ALGAS 27	10+	667	1,667	644.75	15	8	33	18	21,276.64
ALGAS 28	10+	1,667	0.00	3,677.65	44	10	98	22	360,410.00
Arkansas									
ARGAS 1	0-4	0.0	20	6.95	276	61	311	69	2,161.64
ARGAS 2	0-4	20	33	22.19	100	48	113	54	2,507.66
ARGAS 3	0-4	34	67	42.24	209	56	237	64	10,011.72
ARGAS 4	0-4	67	100	69.96	146	47	165	53	11,542.80
ARGAS 5	0-4	100	133	94.19	76	33	86	37	8,100.71
ARGAS 6	0-4	134	167	131.45	57	30	65	34	8,544.08
ARGAS 7	0-4	167	200	143.00	30	18	34	20	4,862.00
ARGAS 8	0-4	200	333	226.13	87	35	98	39	22,160.54
ARGAS 9	0-4	334	667	390.89	79	29	89	33	34,788.97
ARGAS 10	0-4	667	1,667	745.22	36	17	41	19	30,554.07
ARGAS 11	0-4	1,667	0.00	1,359.01	3	4	3	4	4,077.03
ARGAS 12	4-10	0.0	20	7.95	157	35	178	40	1,415.57
ARGAS 13	4-10	20	33	21.71	111	35	126	40	2,734.92
ARGAS 14	4-10	34	67	41.86	251	43	284	49	11,887.19
ARGAS 15	4-10	67	100	73.96	164	38	186	43	13,756.40
ARGAS 16	4-10	100	133	105.05	150	39	170	44	17,858.58
ARGAS 17	4-10	134	167	132.60	91	31	103	35	13,657.50

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

					Gruy		Revised 1993		
State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)
ARGAS 18	4-10	167	200	156.60	83	31	94	35	14,720.29
ARGAS 19	4-10	200	333	231.68	189	36	214	41	49,580.37
ARGAS 20	4-10	334	667	422.80	167	32	189	36	79,909.61
ARGAS 21	4-10	667	1,667	756.84	95	26	108	30	81,738.57
ARGAS 22	4-10	1,667	0.00	2,018.26	17	12	19	13	38,347.03
ARGAS 23	10+	200	333	293.80	1	1	1	1	293.80
Arizona									
AZGAS 1	0-4	34	67	30.83	1	1	1	1	30.83
AZGAS 2	4-10	0.0	20	20.00	1	1	2	1	40.00
AZGAS 3	4-10	67	100	30.00	1	1	1	1	30.00
AZGAS 4	4-10	667	1,667	1,025.23	1	2	1	2	1,025.23
AZGAS 5	4-10	1,667	0.00	2,641.68	2	1	2	1	5,283.37
California-Northern & Coastal									
CACNGAS 1	0-4	0.0	20	5.41	28	15	16	11	86.59
CACNGAS 2	0-4	20	33	21.77	18	13	14	10	304.79
CACNGAS 3	0-4	34	67	43.91	41	21	31	16	1,361.28
CACNGAS 4	0-4	67	100	75.29	26	13	20	10	1,505.72
CACNGAS 5	0-4	100	133	90.36	27	15	20	11	1,807.14
CACNGAS 6	0-4	134	167	144.56	14	11	11	9	1,590.13
CACNGAS 7	0-4	167	200	160.62	6	6	5	5	803.08
CACNGAS 8	0-4	200	333	230.68	17	10	13	8	2,998.87

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

					Gruy		Revised 1993		
State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)
CACNGAS 9	0-4	334	667	339.98	23	13	17	10	5,779.61
CACNGAS 10	0-4	667	1,667	617.42	5	6	6	5	3,704.52
CACNGAS 11	0-4	1,667	0.00	2,313.29	3	4	2	3	4,626.58
CACNGAS 12	4-10	0.0	20	5.52	107	33	73	25	402.61
CACNGAS 13	4-10	20	33	21.40	53	26	38	20	813.32
CACNGAS 14	4-10	34	67	43.83	115	36	87	27	3,813.30
CACNGAS 15	4-10	67	100	72.94	108	36	82	27	5,981.04
CACNGAS 16	4-10	100	133	101.83	89	28	70	21	7,128.10
CACNGAS 17	4-10	134	167	138.36	72	27	55	21	7,609.99
CACNGAS 18	4-10	167	200	168.00	61	24	46	18	7,728.13
CACNGAS 19	4-10	200	333	240.27	166	43	126	33	30,274.51
CACNGAS 20	4-10	334	667	436.98	172	37	130	28	56,808.01
CACNGAS 21	4-10	667	1,667	870.10	61	27	46	20	40,024.73
CACNGAS 22	4-10	1,667	0.00	2,380.39	20	14	17	11	40,466.69
CACNGAS 23	10+	0.0	20	10.10	1	1	1	1	10.10
CACNGAS 24	10+	20	33	16.11	3	3	2	2	32.22
CACNGAS 25	10+	34	67	25.08	3	4	2	3	50.16
CACNGAS 26	10+	67	100	93.67	1	1	1	1	93.67
CACNGAS 27	10+	100	133	89.73	6	5	5	4	448.67
CACNGAS 28	10+	134	167	106.83	2	1	2	1	213.67
CACNGAS 29	10+	167	200	152.22	2	1	2	1	304.43

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
CACNGAS 30	10+	200	333	249.37	8	3	6	2	1,496.23
CACNGAS 31	10+	334	667	457.30	5	1	4	1	1,829.20
CACNGAS 32	10+	667	1,667	965.03	8	1	6	1	5,790.20
CACNGAS 33	10+	1,667	0.00	3,921.66	6	3	5	3	19,608.28
California- Los Angeles Basin									
CALAGAS 1	0-4	0.0	20	10.23	1	1	1	1	10.23
CALAGAS 2	0-4	34	67	47.57	1	1	1	1	47.57
CALAGAS 3	0-4	67	100	92.40	1	1	1	1	92.40
California-San Jose Basin									
CASJGAS 1	0-4	0.0	20	6.99	33	9	25	7	174.72
CASJGAS 2	0-4	20	33	22.57	12	6	9	5	203.15
CASJGAS 3	0-4	34	67	49.74	14	5	11	4	547.15
CASJGAS 4	0-4	67	100	85.02	6	5	5	4	425.08
CASJGAS 5	0-4	134	167	137.03	1	1	1	1	137.03
CASJGAS 6	0-4	167	200	181.07	1	1	1	1	181.07
CASJGAS 7	0-4	200	333	250.08	4	1	3	1	750.25
CASJGAS 8	0-4	334	667	457.42	7	1	5	1	2,287.12
CASJGAS 9	0-4	667	1,667	842.90	11	1	8	1	6,743.18
CASJGAS 10	0-4	1,667	0.00	2,751.10	1	1	1	1	2,751.10
CASJGAS 11	4-10	0.0	20	4.46	8	6	6	5	26.75
CASJGAS 12	4-10	20	33	25.58	2	1	2	1	51.17

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
CASJGAS 13	4-10	34	67	42.17	1	1	1	1	42.17
CASJGAS 14	4-10	67	100	86.92	2	3	2	3	173.83
CASJGAS 15	4-10	100	133	119.60	2	3	2	3	239.20
CASJGAS 16	4-10	134	167	135.67	1	1	1	1	135.67
CASJGAS 17	4-10	167	200	172.10	1	2	1	2	172.10
CASJGAS 18	4-10	200	333	170.60	3	4	2	3	341.20
CASJGAS 19	4-10	334	667	425.40	1	2	1	2	425.40
CASJGAS 20	4-10	667	1,667	1,037.45	5	5	4	4	4,149.81
CASJGAS 21	4-10	1,667	0.00	1,008.98	2	2	2	2	2,017.97
CASJGAS 22	10+	0.0	20	19.13	1	1	1	1	19.13
CASJGAS 23	10+	20	33	10.80	1	1	1	1	10.80
CASJGAS 24	10+	34	67	13.19	6	1	5	1	65.94
CASJGAS 25	10+	67	100	23.05	2	1	2	1	46.10
CASJGAS 26	10+	100	133	27.58	2	1	2	1	55.17
CASJGAS 27	10+	134	167	73.40	1	1	1	1	73.40
CASJGAS 28	10+	167	200	39.83	4	1	3	1	119.50
Colorado									
COGAS 1	0-4	0.0	20	8.52	345	64	384	66	3,270.46
COGAS 2	0-4	20	33	25.49	210	56	217	58	5,530.95
COGAS 3	0-4	34	67	46.25	410	65	424	67	19,609.83
COGAS 4	0-4	67	100	78.33	257	45	266	47	20,836.32

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

					Gruy		Revised 1993		
State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)
COGAS 5	0-4	100	133	104.46	118	34	122	35	12,744.42
COGAS 6	0-4	134	167	143.59	186	24	192	25	27,568.69
COGAS 7	0-4	167	200	148.79	34	15	30	15	4,463.62
COGAS 8	0-4	200	333	230.25	161	21	166	22	38,221.04
COGAS 9	0-4	334	667	351.41	70	18	72	19	25,301.86
COGAS 10	0-4	667	1,667	514.47	11	6	14	6	7,202.62
COGAS 11	4-10	0.0	20	8.88	444	89	459	92	4,074.28
COGAS 12	4-10	20	33	22.01	411	76	425	79	9,354.24
COGAS 13	4-10	34	67	37.65	1,271	109	1292	113	48,638.40
COGAS 14	4-10	67	100	63.93	771	69	797	71	50,953.35
COGAS 15	4-10	100	133	92.17	437	43	452	44	41,662.78
COGAS 16	4-10	134	167	110.05	243	32	251	33	27,621.95
COGAS 17	4-10	167	200	125.16	198	36	205	37	25,656.79
COGAS 18	4-10	200	333	179.37	349	49	361	51	64,753.57
COGAS 19	4-10	334	667	360.27	161	41	166	42	59,804.44
COGAS 20	4-10	667	1,667	622.57	54	17	56	18	34,863.73
COGAS 21	4-10	1,667	0.00	1,489.77	4	5	4	5	5,959.07
COGAS 22	10+	0.0	20	8.18	4	4	4	4	32.70
COGAS 23	10+	20	33	17.40	2	3	2	3	34.80
COGAS 24	10+	34	67	38.07	2	3	2	3	76.13
COGAS 25	10+	100	133	130.97	1	1	1	1	130.97

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

					Gruy		Revised 1993		
State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)
COGAS 26	10+	134	167	164.23	1	1	1	1	164.23
COGAS 27	10+	167	200	187.07	1	1	1	1	187.07
COGAS 28	10+	200	333	92.77	1	1	1	1	92.77
COGAS 29	10+	334	667	448.20	1	1	1	1	448.20
COGAS 30	10+	667	1,667	684.12	2	3	2	3	1,368.23
COGAS 31	10+	1,667	0.00	2,910.87	2	1	2	1	5,821.73
Illinois									
ILGAS 1	0-2	0.0	20	5.39	263	N/A	341		1,836.60
ILGAS 2	0-2	20	33	27.76	16	N/A	21		582.88
ILGAS 3	0-2	0	67	53.29	10	N/A	13		692.77
ILGAS 4	0-2	100	133	110.86	4	N/A	5		554.29
ILGAS 5	0-2	200	333	208.35	2	N/A	3		625.05
ILGAS 6	0-2	667	1,667	374.13	1	N/A	1		374.13
Indiana									
INGAS 1	0-2	0.0	20	0.89	1,291	N/A	1323		1,172.05
INGAS 2	0-2	20	33	22.20	3	N/A	3		66.60
INGAS 3	0-2	34	80	48.03	1	N/A	1		48.03
Kansas									
KSGAS 1	0-4	0.0	20	7.72	1,424	290	1549	317	11,956.02
KSGAS 2	0-4	20	33	23.03	718	180	784	197	18,056.97
KSGAS 3	0-4	34	67	42.86	1,480	189	1617	206	69,311.32

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

					Gruy		Revised 1993		
State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)
KSGAS 4	0-4	67	100	71.56	1,071	110	1170	120	83,725.06
KSGAS 5	0-4	100	133	97.09	901	66	984	72	95,534.71
KSGAS 6	0-4	134	167	119.36	790	48	863	52	103,004.26
KSGAS 7	0-4	167	200	148.06	663	39	724	43	107,196.88
KSGAS 8	0-4	200	333	214.87	1,595	50	1749	55	375,806.08
KSGAS 9	0-4	334	667	392.16	1,082	30	1182	33	463,528.76
KSGAS 10	0-4	667	1,667	786.22	165	14	180	15	141,519.31
KSGAS 11	0-4	1,667	0.00	2,016.29	4	5	4	5	8,065.17
KSGAS 12	4-10	0.0	20	9.27	791	241	864	263	8,007.42
KSGAS 13	4-10	20	33	24.32	493	184	539	201	13,109.33
KSGAS 14	4-10	34	67	43.85	707	240	772	262	33,853.89
KSGAS 15	4-10	67	100	73.45	323	137	353	150	25,926.12
KSGAS 16	4-10	100	133	105.39	223	112	245	123	25,821.17
KSGAS 17	4-10	134	167	134.83	109	67	119	73	16,044.95
KSGAS 18	4-10	167	200	169.37	71	56	78	62	13,210.60
KSGAS 19	4-10	200	333	217.99	180	92	197	101	42,943.63
KSGAS 20	4-10	334	667	394.59	124	67	135	73	53,270.20
KSGAS 21	4-10	667	1,667	807.93	70	35	76	38	61,402.72
KSGAS 22	4-10	1,667	0.00	1,808.96	15	12	16	13	28,943.32

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy: Number of wells	Gruy: Number of fields	Revised 1993: Number of wells	Revised 1993: Number of fields	1993 Total gas production (Mcdf)
Kentucky									
KYGAS 1	0-2	0.0	20	7.09	9,884	N/A	11294		80,089.36
KYGAS 2	0-2	34	67	41.82	884	N/A	1024		42,820.42
KYGAS 3	0-2	67	100	80.61	159	N/A	150		12,091.23
KYGAS 4	0-2	100	133	119.20	139	N/A	159		18,952.46
KYGAS 5	0-2	200	333	217.15	121	N/A	139		30,184.52
KYGAS 6	0-2	334	667	551.40	45	N/A	51		28,121.25
KYGAS 7	0-2	667	1,667	1,356.05	17	N/A	19		25,764.97
Louisiana-North									
LANGAS 1	0-4	0.0	20	5.88	8,290	50	7576	46	44,537.38
LANGAS 2	0-4	20	33	23.26	408	34	373	31	8,675.78
LANGAS 3	0-4	34	67	36.80	257	56	235	51	8,649.13
LANGAS 4	0-4	67	100	55.91	114	44	104	40	5,814.69
LANGAS 5	0-4	100	133	84.01	65	32	59	29	4,956.51
LANGAS 6	0-4	134	167	101.67	36	24	33	22	3,354.97
LANGAS 7	0-4	167	200	118.77	36	23	33	21	3,919.27
LANGAS 8	0-4	200	333	208.80	56	27	51	25	10,648.56
LANGAS 9	0-4	334	667	346.10	24	15	22	14	7,614.29
LANGAS 10	0-4	667	1,667	528.84	21	16	19	14	10,047.98
LANGAS 11	0-4	1,667	0.00	1,222.75	2	3	2	3	2,445.50
LANGAS 12	4-10	0.0	20	7.48	222	66	203	60	1,518.69

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
LANGAS 13	4-10	20	33	20.86	127	53	116	48	2,419.22
LANGAS 14	4-10	34	67	38.99	250	70	228	64	8,888.78
LANGAS 15	4-10	67	100	68.10	207	60	189	55	12,871.23
LANGAS 16	4-10	100	133	98.36	136	56	124	51	12,196.62
LANGAS 17	4-10	134	167	124.53	116	49	106	45	13,200.62
LANGAS 18	4-10	167	200	153.83	100	46	91	42	13,998.17
LANGAS 19	4-10	200	333	212.52	274	67	250	61	53,129.01
LANGAS 20	4-10	334	667	403.91	275	64	251	58	101,380.79
LANGAS 21	4-10	667	1,667	779.52	188	52	172	48	134,077.29
LANGAS 22	4-10	1,667	0.00	2,860.46	89	24	81	22	231,697.47
LANGAS 23	10+	0.0	20	6.45	29	17	27	16	174.17
LANGAS 24	10+	20	33	14.52	10	9	9	8	130.65
LANGAS 25	10+	34	67	28.44	26	18	24	17	682.68
LANGAS 26	10+	67	100	49.59	26	19	24	18	1,190.12
LANGAS 27	10+	100	133	92.79	13	11	12	10	1,113.54
LANGAS 28	10+	134	167	107.70	24	16	22	15	2,369.49
LANGAS 29	10+	167	200	114.10	11	10	10	9	1,141.00
LANGAS 30	10+	200	333	184.16	63	24	58	22	10,681.39
LANGAS 31	10+	334	667	330.93	51	27	47	25	15,553.77
LANGAS 32	10+	667	1,667	846.97	59	21	54	19	45,736.44
LANGAS 33	10+	1,667	0.00	2,135.84	40	15	37	14	79,026.11

(continued)

APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
Louisiana-South									
LASGAS 1	0-4	0.0	20	4.94	11	12	10	11	49.39
LASGAS 2	0-4	20	33	16.82	7	7	6	6	100.91
LASGAS 3	0-4	34	67	33.49	13	8	12	7	401.94
LASGAS 4	0-4	67	100	66.55	9	9	8	8	532.39
LASGAS 5	0-4	100	133	81.85	11	10	10	9	818.55
LASGAS 6	0-4	134	167	96.09	5	6	5	6	480.47
LASGAS 7	0-4	167	200	120.69	10	10	9	9	1,086.21
LASGAS 8	0-4	200	333	185.65	14	13	13	12	2,413.45
LASGAS 9	0-4	334	667	344.10	24	19	22	17	7,570.26
LASGAS 10	0-4	667	1,667	743.76	30	16	27	14	20,081.40
LASGAS 11	0-4	1,667	0.00	1,246.82	13	13	12	12	14,961.88
LASGAS 12	4-10	0.0	20	2.96	40	34	37	31	109.40
LASGAS 13	4-10	20	33	14.59	23	23	21	21	306.33
LASGAS 14	4-10	34	67	30.62	42	35	38	32	1,163.73
LASGAS 15	4-10	67	100	40.61	62	47	57	43	2,314.66
LASGAS 16	4-10	100	133	62.59	39	34	36	31	2,253.08
LASGAS 17	4-10	134	167	90.21	36	32	33	29	2,977.06
LASGAS 18	4-10	167	200	112.42	28	24	26	22	2,922.93
LASGAS 19	4-10	200	333	169.85	100	76	91	69	15,456.35
LASGAS 20	4-10	334	667	303.26	157	114	143	104	43,365.71

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
LASGAS 21	4-10	667	1,667	692.16	167	112	153	103	105,899.88
LASGAS 22	4-10	1,667	0.00	1,918.26	67	48	61	44	117,014.15
LASGAS 23	10+	0.0	20	2.55	75	60	69	55	175.78
LASGAS 24	10+	20	33	12.22	21	20	19	18	232.25
LASGAS 25	10+	34	67	21.88	71	63	65	58	1,422.13
LASGAS 26	10+	67	100	50.37	58	54	53	49	2,669.52
LASGAS 27	10+	100	133	71.77	52	47	48	43	3,444.83
LASGAS 28	10+	134	167	96.13	59	54	54	49	5,191.20
LASGAS 29	10+	167	200	112.88	44	40	40	36	4,515.18
LASGAS 30	10+	200	333	164.12	177	123	162	113	26,586.70
LASGAS 31	10+	334	667	342.46	325	186	297	170	101,709.58
LASGAS 32	10+	667	1,667	781.98	486	205	444	187	347,197.71
LASGAS 33	10+	1,667	0.00	3,612.62	538	195	508	178	1,835,212.51
Michigan									
MIGAS 1	0-4	0.0	20	4.77	89	21	287	68	1,367.71
MIGAS 2	0-4	20	33	11.73	69	21	222	68	2,605.12
MIGAS 3	0-4	34	67	24.47	89	24	287	77	7,024.08
MIGAS 4	0-4	67	100	47.46	77	18	248	58	11,769.37
MIGAS 5	0-4	100	133	67.71	62	20	200	65	13,541.83
MIGAS 6	0-4	134	167	85.20	42	15	135	48	11,501.79
MIGAS 7	0-4	167	200	102.70	47	13	151	42	15,507.06

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
MIGAS 8	0-4	200	333	144.50	109	25	351	81	50,720.79
MIGAS 9	0-4	334	667	279.71	91	29	293	93	81,955.86
MIGAS 10	0-4	667	1,667	586.05	146	36	470	116	275,441.35
MIGAS 11	0-4	1,667	0.00	1,773.05	94	24	306	77	542,554.82
MIGAS 12	4-10	0.0	20	21.49	5	3	16	10	343.89
MIGAS 13	4-10	34	67	69.85	2	2	6	6	419.10
MIGAS 14	4-10	67	100	68.88	2	2	6	6	413.30
MIGAS 15	4-10	200	333	10.89	7	4	23	13	250.48
MIGAS 16	4-10	334	667	250.68	12	4	39	13	9,776.33
MIGAS 17	4-10	667	1,667	244.70	10	5	32	16	7,830.29
MIGAS 18	4-10	1,667	0.00	1,196.94	12	4	39	13	46,680.73
MIGAS 19	10+	34	67	53.73	2	2	6	6	322.40
MIGAS 20	10+	67	100	77.92	2	2	6	6	467.50
MIGAS 21	10+	167	200	116.78	2	2	6	6	700.70
MIGAS 22	10+	334	667	77.92	2	2	6	6	467.50
MIGAS 23	10+	667	1,667	618.42	5	3	16	10	9,894.72
MIGAS 24	10+	1,667	0.00	2,190.33	7	4	23	13	50,377.67
Mississippi									
MSGAS 1	0-4	0.0	20	5.64	19	10	16	7	90.22
MSGAS 2	0-4	20	33	19.13	15	12	11	9	210.44
MSGAS 3	0-4	34	67	35.05	10	8	7	6	245.37

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy		Revised 1993		1993 Total gas production (Mcdf)
					Number of wells	Number of fields	Number of wells	Number of fields	
MSGAS 4	0-4	67	100	68.19	22	11	16	8	1,091.10
MSGAS 5	0-4	100	133	88.60	23	13	17	10	1,506.22
MSGAS 6	0-4	134	167	108.64	16	13	12	10	1,303.68
MSGAS 7	0-4	167	200	151.49	6	6	4	4	605.96
MSGAS 8	0-4	200	333	187.72	32	15	24	11	4,505.23
MSGAS 9	0-4	334	667	317.41	30	15	22	11	6,983.07
MSGAS 10	0-4	667	1,667	629.15	23	12	17	9	10,695.49
MSGAS 11	0-4	1,667	0.00	2,446.34	6	4	4	3	9,785.38
MSGAS 12	4-10	0.0	20	6.11	25	11	19	8	116.18
MSGAS 13	4-10	20	33	18.59	11	6	8	4	148.73
MSGAS 14	4-10	34	67	40.37	32	14	24	11	968.98
MSGAS 15	4-10	67	100	58.71	23	10	17	7	998.12
MSGAS 16	4-10	100	133	85.98	22	9	16	7	1,375.61
MSGAS 17	4-10	134	167	100.36	18	12	13	9	1,304.74
MSGAS 18	4-10	167	200	136.24	10	8	7	6	953.68
MSGAS 19	4-10	200	333	189.30	18	8	13	6	2,460.95
MSGAS 20	4-10	334	667	337.94	23	8	17	6	5,745.06
MSGAS 21	4-10	667	1,667	631.51	11	9	8	7	5,052.05
MSGAS 22	4-10	1,667	0.00	977.54	7	2	5	1	4,887.69
MSGAS 23	10+	0.0	20	3.18	21	11	16	8	50.90
MSGAS 24	10+	20	33	6.76	9	9	10	7	67.63

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
MSGAS 25	10+	34	67	21.81	10	10	7	7	152.69
MSGAS 26	10+	67	100	40.88	9	7	7	5	286.14
MSGAS 27	10+	100	133	81.20	11	7	8	5	649.58
MSGAS 28	10+	134	167	97.27	13	11	10	8	972.74
MSGAS 29	10+	167	200	127.61	9	7	7	5	893.28
MSGAS 30	10+	200	333	180.58	39	22	29	16	5,236.78
MSGAS 31	10+	334	667	341.98	51	30	38	22	12,995.06
MSGAS 32	10+	667	1,667	788.39	77	32	57	24	44,938.45
MSGAS 33	10+	1,667	0.00	3,862.31	89	36	66	27	254,912.17
Montana									
MTGAS 1	0-4	0.0	20	9.11	1,184	95	1243	100	11,328.52
MTGAS 2	0-4	20	33	22.90	585	72	614	76	14,059.17
MTGAS 3	0-4	34	67	40.04	520	77	546	81	21,864.19
MTGAS 4	0-4	67	100	73.20	169	43	177	45	12,956.05
MTGAS 5	0-4	100	133	107.99	82	29	86	30	9,286.95
MTGAS 6	0-4	134	167	133.07	49	23	51	24	6,786.43
MTGAS 7	0-4	167	200	164.55	40	16	42	17	6,911.14
MTGAS 8	0-4	200	333	214.61	48	17	50	18	10,730.59
MTGAS 9	0-4	334	667	400.44	36	14	38	15	15,216.75
MTGAS 10	0-4	667	1,667	727.03	13	4	14	4	10,178.43
MTGAS 11	0-4	1,667	0.00	874.56	4	3	4	3	3,498.23

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
MTGAS 12	4-10	0.0	20	4.53	4	4	4	4	18.13
MTGAS 13	4-10	20	33	23.98	2	3	2	3	47.97
MTGAS 14	4-10	34	67	45.78	9	3	9	3	412.00
MTGAS 15	4-10	67	100	68.29	3	3	3	3	204.87
MTGAS 16	4-10	100	133	106.33	5	3	7	3	744.33
MTGAS 17	4-10	134	167	135.10	3	3	3	3	405.30
MTGAS 18	4-10	167	200	163.45	2	1	2	1	326.90
MTGAS 19	4-10	200	333	143.48	2	3	2	3	286.97
MTGAS 20	4-10	334	667	579.03	1	1	1	1	579.03
MTGAS 21	10+	0.0	20	10.83	1	1	1	1	10.83
MTGAS 22	10+	34	67	37.93	1	1	1	1	37.93
North Dakota									
NDGAS 1	0-4	0.0	20	7.95	54	3	77	4	611.77
NDGAS 2	0-4	20	33	25.59	5	1	7	1	179.11
NDGAS 3	0-4	34	67	42.90	2	1	3	2	128.70
NDGAS 4	0-4	67	100	69.43	1	1	1	1	69.43
NDGAS 5	10+	0.0	20	3.16	3	4	4	5	12.62
NDGAS 6	10+	200	333	48.33	1	1	3	1	145.00
NDGAS 7	10+	334	667	146.81	3	4	4	5	587.24
NDGAS 8	10+	667	1,667	478.33	1	2	1	2	478.33
NDGAS 9	10+	1,667	0.00	2,250.43	3	4	4	5	9,001.73

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy		Revised 1993		1993 Total gas production (Mcdf)
					Number of wells	Number of fields	Number of wells	Number of fields	
Nebraska									
NEGAS 1	4-10	20	33	13.99	6	4	30	20	419.83
NEGAS 2	4-10	34	67	40.93	4	3	20	15	818.67
NEGAS 3	4-10	67	100	37.93	2	3	10	15	379.33
New Mexico									
NMGAS 1	0-4	0.0	20	7.82	2,306	64	3694	103	28,885.87
NMGAS 2	0-4	20	33	22.10	1,126	43	1804	69	39,867.17
NMGAS 3	0-4	34	67	38.97	1,486	43	2380	69	92,744.99
NMGAS 4	0-4	67	100	65.54	635	38	1017	61	66,656.42
NMGAS 5	0-4	100	133	95.90	355	37	569	59	54,566.51
NMGAS 6	0-4	134	167	121.20	241	29	386	46	46,781.54
NMGAS 7	0-4	167	200	150.13	138	25	221	40	33,178.35
NMGAS 8	0-4	200	333	214.76	289	30	463	48	99,435.26
NMGAS 9	0-4	334	667	358.24	155	22	248	35	88,842.61
NMGAS 10	0-4	667	1,667	740.49	59	14	95	23	70,346.91
NMGAS 11	0-4	1,667	0.00	2,844.17	38	4	61	6	173,494.49
NMGAS 12	4-10	0.0	20	6.76	1,151	93	1844	149	12,471.91
NMGAS 13	4-10	20	33	20.21	796	60	1275	96	25,766.53
NMGAS 14	4-10	34	67	39.24	1,908	82	3056	131	119,918.32
NMGAS 15	4-10	67	100	65.70	1,531	61	2449	98	160,888.64
NMGAS 16	4-10	100	133	89.94	1,206	55	1932	88	173,764.07

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
NMGAS 17	4-10	134	167	113.46	842	37	1349	59	153,051.05
NMGAS 18	4-10	167	200	135.86	561	41	899	66	122,134.41
NMGAS 19	4-10	200	333	182.92	953	59	1526	94	279,137.16
NMGAS 20	4-10	334	667	318.43	395	43	633	69	201,565.31
NMGAS 21	4-10	667	1,667	750.05	99	33	159	53	119,257.76
NMGAS 22	4-10	1,667	0.00	2,735.30	52	11	83	18	227,030.01
NMGAS 23	10+	0.0	20	5.21	122	71	195	113	1,015.17
NMGAS 24	10+	20	33	20.37	56	42	90	68	1,833.70
NMGAS 25	10+	34	67	41.01	109	54	175	87	7,176.07
NMGAS 26	10+	67	100	68.94	98	60	157	96	10,823.60
NMGAS 27	10+	100	133	96.16	67	46	107	73	10,289.03
NMGAS 28	10+	134	167	116.06	60	44	96	70	11,141.49
NMGAS 29	10+	167	200	152.41	51	35	82	56	12,497.44
NMGAS 30	10+	200	333	220.45	129	67	207	108	45,633.12
NMGAS 31	10+	334	667	395.22	172	81	276	130	109,080.60
NMGAS 32	10+	667	1,667	863.73	132	63	211	101	182,246.19
NMGAS 33	10+	1,667	0.00	2,245.17	58	30	93	48	208,800.45
New York									
NYGAS 1	0-3	0.0	20	6.00	4,850	N/A	5391		32,334.25
NYGAS 2	0-3	20	33	30.40	168	N/A	187		5,684.73
NYGAS 3	0-3	34	67	46.60	139	N/A	155		7,222.41

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy		Revised 1993		1993 Total gas production (Mcdf)
					Number of wells	Number of fields	Number of wells	Number of fields	
NYGAS 4	0-3	67	100	72.41	95	N/A	106		7,675.29
NYGAS 5	0-3	100	133	127.67	66	N/A	73		9,320.18
NYGAS 6	0-3	200	333	282.72	27	N/A	30		8,481.67
NYGAS 7	0-3	667	1,667	853.38	8	N/A	9		7,680.41
Ohio									
OHGAS 1	0-4	0.0	20	4.78	28,300	N/A	28587		136,735.83
OHGAS 2	0-4	20	33	23.62	3,789	N/A	3827		90,383.96
OHGAS 3	0-4	34	67	48.01	887	N/A	896		43,018.74
OHGAS 4	0-4	67	100	74.27	609	N/A	615		45,675.18
OHGAS 5	0-4	100	133	130.67	424	N/A	428		55,928.56
OHGAS 6	0-4	200	333	288.46	174	N/A	176		50,768.82
OHGAS 7	0-4	667	1,667	880.18	51	N/A	52		45,769.41
Oklahoma									
OKGAS 1	0-4	0.0	20	5.39	2,959	466	3114	492	16,772.70
OKGAS 2	0-4	20	33	16.35	1,169	301	1236	318	20,207.56
OKGAS 3	0-4	34	67	30.36	1,537	329	1624	348	49,305.89
OKGAS 4	0-4	67	100	52.65	895	220	946	233	49,806.14
OKGAS 5	0-4	100	133	78.12	523	129	553	136	43,200.93
OKGAS 6	0-4	134	167	100.10	371	87	392	92	39,239.24
OKGAS 7	0-4	167	200	126.05	249	56	263	59	33,151.38
OKGAS 8	0-4	200	333	172.67	520	106	550	112	94,968.89

(continued)

APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
OKGAS 9	0-4	334	667	306.66	356	78	376	82	115,305.26
OKGAS 10	0-4	667	1,667	597.25	100	23	106	24	63,308.57
OKGAS 11	0-4	1,667	0.00	1,373.57	11	7	12	8	16,482.87
OKGAS 12	4-10	0.0	20	6.33	1,394	285	1473	301	9,320.09
OKGAS 13	4-10	20	33	16.17	1,113	250	1176	264	19,011.26
OKGAS 14	4-10	34	67	30.46	2,363	337	2497	356	76,051.91
OKGAS 15	4-10	67	100	52.75	1,818	284	1921	300	101,333.91
OKGAS 16	4-10	100	133	73.20	1,293	233	1367	246	100,064.44
OKGAS 17	4-10	134	167	96.28	870	180	920	190	88,578.20
OKGAS 18	4-10	167	200	120.39	698	162	738	171	88,850.30
OKGAS 19	4-10	200	333	165.91	1,629	240	1725	254	286,193.81
OKGAS 20	4-10	334	667	297.53	1,295	211	1369	223	407,322.50
OKGAS 21	4-10	667	1,667	610.86	829	141	876	149	535,113.28
OKGAS 22	4-10	1,667	0.00	1,832.28	210	47	222	50	406,767.22
OKGAS 23	10+	0.0	20	4.75	245	88	259	93	1,231.15
OKGAS 24	10+	20	33	13.87	247	84	261	89	3,619.45
OKGAS 25	10+	34	67	27.03	536	135	566	143	15,300.55
OKGAS 26	10+	67	100	47.30	428	117	452	124	21,378.93
OKGAS 27	10+	100	133	68.39	323	90	341	95	23,321.44
OKGAS 28	10+	134	167	91.81	279	91	295	96	27,084.81
OKGAS 29	10+	167	200	112.17	247	83	261	88	29,275.96

(continued)

APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy		Revised 1993		
					Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)
OKGAS 30	10+	200	333	162.21	649	124	686	131	111,278.89
OKGAS 31	10+	334	667	300.85	833	131	880	138	264,747.52
OKGAS 32	10+	667	1,667	678.81	810	107	866	113	587,852.20
OKGAS 33	10+	1,667	0.00	2,394.68	547	86	579	91	1,386,517.36
Oregon									
ORGAS 1	0-4	20	33	28.20	1	1	1	1	28.20
ORGAS 2	0-4	34	67	65.90	1	1	2	1	131.80
ORGAS 3	0-4	100	133	116.82	2	1	2	1	233.63
ORGAS 4	0-4	134	167	162.73	1	1	1	1	162.73
ORGAS 5	0-4	200	333	213.22	5	1	6	1	1,279.32
ORGAS 6	0-4	334	667	392.94	4	1	4	1	1,571.77
ORGAS 7	0-4	667	1,667	996.68	4	1	4	1	3,986.73
ORGAS 8	4-10	67	100	95.07	1	1	1	1	95.07
Pennsylvania									
PAGAS 1	0-4	0.0	20	5.75	23,975	N/A	25709		147,934.68
PAGAS 2	0-4	20	33	24.76	2,301	N/A	2467		61,087.79
PAGAS 3	0-4	34	67	46.76	1,660	N/A	1780		83,238.16
PAGAS 4	0-4	67	100	89.33	516	N/A	553		49,401.62
PAGAS 5	0-4	134	167	157.29	359	N/A	386		60,714.43
PAGAS 6	0-4	200	333	345.63	148	N/A	159		54,955.66

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
PAGAS 7	0-4	667	1,667	1,063.94	43	N/A	46		48,941.25
South Dakota									
SDGAS 1	0-4	0.0	20	10.77	14	3	10	2	107.69
SDGAS 2	0-4	20	33	27.64	5	3	4	2	110.56
SDGAS 3	0-4	34	67	52.23	28	3	20	2	1,044.60
SDGAS 4	0-4	67	100	72.63	3	1	2	1	145.27
SDGAS 5	0-4	100	133	120.33	1	1	1	1	120.33
SDGAS 6	4-10	20	33	25.10	1	1	1	1	25.10
Tennessee									
TNGAS 1	0-2	0.0	20	3.94	560	N/A	582		2,292.87
TNGAS 2	0-2	20	33	27.86	15	N/A	16		445.72
TNGAS 3	0-2	34	67	40.35	11	N/A	11		443.80
TNGAS 4	0-2	67	100	77.66	7	N/A	7		543.63
TNGAS 5	0-2	134	167	164.16	3	N/A	3		492.47
TNGAS 6	0-2	334	667	440.47	1	N/A	1		440.47
Texas-Gulf Coast									
TXGCGAS 1	0-4	0.0	20	6.61	722	328	661	300	4,369.22
TXGCGAS 2	0-4	20	33	21.47	348	211	319	193	6,848.57
TXGCGAS 3	0-4	34	67	40.17	566	293	518	268	20,807.10
TXGCGAS 4	0-4	67	100	66.48	384	227	351	207	23,334.55
TXGCGAS 5	0-4	100	133	93.24	242	150	220	138	20,513.79

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy		Revised 1993		1993 Total gas production (Mcdf)
					Number of wells	Number of fields	Number of wells	Number of fields	
TXGCGAS 6	0-4	134	167	117.98	190	128	174	117	20,528.61
TXGCGAS 7	0-4	167	200	148.55	139	94	127	86	18,866.35
TXGCGAS 8	0-4	200	333	210.55	282	150	258	137	54,323.12
TXGCGAS 9	0-4	334	667	391.74	119	74	109	68	42,699.76
TXGCGAS 10	0-4	667	1,667	704.65	39	25	34	23	23,958.00
TXGCGAS 11	0-4	1,667	0.00	7,122.61	15	12	14	11	99,716.49
TXGCGAS 12	4-10	0.0	20	7.23	1,493	582	1367	533	9,885.28
TXGCGAS 13	4-10	20	33	20.99	884	386	809	353	16,982.14
TXGCGAS 14	4-10	34	67	40.10	1,810	648	1657	593	66,439.96
TXGCGAS 15	4-10	67	100	69.98	1,330	542	1217	496	85,165.84
TXGCGAS 16	4-10	100	133	95.90	963	480	881	439	84,486.31
TXGCGAS 17	4-10	134	167	124.85	853	436	783	399	97,754.72
TXGCGAS 18	4-10	167	200	155.43	721	351	660	321	102,586.06
TXGCGAS 19	4-10	200	333	217.77	1,837	692	1681	633	366,067.63
TXGCGAS 20	4-10	334	667	387.37	1,998	656	1829	601	708,494.06
TXGCGAS 21	4-10	667	1,667	804.99	1,558	492	1426	450	1,147,911.69
TXGCGAS 22	4-10	1,667	0.00	2,232.76	539	191	493	175	1,100,751.34
TXGCGAS 23	10+	0.0	20	6.73	206	149	189	137	1,271.77
TXGCGAS 24	10+	20	33	19.69	145	98	133	90	2,619.00
TXGCGAS 25	10+	34	67	40.21	381	225	351	206	14,114.56
TXGCGAS 26	10+	67	100	71.14	336	187	308	171	21,912.31

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

					Gruy		Revised 1993		
State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)
TXGCGAS 27	10+	100	133	99.40	325	159	297	145	29,522.10
TXGCGAS 28	10+	134	167	131.87	292	160	267	146	35,208.28
TXGCGAS 29	10+	167	200	159.80	243	130	222	119	35,476.27
TXGCGAS 30	10+	200	333	228.37	696	282	637	258	145,470.97
TXGCGAS 31	10+	334	667	411.79	884	291	809	266	333,137.29
TXGCGAS 32	10+	667	1,667	868.09	828	280	758	256	658,014.31
TXGCGAS 33	10+	1,667	0.00	3,066.41	514	170	470	155	1,441,213.61
Texas-North									
TXNGAS 1	0-4	0.0	20	8.21	4,337	596	4133	568	33,929.83
TXNGAS 2	0-4	20	33	24.27	1,512	342	1441	326	34,969.22
TXNGAS 3	0-4	34	67	44.49	1,776	351	1692	334	75,284.47
TXNGAS 4	0-4	67	100	78.28	951	179	906	171	70,917.48
TXNGAS 5	0-4	100	133	110.26	500	84	476	80	52,484.52
TXNGAS 6	0-4	134	167	143.11	373	59	355	56	50,804.43
TXNGAS 7	0-4	167	200	175.42	273	39	260	37	45,609.81
TXNGAS 8	0-4	200	333	245.36	613	51	584	49	143,290.86
TXNGAS 9	0-4	334	667	423.04	358	28	341	27	144,255.16
TXNGAS 10	0-4	667	1,667	835.42	78	10	74	9	61,820.90
TXNGAS 11	4-10	0.0	20	9.06	1,779	439	1695	418	15,364.73
TXNGAS 12	4-10	20	33	24.08	1,083	307	1032	293	24,850.20

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
TXNGAS 13	4-10	34	67	44.32	1,689	433	1609	412	71,318.36
TXNGAS 14	4-10	67	100	77.05	937	271	893	258	68,803.79
TXNGAS 15	4-10	100	133	106.43	509	159	485	152	51,618.71
TXNGAS 16	4-10	134	167	136.38	348	140	332	134	45,279.17
TXNGAS 17	4-10	167	200	169.82	270	91	257	87	43,643.84
TXNGAS 18	4-10	200	333	225.90	516	143	492	136	111,143.53
TXNGAS 19	4-10	334	667	389.43	334	102	318	97	123,839.80
TXNGAS 20	4-10	667	1,667	771.45	95	58	91	56	70,201.87
TXNGAS 21	4-10	1,667	0.00	1,765.23	13	11	12	10	21,182.71
TXNGAS 22	10+	0.0	20	8.67	78	43	74	41	641.40
TXNGAS 23	10+	20	33	22.45	55	31	52	29	1,167.45
TXNGAS 24	10+	34	67	40.45	119	43	113	41	4,571.40
TXNGAS 25	10+	67	100	68.77	122	48	116	46	7,976.77
TXNGAS 26	10+	100	133	94.23	74	34	71	33	6,690.47
TXNGAS 27	10+	134	167	127.38	70	29	67	28	8,534.20
TXNGAS 28	10+	167	200	162.23	53	24	51	23	8,273.48
TXNGAS 29	10+	200	333	221.84	168	57	160	54	35,494.03
TXNGAS 30	10+	334	667	410.15	173	52	165	50	67,675.47
TXNGAS 31	10+	667	1,667	883.81	148	43	141	41	124,617.32
TXNGAS 32	10+	1,667	0.00	2,623.55	64	25	63	25	165,283.49

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy		Revised 1993		1993 Total gas production (Mcdf)
					Number of wells	Number of fields	Number of wells	Number of fields	
Texas-West									
TXWGAS 1	0-4	0.0	20	6.75	603	157	619	161	4,180.32
TXWGAS 2	0-4	20	33	23.44	185	71	190	73	4,453.09
TXWGAS 3	0-4	34	67	43.86	300	97	308	100	13,507.96
TXWGAS 4	0-4	67	100	73.62	143	49	147	50	10,822.73
TXWGAS 5	0-4	100	133	101.61	101	36	104	37	10,567.40
TXWGAS 6	0-4	134	167	130.59	60	24	62	25	8,096.34
TXWGAS 7	0-4	167	200	171.70	49	18	50	18	8,585.00
TXWGAS 8	0-4	200	333	223.51	86	28	88	29	19,668.72
TXWGAS 9	0-4	334	667	411.73	75	21	77	22	31,703.06
TXWGAS 10	0-4	667	1,667	788.33	7	7	7	7	5,518.30
TXWGAS 11	0-4	1,667	0.00	171,517.88	2	3	2	3	343,035.77
TXWGAS 12	4-10	0.0	20	9.16	1,239	184	1268	189	11,616.24
TXWGAS 13	4-10	20	33	24.16	635	141	651	145	15,728.74
TXWGAS 14	4-10	34	67	45.12	1,231	181	1263	186	56,983.77
TXWGAS 15	4-10	67	100	78.01	724	129	743	132	57,964.74
TXWGAS 16	4-10	100	133	108.90	455	99	467	102	50,855.48
TXWGAS 17	4-10	134	167	139.86	324	80	332	82	46,434.88
TXWGAS 18	4-10	167	200	170.31	198	60	203	62	34,572.30
TXWGAS 19	4-10	200	333	225.65	442	106	453	109	102,218.12
TXWGAS 20	4-10	334	667	383.79	266	83	273	85	104,773.60

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy		Revised 1993		1993 Total gas production (Mcdf)
					umber of ,ells	Number of fields	Number of wells	Numbe r of field s	
TXWGAS 21	4-10	667	1,667	767.62	103	44	106	45	81,367.42
TXWGAS 22	4-10	1,667	0.00	2,366.38	27	12	28	12	66,258.51
TXWGAS 23	10+	0.0	20	7.65	76	51	78	52	596.49
TXWGAS 24	10+	20	33	23.40	33	25	34	26	795.74
TXWGAS 25	10+	34	67	42.23	73	55	75	57	3,167.50
TXWGAS 26	10+	67	100	69.86	52	35	53	36	3,702.80
TXWGAS 27	10+	100	133	102.26	35	27	36	28	3,681.19
TXWGAS 28	10+	134	167	131.07	41	32	42	33	5,504.90
TXWGAS 29	10+	167	200	161.94	41	32	42	33	6,801.58
TXWGAS 30	10+	200	333	225.42	115	61	118	63	26,599.90
TXWGAS 31	10+	334	667	424.77	178	62	183	64	77,732.54
TXWGAS 32	10+	667	1,667	984.36	254	62	261	64	256,917.51
TXWGAS 33	10+	1,667	0.00	3,705.64	294	51	302	52	1,119,103.18
Utah									
UTGAS 1	0-4	0.0	20	5.74	42	10	57	14	327.39
UTGAS 2	0-4	20	33	18.60	21	8	29	11	539.26
UTGAS 3	0-4	34	67	38.23	26	10	35	13	1,338.03
UTGAS 4	0-4	67	100	64.59	20	7	27	9	1,744.02
UTGAS 5	0-4	100	133	95.18	16	9	22	12	2,093.94
UTGAS 6	0-4	134	167	130.15	11	6	15	8	1,952.23

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
UTGAS 7	0-4	167	200	141.58	5	6	7	8	991.06
UTGAS 8	0-4	200	333	167.92	9	5	12	7	2,015.07
UTGAS 9	0-4	334	667	427.94	3	4	4	5	1,711.78
UTGAS 10	0-4	667	1,667	749.47	2	3	3	5	2,248.40
UTGAS 11	4-10	0.0	20	8.67	38	12	55	16	476.86
UTGAS 12	4-10	20	33	17.72	29	13	39	17	691.20
UTGAS 13	4-10	34	67	37.79	110	18	149	24	5,630.76
UTGAS 14	4-10	67	100	58.23	92	15	125	20	7,278.85
UTGAS 15	4-10	100	133	90.71	79	13	107	18	9,705.62
UTGAS 16	4-10	134	167	114.97	73	15	99	20	11,382.06
UTGAS 17	4-10	167	200	138.45	42	12	57	16	7,891.92
UTGAS 18	4-10	200	333	196.51	86	17	117	23	22,992.13
UTGAS 19	4-10	334	667	341.48	79	17	107	23	36,537.88
UTGAS 20	4-10	667	1,667	644.98	25	10	34	14	21,929.37
UTGAS 21	4-10	1,667	0.00	10,117.78	9	7	12	9	121,413.38
UTGAS 22	10+	20	33	18.20	2	3	3	5	54.60
UTGAS 23	10+	34	67	66.67	1	1	1	1	66.67
UTGAS 24	10+	100	133	127.30	1	1	1	1	127.30
UTGAS 25	10+	200	333	113.83	2	1	3	2	341.50
UTGAS 26	10+	334	667	148.52	4	4	5	5	742.58
UTGAS 27	10+	667	1,667	699.65	2	3	3	5	2,098.95

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
UTGAS 28	10+	1,667	0.00	15,430.77	28	1	36	1	555,507.73
Virginia									
VAGAS 1	0-5	0.0	20	11.28	325	N/A	590		6,657.50
VAGAS 2	0-5	34	67	37.38	286	N/A	519		19,402.37
VAGAS 3	0-5	67	100	100.52	59	N/A	107		10,755.19
VAGAS 4	0-5	134	167	154.88	23	N/A	42		6,504.83
VAGAS 5	0-5	167	200	209.58	12	N/A	22		4,610.71
VAGAS 6	0-5	200	333	286.09	7	N/A	13		3,719.11
VAGAS 7	0-5	334	667	508.35	21	N/A	38		19,317.15
VAGAS 8	0-5	667	1,667	1,331.08	4	N/A	7		9,317.53
VAGAS 9	0-5	1,667	0.00	4,761.80	1	N/A	2		9,523.60
West Virginia									
WVGAS 1	0-4	0.0	20	5.37	29,959	N/A	31645		169,963.19
WVGAS 2	0-4	20	33	23.12	2,875	N/A	3037		70,200.86
WVGAS 3	0-4	34	67	43.66	2,074	N/A	2191		95,648.45
WVGAS 4	0-4	67	100	83.36	645	N/A	681		56,765.80
WVGAS 5	0-4	134	167	146.69	449	N/A	474		69,528.80
WVGAS 6	0-4	200	333	322.51	185	N/A	195		62,888.84
WVGAS 7	0-4	667	1,667	988.16	54	N/A	57		56,324.90

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APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
Wyoming									
WYGAS 1	0-4	0.0	20	6.63	77	43	80	45	530.42
WYGAS 2	0-4	20	33	21.66	30	18	31	19	671.46
WYGAS 3	0-4	34	67	42.31	83	39	86	40	3,638.66
WYGAS 4	0-4	67	100	66.79	36	23	37	24	2,471.26
WYGAS 5	0-4	100	133	85.06	26	22	26	23	2,211.60
WYGAS 6	0-4	134	167	132.51	18	16	19	17	2,517.68
WYGAS 7	0-4	167	200	150.99	19	14	20	15	3,019.75
WYGAS 8	0-4	200	333	218.29	44	30	46	31	10,041.21
WYGAS 9	0-4	334	667	330.86	34	24	35	25	11,580.13
WYGAS 10	0-4	667	1,667	581.26	28	15	30	16	17,437.75
WYGAS 11	0-4	1,667	0.00	5,628.49	10	10	10	10	56,284.90
WYGAS 12	4-10	0.0	20	6.83	74	47	77	49	525.79
WYGAS 13	4-10	20	33	21.31	59	38	61	39	1,299.95
WYGAS 14	4-10	34	67	41.52	178	75	185	78	7,680.51
WYGAS 15	4-10	67	100	66.49	122	59	125	61	8,310.83
WYGAS 16	4-10	100	133	95.48	128	58	133	60	12,699.39
WYGAS 17	4-10	134	167	120.08	96	47	100	49	12,008.44
WYGAS 18	4-10	167	200	160.95	100	43	104	45	16,738.38
WYGAS 19	4-10	200	333	219.44	241	65	250	67	54,858.96
WYGAS 20	4-10	334	667	388.14	268	64	278	66	107,902.03

(continued)

APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

State/wellgroup	Depth Range (Mft)	Range (Mcfd)		Gas rate per well (Mcfd)	Gruy Number of wells	Gruy Number of fields	Revised 1993 Number of wells	Revised 1993 Number of fields	1993 Total gas production (Mcdf)
WYGAS 21	4-10	667	1,667	765.06	209	53	217	55	166,017.94
WYGAS 22	4-10	1,667	0.00	2,124.09	60	22	62	23	131,693.82
WYGAS 23	10+	0.0	20	4.60	51	37	53	38	243.83
WYGAS 24	10+	20	33	13.95	30	25	31	26	432.59
WYGAS 25	10+	34	67	30.37	88	56	91	58	2,763.99
WYGAS 26	10+	67	100	55.20	80	51	83	53	4,581.46
WYGAS 27	10+	100	133	75.65	57	36	59	37	4,463.06
WYGAS 28	10+	134	167	100.22	37	22	38	23	3,808.18
WYGAS 29	10+	167	200	128.87	40	31	42	33	5,412.40
WYGAS 30	10+	200	333	185.36	97	36	101	37	18,721.03
WYGAS 31	10+	334	667	370.15	145	48	150	50	55,521.76
WYGAS 32	10+	667	1,667	721.65	90	41	96	42	69,278.04
WYGAS 33	10+	1,667	0.00	9,085.16	120	33	124	34	1,126,560.05

APPENDIX B: GRUY ENGINEERING CORPORATION'S GAS WELLGROUPS BY STATE (CONTINUED)

				Gruy		Revised 1993		
State/wellgroup	Depth Range (Mft)	Range (Mcfd)	Gas rate per well (Mcfd)	Number of wells	Number of fields	Number of wells	Number of fields	1993 Total gas production (Mcdf)

(continued)

APPENDIX C

DERIVATION AND INTERPRETATION OF SUPPLY FUNCTION PARAMETER β

APPENDIX C
DERIVATION AND INTERPRETATION OF SUPPLY FUNCTION PARAMETER β

The generalized Leontief functional form that is used to project supply relations for each producing field is set out in Equation (4-1), repeated below for clarity:

$$q_j = \gamma_j + \frac{\beta}{2}\left[\frac{1}{r}\right]^{1/2} \tag{4-1}$$

A closer look at the supply specification in Eq. (4-1) requires an interpretation of the β parameter. Although this parameter does not have an intuitively appealing interpretation, it is related to the producing field's supply elasticity for natural gas--a well-known model parameter. An individual field's supply elasticity for natural gas, ξ_j, can be expressed as:

$$\xi_j = \frac{\partial q_j / q_j}{\partial r / r} = \frac{\partial q_j / \partial r}{q_j / r} \tag{C-1a}$$

or

$$\xi_j = \frac{\partial q_j}{\partial r} \cdot \frac{r}{q_j} \tag{C-1b}$$

where $\partial q_j/\partial r$ is the derivative of quantity supplied by the field with respect to wellhead price (r).

To establish the relationship between ξ_j and β we start by taking the derivative of the facility supply function

(Equation [4.1]) with respect to price, and multiply the expression by r/q_j resulting in the following expression for the supply elasticity:

$$\frac{\partial q_j}{\partial r} \cdot \frac{r}{q_j} = \xi_j = -\beta \frac{1}{4q_j} \left[\frac{1}{r}\right]^{1/2} \tag{C-2}$$

Since economic theory dictates that the supply elasticity is positive (i.e., $\xi_j > 0$) and q_j and r are positive, Equation (C-2) above indicates that the parameter β is negative, i.e., $\beta < 0$. Finally, the solution for β from Equation (C-2) reveals the following expression:

$$\beta = -\xi 4q \left[\frac{1}{r}\right]^{-1/2} \tag{C-3}$$

where

ξ = market supply elasticity, and

q = production-weighted average annual level of natural gas production per well.

This approach derives a single β value based on market-level data.

APPENDIX D

NATURAL GAS MARKET MODEL SUMMARY

APPENDIX D
NATURAL GAS MARKET MODEL SUMMARY

This appendix provides a complete list of the exogenous and endogenous variables, as well as the model equations.

D.1 EXOGENOUS VARIABLES

η_i^d	Demand elasticity for natural gas by end-user (i).
ξ^I	Import supply elasticity of foreign natural gas.
β, γ_j	Supply function parameters for natural gas by U.S. producing field (j).
A^I	Import supply function parameter for natural gas (Multiplicative constant).
B_i^d	Demand function parameters for natural gas by end-user (i) (Multiplicative constants).
c_j	Regulatory control costs (per Mcf of output) for producing field (j).

D.2 ENDOGENOUS VARIABLES

r	Wellhead price of natural gas ($/Mcf).
ρ_i	End-user price of natural gas where i represents residential, commercial, industrial, and utility consumers.
$q_j^S \cdot q^I \cdot Q^S$	Domestic (field-level) and foreign supply of natural gas ($q_j^S \cdot q^I$) and market supply of natural gas (Q^S).

$q_i^d \cdot Q^D$ Domestic end-user demand (q_i^d) and market demand for natural gas (Q^D).

D.3 MODEL EQUATIONS

Market Supply of Natural Gas:

$$Q^S = q^I + \sum_j q_j^S \ ,$$

where
$$q^I = A^I \, [r]^{\xi^I}$$

and

$$\sum_j q_j^S = \sum_j \left\{ Y_j + \frac{\beta}{2} \left[\frac{1}{r}\right]^{1/2} \right\} \text{without regulation}$$

or

$$\sum_j q_j^S = \sum_j \left\{ Y_j + \frac{\beta}{2} \left[\frac{1}{r - c_j}\right]^{1/2} \right\} \text{with regulation}$$

Market Demand of Natural Gas:

$$Q^D = \sum_i q_i^d \ ,$$

where
$$q_i^d = B_i^d \, [p_i]^{\eta_i^d}.$$

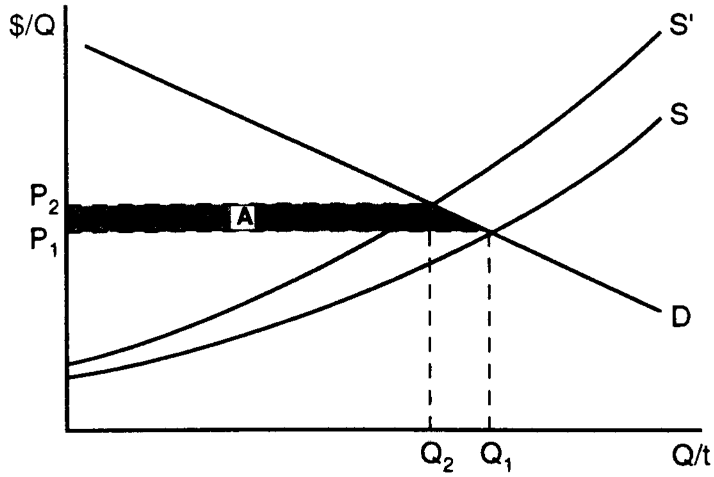
APPENDIX E

APPROACH TO ESTIMATING ECONOMIC WELFARE IMPACTS

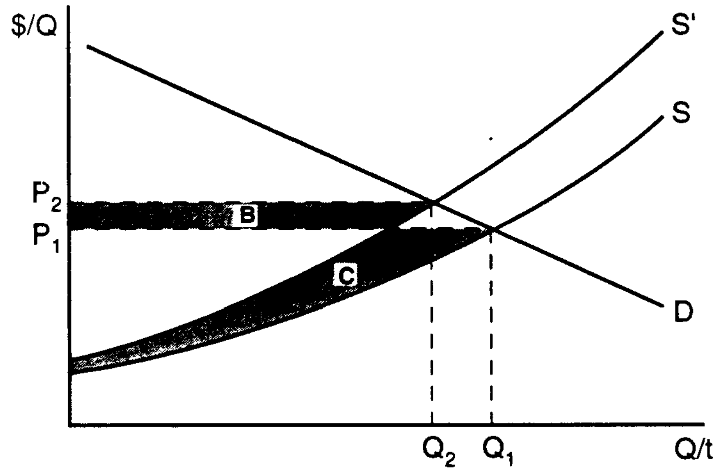
APPENDIX E
APPROACH TO ESTIMATING ECONOMIC WELFARE IMPACTS

The economic welfare implications of the market price and output changes of natural gas with the regulations can be examined using two slightly different tactics, each giving a somewhat different insight but the same implications: (1) changes in the net benefits of consumers and producers based on the price changes, and (2) changes in the total benefits and costs of natural gas based on the quantity changes. For this analysis, we focus on the first measure--the changes in the net benefits of consumers and producers. Figure E-1 depicts the change in economic welfare by first measuring the change in consumer surplus and then the change in producer surplus. In essence the demand and supply curves previously used as predictive devices are now being used as a valuation tool.

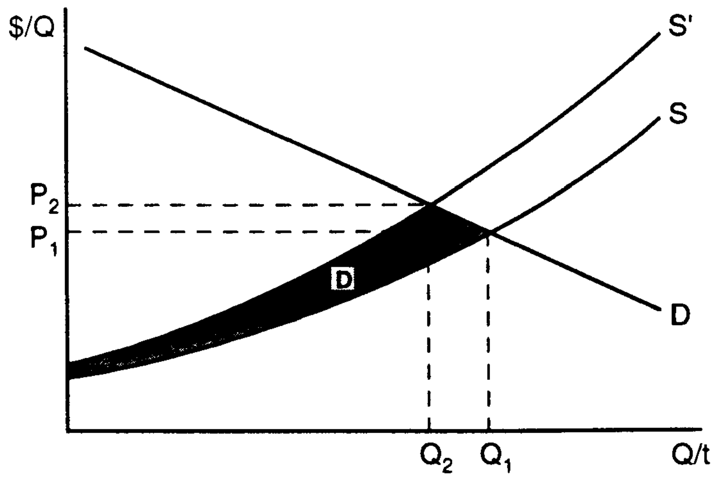
This method of estimating the change in economic welfare with the regulations decomposes society into consumers and producers. In a market environment, consumers and producers of the good or service derive welfare from a market transaction. The difference between the maximum price consumers are willing to pay for a good and the price they actually pay is referred to as consumer surplus. Consumer surplus is measured as the area under the demand curve and above the price of the product. Similarly, the difference between the minimum price producers are willing to accept for a good and the price they actually receive is referred to as producer surplus. Producer surplus is measured as the area above the supply curve to the price of the product. These areas may be thought of as consumers' net benefits of



(a) Change in Consumer Surplus with Regulation



(b) Change in Producer Surplus with Regulation



(c) Net Change in Economic Welfare with Regulation

Figure E-1. Economic welfare changes with regulation: consumer and producer surplus.

consumption and producers' net benefits of production respectively.

In Figure E-1, baseline equilibrium occurs at the intersection of the natural gas demand curve, D, and supply curve, S. Price is P_1 with quantity Q_1. The increase cost of production with the regulations will cause the market supply curve to shift upward to S'. The new equilibrium price of paper is P_1. With a higher price for natural gas there is less consumer welfare, all else being unchanged. In Figure E-1(a), area A represents the dollar value of the annual net loss in consumers' benefits with the increased price of natural gas. The rectangular portion represents the loss in consumer surplus on the quantity still consumed, Q_2, while the triangular area represents the foregone surplus resulting from the reduced amount of natural gas consumed, Q_1-Q_2.

In addition to the changes in consumer welfare, there are also changes in producers welfare with the regulations. With the increase in natural gas price producers receive higher revenues on the quantity still purchased, Q_2. In Figure E-1(b), area B represents the increase in revenues due to this increase in price. The difference in the area under the supply curve up to the original market price, area C, measures the loss in producers' surplus, which includes the loss associated with the quantity no longer produced. The net change in producers' welfare is represented by area B-C.

The change in economic welfare attributable to the compliance costs of the regulations is the sum of consumer and producer surplus changes, that is, - (A) + (B-C). Figure E-1(c) shows the net (negative) change in economic welfare associated with the regulations as area D. However, this analysis does not include the benefits that occur outside the natural gas market--the value of the reduced levels of air pollution with the regulations. Inclusion of this benefit may reduce the net cost of the regulations or even make them positive, that is, total benefits, private market benefits as estimated above plus the benefits in the quality of the environment, may exceed total costs.

APPENDIX F

DATA SUMMARY OF
COMPANIES INCLUDED IN
FIRM-LEVEL ANALYSIS: 1993

TABLE F-1. DATA SUMMARY OF COMPANIES INCLUDED IN FIRM-LEVEL ANALYSIS: 1993

Comp. ID	Company Name	SIC Code	Employment (#)	Sales ($000/yr)	Assets ($000)	Net Income ($000/yr)	Total Liquid Production (Bcf)	Total Natural Gas Production (Bcf)
1	Adams Resources & Energy Inc.	1311	291	695,445	50,295	1,452	0.54	0.885
2	Alamco, Inc.	1311	87	11,900	43,261	1,552	0.37	3.197
3	Alexander Energy Corp.	1311	46	14,207	54,158	1,245	2.02	3.692
4	Alfa Resources Corp.	1311	11	1,354	1,261	5	0.6	0.011
5	Alleghany & Western Energy Corp.	4924	565	185,534	195,680	3,746	0.05	1.518
6	Alta Energy Corp.	1311	31	16,926	58,467	(3,750)	4.92	1.665
7	Amber Resources Co.	1311	2	469	3,604	(10)	0.02	0.232
8	Amerada Hess Corp.	2911	10,100	5,872,741	8,641,546	(268,203)	260	183.000
9	American Exploration Co.	1311	297	59,088	185,598	(19,186)	11.89	11.790
10	American Natural Energy Corp.	1311	121	8,425	21,169	704	0.81	2.640
11	Amoco Corp.	2911	46,994	28,617,000	28,486,000	1,820,000	1000	867.000
12	Apache Corp.	1311	884	466,638	1,592,407	37,334	121	109.300
13	ARCO	2911	26,800	19,183,000	23,894,000	269,000	2210	332.000
14	Ashland Oil Inc.	2911	31,800	10,283,325	5,551,817	142,234	4	36.200
15	Barrett Resources Corp.	1311	60	42,686	90,740	5,756	0.75	7.214
16	Basic Earth Science Systems Inc.	1382	13	1,653	2,745	(23)	0.77	0.126
17	Basin Expl. Inc.	1311	123	37,968	131,520	5,150	8.44	13.330

(continued)

TABLE F-1. DATA SUMMARY OF COMPANIES INCLUDED IN FIRM-LEVEL ANALYSIS: 1993 (CONTINUED)

Comp. ID	Company Name	SIC Code	Employment (#)	Sales ($000/yr)	Assets ($000)	Net Income ($000/yr)	Total Liquid Production (Bcf)	Total Natural Gas Production (Bcf)
18	Belden & Blake Corp.	1311	292	77,718	135,174	3,220	4.53	7.373
19	Bellwether Exploration Co.	1311	6	3,655	12,480	41	0.49	0.483
20	Berry Petroleum Co.	1311	125	67,761	135,159	32	36.17	0.771
21	Black Dome Energy Corp.	1311	3	678	1,040	62	0.03	0.286
22	Black Hills Corp.	1311	449	139,373	352,853	22,946	3.27	0.777
23	Box Energy Corp.	1311	57	37,102	128,882	2,161	8.04	3.912
24	Western Gas Resources	4923	825	932,338	1,114,748	38,102	1.07	15.850
25	Louis Dreyfus Natural Gas Corp.	1311	556	95,181	481,488	2,260	21.06	30.540
26	Callon Consolidated Partners LP	1311	126	8,805	19,349	165	2.64	6.847
27	Castle Energy Corp.	1311	402	601,000	392,738	67,837	0.45	3.472
28	Chevron Corp.	2911	49,245	37,082,000	34,736,000	1,265,000	1440	751.000
29	Cliffs Drilling Co.	1381	352	66,396	133,523	3,626	0.44	1.651
30	Coastal Corp.	1311	16,570	10,136,100	10,277,100	115,800	49.4	122.000
31	Columbia Gas System	1311	10,172	3,398,500	6,957,900	152,200	36.03	71.500
32	Columbus Energy Corp.	1382	36	12,913	22,938	3,806	2.93	1.693
33	Comstock Resources Inc.	1311	27	22,453	74,095	2,324	2.78	7.274
34	Conoco Inc.	2911	25,782	15,771,000	11,938,000	812,000	400	305.000

(continued)

TABLE F-1. DATA SUMMARY OF COMPANIES INCLUDED IN FIRM-LEVEL ANALYSIS: 1993 (CONTINUED)

Comp. ID	Company Name	SIC Code	Employment (#)	Sales ($000/yr)	Assets ($000)	Net Income ($000/yr)	Total Liquid Production (Bcf)	Total Natural Gas Production (Bcf)
35	Consolidated Natural Gas Co.	4923	7,615	3,194,616	5,409,586	205,916	39.07	124.000
36	Crystal Oil Company	1311	92	35,940	117,334	1,040	11.06	7.551
37	Delta Natural Gas Co. Inc.	4923	177	31,221	55,130	2,621	0	0.270
38	Eagle Exploration Co.	1311	2	355	1,336	120	0.03	0.009
39	Edisto Resources Corp.	4923	192	175,069	168,243	5,600	3.53	11.160
40	Energy Development Corp.	1311	235	281,066	679,437	46,341	26.1	95.000
41	Enron Corp.	1382	7,780	8,003,939	11,504,315	332,522	25.2	240.000
42	Ensearch Corp.	1311	10,400	1,902,299	2,760,261	59,237	24.81	70.030
43	Equitable Resources Inc.	4923	2,454	1,094,794	1,946,907	73,455	21.12	53.550
44	Espero Energy Corp.	1311	8	6,050	9,383	116	1.26	1.891
45	Exxon Corp.	2911	95,000	111,211,000	84,145,000	5,280,000	2020	697.000
46	Forest Oil Corp.	1311	183	105,148	426,755	(21,213)	14.93	41.110
47	Great Northern Gas Co.	1311	4	667	1,469	177	0	0.384
48	Hallwood Energy Prtnr LP	1311	200	49,613	171,624	13,064	8.81	14.070
49	KN Energy Inc.	4923	1,600	493,349	731,269	24,275	1.51	5.100
50	Lomak Petroleum Inc.	1311	150	19,075	76,333	1,391	3.18	2.590
51	Louisiana Land & Exploration	1382	709	815,400	1,838,700	9,600	88	65.600

(continued)

TABLE F-1. DATA SUMMARY OF COMPANIES INCLUDED IN FIRM-LEVEL ANALYSIS: 1993 (CONTINUED)

Comp. ID	Company Name	SIC Code	Employment (#)	Sales ($000/yr)	Assets ($000)	Net Income ($000/yr)	Total Liquid Production (Bcf)	Total Natural Gas Production (Bcf)
52	Maxus Energy Corp.	1311	2,190	807,000	1,987,400	(49,400)	46	76.000
53	Meridian Oil Inc.	1311	1,700	1,246,502	4,375,165	303,138	153.1	336.000
54	Mesa Inc.	1311	382	232,908	1,533,382	(102,448)	57.88	79.820
55	Mitchell Energy & Development Corp.	1311	2,900	952,809	2,415,476	19,687	203	74.400
56	Mobil Corp.	2911	63,700	63,975,000	40,585,000	2,084,000	1110	558.000
57	Noble Affiliates Inc.	1311	503	286,583	1,067,996	12,625	60.64	71.310
58	Nuevo Energy Co.	1382	630	107,832	287,591	8,933	19.33	16.770
59	Occidental Petroleum Corp.	1311	23,600	8,544,000	17,123,000	283,000	210	219.000
60	ONEOK Inc.	4923	2,208	789,777	1,104,468	38,424	4.43	8.401
61	Oryx Energy Co.	1382	1,600	1,054,000	3,624,000	(100,000)	240	191.000
62	Pennzoil Co.	2911	9,901	2,782,397	4,886,203	141,856	240	220.000
63	Phillips Petroleum Co.	1311	21,400	12,545,000	10,868,000	243,000	470	345.000
64	Plains Petroleum Co.	1311	106	64,280	126,792	1,727	12.2	23.760
65	Pogo Producing Co.	1311	100	139,568	239,774	25,061	42.2	32.320
66	Presidio Oil CLA	1382	137	48,267	280,420	(7,233)	14.36	15.340
67	Questar Corp.	1311	2,659	664,062	1,417,687	81,692	20.56	67.810
68	Sage Energy Co.	1311	105	43,399	49,632	6,735	15.18	6.305
69	Samson Energy Co. LP	1311	176	22,374	41,805	4,329	2.51	7.641
70	Sante Fe Energy Resources	1311	839	446,000	1,076,900	(77,100)	219	60.300
71	Shell Oil Co.	2911	28,893	21,092,000	26,851,000	781,000	1470	539.000
72	Snyder Oil Corp.	1311	289	229,685	479,536	25,664	34.51	35.080

(continued)

TABLE F-1. DATA SUMMARY OF COMPANIES INCLUDED IN FIRM-LEVEL ANALYSIS: 1993 (CONTINUED)

Comp. ID	Company Name	SIC Code	Employment (#)	Sales ($000/yr)	Assets ($000)	Net Income ($000/yr)	Total Liquid Production (Bcf)	Total Natural Gas Production (Bcf)
73	Sonat Inc.	4923	5,300	1,966,664	3,213,997	261,240	37.44	146.100
74	Sooner Energy Corp.	1311	2	392	352	219	0.02	0.077
75	Texaco Inc.	2911	38,000	34,071,000	26,626,000	1,068,000	1550	652.000
76	Tide West Oil Co.	1311	34	96,302	106,606	4,030	0.58	2.317
77	Unocal Corp.	2911	14,687	8,344,000	9,254,000	213,000	480	365.000
78	USX-Marathon Group	2911	44,872	11,962,000	10,806,000	(29,000)	410	193.000
79	Wainoco Oil Corp.	2911	434	366,556	296,811	2,504	7.47	2.504
80	Wolverine Exploration Co.	1311	4	7,061	10,763	4,953	1.12	1.467

TECHNICAL REPORT DATA

(Please read Instructions on reverse before completing)

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16 ABSTRACT

This report evaluates the impacts of the final rule for controls of hazardous air pollutants (HAPs) in the Oil and Natural Gas Production industry and the Natural Gas Transmission and Storage industry. Total social costs are estimated by evaluating costs of compliance with the rule and associated market impacts, including: price changes in the natural gas market, adjustments in quantity produced, small entity impacts, and employment impacts.

17 KEY WORDS AND DOCUMENT ANALYSIS

a DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c COSATI Field/Group
economic impacts small entity impacts social cost	Air Pollution control Economic Impact Analysis Regulatory Flexibility Analysis	

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