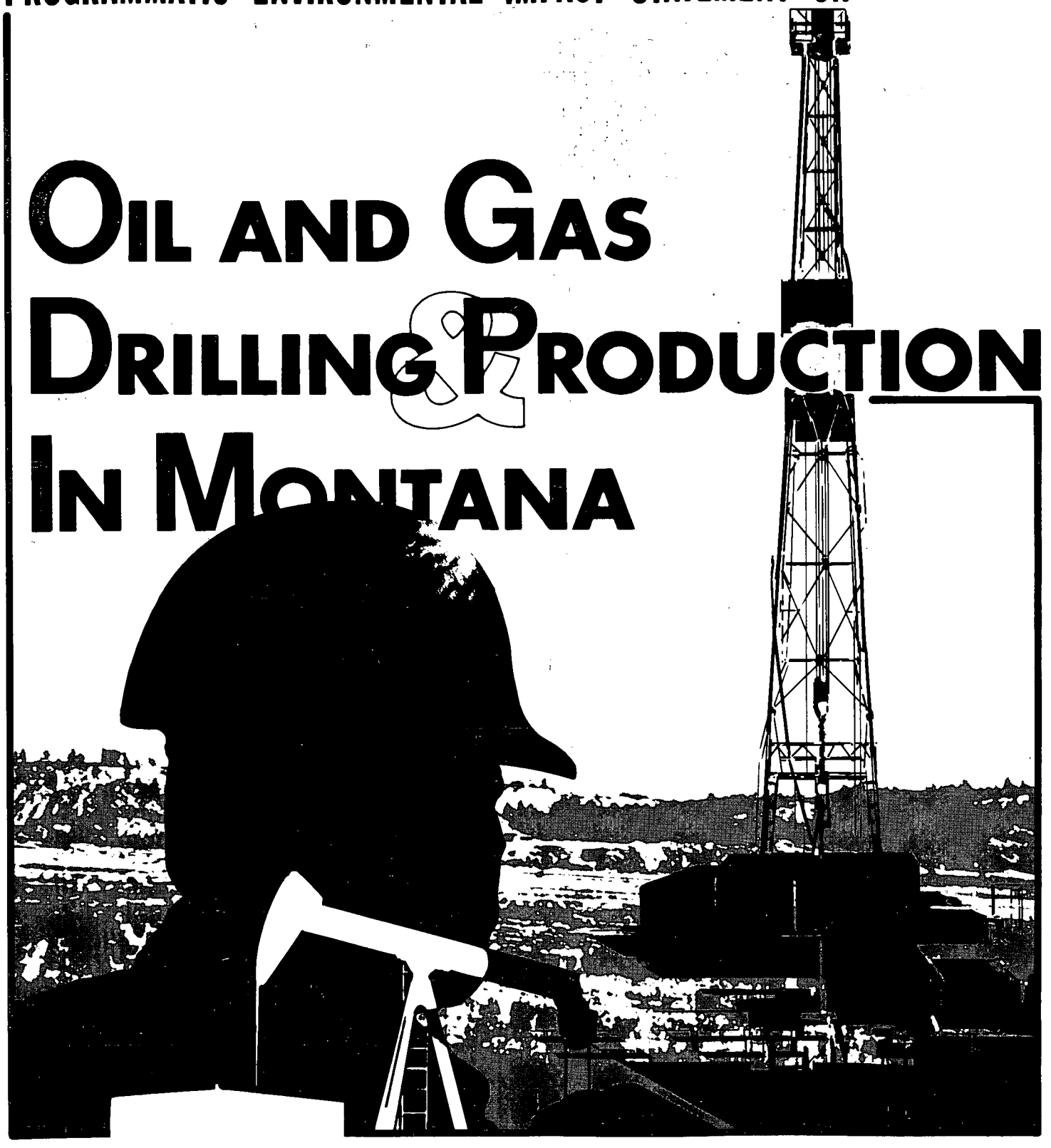
PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT ON

OIL AND GAS DRILLING & PRODUCTION IN MONTANA



Draft EIS

January 1989

Board of Oil and Gas Conservation

DRAFT PROGRAMMATIC ENVIRONMENTAL

IMPACT STATEMENT

OIL AND GAS DRILLING AND PRODUCTION IN MONTANA

prepared for the

BOARD OF OIL AND GAS CONSERVATION

Pursuant to Senate Bill 184
with assistance from

Office of the Governor
Department of Health and Environmental Sciences
Department of Fish, Wildlife and Parks
Department of State Lands
Department of Natural Resources and Conservation

January 1989

PREFACE

The Montana Environmental Policy Act (MEPA) requires state boards and agencies to consider to the fullest extent possible the environmental consequences of their actions. In doing so, agencies are encouraged to apply both the natural and social sciences and to identify how their programs or projects may be conducted to minimize environmental consequences. Typically, agencies provide written documentation of their environmental reviews.

The Board of Oil and Gas Conservation (Board) has among its several responsibilities the requirement that it approve applications to drill oil and gas wells. This Environmental Impact Statement (EIS) was written to assist the Board in complying with MEPA when it processes such applications. It provides a reference as to what are the potential impacts when drilling in the various regions of Montana, and suggests ways that such impacts can be either minimized or prevented. The EIS places no new statutory or rule making responsibilities on the Board, but does suggest that the Board may want to consider initiating rule making, revising its staffing responsibilities, and working more closely with other government agencies.

The goal in preparing this document was to provide a quick and efficient method for the Board to follow in integrating MEPA into its decision making. The analysis shows that for the vast majority of wells, the only document necessary to show compliance with MEPA is a brief checklist prepared by the Board's staff. To facilitate the completion of this checklist, the EIS suggests which types of supplemental information should be supplied by the applicant.

Senate Bill 184 mandated preparation of this programmatic statement for the Board and charged the Office of the Governor with responsibility for overseeing the preparation. This draft EIS was prepared during the term of Governor Ted Schwinden. The Board will be responsible for conducting hearings on the draft EIS. With the change of administration in January 1989, the Office of Governor Stan Stephens inherits responsibility under Senate Bill 184 for assisting the Board in preparation of the final EIS. Under provisions of Senate Bill 184, the two-year exemption from the requirements of MEPA ends on June 30, 1989. At that time, the Board is required to have in place a process for evaluating individual drill permits under MEPA.

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CHAPTER ONE
INTRODUCTION

BACKGROUND OF THE PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT

This Programmatic Environmental Impact Statement on oil and gas drilling and production has been prepared by the Office of the Governor according to the requirements of Senate Bill 184 as passed by the 1987 Montana Legislature. The legislation temporarily exempts the Board of Oil and Gas Conservation (Board) from the requirements of the Montana Environmental Policy Act (MEPA) when issuing permits to drill for oil or gas. The exemption will remain in effect until the Board adopts a version of this document for use in issuing future drilling permits, or until June 30, 1989.

MEPA requires all agencies of the state to recognize and consider to the fullest extent possible the consequences that their actions may have on the quality of the human environment (75-20-201, MCA). Over the past several years the question of how to integrate MEPA requirements with regulation of the oil and gas industry has been a subject of controversy and uncertainty. Senate Bill 184 reflects a consensus view reached by the 1987 Legislature, with the support of the administration, that the uncertainty should be resolved. Senate Bill 184 specifies that the Programmatic Environmental Statement must include the following information:

> (i) such environmental impacts as may be found to be associated with the drilling for and production of oil and gas in the major producing basins and ecosystems in Montana;
>
> (ii) a record of information and analysis for the board of oil and gas conservation to rely upon in responding to public and private concerns about drilling and production;
>
> (iii) such methods of accomplishing drilling and production of oil and gas as may be found to be necessary to avoid permanent impairment of the environment or to mitigate long-term impacts so that the environmental and renewable resources of the ecosystem may either be returned to conditions similar to those existing before drilling or production occurs or conditions that reflect a natural progression of environmental change;
>
> (iv) the process that will be employed by the board of oil and gas conservation to evaluate such environmental impacts of individual drilling proposals as may be found to exist;
>
> (v) an appropriate method for incorporating such environmental review as may be found to be necessary into the board's rule and drill permitting process and for accomplishing the review in an expedient manner; and
>
> (vi) the maximum time periods that will be required to complete the drill permitting process, including environmental review.

Section 75-1-201, MCA of MEPA provides general directions to state agencies regarding how the policies, regulations, and laws of the state shall be interpreted and administered in accordance with stated policies. All agencies of the state are, to the fullest extent possible, directed to:

> (i) utilize a systematic, interdisciplinary approach which will insure the integrated use of the natural and social sciences and the environmental design arts in planning and in decision making which may have an impact on man's environment; and
>
> (ii) identify and develop methods and procedures which will insure that presently unquantified environmental amenities and values may be given appropriate consideration in decision making along with economic and technical considerations.

State agencies also must prepare an environmental impact statement for major actions of state government significantly affecting the quality of the human environment. The rules that implement MEPA contain the primary guidance that state agencies use to interpret and administer this section of the law. The MEPA rules define the "human environment" as including biological, physical, social, economic, cultural, and aesthetic values. The rules also define a type of document known as a "preliminary environmental review" (PER)--in new rules being adopted by the Administration, this document would be known as an "environmental assessment" (EA)--which agencies prepare in order to make an initial determination about whether a proposed action would be a major action of state government significantly affecting the quality of the human environment

(75-1-201, MCA). If significant impacts appear reasonably likely to occur, an "environmental impact statement" (EIS) is necessary. If the PER (or EA) indicates that a proposed action would not have significant impacts, no further analysis is required by MEPA and the agency may proceed with the proposed action. There is no specified length or level of detail that a PER (or EA) must contain, but they normally are brief documents that many agencies of state government prepare in the form of short checklists. The checklists include items representing the full range of resources and values that are part of the human environment.

A "programmatic review" is a MEPA document that the rules define as a "general analysis of related agency-initiated actions, programs or policies, or the continuance of a broad policy or program" that may "in part or in total...constitute a major state action significantly affecting the quality of the human environment." Programmatic reviews must discuss the impacts associated with the agency action or program, alternative ways of conducting the action, and the cumulative environmental effects of the alternatives. A particular purpose of this document is to identify how the Board can incorporate environmental review into its drill permitting process while allowing the expedient review of individual drilling permit applications.

PURPOSE AND SCOPE OF THE PROGRAMMATIC STATEMENT

This document has been prepared by an interagency technical committee composed of personnel from state and federal agencies that have (1) regulatory responsibility for activities associated with oil and gas development or (2) expertise concerning aspects of the human environment that may be affected. The Governor also appointed a special nine-member group known as the Oil and Gas Drilling Advisory Council to provide policy guidance. Figure 1 shows the organization and membership of the advisory council and technical committee.

The various phases of oil and gas exploration and development are illustrated in Figure 2. In chronological order, the oil and gas development process may be broadly categorized as including leasing, seismic and other forms of geophysical testing, drilling, production (including well completion, primary field development, and secondary and tertiary recovery techniques) and abandonment.

Senate Bill 184 is directed toward the Board's primary areas of regulatory responsibility: oil and gas drilling and production. The analysis of environmental impacts and mitigation methods in later chapters is therefore focused on these phases of development. Well and field abandonment methods are included because they also are regulated by the Board and because the methods used to abandon a well site or field are of major importance in avoiding long term impacts or permanent impairment of the environment.

Leasing and seismic exploration are not treated in detail here because they are outside the scope of Senate Bill 184. Leasing is not addressed except for the general description of oil and gas development activities because it is clearly not within the scope of the Board's regulatory authority and therefore, for purposes of MEPA-related analysis, is not part of any "action" the Board takes. Discussion of seismic exploration is limited for similar reasons. The counties rather than the Board are responsible for issuing seismic permits. The Board has responsibility for shot-hole plugging and abandonment, and has rules governing these activities, but seismic activity is not part of either drilling or production activities as specified in Senate Bill 184.

The 1987 Montana Legislature passed a bill directing the Board to adopt rules necessary for the state to take over responsibility for underground injection control (UIC). This regulatory program currently is administered by the U.S. Environmental Protection Agency (EPA) under the authority of the Safe Drinking Water Act. The main purpose of the program is to protect underground drinking water supplies from being contaminated by injected fluids. Sources of such fluids are generally associated with oil and gas production where there is reinjection of brackish wastewater and brines that have been brought to the surface with oil and gas. Reinjection is done both for disposal purposes and for enhanced recovery of oil and gas. The Board will assume control over the UIC program after EPA approves a detailed state implementation plan. Board discretion under this program will be limited by the agreed-upon procedures to be described in the plan.

FIGURE 1

ORGANIZATION FOR PREPARATION OF THE PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT

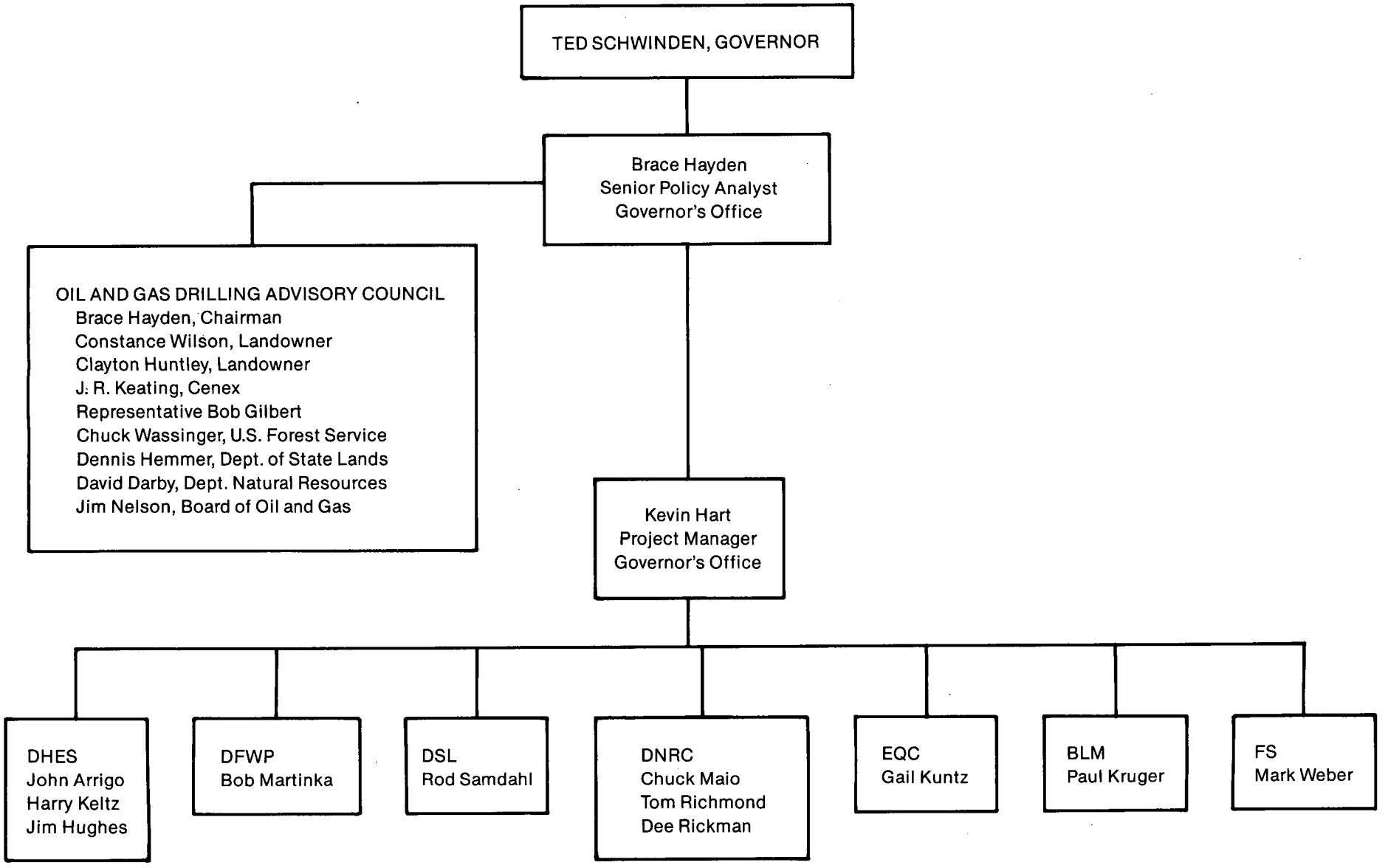
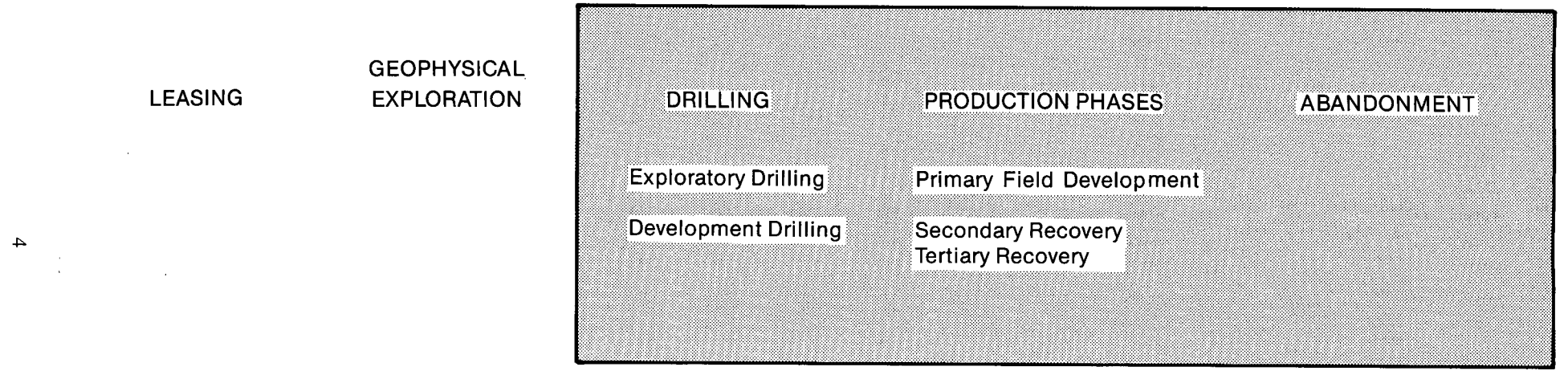


FIGURE 2
SCOPE OF THE PROGRAMMATIC IMPACT STATEMENT



STATISTICAL REVIEW OF DRILLING AND PRODUCTION IN MONTANA

Natural gas was discovered in the state in 1915 and the first oil well began production one year later in 1916. Since that time, through 1986, some 28,000 drilling projects have been completed in the state, resulting in over 6,800 wells now producing. Test wells have been drilled in 52 of Montana's 56 counties with 32 of those counties currently receiving income from production of oil or gas. Montana ranks as the 14th largest oil producer and 20th largest natural gas producer among the 50 states. Figures 3 and 4 show the levels of oil and gas production in Montana. The deepest test well to date was drilled in 1984 near Kalispell and reached 17,774 feet below the surface (Bryant 1985). The amount of drilling activity in Montana has varied with the price of oil and gas. Figure 5 shows drilling activity each year since 1975. From 1983 through 1987, an average of 545 drilling projects were completed annually. During 1981, a peak year of activity in Montana, 1,149 drilling permits were issued by the Board.

Montana contains 93.3 million acres of surface land. The federal government owns 27.6 percent of the total surface, and nearly 55 percent of the western half of the state. State government owns 6 percent of the total land, leaving approximately two-thirds of Montana in private ownership. At the close of 1986, approximately 47 percent of Montana was under lease for oil and gas (Montana Petroleum Association 1987). According to the Montana Petroleum Association (1987) figures, a small percentage of this area, about 3 percent, has actually been explored through drilling. Figure 6 shows the general location of oil and gas fields in the producing regions of Montana.

TAXES

Five categories of state taxes pertain to oil and gas operations.

Personal Property Tax. An annual county tax on physical equipment, the description and book value of which are furnished to the assessor of the county in which the property is located for classification and evaluation. The tax, based on current mill levy, is payable within 30 days of receipt of the tax notice.

Net Proceeds Tax. A property tax levied by counties on the net profits received by operators and royalties paid to private individuals from wells extracting oil or gas owned by nongovernmental entities. The tax is based on a mill levy or a percent of sales calculated by deducting operating expenses from profits earned. The tax is collected by the county where the oil or gas was produced.

Conservation Tax. The state conservation tax is assessed on gross oil and gas sales revenues and charged to all working interest and royalty owners except government royalties.

Severance Tax. The state severance tax is based on gross sales revenues. It is charged to all working interest owners and royalty owners except where government owns the royalties.

Resource Indemnity Trust Tax. A state tax based on sales revenues, chargeable to all working interest owners and royalty owners including government royalties. This tax is held in a trust and the interest is used to repair or correct environmental damage caused by past mineral extraction where no liable party can be held responsible for the clean up.

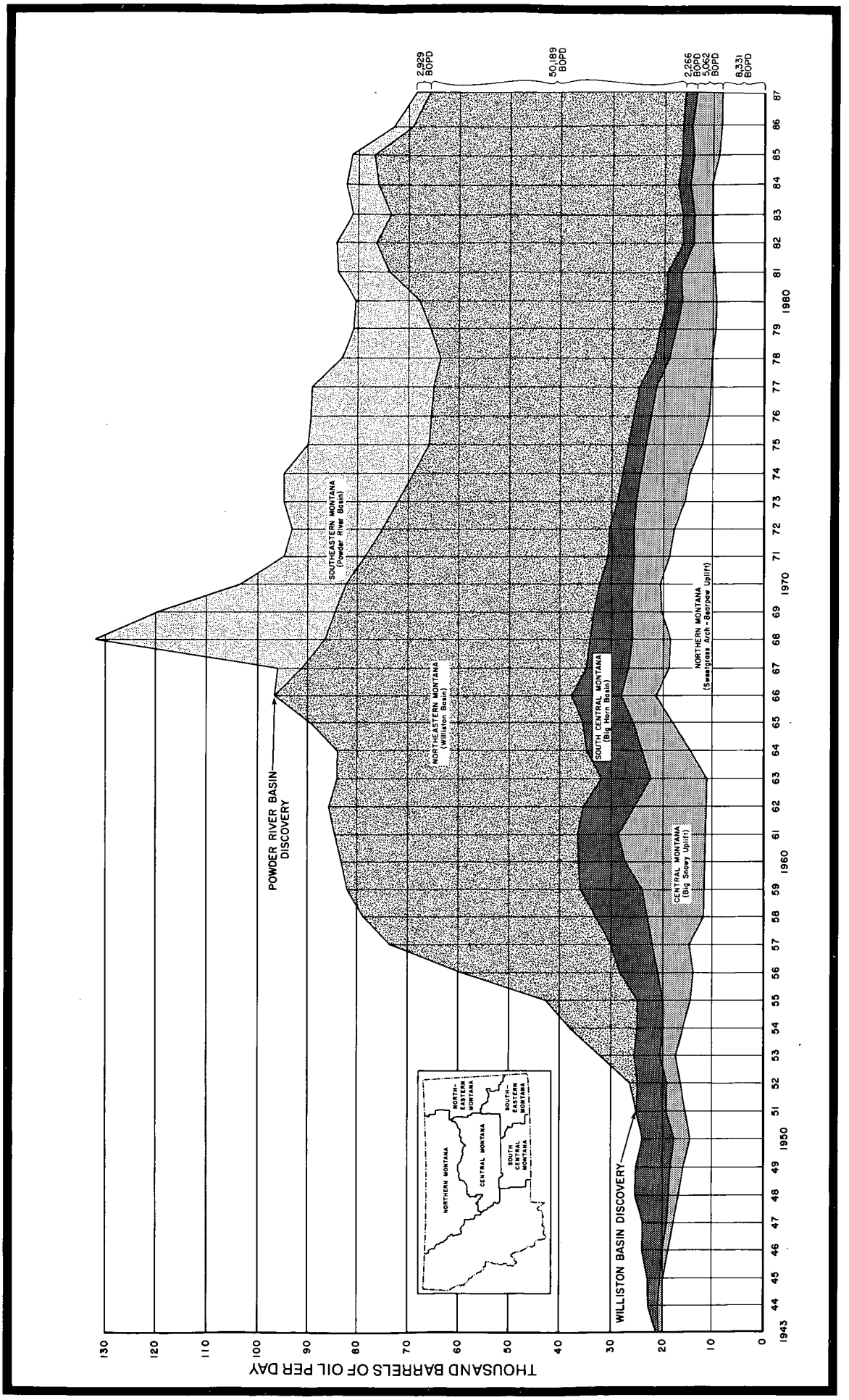
Cumulative value of the four taxes on production, excluding the property tax, totals 12.7 percent of the oil revenue and 15.35 percent of the gas revenue. Collections from the Net Proceeds Tax and Severance Tax during 1986 totaled $125,323,422. In the same year, state government received $13.6 million in royalty income while the federal government collected royalty income of $6.6 million.

BOARD OF OIL AND GAS CONSERVATION

ORGANIZATION AND COMPOSITION

The Board is a seven member, independent, quasi-judicial body that relies on the Department of Natural Resources and Conservation (DNRC) for administrative support. The Governor appoints a majority of the members at the beginning of his term and appoints the remaining members in the middle of his term. All members must be confirmed by the Senate. Once appointed, members can be removed by the Governor only for cause. Membership of the Board must, by law, include three representatives from the oil and gas industry, each of whom must possess at least three

FIGURE 3
MONTANA CRUDE OIL PRODUCTION FOR YEARS 1943 TO 1987

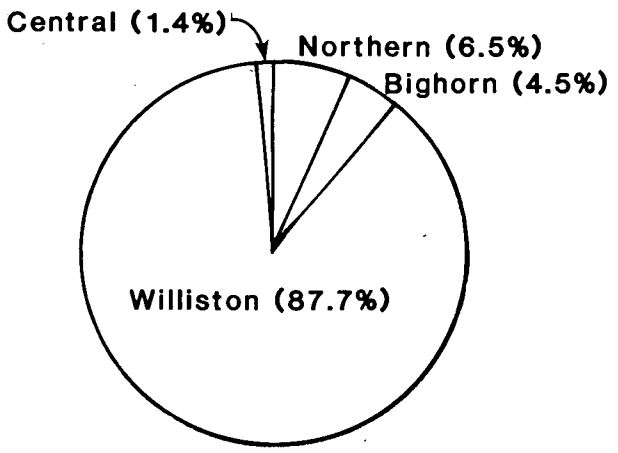


SOURCE: DNRC, 1987

FIGURE 4
MONTANA NATURAL GAS PRODUCTION FOR 1987

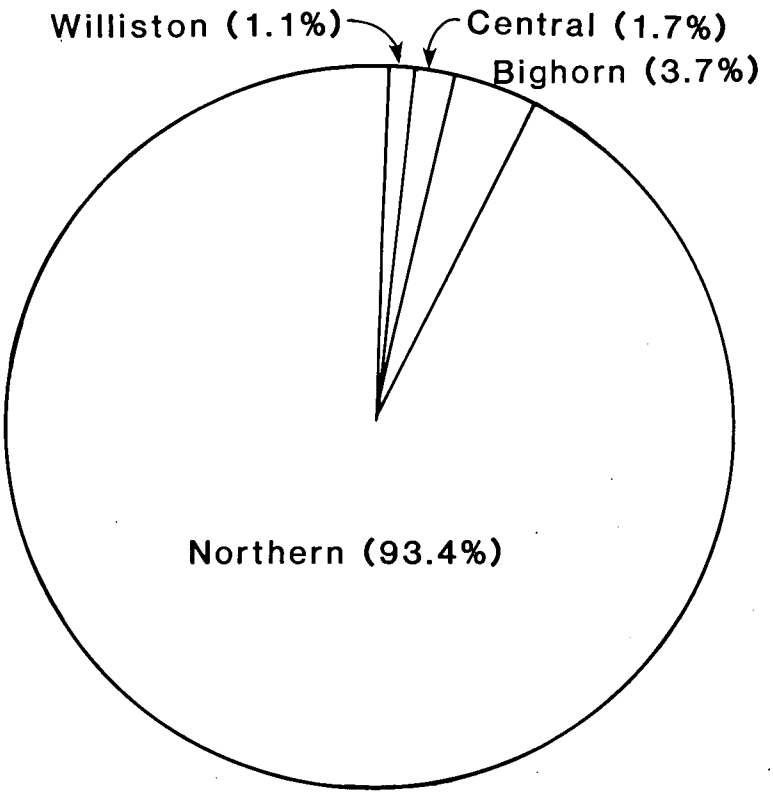
GAS PRODUCED WITH OIL FROM OIL WELLS

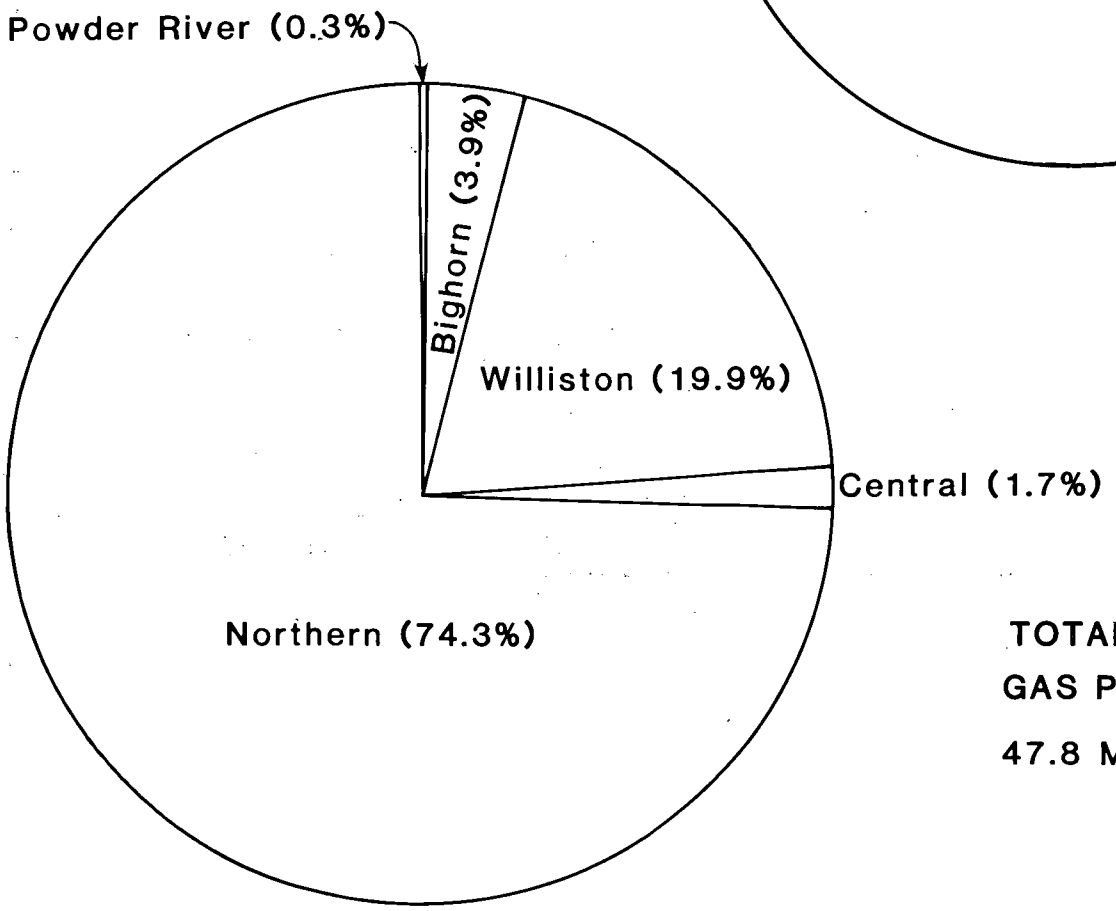
10.4 MILLION MCF



GAS PRODUCED FROM GAS WELLS

37.5 MILLION MCF





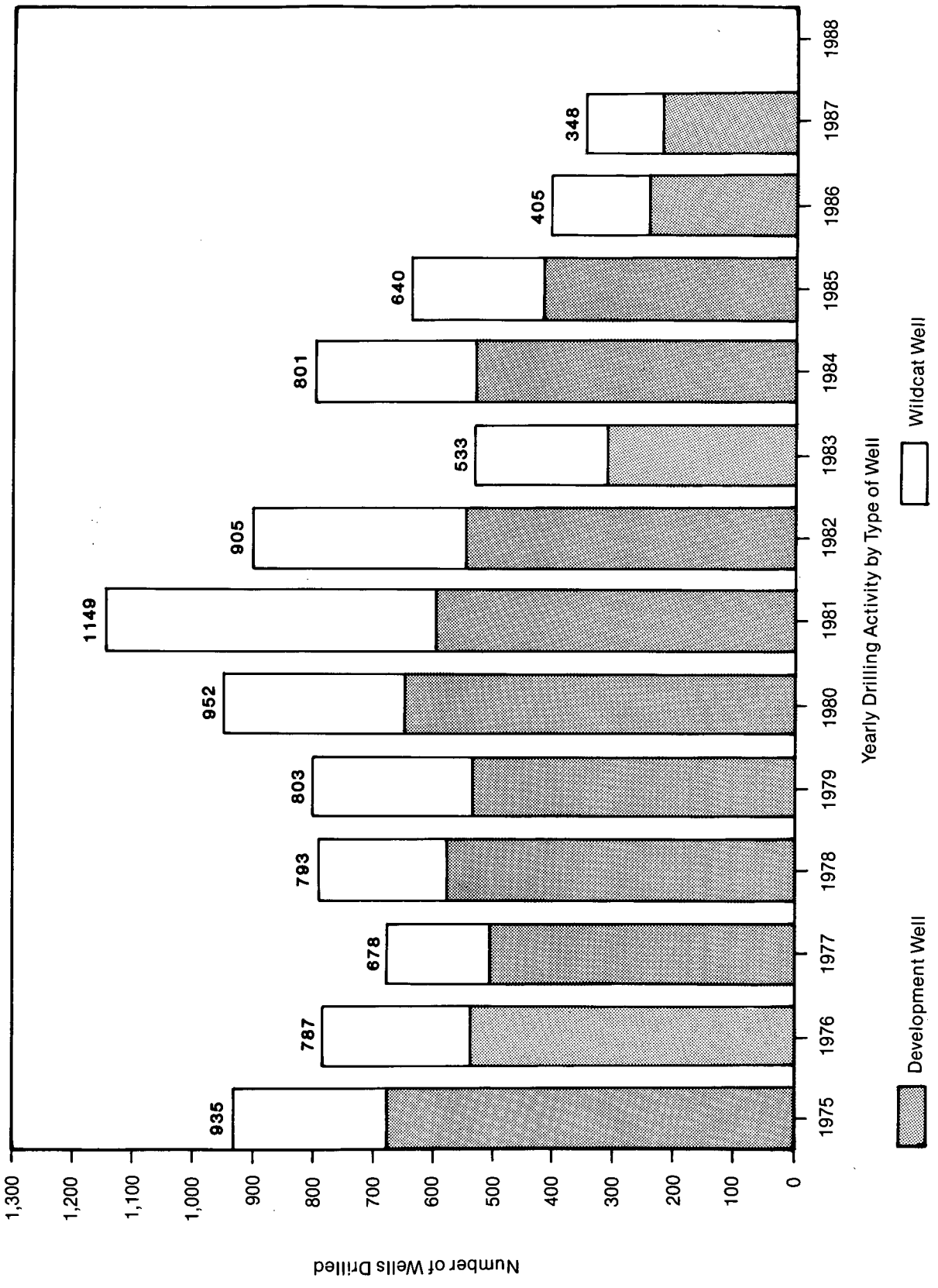
TOTAL MONTANA GAS PRODUCTION

47.8 MILLION MCF

SOURCE: DNRC 1987

FIGURE 5

MONTANA DRILLING ACTIVITY BY TYPE OF WELL



SOURCE: MONTANA OIL AND GAS ANNUAL REVIEWS 1975-1987

GAS PLANTS
1. CUT BANK ABSORPTION
2. GYPSY HIGHVIEW GATHERING SYS.
3. FAIRVIEW
4. BOB RHODES
5. STATE LINE NATURAL GAS PROC.
6. PERRY-PETROLANE
7. SO. PINE
8. CABIN CREEK
9. BIG HORN FRACTIONATION
10. DRY CREEK ABSORPTION

EXPLANATION

OIL FIELD (DOMAN) (N.P.) = Not Producing
GAS FIELD (JARGON)
OIL PIPELINE
GAS PIPELINE
REFINERY ▲ GAS PLANT
REFINED PRODUCTS PIPELINE
BOUNDARY DIVIDING NORTHERN AND SOUTHERN DISTRICTS

★ Billings - Southern District & Technical Office
★ Shelby - Northern District Office
★ Helena - Administrative Office

FIGURE 6
MONTANA
OIL AND GAS FIELDS, PIPELINES AND REFINERIES

1986

BOARD OF OIL AND GAS CONSERVATION

PJK '83

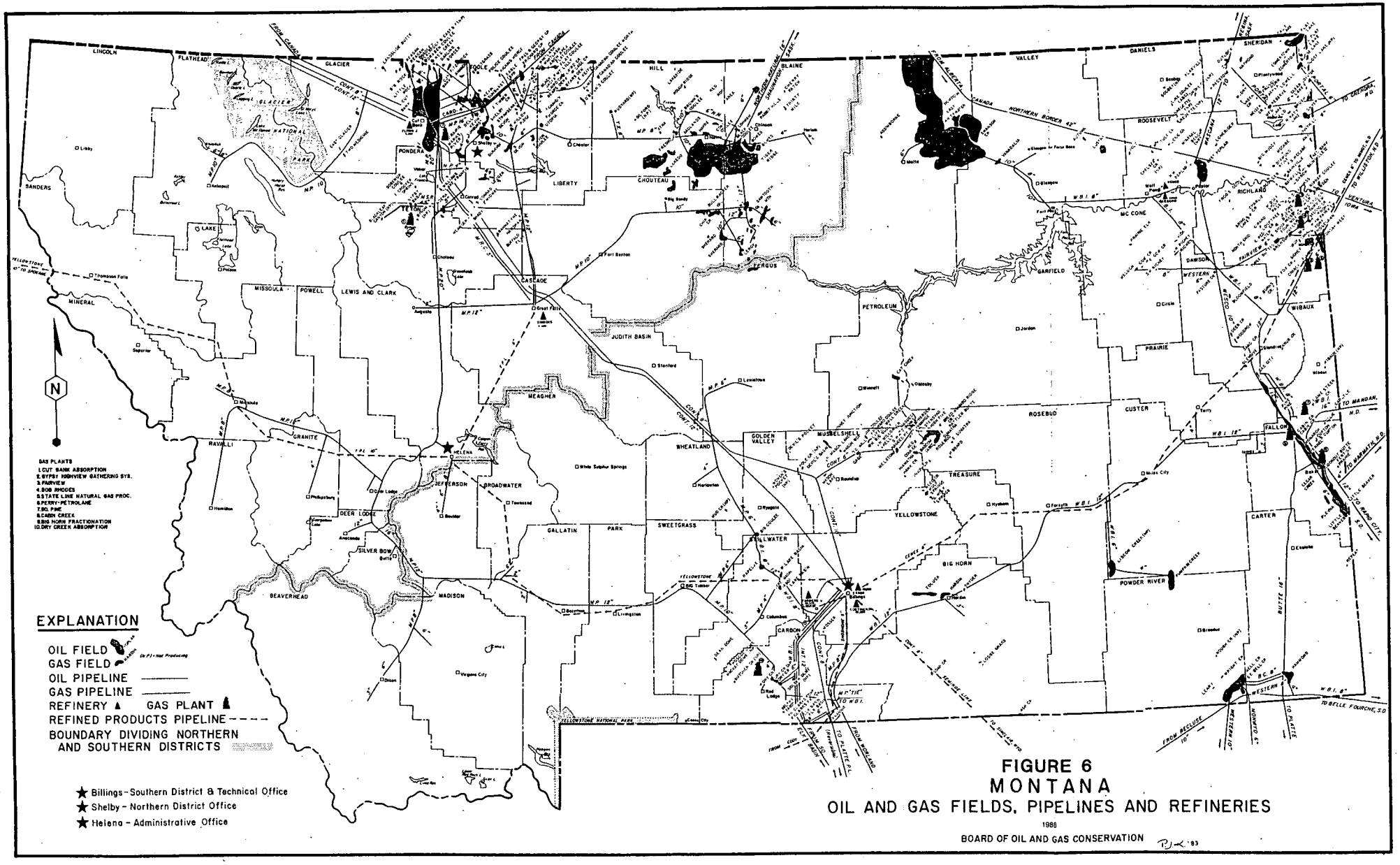


FIGURE 6
MONTANA
OIL AND GAS FIELDS, PIPELINES AND REFINERIES

1980

BOARD OF OIL AND GAS CONSERVATION

years experience in oil or gas production. Two members must be landowners — one landowner who owns both surface and mineral rights and one who owns only surface rights. One member of the Board must be an attorney licensed to practice law in the state. The Board has the power to hire its own staff and may prescribe the salaries and duties of four professional staff members.

The Oil and Gas Conservation Division, attached to DNRC, maintains staff at three offices across the state and has established satellite offices in two other cities (see Figure 7). The Board's administrative functions are handled through the Helena office, which reports to the Board under the administrative procedures of DNRC. The Billings office serves a number of technical functions. The Board's petroleum geologist (who is also the division administrator), petroleum engineer, and chief field inspector are located in the Billings office. Most of the records required by law are maintained at the Billings office, including a reference library containing representative rock samples obtained during oil and gas drilling across Montana. This office also serves as the southern district office and provides two field inspectors to supervise oil and gas operations for the central Montana region. The third office is maintained in Shelby and serves the northern district (see Figure 6). The satellite offices, which mainly serve as a base of operations for two other field inspectors, are located in Glendive and Plentywood.

Applications for drilling permits or other approvals required from the Board for oil and gas operations are filed with either the Billings or Shelby office. The Billings office processes drilling permits for most of the state except those for activities in the northern district which are reviewed and approved through the Shelby office.

Funding for the Board is derived primarily from the privilege and license tax based on the wellhead price of each barrel of oil and each 10,000 cubic feet of gas produced in the state. The Board has the authority to raise and lower this tax under provisions of the Administrative Procedure Act, although by statute the tax may not exceed a rate of 0.2 percent. The Board is currently charging the maximum allowed. Other revenue is derived from drilling permit fees that range from $25 to $150 based on the anticipated depth of the well. All money collected from these sources is earmarked for the Board's use. The Board's budget allocation and authorization to spend is part of DNRC's biennial budget appropriation.

STATUTORY AUTHORITY OF THE BOARD

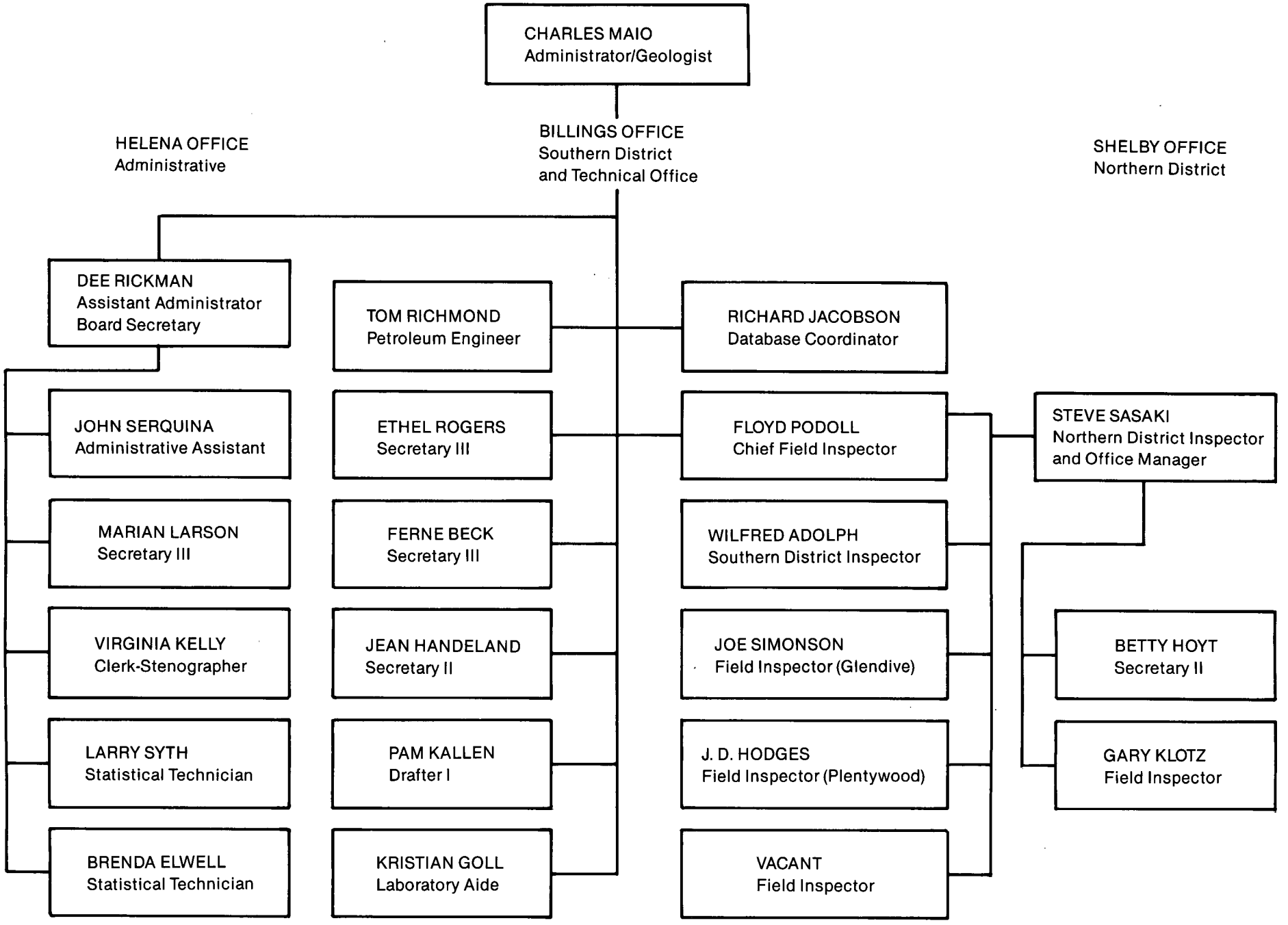
The Board was established in 1953 with the passage of the Montana Oil and Gas Conservation Act (82-11-101 et. seq, MCA). This law was patterned after the Interstate Oil Compact Commission's model statute for conservation and waste regulation of the oil and gas resource. Conservation in this context means the spacing, drilling and producing of wells in a manner that maximizes the ultimate economic recovery of oil and gas from a reservoir or common source of supply. Waste means physical waste such as the unauthorized depletion of reservoir pressure resulting in less oil production, and economic waste, including the drilling of unnecessary wells. As a result of a decision by the Montana Supreme Court, the Board also must consider the correlative rights, the common interest or shares, of adjacent mineral owners in oil or gas underlying several leases when making its decisions.

Under Montana law, no oil or gas exploration, development, production, or disposal well may be drilled until the Board issues a drilling permit. The requirement that a permit be issued before drilling begins applies to all private, state and most federal lands, but excludes Indian lands. In November 1987, the Board and the Bureau of Land Management (BLM) signed a cooperative agreement to coordinate their decisions regarding issuance of permits to drill. Under this agreement, the Board issues a permit to drill for all federal oil and gas minerals in Montana. This agreement provides for coordination and cooperation in the issuance of permits to drill but does not require environmental reviews or surface and subsurface protection measures. Such measures are determined by BLM on a site-by-site basis and attached as conditions to the federal application to drill.

The powers and duties of the Board in regulating oil and gas activities are defined in 82-11-111, MCA. The Board "shall make such investigations as it considers proper to determine whether waste exists or is imminent or whether other facts exist which justify any action by the Board under the authority granted" to it by the legislature (82-11-111(1), MCA). The Board also is authorized to require "measures to be taken to prevent contamination of or damage to surrounding land and underground strata caused by drilling operations and production, including but not limited to regulating the disposal or injection of salt water and disposal of oil field wastes" (82-11-111(2)(a), MCA). The Board is authorized to adopt and enforce rules and orders to meet the purpose and intent of the law (82-11-111(2)(c), MCA). The Board has established administrative rules for seismic shot hole plugging, drilling, well spacing, safety, production and abandonment, plugging and restoration.

The 1987 Legislature expanded the Board's authority to include responsibilities for regulating Class II injection wells, which are used to enhance oil or gas recovery, dispose of water or fluids, and store liquid hydrocarbons. This legislation also provided additional enforcement authority that the Board may invoke if its rules or orders are violated. Prior to passage of this legislation, the Board could only bring suit in district court to force compliance with its rules and orders if other methods of correcting discovered violations were unsuccessful.

FIGURE 7
ORGANIZATION OF THE OIL AND GAS CONSERVATION DIVISION
DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION



The regulatory philosophy of the Board is founded on the principles of resource conservation and prevention of waste. In the past, the Board has adhered firmly to these principles in implementing Montana's oil and gas legislation. The Board's position is that permits are issued for the primary purpose of ensuring that wells are located and drilled in a manner that prevents economic and resource waste and protects correlative rights. The Board has not considered permit issuance to be a major state action under the Montana Environmental Policy Act.

This document cannot resolve existing legal ambiguities concerning either limits of the Board's authority or the limits of its discretion to address environmental issues. Rather, as discussed in detail in Chapter Five, a major purpose of this programmatic impact statement is to assist the Board in determining how to incorporate any necessary environmental review into its rules and permitting process. Progress in this area is necessarily linked to the discussion in subsequent sections of this document that describes (1) the types of environmental impacts that may be associated with oil and gas development; (2) potential mitigation strategies that reduce the impacts; and (3) the existing statutory framework and regulatory practices of other government agencies with jurisdiction over oil and gas drilling and production. Recommendations to the Board will be based on consideration of all this information.

As part of the programmatic impact statement process, public scoping meetings were held in Great Falls, Bozeman, and Sidney. During these meetings, the purposes of the project were discussed and comments were received regarding issues for consideration in this document. Additional public meetings will be held during a 60-day period following release of the draft programmatic environmental impact statement. A final programmatic environmental impact statement will then be prepared. This final document will contain responses to comments received during the comment period, and any new information which becomes available since release of the draft that alters or modifies the analysis contained here. In addition, the final EIS will contain any recommendations from the Advisory Council to the Board regarding a process to fulfill the requirements of Senate Bill 184.

The following chapters of this programmatic impact statement discuss the following items. Chapter Two contains a description of drilling and production activities in Montana. Chapter Three discusses the existing regulatory practices of the various governmental agencies regulating drilling and production. Chapter Four presents the range of potential impacts associated with drilling and production and describes measures that can be taken to mitigate adverse impacts associated with drilling or production activities. Chapter Five presents a summary of impacts and mitigating measures and describes a variety of options available to the Board for incorporating environmental review into its rules and drill permit process.

CHAPTER TWO

OIL AND GAS DRILLING AND PRODUCTION OPERATIONS

The action under consideration in this EIS is the drilling for and production of oil and gas. The process begins with the Board's issuance of a permit to drill. Drilling activities can be classified into two general categories: exploratory, also known as wildcat, drilling to collect information about subsurface formations or to test structures to determine the presence or absence of oil or gas, and development drilling to establish a producing oil or gas field. A majority of wildcat wells and about one-third of development wells drilled in Montana during a given year are dry holes where no hydrocarbons are found or where the well is not capable of producing oil or gas in commercial quantities (see Figures 8 and 9).

Once a well is drilled and commercial quantities of oil or gas are found, additional approval to begin producing hydrocarbons may or may not be required depending on whether the well can comply with rules established by the Board.

The Board has divided the state into regions along county lines (see Figure 10). It is convenient to discuss drilling operations within the context of the Board's regions, as certain statistical information is maintained by region and there are similarities in drilling operations within a region that may not exist from region to region. The regions are: Big Horn Basin (south central Montana), Powder River Basin (southeastern Montana), central Montana (Big Snowy Uplift), Williston Basin (eastern Montana), northern Montana (Sweetgrass Arch - Bearpaw Uplift), and the Montana Disturbed Belt (Overthrust Belt). Western Montana (west of the Disturbed Belt) could be considered a seventh region, currently not productive of oil or gas.

Wells could be considered "typical" for a given region on the basis of several criteria, primarily depth and drilling (or producing) hazards, or operating conditions common to the region. For example, a 12,000-foot well would be typical of the Williston Basin, but not typical of central Montana. In 1986, the average depth of the 11 wells drilled in Richland County (Williston Basin) was 12,123 feet, contrasted with the average depth of 3,672 feet for the 11 wells drilled in Musselshell County (central Montana) during the same year. Other examples to illustrate the differences between a typical well in various regions of Montana are discussed later in this section. Fact sheets for the various regions, provided in Technical Appendix 1, describe drilling and production characteristics for the usual well in each of the regions.

SUMMARY OF DRILLING AND PRODUCTION OPERATIONS

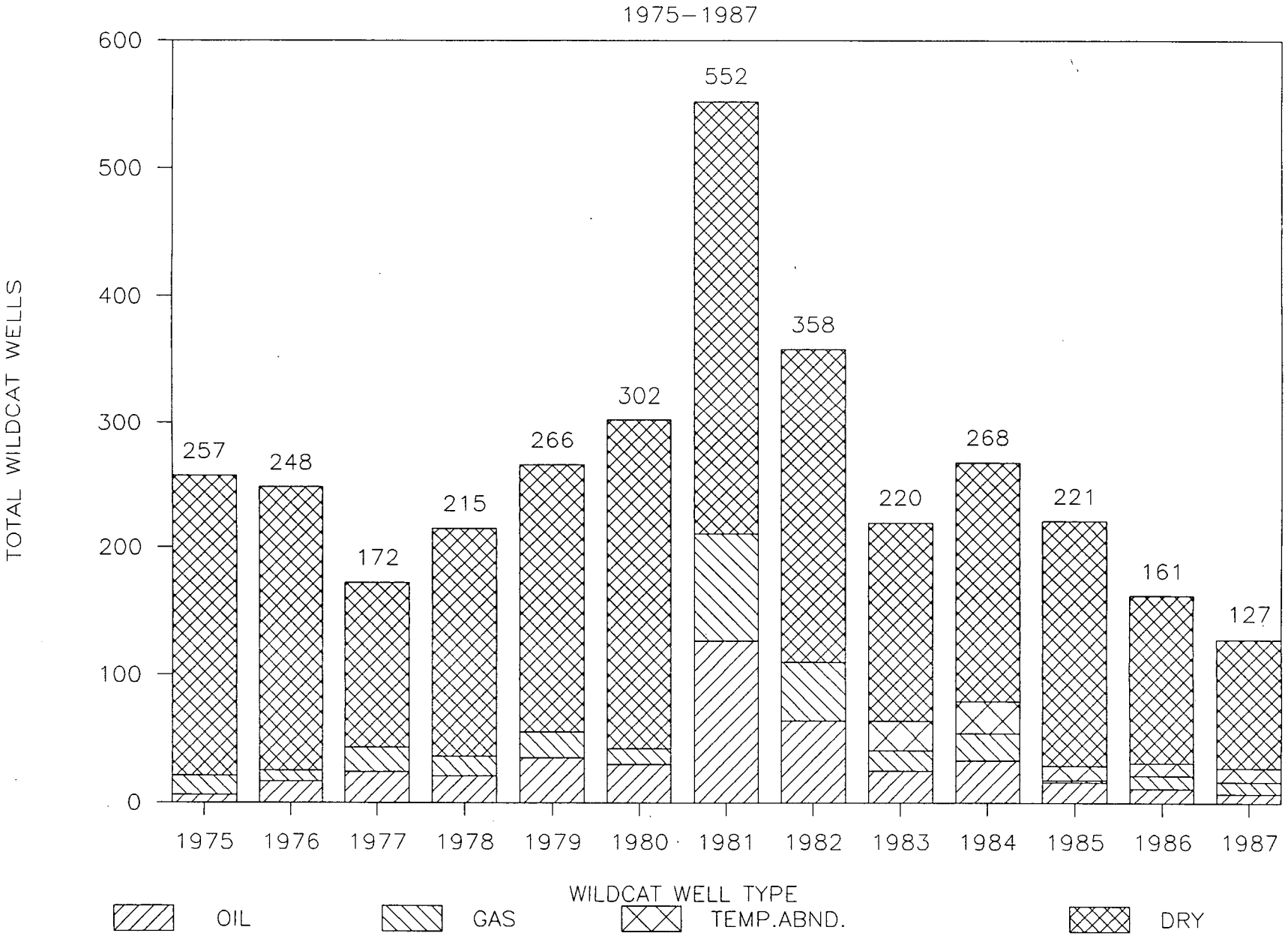
Figure 11 shows the general sequence of operations associated with phases of oil and gas activity. A drilling location usually is the spot believed by the geologist or geophysicist to have the best chance of encountering either oil or gas based on interpretation of the seismic and other data. Some adjustment to the selected location may be necessary to allow for regulatory spacing requirements, leasehold ownership patterns, and surface obstructions. The various steps that are followed in preparing for and conducting a drilling operation and the consideration made when drilling in various regions of Montana are described below.

ACCESS REQUIREMENTS

Road location and size, standards of construction and permanence depend upon a number of factors. In order to minimize construction and restoration cost, the operator generally will propose a road and location built to the minimum standards suitable for the proposed operation. For example, a shallow exploratory gas well in northern Montana only requires about three total days to drill and requires little heavy truck traffic. A trail bladed to clear brush and rocks is generally adequate for this short-term access. Moderate-depth exploratory wells may need a higher standard road and bigger location to accommodate the larger, heavier equipment and traffic. Drainage crossings may be needed and gravel or scoria may have to be added to the road surface, depending on the time of year and the duration of occupation. Deep exploratory wells requiring a long period of site occupation normally need a fairly high standard road which typically would include a gravel surface and ditched and crowned roadway with culverts for drainage crossings. The possibility that production equipment may be needed eventually at exploratory sites also should be considered in road and location construction.

Minimum standard roads are generally bladed with a bulldozer to width of about 10 feet and would cover about

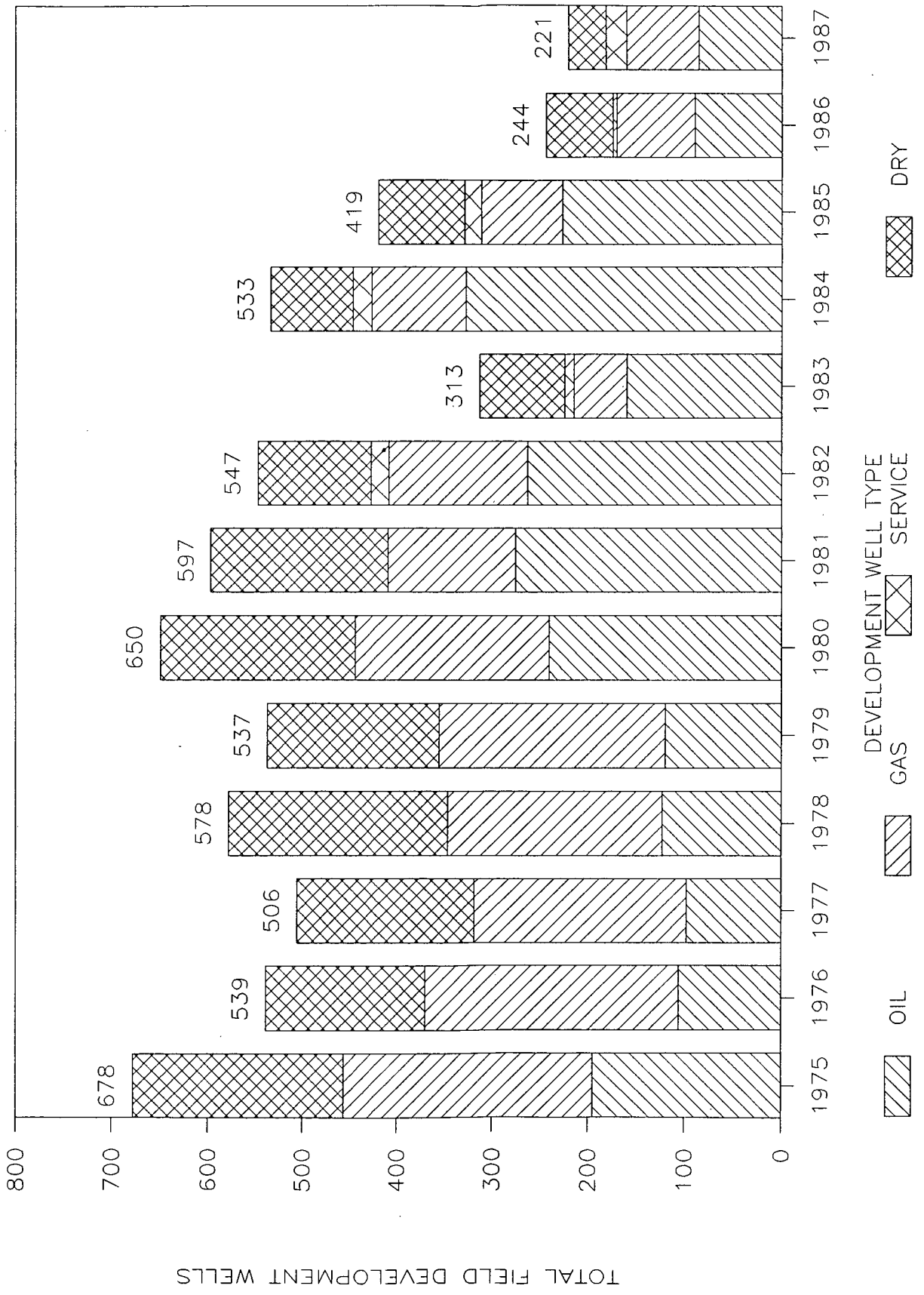
FIGURE 8
CATEGORIES OF WILDCAT WELLS DRILLED IN MONTANA



SOURCES: Montana Department of Natural Resources and Conservation, 1975 – 1987

FIGURE 9

CATEGORIES OF DEVELOPMENT WELLS DRILLED IN MONTANA



SOURCE: Montana Department of Natural Resources and Conservation, 1975 – 1987

FIGURE 10

ADMINISTRATIVE DISTRICTS AND OIL AND GAS REGIONS IN MONTANA

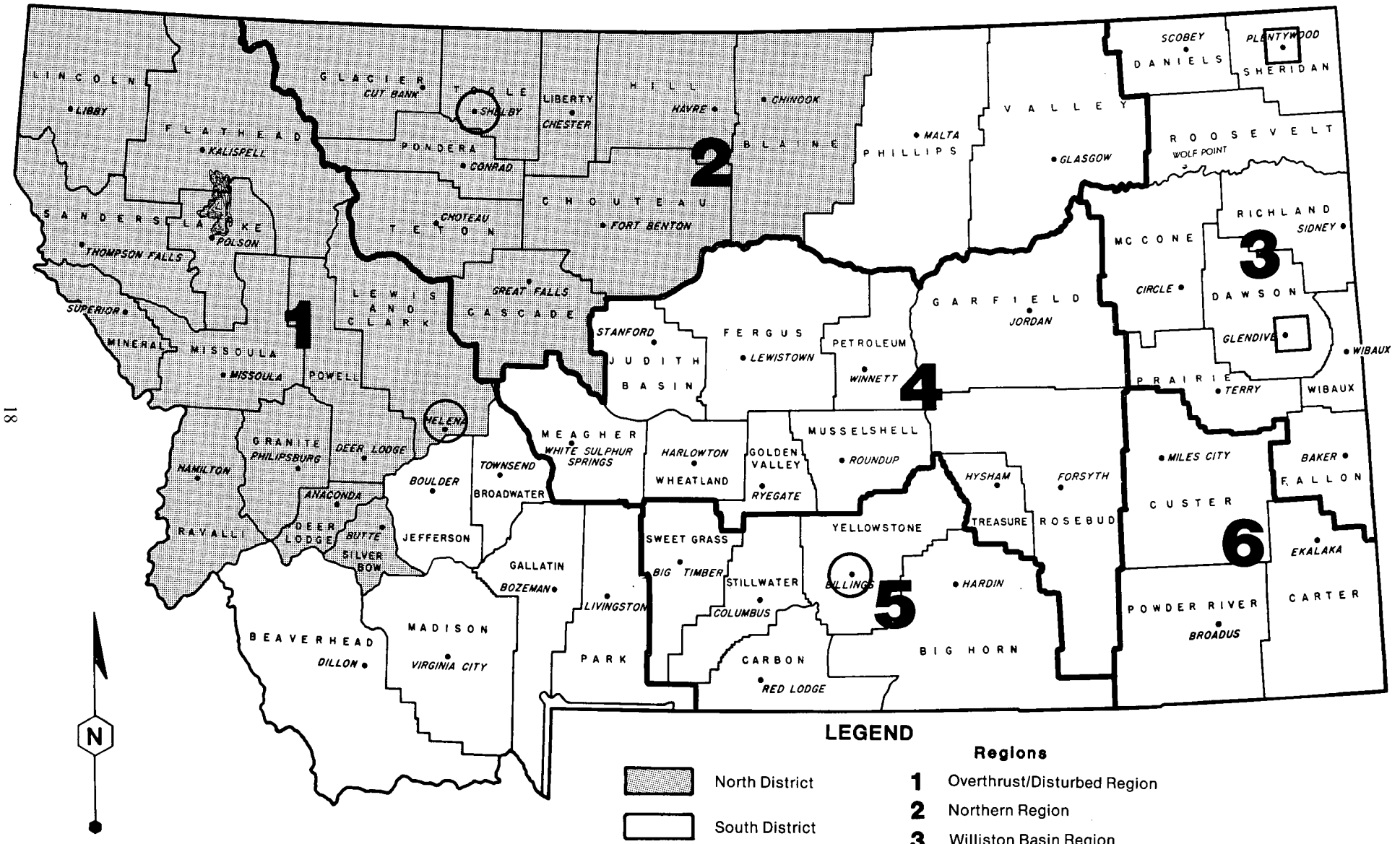
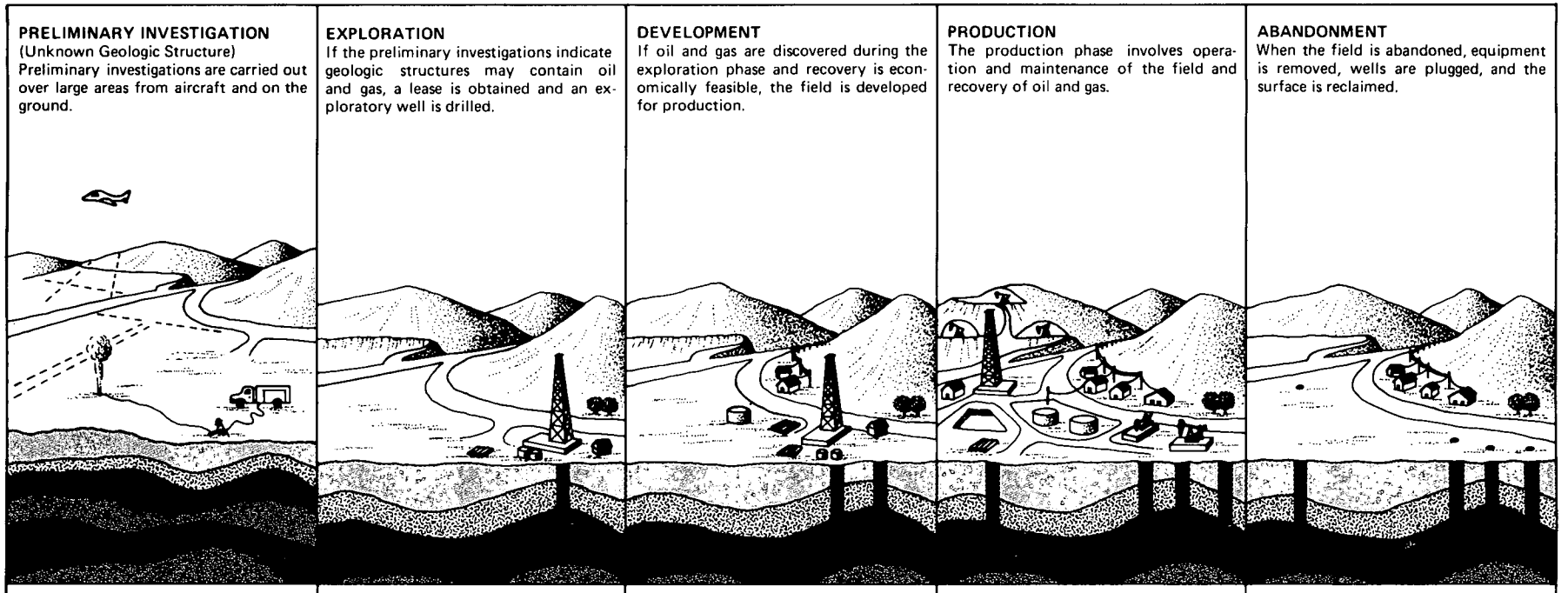


FIGURE 11

SEQUENCE OF OPERATIONS IN AN OIL AND GAS FIELD



PRELIMINARY INVESTIGATION	EXPLORATION	DEVELOPMENT	PRODUCTION	ABANDONMENT
(Unknown Geologic Structure) Preliminary investigations are carried out over large areas from aircraft and on the ground.	If the preliminary investigations indicate geologic structures may contain oil and gas, a lease is obtained and an exploratory well is drilled.	If oil and gas are discovered during the exploration phase and recovery is economically feasible, the field is developed for production.	The production phase involves operation and maintenance of the field and recovery of oil and gas.	When the field is abandoned, equipment is removed, wells are plugged, and the surface is reclaimed.
Airborne Surveys Surface Surveys Geochemical Surveys Stratigraphic & Other Mapping Geophysical Surveys Explosive Method Thumper Method Vibrator Method Gravity & Other Methods Geologic Surveys	Wildcat Well Drilling Access Roads Camp & Buildings (Remote Areas)	Development Drilling Access Roads Pipelines Utility Lines Separators Storage Tanks Camp & Buildings	Continued Drilling & Development of Field Pressure Maintenance System Disposal of Waste Secondary & Tertiary Recovery System Communication & Production System Communities	Equipment, Buildings & Facilities Removal Field Cleanup Well Abandonment & Plugging Eliminate Hazard Surface Reclamation Landscaping Reseeding Other Erosion Control

Source: BLM 1986, Pinedale RMP

1.5 acres per mile. Higher standard roads are about 16 feet wide and use about 1.9 acres per mile. Drainage crossings are generally avoided to the extent possible and the road alignment is selected to minimize road length.

Development wells in an existing oil or gas field generally will require roads built to the standards in the field. For example, well-to-well roads may be single-lane (10 to 16-feet wide) and unsurfaced, while the main road through the field may be ditched and crowned, graveled, and 24-feet wide. In some cases road improvement is not scheduled until after the proposed well has been completed for production. Additional considerations in determining the size, location, and standard of roads in existing fields would include the need for tank battery sites, flowline and pipelines, on-site equipment and storage, and equipment for future well operation or repair.

TYPES OF RIGS

Many technical considerations govern the selection of a drilling rig for a given site. Rigs are commonly rated by their ability to drill and complete a well to a particular depth. Considerations include: derrick load and drill pipe standback capacities, hoisting equipment and capacity, mud pump and circulating system capabilites, and auxiliary equipment availability, including blow-out preventers, boiler, and light plant. A rig must be capable of drilling efficiently to a given depth and running casing to that depth. The rigs available in a given area of the state are equipped to drill the "usual" well in that area, making rig selection for most of the proposed development and wildcat wells a matter of availability, cost, and the overall reputation of the drilling contractor. Rig selection becomes more complex in deeper, high pressure or critical operating environments. For example, an operator may desire a higher substructure (the platform on which the derrick is mounted) to allow more or larger blow-out preventers. Additional circulating system capacity and mud-handling equipment may be desirable for such a well. In this case, the rig may need high-speed mud mixing equipment, desander/desilters, a gas-mud separator ("gas buster"), and more standby premixed mud storage.

Typical rigs vary considerably from region to region. In northern Montana a portable, truck-mounted rig is commonly used to drill shallow (1,000 to 2,000 feet) oil and gas wells. These rigs require only about 4 or 5 truckloads of equipment and use a single derrick about 70 feet high capable of handling one length (± 30 ft.) of drill pipe at a time. This type of rig may be driven cross-county to the well site without a road being needed.

In central Montana and in deeper areas of northern Montana (1,000 to 5,000 feet drilled depth), the most common rigs are double derrick, capable of pulling two lengths (joints) of drill pipe at a time. These rigs require about 7 to 14 truckloads of equipment and are 110 to 135 feet high. Triple derrick rigs are common elsewhere in the state. These rigs require 20 to 50 truckloads of equipment. Derrick height is generally 150 to 170 feet.

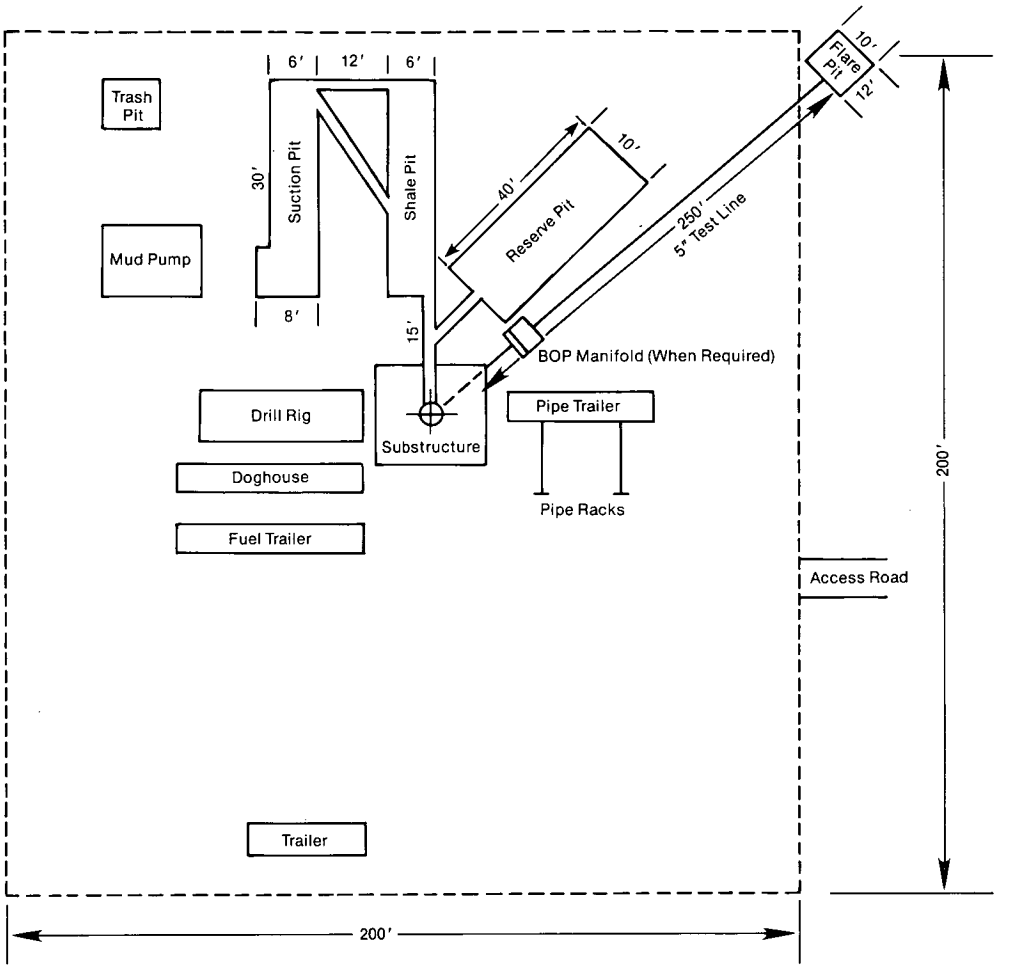
SITE CONSTRUCTION

Once a drilling rig has been selected, the road and location pad are constructed to fit the rig's requirements. The shallow wells in northern Montana require small location pads, usually about 1/2 acre or less (see Figure 12). Deeper wells, such as the 6,000 to 8,000-foot wildcats in the Powder River Basin, may require a 2 to 3 acre drilling site (sese Figure 13). Very deep tests, such as some drilled in western Montana, may need as much as 6 acres (see Figure 14). The location of construction results in the preparation of a level area large enough for the rig itself (including room to lay down the derrick mast), the attendant mud tanks, storage facilities, pipe racks, parking area, and trailer houses for on-site personnel. Rig crews do not commonly live on the location, instead commuting from towns in the vicinity of the well site. Some operations, however, do involve a "work camp" requiring room to accommodate the additional living quarters. Selection and construction of the well site is planned such that the load-bearing portion of the rig structure is located on undisturbed soil. This is to avoid settling of the rig and the associated problem of keeping drilling equipment centered over the hole; also, an out-of-plumb condition can subject load-bearing rig parts to unusual stresses which may exceed design criteria and cause difficulty in drilling a straight hole.

RESERVE AND OTHER WORKING PITS

An earthen reserve pit (in air-drilled holes this is usually called the blooie pit) is excavated near the rig in a location and size to suit the rig and the depth to be drilled. It is desirable to build the pit in such a manner that a significant part of the pit capacity is in undisturbed soil rather than fill material; this prevents possible collapse of pit walls if the fill material is not properly compacted and reduces the amount of construction necessary to build the pit. The pit serves as storage for drilling fluids and as a receptacle for drill cuttings and other solids removed from the circulating system. In air-drilled holes the blooie pit serves to contain drill cuttings and any water encountered during drilling. It also serves as a flare pit in the event natural gas is encountered. In several regions (northern and central Montana particularly), earthen working pits are constructed in addition to the reserve pits. These pits are part of the active circulating system. Mud is taken from the pit by the mud pump and returned to the pit after being circulated through the mud system. In most other parts of the state, steel mud pits or tanks are used for this part of the circulating system. Usually a small trash pit is constructed on location and used to collect mud sacks and other miscellaneous debris generated during drilling operations. Privy pits or holes and sometimes sewage-holding tanks are installed, depending on the anticipated length of occupancy.

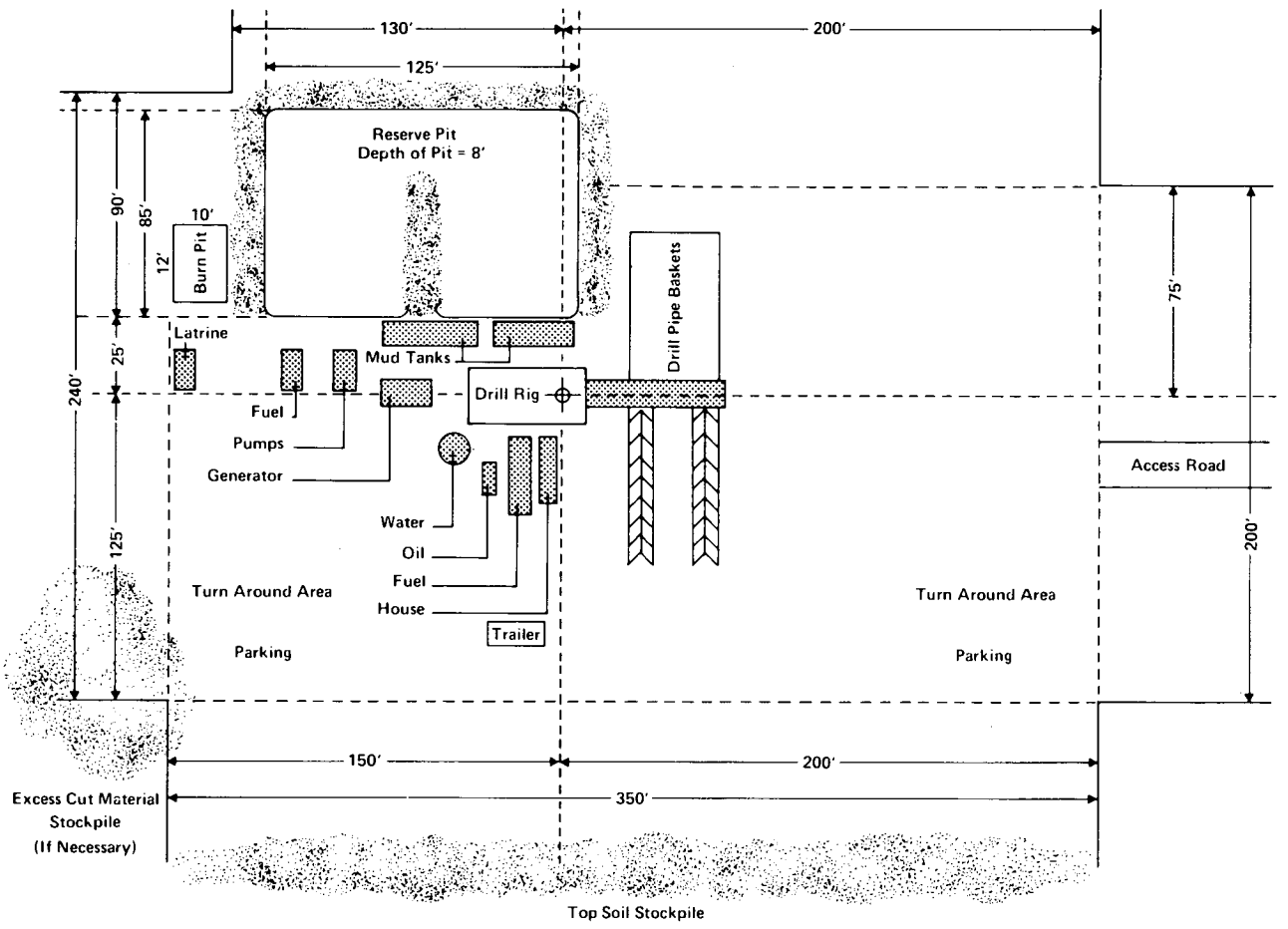
FIGURE 12
LOCATION LAYOUT FOR A WELL UP TO 3,500 FEET DEEP



SOURCE: BLM, 1988

FIGURE 13

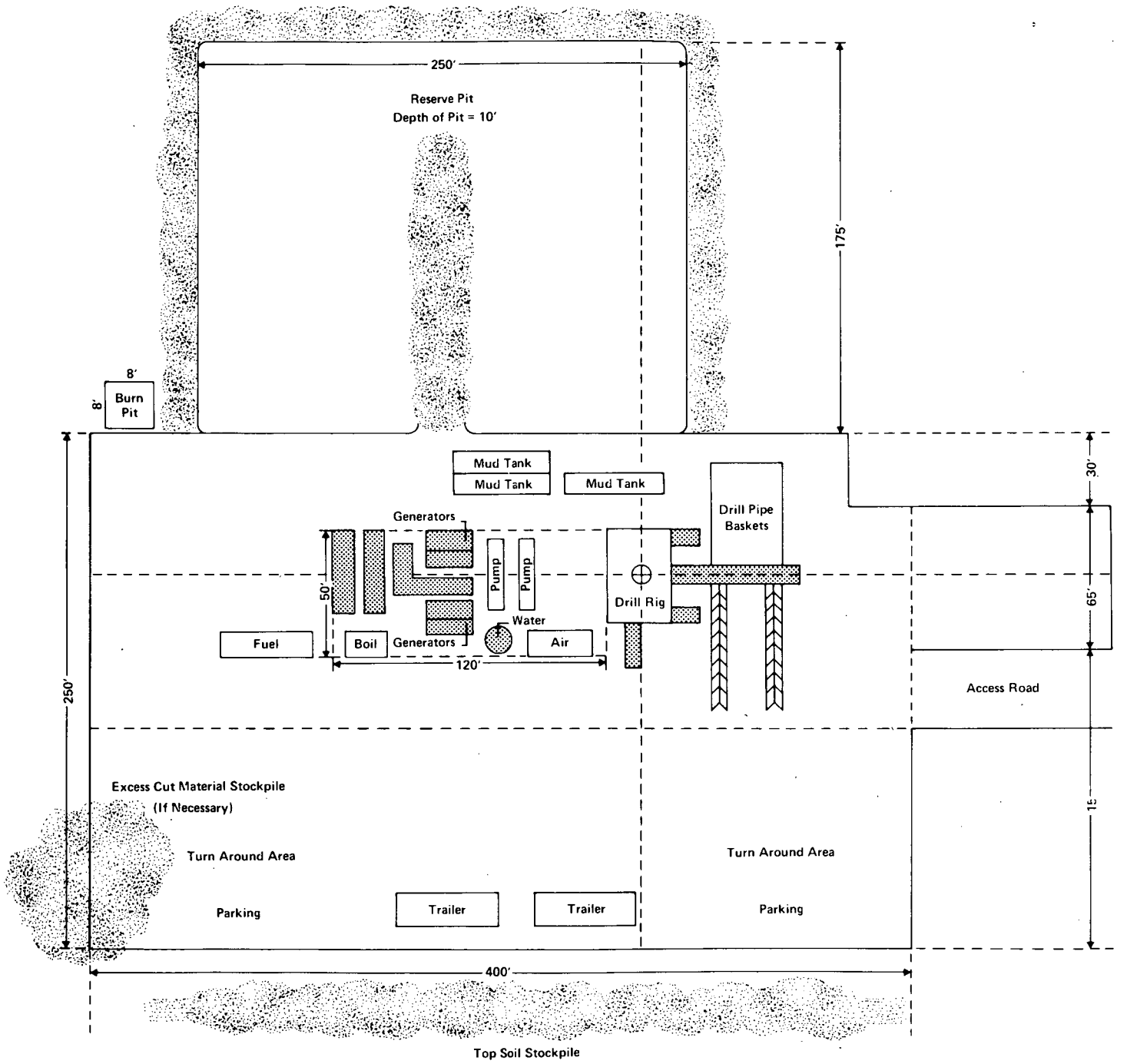
LOCATION LAYOUT FOR A WELL 6,000 TO 9,000 FEET DEEP



SOURCE: BLM 1980

FIGURE 14

LOCATION LAYOUT FOR A WELL 9,000 TO 15,000 FEET DEEP



SOURCE: BLM 1980

Occasionally, a water well is drilled on location to provide a source of drilling water; more commonly, water is hauled from a nearby surface source, such as stock dam or well.

Reserve pits vary from about 50-by-100 feet and 6 feet deep to 100-by-150 feet, 12 feet deep. Earthen working pits are typically 20-by-100 feet and 4 to 6 feet deep. Very rarely, closed mud systems are used in which no earthen pits are required. This system requires additional tankage and a suitable disposal site for the excess liquids and drill cuttings. Closed systems may be used in conjunction with expensive mud systems, such as those using oil-based mud, when the economic benefit of recovering the mud for reuse outweighs the additional costs of the closed mud system.

Typically, in the Williston Basin where saltwater-based muds are used, the reserve pit is lined with a one-piece reinforced plastic liner. The liner is unfolded in the excavated pit and anchored over the top of the pit walls with an earth cover. Bentonite (clay) is sometimes used, either alone or under a plastic liner, in parts of the state where gravel, coal, or other permeable materials are exposed during pit construction. Bentonite, when used as a liner, is spread about 6 inches deep over the bottom and up the sides of the pit. Upon contact with water, the bentonite swells and forms a barrier to fluid movement through the pit bottom and walls.

SETTING SURFACE CASING

After the road and drill pad are built and the reserve pit excavated and lined, the rig is trucked in and rigged up. The well may be spudded (begun) with the drilling rig, or may have been spudded previously with a "dry hole digger" or "spudder," which is a truck-mounted auger. A short string (30 to 60 feet) of large diameter (24 to 36 inch) "conductor" pipe is usually set by the spudder and cemented or grouted in place. After the well is spudded and conductor pipe installed, the drilling rig begins operations by drilling the "surface hole" below the conductor pipe with a relatively large diameter bit. In the Williston Basin, a 12 1/4-inch outside diameter bit is commonly used to drill the surface hole to allow 8 5/8-inch or 9 5/8-inch outside diameter surface casing to be run. Surface hole drilling is typically done with clear water, native mud (formed in the process of drilling through natural clay bearing formations with clear water), or lightly treated (bentonite added) spud mud. Freshwater drilling fluids are used in the surface hole until surface casing is set. In some cases air is used as the circulating fluid.

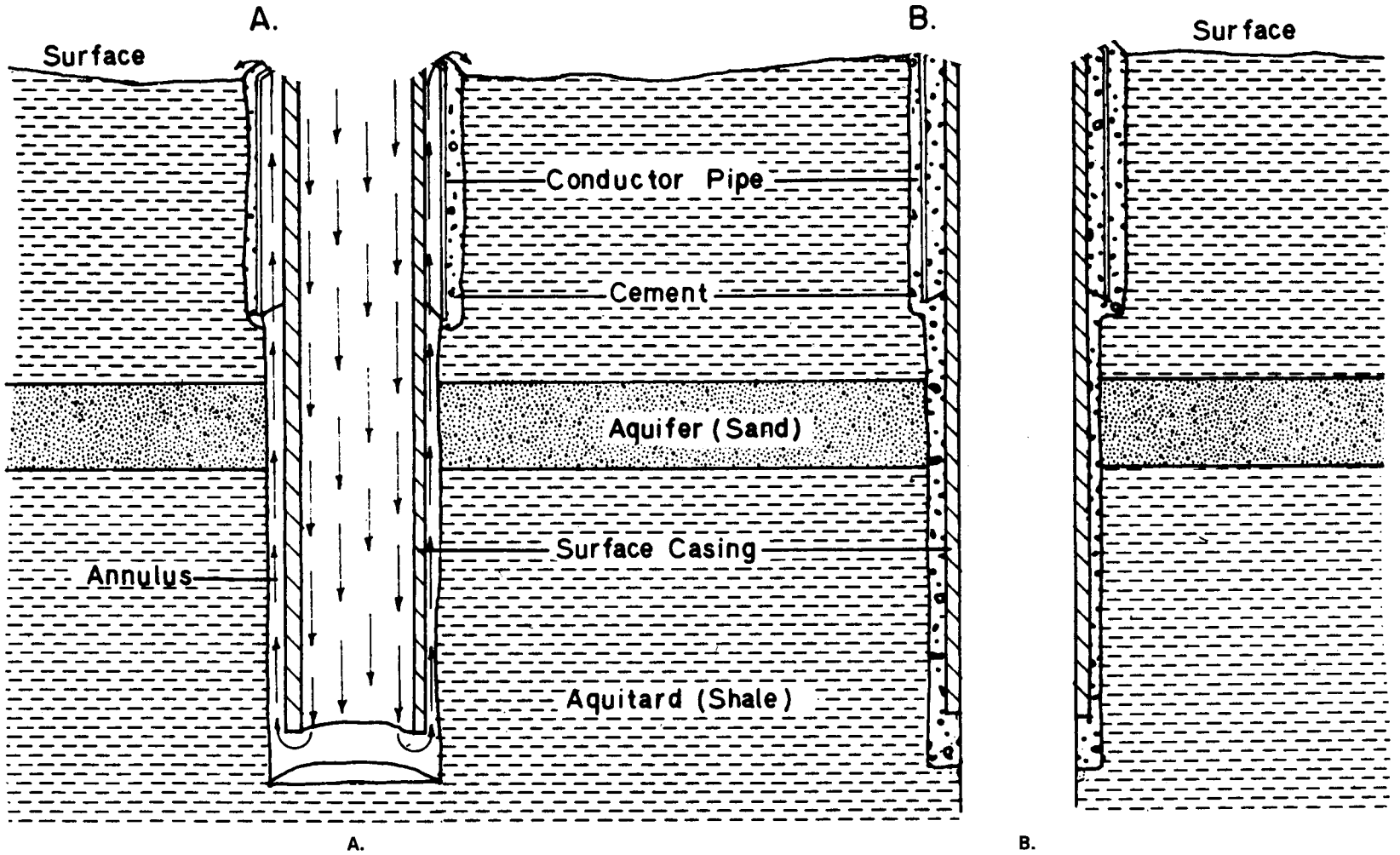
The surface casing setting depth is selected to protect fresh water aquifers and provide a competent casing seat. The size, weight, and grade of casing, and the amount set, are selected to provide suitable pressure protection for subsequent drilling and adequate size and structural strength for landing additional casing strings (which are mechanically attached to the top of the surface casing). As a general rule, surface casing will be set to at least 150 feet or 5 to 10 percent of the total depth of the well. In the Williston Basin, the lower end of surface casing is set at least 50 feet into the Bearpaw Shale, which normally is 1,000 to 2,000 feet below the surface in this area. This casing protects the fresh water in the Fox Hills and other formations overlying the Bearpaw Shale. When drilling reaches the depth for setting surface casing, the drill assembly and drill pipe are removed and surface casing is placed in the hole (see Figure 15). The drill pipe is inserted down the casing to the bottom of the hole. Cement is pumped down the hole through a "float shoe" or "collar" attached to the end of the drill pipe. This process, referred to as cementing under pressure, forces cement into the annular space between the casing and hole from the bottom of the casing to the surface of the hole (see Figure 15). Pressure is maintained on the cement to keep it in place. The period during which the cement is curing is termed "waiting on cement." During this period blow-out preventers are installed, along with the necessary plumbing to operate under the high-pressure environment encountered while drilling to depth. Casing and blow-out preventers are tested before drilling through the bottom part of the surface casing. Mud may be mixed at this time, depending on anticipated hole conditions and the formations to be encountered (see following sections). If feasible, drilling below the surface casing will commence with water or the native mud accumulated while drilling the surface hole.

DRILLING FLUIDS AND MUDS

The drilling fluid used in Montana ranges from air or untreated fresh water to expensive and complex emulsion mud. Drilling fluid serves several purposes in the drilling operation, and its composition usually is a compromise among a number of desirable and undesirable properties. Drilling mud lifts the cuttings from the drilled hole, lubricates and cools the drill bit, provides hydrostatic pressure to control influx of formation fluids, and builds a hole-stabilizing filter cake to control caving and loss of drilling fluid to porous zones. The penetration rate or speed of drilling is influenced by the drilling mud. Low viscosity fluids increase the rate of penetration at the expense of properties of a more viscous fluid. For example, air as a drilling fluid has excellent drilling properties in penetration rate and in keeping swelling clays from hydrating in the presence of water-based fluids. It exerts very low hydrostatic pressure and allows even gas from the low-pressure sands in northern Montana to flow into the well bore during drilling, providing a virtually continuous test of potential productivity while drilling, but its effectiveness falls rapidly if large quantities of water enter the well bore. Air is limited in the amount of water it can eject from the well. Air drilling usually is not considered suitable in high pressure or hazardous operating areas.

Most liquid-drilled wells in Montana, with the Williston Basin as the exception, are drilled with a freshwater-bentonite-clay mud system. The primary ingredient is the inert bentonite, also called "gel." Freshwater gel muds allow relatively easy adjustments of viscosity, gel strength, and mud weight by addition of clay or water as

FIGURE 15
SETTING THE SURFACE WELL CASING



A.

Conductor pipe has been cemented into place. A predetermined amount of casing has been inserted into the well bore below the deepest fresh water zone. Cement is pumped down the inside of the casing until cement flows to the surface through the annulus.

B.

The cement has hardened and both casing and cement have been tested under pressure. The cement in the bottom of the casing has been drilled out so that drilling can be resumed.

Cementing the surface well casing to prevent the contamination of fresh water zones and to support the production casing.

Source: Brostuen, 1981. North Dakota Geological Survey.

needed. Bentonite by itself has many but not all of the desired properties of a drilling fluid. Mud additives are used to adjust certain mud properties to meet hole-drilling requirements. For example, fluid loss to porous formations can be fairly high in a clay-only system, so starch may be added to the mud to reduce fluid loss. Starch for drilling mud is made from corn. The starch is separated from the corn and heat treated so that the starch grains will rapidly swell and gelatinize. Pumpability of the mud may be adversely affected by attempting to build mud weight with gel alone, so a weighting additive sometimes is used. Barite, an inert, naturally occurring mineral, often is used for this purpose. In extreme cases (not encountered in Montana), hematite (an iron-bearing material) can be used to build very heavy muds. Additives are available to thin the mud, lubricate the bit, inhibit pipe corrosion, and prevent bacterial action in the mud system. Mud pH is adjusted by adding sodium hydroxide or caustic soda. Materials used to restore lost circulation are available at the location, but are added to the active mud system only when needed. Cottonseed hulls, crushed walnut shells, cellophane flakes, and a myriad of other similar agents that fill voids in the rock are sold for this purpose. The chemical composition of a drilling mud is tailored to match the downhole conditions encountered during drilling.

A typical drilling mud in central Montana includes fresh water, bentonite, soda ash (sodium carbonate) to precipitate excess calcium in the water, and lignite, a nontoxic thinner or dispersant. In the Williston Basin, saltwater-based drilling muds are used below the surface pipe to avoid washing out or dissolving large quantities of the several salt-bearing formations encountered during drilling in this region. In the Williston Basin, a typical water-base mud includes saltwater (usually greater than 250,000 parts per million dissolved NaCl), attapulgite clay, soda ash, starch for water-loss control, paraformaldehyde as a preservative to prevent fermentation of the starch, and a filming amine to prevent corrosion of the drill pipe. Saturated salt mud typically contains up to 125 lbs of salt per 42-gallon barrel of water. The amount of salt added to the drilling mud can be reduced by use of produced water trucked to the site from nearby wells. Sodium hydroxide would be used for pH control. A high pH mud is desirable when penetrating formations that contain hydrogen sulfide gas, as the hydrogen sulfide reacts with the mud to form a solid precipitate and avoids free hydrogen sulfide in the mud system. A hydrogen sulfide scavenger such as zinc carbonate is added to the mud system if the high mud pH is inadequate to control larger quantities of hydrogen sulfide.

Drilling mud containing oil is used on occasion in the Williston Basin, and sometimes in deep wildcats in other areas. These systems are expensive and must be supervised closely to maintain the necessary properties. These muds do have excellent drilling properties, particularly in the salt sections. Oil-base mud is generally insensitive to contaminants such as anhydrite, salt, and gypsum and is useful in drilling heaving shales that hydrate and slough when drilled with water-based muds.

Oil-based mud may contain some combination of diesel fuel, crude oil, oxidized asphalt, fatty and organic acids, an alkali (usually lime or calcium hydroxide), and some water and stabilizing agents. The acids react with the alkali to form a soap that governs the viscosity of the mixture. The asphalt, if present, is the colloidal fraction that provides the wall-cake properties similar to the bentonite in a water-based mud. Due to the expense and nature of oil-base fluids, this mud is usually recovered for further use, and is generally kept in a closed mud system and not placed in the reserve pit after completion of the well.

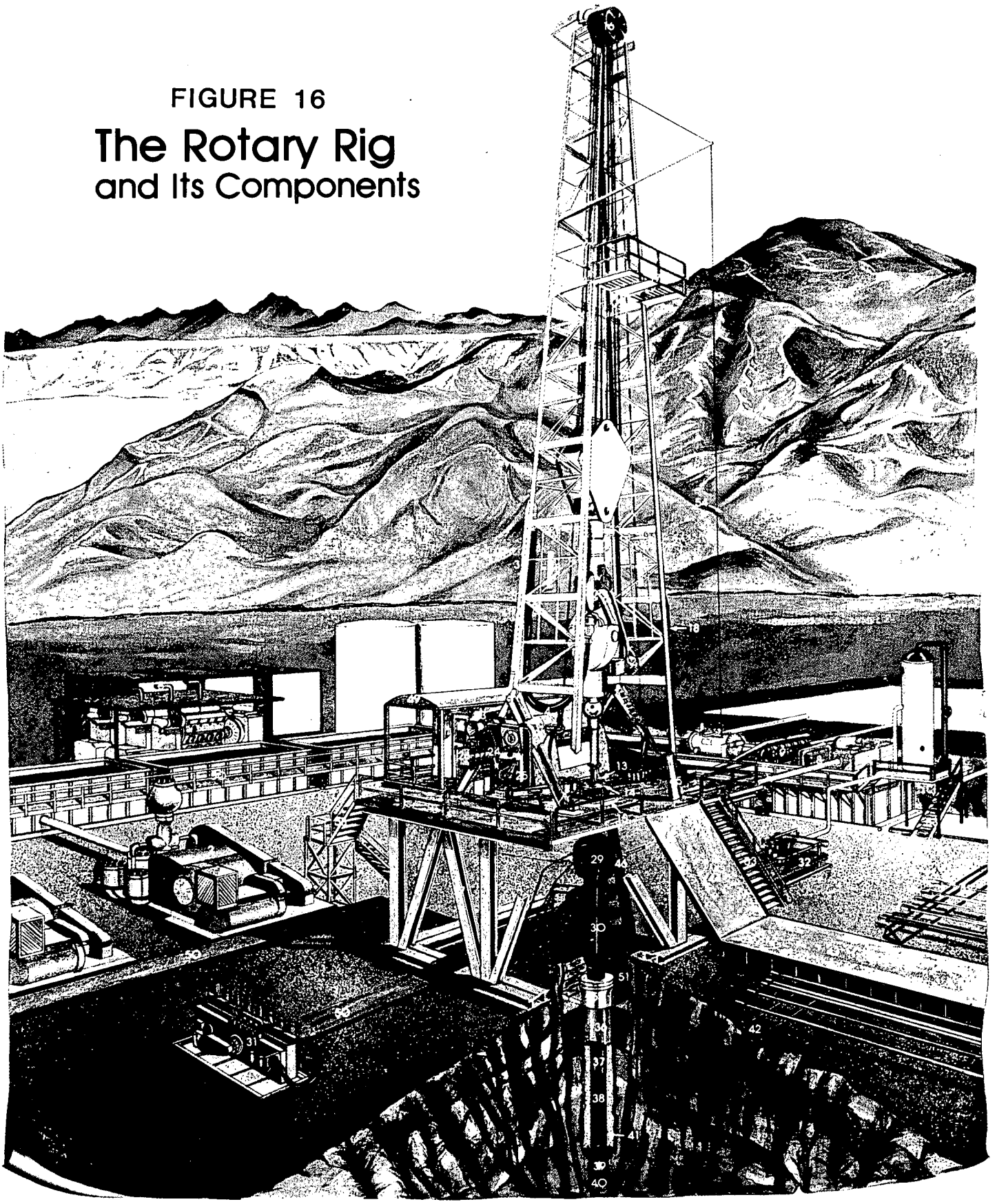
DRILLING PROCESS

Figure 16 shows the various equipment and systems associated with a large rotary drilling rig. The drilling process commonly uses a three-cone roller bit equipped with three nozzles that direct the circulating fluid (mud) downward against the rock being drilled (see Figure 17). As the bit is rotated, mechanical force causes the rock to fracture and break or chip forming the "cuttings." The drilling mud flushes the cuttings away from the bit and lifts the cuttings to the surface. The bit is attached to the drill collars, which are heavy joints of pipe placed at the bottom of the drill pipe for weight and stiffness. There may be other items of equipment, termed the "bottom hole assembly," located in this portion of the drill string. Stabilizers and reamers are part of the bottom hole assembly; the design and configuration of this assembly and the number and size of drill collars is selected to conform to anticipated hole conditions. Above the drill collars are the joints of drill pipe, and attached to the uppermost joint of drill pipe is a square or hexagonal (occasionally other shapes may be encountered) piece of pipe called the Kelly. The Kelly is turned by an appropriately shaped "Kelly bushing," in turn rotated by the rotary table. Drilling mud is pumped through the Kelly and drill stem from a "swivel" attached to the rotary hose, which is a steel-reinforced rubber or synthetic hose. The rotary hose is connected to the standpipe, which is plumbed back to the rig's mud pump. The drill stem and swivel is suspended from the "hook" and can be raised and lowered with the block and tackle arrangement strung in the derrick. The drilling line, a high strength steel cable, is passed through the sheaves in the standing block (attached to the derrick) and the traveling block (which moves up and down) and is controlled by the draw works.

During drilling, 30-foot joints of drill pipe must be added to the top of the drill stem, below the Kelly. The Kelly is raised with the draw works, unscrewed from the drill stem and lowered into a shallow hole drilled for this purpose, called the "rat hole." A joint of pipe is then picked up from a hole close to the rotary table—the "mouse hole"—and screwed to the top of the drill stem, which in the meantime has been suspended in the rotary table with a heavy steel wedge called the "slips." The drill stem with new joint of pipe is lowered into the hole and the Kelly reattached and lowered until the drill stem is "on bottom." Drilling then resumes, and another

FIGURE 16

The Rotary Rig
and Its Components



CIRCULATING SYSTEM
1. Mud pits
2. Mud pumps
3. Standpipe
4. Rotary hose
5. Bulk mud components storage
6. Mud return line
7. Shale shaker
8. Desilter
9. Desander
10. Degasser
11. Reserve pits

ROTATING EQUIPMENT
12. Swivel
13. Kelly
14. Kelly bushing
15. Rotary table

HOISTING SYSTEM
16. Crown block and water table
17. Monkeyboard
18. Mast
19. Traveling block
20. Hook
21. Elevators
22. Drawworks
23. Cathead
24. Brake
25. Weight indicator
26. Driller's console
27. Substructure
28. Drilling line

WELL-CONTROL EQUIPMENT
29. Annular blowout preventer
30. Ram blowout preventers
31. Accumulator unit
32. Choke manifold
33. Mud-gas separator

POWER SYSTEM
34. Power-generating plant
35. Fuel tanks

PIPE AND PIPE-HANDLING EQUIPMENT
36. Conductor pipe
37. Surface casing
38. Drill pipe
39. Drill collars
40. Drill bit
41. Annulus
42. Pipe racks
43. Catwalk
44. Pipe ramp
45. Rathole
46. Mousehole
47. Tongs
48. Tong counterweights

MISCELLANEOUS
49. Doghouse
50. Walkways
51. Cellar
52. Casinghead
53. Stairways
54. Hoisting line
55. Gin pole

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FIGURE 17
CONVENTIONAL THREE CONE ROLLER DRILL BIT

As the bit is rotated, the teeth on the cones turn and bite into the rock and chip off fragments. Drilling fluid passes through the bit to cool and to lubricate it and to carry the rock chips to the surface.

Source: Brostuen, 1981. North Dakota Geological Survey

joint of drill pipe is picked up from the "pipe rack" and lowered in the mouse hole. This entire operation is termed "making a connection."

When it is necessary to remove a worn drill bit, the entire drill stem must be removed from the hole. This process is called "making a trip." The drill pipe and collars are unscrewed and stood back in the derrick. The length of pipe that can be removed at one time is called a "stand" and is determined by the height of the derrick. Commonly there are three joints of pipe to a stand, although some smaller rigs pull doubles (two joints). Some small rigs only pull singles and have no stand-back capacity, picking up and laying down pipe from the pipe rack on each trip. Some uncommonly large rigs pull four joints to the stand, a "fourble" derrick.

Many of the drilling rigs that operate in Montana are powered by one or more diesel engines that directly run the draw works, rotary table, and mud pumps through a power transmission device called the "compound." Larger rigs active in the deeper basins of Montana use diesel engines to drive electric generators, and electricity is used to power various rig parts. Diesel rigs have a light plant or electric generator as a separate unit to provide lights and operate the various motors. A rig may also have a boiler for winter operations to provide heat and steam for thawing frozen items.

Drilling rigs ordinarily run 24 hours a day, 7 days a week. Rig crews usually work 8-hour tours (pronounced "towers"). The number of crew members varies. The driller is in charge of the crew and operates the rotary equipment and draw works from the driller's console. He is responsible for much of the day-to-day activity of the rig, including recordkeeping for the events of his tour. The derrickman is positioned on the "monkey board" in the derrick during trips to handle and rack the drill pipe. The motorman is responsible for the routine maintenance of the rig's engines. There are also one or more floor hands to assist on the rig floor during trips. Because of the relatively small number of crew members, each is assigned other duties to perform while routine drilling is under way. The driller, however, must be near the console while drilling is proceeding.

BLOWOUT PREVENTION PROCEDURES AND EQUIPMENT

Blowout prevention (BOP) equipment is installed to prevent the loss of control of a well while drilling (see Figure 18). If the density of mud used in drilling is not sufficient, some fluid from a porous and permeable formation may enter the wellbore. The formation fluid can be gas, oil, water or a combination of these. In some parts of the state, in particular near aquifer recharge areas, fresh water flows may be encountered. However, a gas "kick" is most common and usually the most difficult to control. Since gas is compressible, it tends to expand in the wellbore as it travels to the surface and decompress. This expansion displaces mud and further decreases the hydrostatic pressure, allowing more gas to enter the wellbore. If not controlled, gas can cause the well to "blow out," pushing all the mud out of the hole. The type of blowout prevention equipment used is dependent upon the area of the state and type of well being drilled. Board rules require use of blow-out prevention equipment in a proven productive area to be equivalent to that established by practice in the area. In unproven areas, a mastergate valve and blow-out preventer is required along with suitable choke and kill lines. There are generally two types of blow-out preventers—ram, and annular (bag type) preventers. Ram preventers are hydraulically or manually operated valves that are connected to the surface casing of intermediate casing strings. The rams are designed to close on an open hole (blind or blank rams) or on drill pipe (pipe rams). In very rare circumstances, blind/shear rams, designed to sever or crush the drill pipe and close the hole, may be used. Annular preventers are capable of closing around drill pipe, collars, tool joints, and even the Kelly, but do not have any rotating parts. They also can close on open hole. This is the topmost preventer installed and is operated by using hydraulic fluid to extrude a heavy rubber-like seal assembly until it closes the annular space around the pipe (or closes the open hole). This preventer is often called a "Hydril," although Hydril is a trade name for one manufacturer of this type preventer.

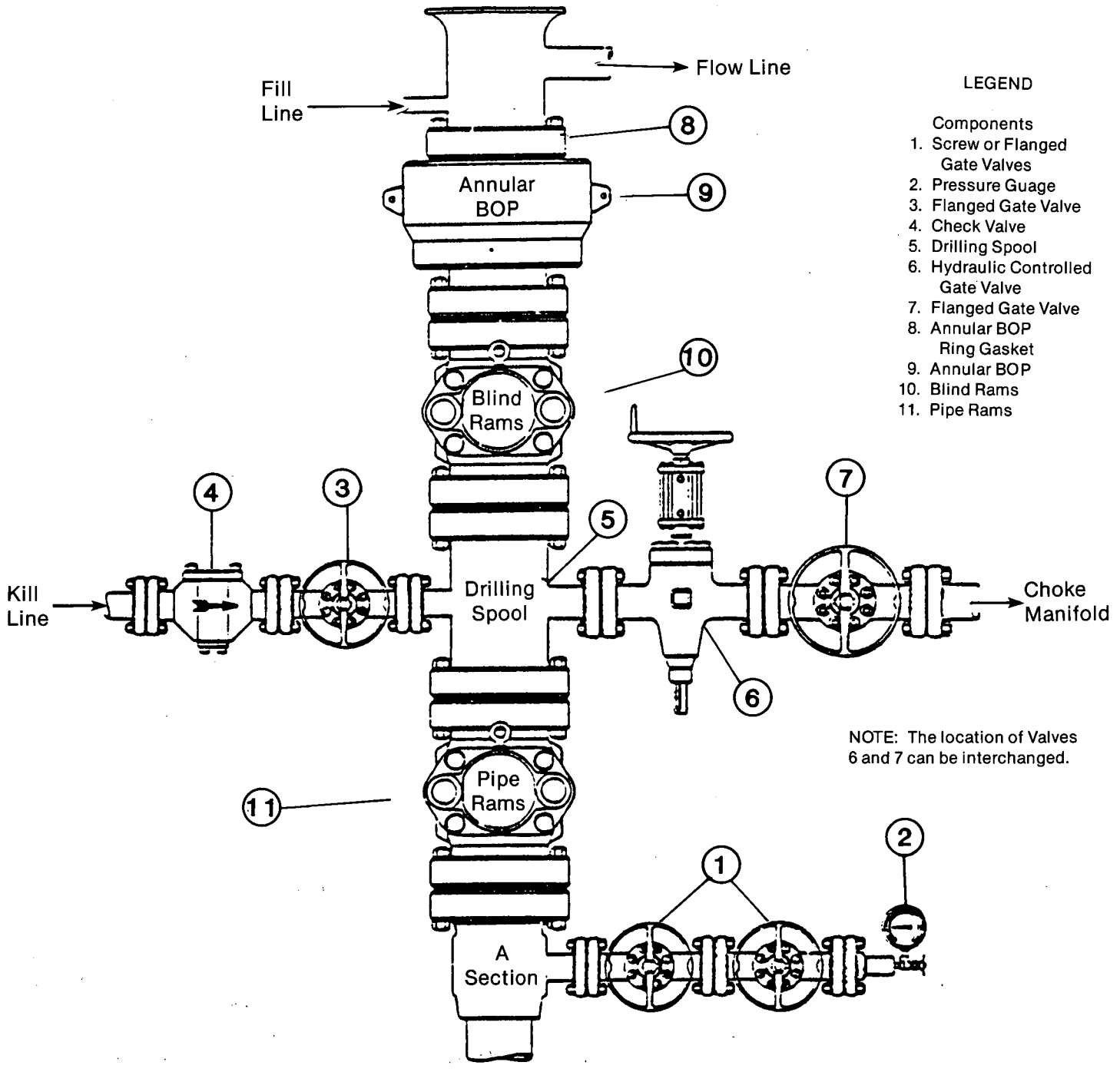
In contrast, when drilling with air, a rotating head is used to seal the hole around the drilling equipment and serves a function similar to an annular preventer, although a rotating head allows for continuous drilling.

Common BOP equipment for a well in the Williston Basin includes an annular preventer, one set of pipe rams, and one set of blind rams. Another part of the BOP equipment is the choke manifold which allows controlled venting or bleeding of well presure to the pit through a vent or flare line. In northern Montana where relatively low-pressure formations predominate, a master gate (a manually operated gate valve with an opening large enough to allow passage of the bit and drill stem) with an annular preventer is generally adequate. As recommended by the American Petroleum Institute, blow-out prevention equipment can be installed in several different stack configurations and is bolted to the wellhead with high-pressure flanges.

Hydraulic pressure for blow-out preventers is provided by an "accumulator" which can operate either on rig power or on standby bottled inert gas. BOP equipment commonly has two remote controls—one on the rig floor and another at the accumulator. A kill line is also connected to the wellhead assembly to allow drilling mud to be pumped into the hole from the active mud tanks or from standby pre-mixed mud tanks in the event the normal circulating system cannot be used.

If a kick occurs during drilling, the pipe rams or the annular preventer can be activated to quickly close the annulus surrounding the casing. The drill pipe itself can be

FIGURE 18
BLOW OUT PREVENTER
THREE PREVENTER STACK



SOURCE: BLM, 1988

closed with a valve in the Kelly (the "Kelly cock"). If the well begins flowing with the drill pipe out of the hole, the blind rams (or master gate) can be used to close in the well. Kicks are usually detected by an increase in the apparent amount of mud in the circulating system—caused by fluids from rock formations displacing the mud from the hole. Mud pit levels can be monitored visually or with automatic indicators that sound an alarm if the pit level begins increasing. Once a kick is detected, well-control procedures are commenced. There are several accepted kick control methods (see Figures 19 and 20 for examples). These methods all provide means to reestablish well control by circulating formation fluids out of the mud system and increasing the hydrostatic pressure of the drilling fluid to prevent a further entry of formation fluid. Mud is mixed to the weight specification needed to provide the additional hydrostatic pressure, and this mud is pumped down the drill pipe. The choke manifold is used to bleed well pressure, either to the pit or through a mud-gas separator in the circulating system. The choke opening can be adjusted to maintain pressure control during pumping. By the time the gas bubble has been circulated out of the well, the lighter mud originally in the well has been displaced with the newer, heavier mud and the well will be under control.

WELL TESTING AND LOGGING

During the process of drilling, prospective pay zones and "shows" of oil or gas are noted by the well-site geologist, who is usually responsible for evaluation of well cuttings, drilling breaks (periods when drilling is faster, indicating porosity), and any cores cut. If a good show is encountered, a drill stem test may be taken of the prospective interval. Testing is usually performed by a third-party contractor under the supervision of the operator's representative or the well-site geologist. A trip has to be made to remove the bottom hole assembly and to attach the test tool to the end of the drill string. The test tool allows the tested interval to be isolated from the wellbore and temporarily produced through the drill pipe. The results of the test, pressure readings, and times are carefully noted. Care must be taken while pulling the test tool to avoid swabbing the well; pulling the tool too quickly will temporarily reduce the hydrostatic pressure below the tool and induce fluid flow from the formation. Care must also be taken if the drill stem test caused formation fluid to collect in the drill pipe. It is good operating practice to pull the test tool only during daylight hours to allow safer handling of any oil or gas in the pipe. In areas (primarily the Williston Basin) where hydrogen sulfide gas may be present, the test is usually "reversed out," meaning that mud is pumped down the annulus and up the drill pipe (normal circulation is the opposite) to displace the test fluids out the flare line and away from the rig.

After the well reaches total depth, it is electrically or radioactively logged by a specialty well logging contractor. Logging tools are run to total depth and the logging instruments turned on and calibrated. The well is logged from the bottom up with the type and number of logs selected by the operator. Well logs are evaluated on-site in consultation among the logger, geologist, drilling engineer, and other interested parties. After the logs, drill stem tests, sample shows, and other pertinent information are considered, a decision is made to run pipe (complete the well) or plug. Since the cost of the production string of casing is a major part of the completed well costs, this is a critical economic decision and must be made relatively quickly.

WELL COMPLETION

If the well appears capable of commercial production, the drilling rig runs casing into the hole. Completion practices vary considerably through the state. It is fairly common in northern Montana to drill to a point just above the productive formation and set a production casing. The depth for casing is usually determined through geologic interpretation from surrounding wells in the area. The productive zone is then drilled (usually with air or cable tools) and completed without casing (open hole). This has the advantage of allowing the entire productive interval to be exposed for production. In the remainder of the state, the well is usually drilled entirely through the pay zone, casing run to total depth, and cement circulated around the casing from the bottom to a point well above the pay. The pay zone(s) are then selectively perforated opposite the best places shown on the well log. A selectively perforated well has somewhat better chance of controlling water production from the pay zone than an open hole well. The drilling rig is usually moved out and a completion or workover rig moved in to finish the well. The casing is perforated at the interval selected, and tubing, pumping equipment (if the well will not flow without pumping), and wellhead assembly is installed. Commonly a well's production is tested for a period (usually 10 to 30 days) before permanent surface equipment, including a tank battery, is installed.

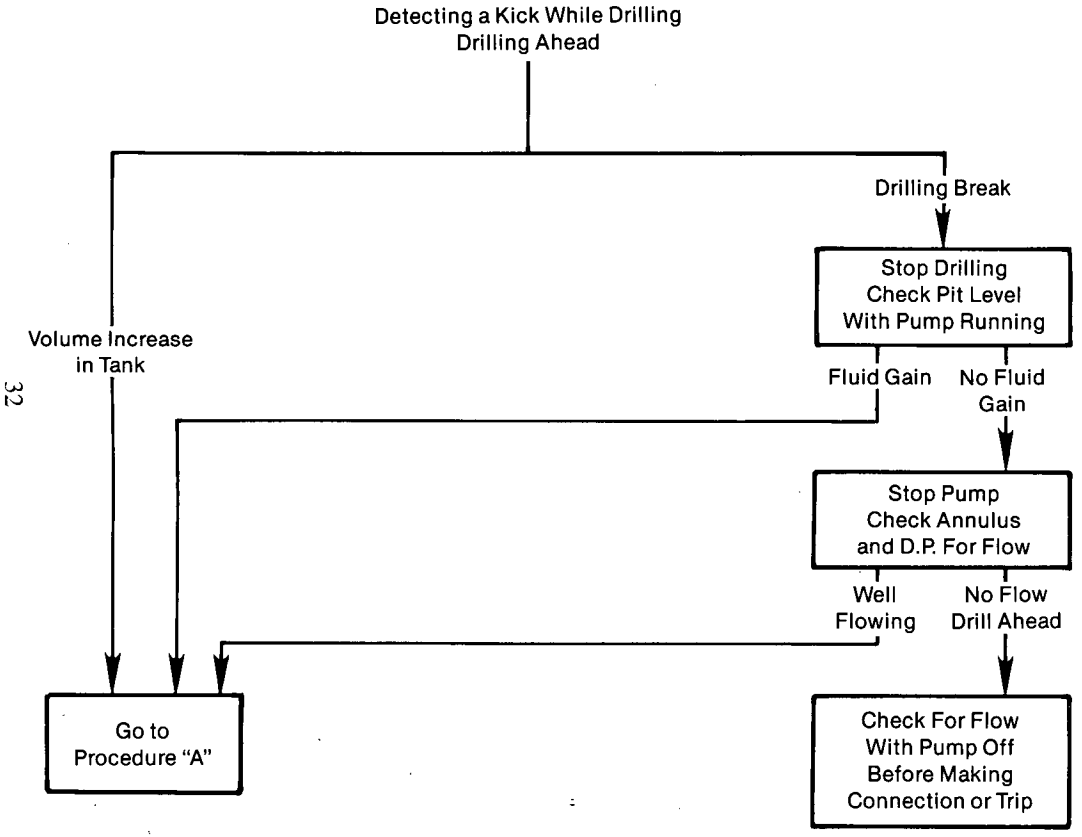
PRODUCTION

During the test period, oil and gas from the well often will be stored in temporary rental tanks, or if the well is in an established field, a flowline may be installed to an existing tank battery. The type of production facilities varies depending on the type of well (oil, gas, both) and whether the well will flow without pumping. All oil wells are produced through tubing. Gas wells do not require tubing for production but tubing can be used under certain circumstances—for example, to remove water produced with the gas.

A well can produce oil or gas alone, or both together. The Williston Basin is primarily an oil producer with variable quantities of gas produced along with the oil. Except for the shallow gas fields along the Cedar Creek Anticline in the southern portion of the region, gas wells are very rare in Montana in the formations from Mississippian down to Ordovician age, which are usually productive in other areas.

FIGURE 19

GENERAL PROCEDURES FOR WELL CONTROL



PROCEDURES

A IF WELL KICKS WHILE DRILLING OR CIRCULATING

1. If Time Permits, Pick Up Kelly to get Drill Pipe Opposite Annular Preventer.
2. Stop Mud Pump
3. If Time Permits Open Choke Line Gate Valve.
4. Close Annular Preventer.
5. Close Mud Pit Choke Gate Valve Slowly (to Near Complete Shut Off) and Then Close Mud Pit Valve.
6. Read Shut-In Drill Pipe and Annulus Pressure.
7. Read Pit Rise.
8. Record Pressures Obtained on **Kick Control Work Sheet.**
9. Call Drilling Foreman if he is Not Already on Location.
10. Open Mud Pit Valve and Mud Pit Gate Choke.
11. Circulate the Well per Instructions of the Kick Control Worksheet.
12. Continue to Circultate with Constant Drill Pipe Pressure Until the Drilling Foreman Arrives and is Prepared to Proceed.

B IF WELL KICKS WHILE TRIPPING (OR DOES NOT TAKE PROPER AMOUNT OF MUD).

1. Go Back to Bottom as Quickly as Possible.
2. If Necessary and Feasible, Install Inside BOP.
3. Consider Top Kill Procedure or Stripping in While Venting Well.
4. When On or Near Bottom, Circulate Drill Pipe Free of Foreign Fluid, Check Shut-In Pressures, and Kill Welll as Above.

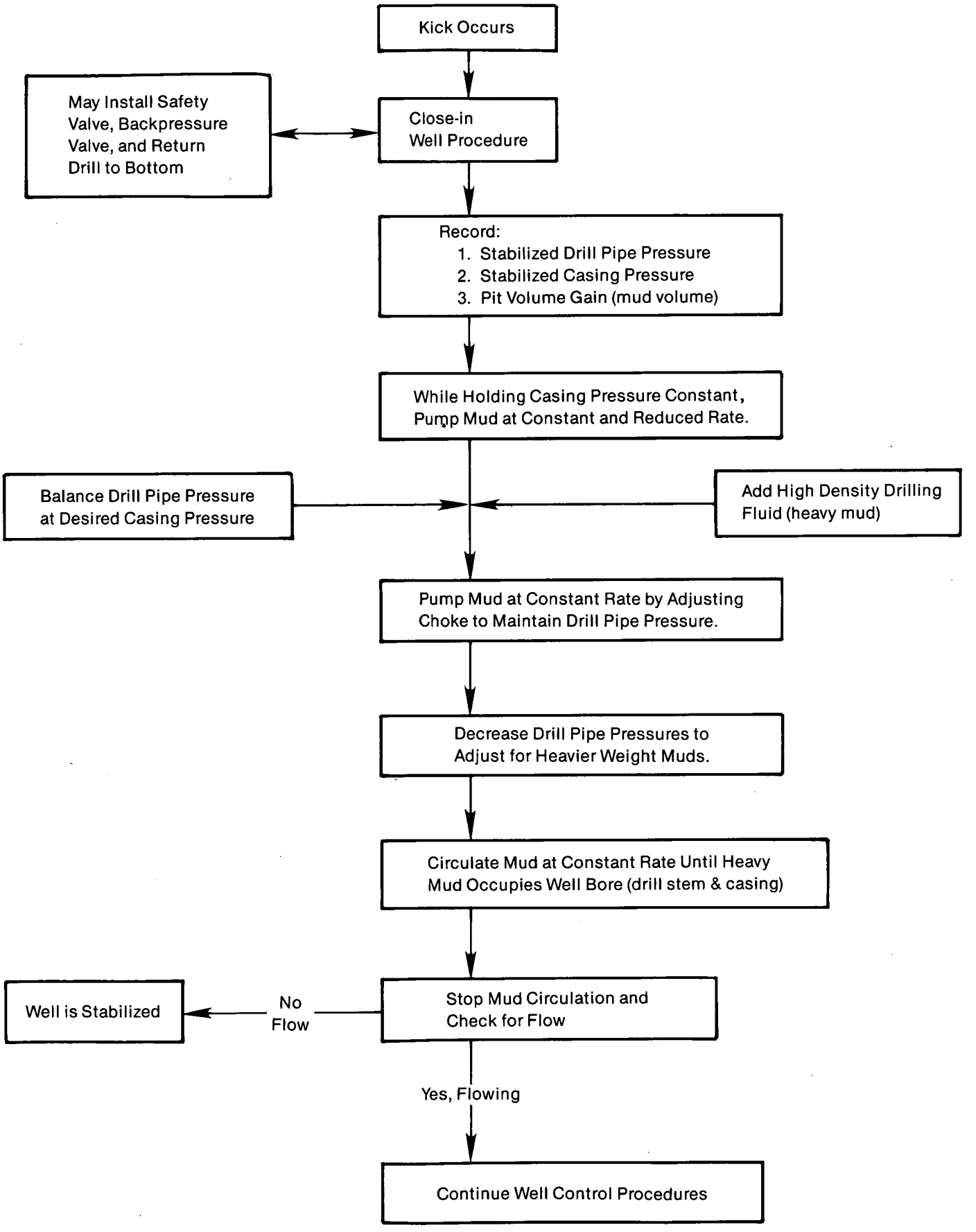
C IF WELL KICKS WHILE OUT OF HOLE.

1. Run as Much Pipe in Hole as Possible, Using Inside BOP and Stripping in if Feasible and Necessary.
2. If it is Not Possible to Run Pipe Shut Well In, Monitor Shut-In Pressure and Bleed Off to Avoid Casing Burst or Fracture Around Shoe of Casing to Surface.
3. Consider Top Kill Procedure or Stripping in While Venting Well.

Source: Shell Oil Company, 1975.

FIGURE 20

"WAIT AND WEIGHT" WELL CONTROL PROCEDURES



SOURCE: Adapted from Sohio 1986

The northeastern portion of Montana mainly produces natural gas. The Bowdoin and Tiger Ridge fields are examples of the typical shallow gas fields that produce dry gas (no gas liquids or oil and very little water) from depths generally less than 2,000 feet. The northwestern portion of Montana is typified by the Kevin-Sunburst and Cut Bank fields which produce oil with little or no associated gas. Productive formations in this area lie above 3,500 feet. Several gas fields in the western portion of northern Montana have producing characteristics similar to the large gas fields to the east.

Central Montana primarily produces oil, with virtually no gas. Some oil wells in this area produce small quantities of gas which is used to fuel production equipment. Production formations in this area commonly are less than 5,000 feet down. The Powder River Basin in southeast Montana produces oil from the Muddy formation in the Bell Creek field at about 5,000 feet; there are a few other small oil fields at similar depths. Also in the Powder River Basin, some gas is produced in small, relatively shallow fields.

Montana's portion of the Big Horn Basin produces oil in the Elk Basin area and oil and gas with condensate (natural gas liquids) in the Dry Creek area. Other oil and gas fields in the Basin generally produce from levels above 7,000 feet.

Generally, a gas well requires less production equipment than an oil well. In the shallow gas areas of Montana, surface facilities usually consist only of the wellhead and a small metal building containing the metering equipment. The wellhead for a low-pressure gas well is small and includes a valve arrangement to control flow from the well. The common method of measurement of gas is an orifice meter and clock-driven recording chart. Line pressure, temperature, and the differential pressure caused by the pressure drop as gas passes through an orifice of known diameter is recorded on the chart. Seven-day charts are common; the well is visited weekly to change the chart and check the status of the well. Higher pressure gas wells, which are not common in Montana, are equipped with a larger, heavier-duty wellhead (Christmas tree), perhaps 6 feet or more in height.

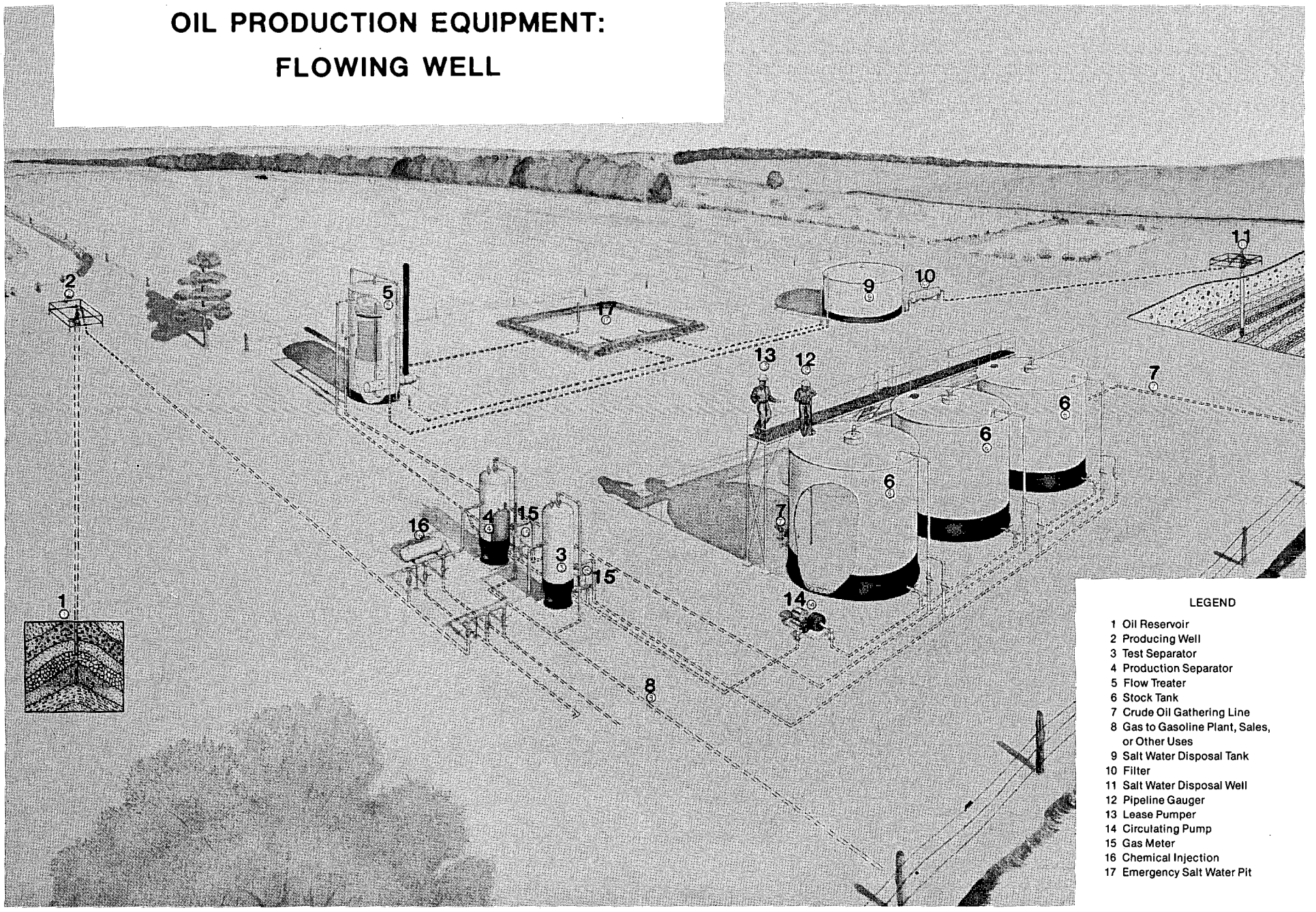
Other equipment that can be associated with gas production includes a dehydration unit to remove water vapor from the gas, a small refrigeration unit to remove liquid hydrocarbons from the gas stream, and line heaters to warm the gas and keep the lines from building up liquids and freezing. This equipment is generally quite small when installed at an individual wellsite. More commonly the individual wells in a field are tied together (after metering the individual wells' production) in a gathering system. The gathering system can be part of a larger gas plant system that includes centralized dehydration and liquid recovery equipment. Gas plants also may include sweetening facilities to remove hydrogen sulfide gas from the gas stream, and compressors to deliver the sweetened dry gas to the main gas line, usually owned by one of Montana's utility companies. Low pressure gas fields, where the individual wells do not have enough wellhead pressure to feed gas into a major line, commonly will be connected to a compressor plant. The compressor may be located in the gas field, or in another location close to the main gas line. Much of Montana's shallow gas production, particularly in the northern region, is dry gas consisting almost entirely of methane with no hydrogen sulfide or other contaminants. Much gas comes as a by-product of oil production in the Williston Basin. This gas is often transported to a gas plant for liquid recovery, compression, and sweetening, although not all of the gas produced in this region contains hydrogen sulfide.

The surface facilities and production methods for oil wells depend upon both the characteristics of the well (flowing or artificial lift) and the size and mineral ownership pattern of the field. Generally, lease terms and state rules require that oil production be accurately measured on the leasehold before the product can be transported from the property or combined with production from other leases. This may result in a number of individual tank batteries in a field, although multiple wells on the same lease may discharge into one lease battery. In unitized fields, those where all owners share in the total production, one (sometimes more in large fields) consolidated tank battery may serve the entire unit. In common storage an operator may request permission from the various interest owners for economic reasons to gather all the production in a single battery. If permission is received and the method of allocating production back to the individual leases is accepted, a single tank battery may be used to replace two or more batteries.

Tank batteries typically consist of two or three storage tanks for oil, a water tank, and a heater-treater (see Figure 21). Oil storage tanks provide several days of production storage. For large capacity wells it may be impractical to install tanks for more than one or two days storage. Since all wells naturally decline in production, operators will generally install tankage to meet production needs for the longer term rather than installing a large number of tanks that may not be needed within a few months after production begins. Tanks may hold from 200 to 500 barrels (occasionally more) each and have either bolted or welded seams. Tanks are plumbed together such that each tank can be filled and emptied separately, and the tanks can be equalized and circulated one to another with a small centrifugal pump, or by gravity. Tank contents can be pumped (circulated) through the heater-treater. Tanks are commonly filled from the top and emptied (for sales) from the bottom.

Oil wells often produce water along with the oil. Water can either be free or emulsified with the oil, or some combination of free water and emulsion. Heater-treaters are one type of equipment used to separate the water from the oil (see Figure 22). A heater-treater is used to heat the mixed water and oil to break the emulsion and free the water from the mixture. The fluid is seldom heated to more than about 170 degrees Fahrenheit. The treater is equipped with a float

FIGURE 21
OIL PRODUCTION EQUIPMENT:
FLOWING WELL



SOURCE: API, 1981, Primer of Oil and Gas Production

valve arrangement and periodically dumps water and oil through separate lines to the water and oil tanks. A gas line at the top of the vessel removes gas and vapors.

Free water knockouts and gun barrel tanks are other types of equipment used to remove free water from the oil. These are usually unheated vessels that hold the oil and water mixture until gravity separates the two components.

A flowing oil well usually does not require any surface equipment except for the wellhead and valves to control the flow. Flowing wells produce through a choke assembly that can be adjusted to maintain a more or less constant flow and back pressure on the well. Oil flows from such wells through small-diameter tubing (2 3/8 to 2 7/8 inch is common) suspended from the wellhead and extending down to near the pay zone. Government regulations require that flowing wells must be equipped to flow through tubing, as less reservoir energy is needed to push oil up the tubing than would be required to push oil up the casing.

The drive mechanism of the individual reservoirs largely determines the production characteristics and recovery from the reservoir. In a gas drive reservoir, oil is forced to the wellbore by the pressure of gas dissolved in the oil. As oil is removed and the reservoir pressure reduced, less energy is available and the production declines. When the reservoir pressure falls below that needed to support the hydrostatic pressure of a full column of oil, a flowing well ceases to flow.

In a water drive reservoir, energy is provided by water pressure from formations surrounding and/or underlying the oil-bearing strata. With a strong water drive, wells may flow for a long time before artificial lift is required. A water drive generally provides the greatest natural recovery from a reservoir.

Once an oil well ceases to flow, some method of artificial lift must be installed to continue producing the well. In areas where sufficient natural gas at relatively high pressure (usually at least 250 psi) is available, a gas lift may be feasible. This method injects gas into the oil to lighten the fluid and lift it to the surface. Gas lift requires little more surface equipment than a flowing well.

Another method of extracting oil is to use a submersible electric pump. Such a pump requires little more surface equipment than a flowing well. The electric motor and pump assembly is run into the well on the tubing string. These pumps are generally installed in high rate wells and can move several thousand barrels per day of fluid, depending upon the horsepower and capacity of the pump assembly and the reservoir characteristics. The surface equipment includes power lines and a recording ammeter to monitor the pump's power usage. This type of artificial lift requires 3-phase 440 volt electric service.

A submersible hydraulic pump also can be used for artificial lift. In this producing method, hydraulic fluid (usually crude oil) is used to power a down-hole hydraulic motor and pump. Typical surface facilities include the power oil pump, a power oil tank, and a riser that fits on top of the wellhead. The power oil pump is usually a small electric-driven positive displacement pump, although a gas engine can be used.

The rod pump method is the most common artificial lift. This method uses a mechanical pump installed in the tubing and operated by rods that extend to the surface. Both large and small capacity wells can be produced by rod pumps, as the pumps are available in several sizes and stroke lengths. The surface pumping equipment most commonly associated with rod pumped wells is the "rocking horse" or beam pumping unit (see Figure 23). The surface pumping unit is powered by an electric motor or internal combustion engine. Pumping units are available in various sizes to meet the needs of a given installation. Design criteria for a pumping unit include well depth, fluid production capacity, and weight of the produced fluids. The deeper the well, the larger the pumping unit required, because the deeper wells must operate with longer, heavier rod strings and greater fluid weight. Wells that produce a large percentage of water may require a larger unit than the same depth well that produces mostly oil. High capacity wells may need a large, long stroke pumping unit.

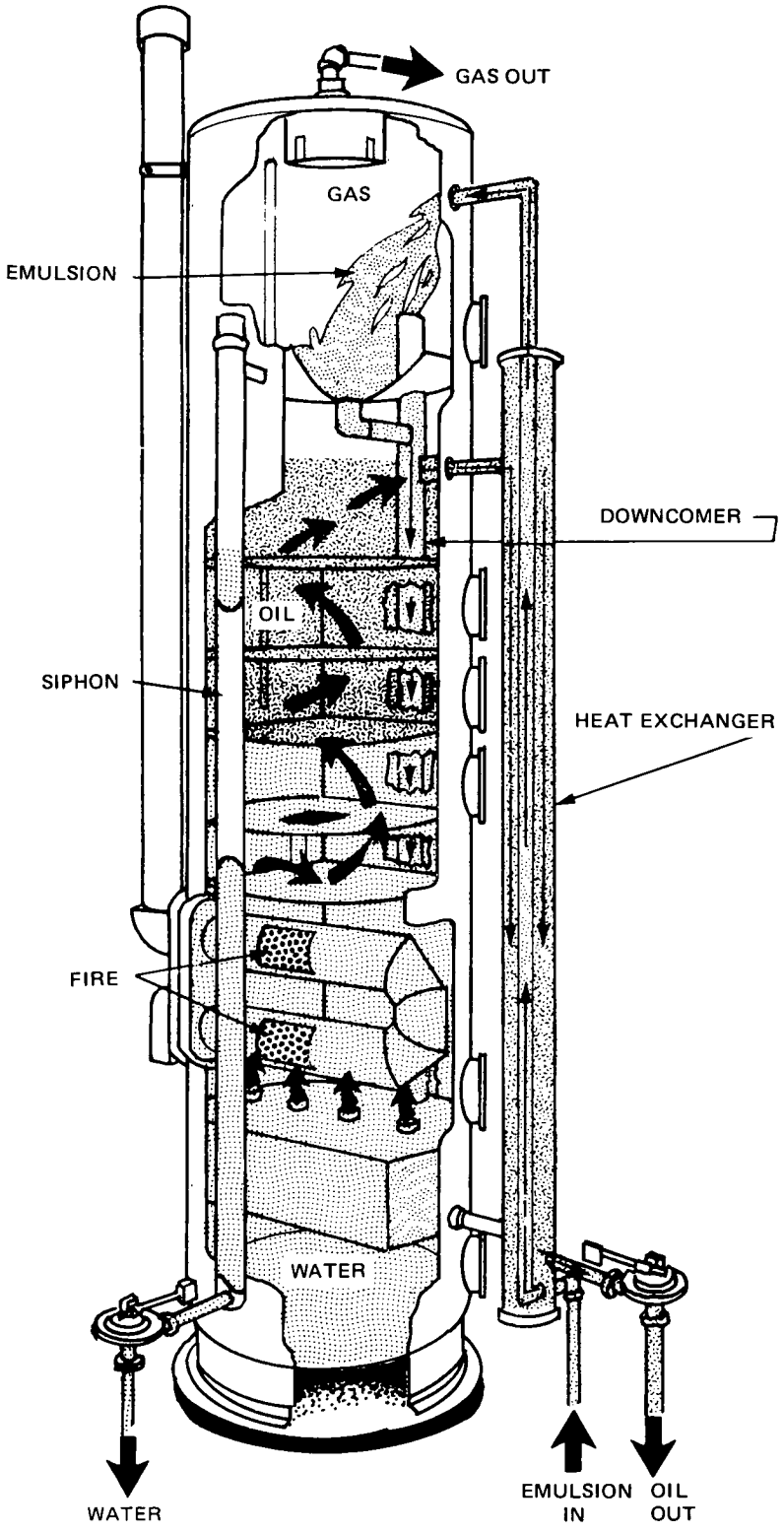
The type of motor or engine used on a pumping unit depends largely on whether electricity is available. Electric motors are the first choice, due to reduced maintenance and operating cost. If enough natural gas is available, a natural gas engine can be used, and if not, propane can be used for fuel. Gas engines can be either large-bore, slow-running, single-cylinder engines, or multi-cylinder, higher RPM engines. The multi-cylinder engines generally run more quietly than the single-cylinder "Ajax" type engine. However, the single-cylinder engines are exceptionally durable.

PRODUCED WATER DISPOSAL

Since many oil wells and some gas wells produce water along with the oil and gas, water disposal facilities are necessary at well sites or tank battery facilities. Some of the water produced in Montana is relatively fresh (less than 3,000 mg/l total dissolved solids in the water) and some is saline. Most of the water produced in the Williston Basin is saline and some is much more salty than seawater. Water produced in other areas of the state is relatively fresh, although water quality varies depending upon the formation being produced. Most salt water is disposed of in injection or disposal wells. Some of the fresher waters are stored in earthen pits and allowed to evaporate. Water of adequate quality is allowed to be discharged for beneficial use to surface impoundments under the discharge permit rules of the Department of Health

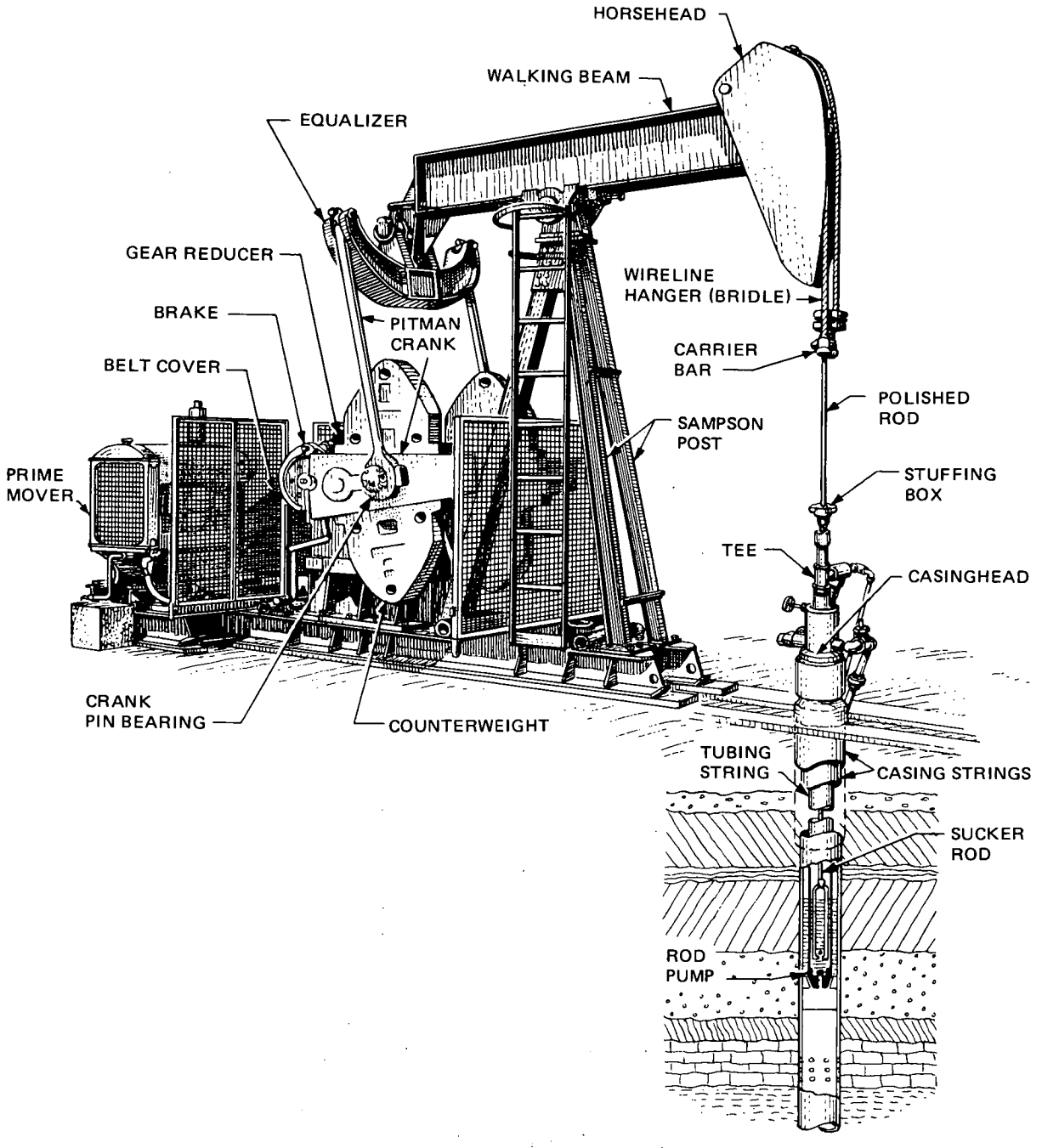
FIGURE 22

CUTAWAY VIEW OF VERTICAL HEATER-TREATER



Source: PETEX, 1982. Fundamentals of Petroleum.

FIGURE 23
ROD PUMP AND COMPONENTS



Source: Courtesy Petroleum Extension Service (PETEX)
The University of Texas at Austin, 1982.
Fundamentals of Petroleum.

and Environmental Sciences. Unless earthen pits are located in heavy clay or other impermeable soil, they must be sealed or lined to prevent leakage to groundwater. Earthen pits generally are not suitable for evaporation of large quantities of water, as the evaporation rate limits the ability of a pit to dispose of the water. Most of eastern Montana is a net evaporation area (evaporation exceeds precipitation), but the size and number of pits needed to evaporate large amounts of water generally exceeds what a prudent operator would want to build and maintain.

The process of water disposal through injection wells is similar in some ways to the use of water flooding in the enhanced recovery of oil. The principal distinction is that disposal wells inject water into a nonproductive formation, or the nonproductive portion of a productive formation.

All injection wells are completed and operated in the same manner whether for disposal or for enhanced recovery. Typically, the injection well is a perforated completion. The casing is set through the injection zone, cemented in place from the bottom of the hole to a point 100 feet or more above the zone. The casing in the zone is then perforated with a perforating tool. Tubing is run into the well along with a tool to seal the space between the tubing and the casing (injection packer) and the packer set just above the injection zone. The packer and tubing isolate the portion of the casing above the packer from the injection fluid and allow the annulus (space between the tubing and casing) to be monitored for leaks. This annulus is often filled with a corrosion-inhibiting liquid (a small amount of potassium chloride mixed with water is common). If the injected fluid is corrosive, the inside of the tubing may be coated with plastic.

The surface facilities for a disposal well are usually located close to the well. These facilities may be only a water tank and pump (usually electric). Disposal wells normally are operated by the producer and are an integral part of the operation for a given field or group of wells. One disposal well may serve one or several producing wells, with water brought to the disposal facility by flowlines from the production tanks. In some areas, there are commercial disposal wells, and water usually is brought to these wells by many operators. Commonly this water is trucked, although pipelines are used in some fields. Commercial facilities usually have cement pits or tanks to allow settling time before the water is injected. Water from drilling pits is sometimes brought to these wells and allowed to sit long enough to settle out any mud that might plug the injection zone.

ENHANCED OIL RECOVERY

Wells that use gas or water pressure to produce oil usually leave 75 to 80 percent of the oil in place. Additional oil can be produced through enhanced recovery, which includes secondary recovery (usually a waterflood), tertiary recovery (generally follows waterflooding and may include injection of CO_2, polymer, or other chemical), and pressure maintenance (may be water injection or gas repressuring to keep reservoir pressure relatively high). A secondary recovery project may recover an additional 10-15 percent of the oil, while a tertiary project may recover an additional 10 percent. Enhanced recovery projects are highly influenced by economics and oil prices. Very few new secondary or tertiary projects have started in Montana in recent years.

Before an enhanced recovery project is begun, it is usually necessary to pool the interests of the various parties (both working interests and royalty owners), establish a single unit operator, and provide an acceptable method for sharing the proceeds and costs of production. Once a unit is established, each leasehold owner and operator shares in production from the unit in proportion to the allocation schedule agreed upon. In essence, the unit agreement dissolves the lease boundaries and provides flexibility to convert existing wells, and drill new wells for injection or production without concern for the interior property lines or ownership differences. Some enhanced recovery projects may be implemented on a cooperative basis without the formation of a unit, but these are usually small projects involving only one or two leases.

Some fields and formations are not amenable to waterflooding or other enhanced recovery processes. Many of the relatively new Red River fields in the Williston Basin, for example, are too small for either injection or waterflood to be considered. Also, many of the carbonate reservoirs (limestone and dolomite formations) produce from natural fractures in rocks that have little porosity or permeability. It is difficult to effectively waterflood such formations, as the injected water will tend to follow the fracture system without displacing oil from the rock. Some carbonate reservoirs do respond to waterflooding if the production is from the rock porosity and not from fractures. For example, there are very successful Red River waterfloods along the Cedar Creek Anticline in southeastern Montana and in other Red River fields in the Williston Basin.

Sandstone reservoirs are generally suitable for waterflood if they are big enough to warrant the expense of the project. The Tyler sandstone formation in central Montana, for example, is being effectively waterflooded in a number of fields.

The source water for waterflooding need not be drinking water quality and often is not. The water may be softened to remove minerals or treated with bactericide and corrosion inhibitors.

Water for waterfloods is generally obtained by recycling the water produced from the same formation. Additional (make-up) water may be obtained from the water produced from other formations or from other oil fields nearby. In some cases, other water sources may be used, including water wells and (rarely) surface water. The primary concern in using water not from the oil-bearing formation is

the water's compatibility with the existing formation water. Dissolved minerals in the make-up water may be incompatible with the water in the formation, causing precipitation of insoluble precipitates which could plug off the formation. Also, dissolved oxygen or other gases common in surface water could cause excessive corrosion of equipment. Bacteria and micro-organisms (also common in surface water) can flourish in the injection water system and cause formation plugging or corrosion problems.

The surface facilities for a waterflood project are often located centrally in the field or unit. These facilities can be quite large. They include water storage tanks, water treating equipment, injection pumps, and the piping manifolds and volume/pressure measuring equipment for the injection wells. The waterflood plant may be manned on a continuous 24-hour basis. The polymer (for tertiary projects) or other chemicals such as corrosion inhibitors usually are stored and mixed at the plant. In a unitized project, there often is very little surface equipment at the wellsite. The injection lines leading to these wells are buried, and sometimes the injection well itself opens into a small insulated shed or enclosure.

A tertiary recovery project may include injection of CO_2 or chemicals, steam flood, or steam soak methods. A small one-well CO_2 pilot project was tried in Montana using trucked CO_2. Another small project is now under way, injecting naturally-occurring CO_2 from one well into another nearby well. A steam soak project (steam is injected for a period of time to enhance production) was tried in Montana, but has been discontinued because of cost.

Several polymer injection projects have been approved in Montana. In some of these projects, polymer mixed with water is injected on a continuous basis, and in others polymer-bearing water is injected for a period of time, followed with injection of plain water. Guar gum, a natural thickener, is sometimes used in place of the artificially manufactured polymers. The polymer or guar changes the viscosity and flow properties of the water to cause better displacement of oil from the rock, or to restrict flow in the high permeability zones which have already been flushed with water, causing water to flow into zones of low permeability.

WELL REPAIR AND MAINTENANCE

Some repair or reworking is likely to take place during the life of a well. A distinction is generally made between well repair and a workover. A workover may include deepening the well to another zone, or performing a major well stimulation project. Well repair may be required to remove and replace the pump or fix a broken ("parted") rod string. Well repair also may include tubing removal and replacement. The equipment needed for repair work is usually small and portable. A rod-pulling rig can be little more than a truck with a pole mast ("gin pole") and the necessary hoisting equipment and tools to pull the rods and pump. For deeper wells and jobs that require removal or repair of the tubing, a workover rig may be used. These are truck-mounted rigs with a telescoping derrick and heavier duty hoisting equipment than the small "pulling units." Some workover rigs can do some limited drilling: for example, drilling out the cement left in the casing after a remedial cementing operation. Pulling units and workover rigs are not usually equipped with lights and a generator and normally operate during daylight hours. Well repair work is often done in one day or less. A pulling unit can service two or three and sometimes more wells in a day.

Workovers generally involve a more extensive operation. Workover rigs may be on site for two or three days to a week or more, depending on the operation being performed. In a case where the workover consists of plugging back an existing well to a new but higher stratigraphic pay zone, the workover rig is rigged up over the hole (some surface equipment is removed or moved away to allow access to the well), and the tubing and rods are removed and stood back in the mast or laid down on the ground (on a wood or metal rack). The old zone must be plugged. A cement plug can be set opposite the perforations by running tubing to the bottom of the zone to be plugged and pumping cement down the tubing. The tubing is withdrawn, leaving the cement to set in place. Another method uses a wire line plug (cast iron bridge plug) run on electric cable to a point above the perforations; and set with a small explosive charge that expands the plug and seals it against the casing walls. If the bridge plug is capped with 2 to 5 sacks of cement, it is considered a permanent plug. The cement is placed on top of the plug with a dump bailer, a pipe with a trip mechanism at the bottom. When the bailer hits the plug, the cement inside is released on top of the plug. After the old zone is plugged, a perforating gun is lowered to the new pay zone and holes made in the casing. If the new zone produces without stimulation, the production tubing is run back in the hole and secured. Rods and pump are replaced, and the wellhead and pumping equipment is put back in order and turned on.

Well stimulation may be necessary in newly completed wells, in wells recompleted to a new zone, or when production has declined and needs to be restored. Typical well stimulation treatments include acidization and hydraulic fracturing. Small acid treatments are often given to a well soon after the productive zone is perforated. These jobs use relatively small amounts (500 to 1000 gals) of acid to clean the perforations and formation and remove drilling mud. Larger acid jobs are used to dissolve the formation rock itself and increase the size and number of flow channels to the wellbore. These jobs may use 10,000 gallons or more of hydrochloric acid. Acid is typically diluted with water to 15 percent concentration. In some cases, 28 percent acid will be used. Acetic acid is usually added to prevent the acid from attacking the steel casing and tubing. Hydrochloric acid is diluted and brought to the location in large tanker trucks. Acid is pumped down the well into the target formation and left in contact with the rock until all the acid is neutralized.

A fracture treatment is the use of hydraulic pressure to physically crack rock so oil can flow more freely. "Proppants" such as sand, glass beads, or other substances may be added to hold the fractures open after the pumping stops. Proppants must be strong so that they are not crushed by the weight of the formations. "Fracture fluids" used for cracking the formations may be thickened water, crude oil, refined oil, or natural gas condensate. Trucks carrying proppant and frac fluid (in separate trucks), and high pressure pump trucks are brought to the well and hooked together through a manifold to allow mixing of the frac fluid with the proppant; the mixture is blended and pumped on the site. The pumping rate, pressure, and fluid-proppant blending all must be closely monitored to achieve the desired results. Large fracture treatments may involve several thousand gallons of fluid, thousands of pounds of proppant, and many pump and transport trucks.

In some cases, combination acid-frac jobs may be desired. These involve both the acidizing and fracturing procedures. Acid is used to etch the surfaces of the fractures, rather than using proppant to hold the fractures open.

Acidizing, fracturing and acid-fracturing are suitable treatments for limestone and dolomite formations. Sandstone formations can be successfully fractured but are not suitable for acidization except for small mud cleanout jobs, because the sandstone does not react to acid.

Following treatment, and often during the initial stages of testing a new well, the well is swabbed. This involves pulling a rubber or synthetic swab cup assembly up the well to induce flow from the pay zone. The swab tool is designed to allow free downward movement, but to form a seal against the tubing wall when pulled up. Swabbing is done to recover the "load" from the well, which could be the spent acid water from an acid job, or the fracture fluid from a frac job. Material scrubbed from the well may be conveyed to tanks if it is oil-based fluid, or to the pit if it is water.

WELL ABANDONMENT AND SITE RESTORATION

SITE RESTORATION

Wells that are completed as dry holes are generally plugged with the drilling rig on location. Plugging is accomplished by placing cement through the open-ended drill pipe opposite porous formations, or as necessary to ensure at least one plug each 2,500 feet. A plug is set at the base (shoe) of the surface casing, and another is set at the top of the surface casing. A dry hole marker is often placed at the surface to identify the well location. The marker is usually a piece of 4-inch pipe about 10 feet long, with 4 feet above general ground level, and 6 feet embedded in the cement of the surface plug. The top of the pipe is usually welded shut. If the surface owner does not wish the dry hole marker installed, the surface casing is cut off at least 3 feet below ground level, and a plate is welded to the top of it.

Surface restoration begins after the drilling rig and equipment is removed from the site. Typically, a period of time is allowed for the liquids in the reserve pit to evaporate. Alternatively, the pit liquids may be skimmed from the pit, loaded into trucks, and hauled to a disposal well or to another drilling operation for use as drilling water. Removal of the pit liquids is most common in the Williston Basin. In some cases where the drilling fluid is a freshwater/clay system, the pit contents are removed and used to line stock ponds and dams. This is done only at the request of the landowner, and is most common where surface soils are gravelly or otherwise very permeable.

RESERVE PIT RECLAMATION

Reserve pit reclamation methods also vary among the oil and gas producing regions, with certain methods being unique to the Williston Basin. In most areas of the state, except for the Central and South-Central regions, the "top water" or fluids remaining on the surface of the pit are suctioned up and taken to disposal wells. In cases where drilling results in a dry hole, the fluids may be pumped back down the hole as part of the plugging operation. In some cases, particularly where there are no disposal wells nearby or where the landowner is not immediately concerned about resuming use of the surface (e.g., in rangeland), the pit may be left to dry out for three or four months. Sometimes, small amounts (less than one barrel) of oil residue remain after the top water is taken off or evaporated; this oil is skimmed or vacuumed up.

At this point the pit is filled in. Dirt is usually mounded on top to allow for settling. Occasionally a landowner will request that the pit muds be taken out and used to help plug or reinforce a water reservoir or dike. Also, landowners have occasionally requested that the reserve pit muds be spread on their fields. However, the muds are typically left in the pit.

In the Williston Basin, a common method of pit reclamation is to break or tear the liner after the top water has been hauled away, dig trenches leading from the bottom of the pit for any remaining fluids to drain out, and then backfill the pit. The layer of mud in the bottom of the pit is

typically about two feet thick. About two feet or so of soil is added initially and the pit may be left to settle for up to a year before adding a final "top dressing" of soil. The trenching method is used because salt-based muds and fluids take longer to dry out than fresh water muds and the pits in the Williston area tend to be larger than in other parts of the state, requiring a longer period of time for fluids to evaporate.

Except in rare instances, the trenching method is not used for federal wells because BLM requires other methods of pit reclamation. In most cases where a liner is installed, BLM requires one of three options. One option is to remove the top water and mud slurry for disposal off site. Two options for on-site disposal are allowed. Once the top water has been removed, the mud slurry is left to dry out, either by natural evaporation or by solidification by addition of chemical drying agents. The liner is then folded over and the pit is reclaimed.

Along the Cedar Creek Anticline, the pit liners are commonly folded in and buried with the contents intact. This practice requires a special technique and is labor intensive. Because the Cedar Creek area is pasture land rather than cropland and because the soils tend to be drier and primarily consist of heavy clays, the muds do not tend to remain soggy or create the other problems for pit reclamation. Also, there are numerous pipelines throughout the Cedar Creek area and trenching could interfere with these lines.

After the reserve pit dries out enough to support heavy equipment, the pit itself is backfilled and the site recontoured to conform with the original land surface. In some cases the landowner will request that the site be left level as a livestock feeding or storage area. Topsoil is spread over the pit area and the location. Reseeding is done to the landowner's specifications. If the location is in a cultivated area, the dry hole marker requirement is waived.

WELL ABANDONMENT

Producing wells that decline in production to the point they cannot be operated profitably may be idled or shut in. Wells in this status usually are still mechanically capable of producing, since the production equipment has not been removed. Some wells are idle due to mechanical problems, and will be returned to service when repaired. Depending upon the productive capabilities of the particular well, repairs may be deferred for a considerable period of time. Good wells are usually repaired quickly.

Wells may be placed in a temporarily abandoned status, pending future use. Depleted wells may be held for use in a future waterflood program, or as a disposal well. There may be several temporarily abandoned wells in active enhanced recovery projects. These wells may be used as observation wells, or held for use as injection wells (and occasionally as producers) as the project proceeds. Temporarily abandoned wells usually have much of the surface and downhole production equipment removed, and may be equipped with a downhole retrievable plug, or a drillable cast iron bridge plug to isolate the producing formation.

Wells for which there is no future use are permanently abandoned. Since these wells are equipped with production casing to surface, the plugs may be either cement or bridge plugs placed with a wire line or a combination of both. If the operator proposes to recover a portion of the production casing, the "free point" of the casing, or portion of casing above the plug, is located, and the casing is "shot off" with an explosive charge, or a chemical or "acid cutter." A few joints of the casing are removed and a cement plug is placed across the "stub" of casing left in the well. Depending upon the amount of casing removed, additional "open hole" plugs may be needed to plug off porous formations.

If no production casing can be recovered (or the amount of recoverable casing is not worth the cost of recovery), the well may be entirely plugged with one or more cement-capped bridge plugs. A surface plug will be set in the top of the casing, and cement placed in the annular space between the surface casing and production casing. In older wells, the surface casing may not be adequate to fully protect the fresh water zones in the area. Generally, the annular space between the production casing and open hole is filled with either the cement used in completing the well, or the drilling mud used to drill the well. Under normal circumstances the hydrostatic pressure and the plugging properties of the drilling mud is sufficient to prevent fluid migration in the uncemented portion of the hole. When the surface casing is not deep enough, or where the existing equilibrium in the annulus could be affected (e.g. a nearby waterflood project), the production casing will be perforated and cement pumped in the annular space between the surface casing and production casing. The perforations may be just below the surface casing "shoe," or deeper if the surface casing is not adequate to cover the fresh water formations.

Surface restoration of the wellsite is similar to that done for a dry hole. All equipment, including the tank battery (if present at the well), is removed. Sometimes a small emergency pit or "workover" pit is present, and this has to be backfilled. If a cement base constructed for the pumping unit is present, it will be buried onsite or broken up and removed. Flowlines or gas lines will be removed or abandoned in place (commonly these lines are buried deep enough that they will not interfere with farming machinery). After the equipment has been removed, the location is recontoured and compacted soil is scarified and the site reseeded.

CHAPTER THREE

ROLES AND RESPONSIBILITIES FOR OIL AND GAS ACTIVITIES

One of the purposes of this Programmatic Impact Statement is to describe the regulatory framework that governs oil and gas drilling and production in Montana. Any description of the differing authorities and roles of surface and mineral owners, operators and agencies of federal, state and local government agencies involved with oil and gas drilling and production produces a complicated mosaic of overlapping responsibilities. This section briefly describes the role of each of the various parties and agencies that participate in oil and gas development activities, placing emphasis on drilling and production.

LEASING

The first phase of oil and gas activity is leasing, where rights to explore for and develop oil or gas resources are acquired. Oil and gas leases are contracts between mineral owners and oil and gas operators. Mineral owners may be private parties, corporations, or governmental entities. Leases are obtained by negotiation with private and corporate owners, and in the case of government agencies, through open filing or by competitive bid. The lease instrument grants the lessee the right to explore for and remove the minerals subject to payment of rentals and royalties to the lessor.

The Board of Oil and Gas is not involved in the leasing process. While the lease grants certain rights to the oil and gas operator, actions taken to drill and produce oil or gas are subject to the regulatory requirements of the Board.

PRIVATE LEASING

An oil and gas lease is a contract between the mineral owner and oil and gas operator for the purpose of exploring for and developing oil and gas minerals. In most cases the operator is granted the right of access to the surface of the land in order to perform exploration and development activities. The oil and gas lease contains provisions relative to the use of the surface by both parties while the contract is in effect. Land owners usually negotiate special surface use conditions along with other provisions in the oil and gas lease.

Often the mineral ownership is severed from the surface ownership resulting in a "split estate." In these instances the mineral owner or his lessee has the right to occupy and use as much of the surface as is reasonably necessary to explore, produce and remove the oil and gas. The surface owner is entitled to compensation for any damage done by the mineral activity. Owners of these split estates can be private parties, corporations or government entities. Montana has a Surface Owner Damage and Disruption Compensation Law (82-10-501 et. seq., MCA) which is more fully discussed under the section on drilling.

MONTANA DEPARTMENT OF STATE LANDS

The Department of State Lands (DSL) manages about 6.4 million acres of minerals and 5.20 million acres of surface held in trust for the benefit of the public schools. Since 1927, the policy of the Board of Land Commissioners has been to lease these lands for purposes providing the greatest long-term monetary benefit for the school trust. DSL has leased varying amounts of its land for oil and gas development. Although nearly all of the 6.4 million mineral acres is available for leasing (excluding some tracts that have been withdrawn), the most ever under lease at one time was 5,050,726 acres, or 79.1 percent of the land, in September of 1982. The smallest amount of land under lease in recent history was 1,831,728 acres (28.6 percent) in December of 1987, as a result of the falling prices of oil and gas. Excluding interest payments, proceeds from the sale of oil and gas leases, and rentals and royalties from such leases, provided $8,388,565 to DSL in fiscal year 1987. This amounts to about 33 percent of the total income DSL received from all of its sources of income combined, including timber, mining, agriculture, and grazing. The Board of Land Commissioners and DSL function as a leasing agent for other state agencies that control land and mineral interests, including the Department of Highways and Department of Institutions. The Board of Land Commissioners has adopted rules and regulations governing leasing of trust lands for oil and gas development.

DSL uses an environmental checklist to review each proposed lease sale and all proposed oil and gas activities that have potential to disturb the land surface. When potentially adverse impacts are identified through this review, a more detailed environmental review is conducted. DSL does not typically produce detailed impact statements for individual oil and gas drilling operations, but has conducted one expanded review of drilling in a detailed PER. DSL has required a phased review with analyses conducted at both the drilling

and production stages of oil and gas operations when a PER identifies that under certain conditions the potential for significant cumulative impacts exists.

Through the leasing process, DSL retains authority to place whatever reasonable stipulations are deemed necessary to protect the surface values of the land and its environmental resources. Stipulations usually are determined as a result of the checklist or subsequent more detailed environmental review, and may include restrictions on surface activity to prevent stream sedimentation, surface erosion, fire, weeds, disruption of seasonal wildlife use, or to protect significant historical or archaeological resources. DSL rules require that the surface owner or surface lessee be consulted regarding the location of all facilities, including roads, in order to minimize conflicts with use of the surface.

MONTANA DEPARTMENT OF FISH WILDLIFE AND PARKS (DFWP)

DFWP manages approximately 350,000 acres of land for the fostering of fish, wildlife, and recreation. Of this total surface area, the agency owns the mineral rights on about 75,000 acres. DFWP has leased a small portion of its mineral holdings amounting to about 980 acres. The Montana Fish and Game Commission has adopted policies and procedures for leasing of DFWP-owned oil and gas minerals. Where it controls both surface and mineral estates, the Commission has not allowed surface occupancy of its lands. However, such action may be allowed for valid reasons such as protection against depletion of its oil or gas minerals by drainage.

According to DFWP rules, an environmental review is prepared to determine whether leasing would jeopardize the use of the land, and, if leasing is allowed, under what conditions. Much of the land owned by DFWP was acquired with state dollars matched by various federal funds. Expenditure of this money for property requires DFWP to manage the land to minimize conflicts with the purposes for which the land was purchased.

U.S. BUREAU OF LAND MANAGEMENT

The Mineral Leasing Act of 1920 gives the Bureau of Land Management (BLM) the duty and responsibility to regulate all phases of oil and gas activity involving federal minerals. BLM also is responsible under the Federal Land Policy and Management Act of 1976 to review and approve oil and gas surface activities in compliance with land management plans adopted for each BLM district. Overall, the National Environmental Policy Act imposes upon BLM an obligation to determine the environmental consequences of its action under these laws and to take appropriate measures to protect the land and other resources from impacts due to federal mineral exploration and extraction.

In Montana, BLM controls mineral leasing on approximately 18,590,000 acres of BLM land and 16,753,000 acres of National Forest land. BLM controls 8,927,400 acres of surface through its various districts. Through the leasing process, BLM has considerable authority to avoid environmental impacts by placing restrictive conditions on mineral leases.

BLM conducts an environmental analysis, normally in conjunction with its resource management plans for the issuing of oil and gas leases. All federal oil and gas available for leasing, regardless of surface ownership, is subject to standard lease and special stipulations recommended by the BLM district offices or other surface-managing agency such as the Forest Service. The policy of the state BLM office is to use the least restrictive stipulations that will achieve resource protection goals. BLM leases contain standard terms allowing the protection of various environmental concerns, including aesthetics, erosion control, historical, archaeological, or paleontological resources, and threatened or endangered species. Surface use may be restricted to achieve this protection. Special stipulations are applied as necessary through BLM's individual lease reviews, but such measures can be appealed to the Interior Board of Land Appeals.

U.S. FOREST SERVICE

The U.S. Forest Service controls 16,752,700 acres of surface in Montana. The Forest Service evaluates and approves leasing and the surface use plans for drilling operations on its lands because of its responsibility for surface resources, but BLM has the responsibility for leasing and issuing a drilling permit.

SEISMIC OPERATIONS

BOARD RESPONSIBILITY AND PRACTICE

The Board's responsibility and authority over seismic operations is found in portions of two different statutes. Table 1 lists the various responsibilities of the Board and others. The proper procedures and materials to be used for shot hole plugging are determined by the Board (82-1-104(2), MCA). Also, section 82-11-123(4) authorizes the Board to require "the restoration of the surface lands to their previous grade and productive capability after a well is plugged or a seismographic shot hole has been utilized and necessary measures to prevent adverse hydrological effects from such hole or well unless the landowner agrees in writing to a different plan."

Table 1. Matrix of Responsibilities in Seismic Exploration.

Responsible Party	Action Required	Comments
1. County Clerk and Recorder	Collect $5 fee and issue seismic permit. Maintain records.	Depends on Board staff for determination of violations of law or rules.
2. County Attorney	Prosecute violations (82-1-109, 110, MCA; 46-18-212, MCA).	Depends on Board staff to forward violations of law or rules. Violations are misdemeanors, fines of $5,000 and 6 months in jail possible.
3. Board	1. Adopt rules for: a) identifying seismic crews and designating areas where activity not allowed (82-1-101(2), MCA); b) verifying that permits issued by counties are to authorized seismic crews (82-1-106(2), MCA); c) plugging shot holes and restoring surface (82-11-123(4), MCA).	(ARM 36.22.503, 504) Checks for proper and valid bond. Inspects reclamation (ARM 36.22.501, 502).
	2. Taking steps to ensure compliance with seismic requirements (82-1-106(3), MCA).	Notifies County Attorney if there are violations.
4. Operator	1. Post bond with Secretary of State (82-1-104(1), MCA).	Surety Bond $10,000 single crew $25,000 two or more crews
	2. Obtain seismic permit from county (82-1-105 et. seq., MCA).	
	3. If explosives used, file notice directly with Board (82-11-122, MCA).	
	4. Give 10-day notice to surface owner.	
5. Other Requirements:		
DSL	Seismic permit needed on state parcels when seismic work not under valid lease (ARM 26.3.230-234).	Relies on inspection of Board for proper plugging and abandonment.
DFWP	Seismic permit needed for work on DFWP lands.	Preliminary environmental review completed before permit issued. Permit may include environmental stipulations.
Forest Service	Seismic permit required on all National Forest lands (F.S. Manual 2812.2).	Processed under forest/regional mineral and environmental policies. Bond may be required.
BLM	Plan of operations and bond required (43 CFR 3045).	Processed under district oil and gas leasing program requirements.
Conservation Districts	310 Permit under Montana Natural Streambed and Land Preservation Act (75-7-101 et. seq., MCA).	DFWP assists district in review of any surface disturbing activities in or adjacent to perennial streams. Consultation with district required to determine whether activity needs permit.

Source: Compiled by Kevin Hart, DNRC.

Inspections by the Board staff generally do not occur when seismic lines are shot. The Board relies on reports seismic companies file with each county clerk to determine whether shot holes were adequately plugged. From the reports the Board's staff identifies where problems were noted and spot checks sites to determinewhether proper plugging and surface restoration has occurred.

The staff typically works with individual seismic companies to correct problems identified through inspections or by public complaints. The Board's staff has been successful working with individual operators to achieve compliance with plugging rules. The Board's staff reports that problems about seismic operations and improper shot-hole plugging are much less than they were in the past during periods of increased activity. The reduction in complaints and problems is due not only to reduced seismic activity but also to the work of reputable seismic operators and to greater efforts by the Board's staff to increase awareness about requirements for properly plugging and abandoning shot holes.

OTHER REQUIREMENTS ON SEISMIC OPERATIONS

Depending on the location of the seismic operation and ownership of the land, other requirements also may apply (see Table 1).

DRILLING OPERATIONS

BOARD AUTHORITY AND PRACTICE

Before drilling an oil or gas well, an operator must file a notice of intent to drill with the Oil and Gas Conservation Division, and receive a drilling permit (82-11-122 and 134, MCA). The notice of intent is filed on the Board's Sundry Notice, also known as a Form 2 (see Figure 24). The notice must be accompanied by the drilling permit fee and a plat showing the surveyed location of the proposed well. The fee ranges from $25 to $150, depending on the depth of the well. Based on the plat, the Board's staff determines whether the proposed well complies with the spacing required within a particular field, or whether it meets the statewide well location and setback rules.

Before a drilling permit is issued, the Board staff checks to see that a valid bond is on file with the Helena office to ensure that the operator properly plugs and abandons the well. Board rules regarding bonds are under revision and are likely to change substantially in the next 12 to 18 months.

Under established procedures, a drilling permit is granted if the notice contains the required information and meets established rules on bonding, spacing and setting of surface casing. In evaluating drill proposals, the Board staff relies on its own knowledge and on information supplied in the drilling permit application. Additional information is sometimes volunteered by operators as part of the application for a drill permit. Most commonly this information is a drilling prognosis explaining what the operator expects to find during drilling. Operators also may volunteer a drilling program and safety measures, which are required for all wells on federal land. The Board's staff typically does not contact other state agencies regarding individual drilling permits unless specifically requested to do so. Frequently, the staff will contact an operator to clarify information about a drilling proposal. In the case of wells on federal land, the staff will contact the BLM with questions.

An application for a permit to drill is typically received, reviewed and approved by the division staff the same day it is filed. No site inspections are done prior to issuance of a permit. Unless volunteered by an operator, no information is collected or analyzed in regard to surface topography, soil type, soil permeability, distance from surface or groundwaters, access issues, air quality, safety or other aspects of the drilling proposal.

The Board recognizes the highly variable drilling conditions in the state, and for this reason, the rules are general in nature. Most drilling permits are approved by the staff without involvement by the Board. The Board acts when a proposed well requires an exception to established spacing or location requirements or when an operator has had past problems complying with established rules. The Board conducts a public hearing when an exception to its rules is sought by an applicant. Exceptions are granted when the applicant can show that interests of resource conservation and prevention of waste and correlative rights will be met.

The notice of intent to drill becomes the drilling permit when stamped approved by the Board staff. A permit is stamped with notices alerting the operator that certain rules must be complied with during drilling operations. Table 2 lists the conditions most often placed on a permit to drill.

It is a goal of the Board's inspectors to visit each drilling location once while drilling is occurring. Where drilling operations last only a short time or when increased drilling activity is occurring across the state, a visit to every site sometimes is not possible.

Form No. 2 R 4-85

FIGURE 24

(SUBMIT IN QUADRUPLICATE)

TO

BOARD OF OIL AND GAS CONSERVATION OF THE STATE OF MONTANA

BILLINGS OR SHELBY

NOTICE
THIS FORM BECOMES A PERMIT WHEN STAMPED APPROVED BY AN AGENT OF THE BOARD.

ARM 36.22.307	ARM 36.22.1003
ARM 36.22.601	ARM 36.22.1004
ARM 36.22.602	ARM 36.22.1013
ARM 36.22.603	ARM 36.22.1301
ARM 36.22.604	ARM 36.22.1306
ARM 36.22.605	ARM 36.22.1309

SUNDRY NOTICES AND REPORT OF WELLS

Notice of Intention to Drill *		Subsequent Report of Water Shut-off	
Notice of Intention to Change Plans		Subsequent Report of Shooting, Acidizing, Cementing	
Notice of Intention to Test Water Shut-off		Subsequent Report of Altering Casing	
Notice of Intention to Redrill or Repair Well		Subsequent Report of Redrilling or Repair	
Notice of Intention to Shoot, Acidize, or Cement		Subsequent Report of Abandonment	
Notice of Intention to Pull or Alter Casing		Supplementary Well History	
Notice of Intention to Abandon Well		Report of Fracturing	

(Indicate Above by Check Mark Nature of Report, Notice, or Other Data)

....., 19.....

Following is a {notice of intention to do work / report of work done} on land {owned / leased} {described as follows:

LEASE TYPE ..... (Private, State, Federal, Indian) LEASE .....

.....MONTANA..... (State) (County) (Field)

Well No..... (m. sec.) (Township) (Range) (Meridian)

The well is located ..... ft. from {N / S} line and ..... ft. from {E / W} line of Sec.....

* For notice of intention to drill, write the API# or the well name of another well on this lease if one exists_____

LOCATE WELL SITE ACCURATELY ON PLAT ON BACK OF THIS FORM.

The elevation of the ground or K.B. above the sea level is .....

READ CAREFULLY **DETAILS OF PLAN OF WORK** READ CAREFULLY

(State names of and expected depths to objective sands; show size, weights, and lengths of proposed casings, cementing points, and all other important proposed work, particularly all details of Shooting, Acidizing, Fracturing.)

DETAILS OF WORK
RESULT

Approved subject to conditions on reverse of form

Date.....

By.....
District Office Agent **Title**

Company.....

By.....

Title.....

Address.....

BOARD USE ONLY
API WELL NUMBER
25
STATE COUNTY WELL

NOTE:—Reports on this form to be submitted to the appropriate District for approval.
DRILLING PERMIT EXPIRES SIX MONTHS FROM DATE OF APPROVAL.

Locate well by footage measurement from legal subdivision (Section) line and nearest drilling or producible well, if any.

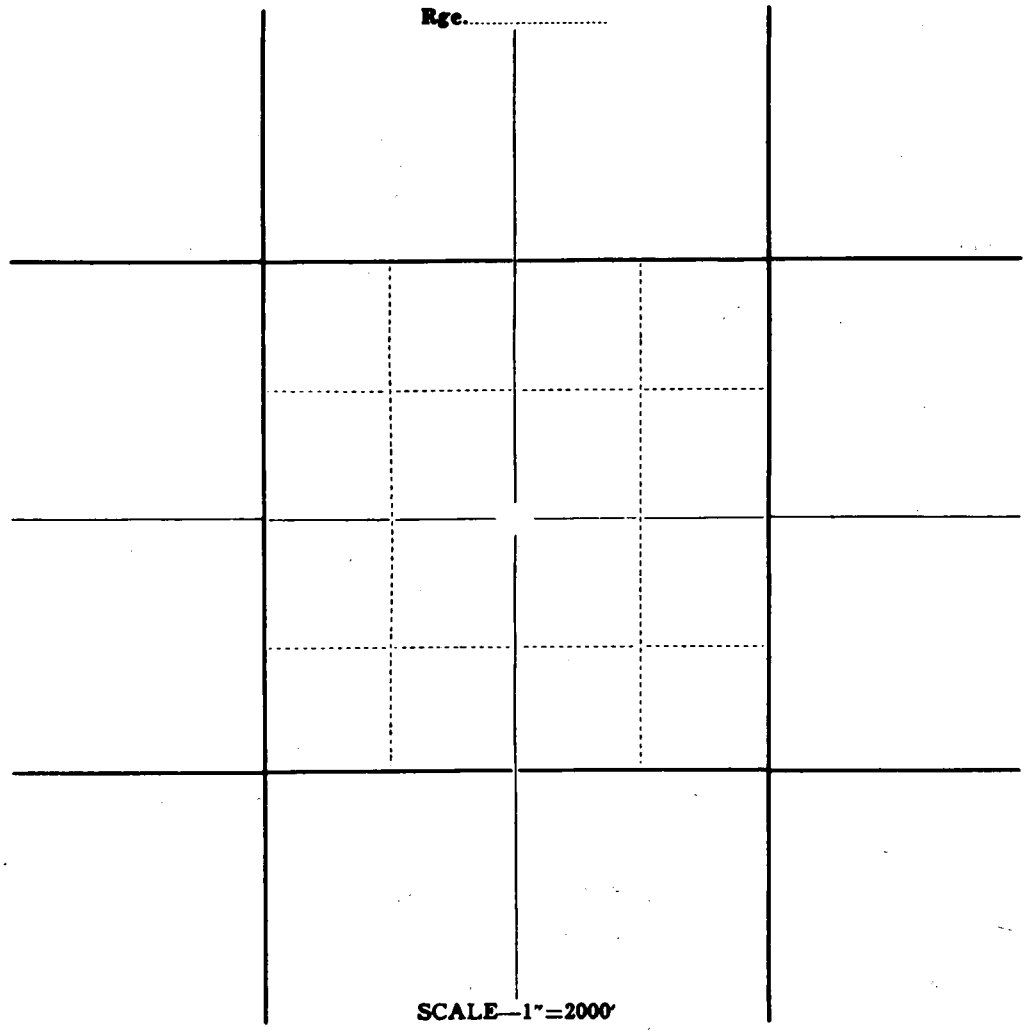
Form No. 2
File at
Billings
or Shelby

Rge......

Form No. 2
File at
Billings
or Shelby

Locate
Well
Correctly

Twp......



SCALE—1"=2000'

THE NOTICE OF INTENTION TO DRILL THIS WELL IS APPROVED SUBJECT TO THE FOLLOWING CONDITIONS:

1. Any person, before commencing the drilling of any oil or gas well or water source or injection well shall secure from the Board a drilling permit and shall pay to the Board the following amounts: for each well whose estimated depth is thirty-five hundred (3,500) feet or less, twenty-five dollars ($25.00); from thirty-five hundred and one (3,501) feet to seven thousand (7,000) feet, seventy-five dollars ($75.00); seven thousand and one (7,001) feet and deeper, one hundred fifty dollars ($150.00).

2. No well is to be spudded in unless the proper surety drilling bond has been posted and approved by the Board of Oil and Gas Conservation of the State of Montana. Date of spudding must be reported to the Board verbally or in writing within 72 hours of commencing drilling.

3. Cable tool operators must construct an adequate sump to contain all mud and water bailed from the hole.

4. Surface or conductor casing must be properly cemented by an approved method and pressure tested to determine a tight bond with the surrounding formations in case an unexpected flow of oil, gas or water should be encountered, unless special permission has been granted for formation shut-off.

5. Any production casing must be cemented unless a formation shut-off or packer is approved by the Board. Sufficient cement must be used to protect the casing and all possible productive and fresh water bearing formations exposed in the process of drilling and not otherwise protected.

6. All production casing must be tested by bailing or pressure to determine if there is a tight bond with the surrounding formations or possible leaks in the casing. The results of the test must be reported on Form No. 2, said report to include the size, weight, thread and length of casing, amount of cement used, and date work is done. If test shows failure, the defect must be corrected before any drilling operations are resumed.

7. Any contemplated change in status of a well such as to plug and abandon, deepen, plug back, redrill, alter casing, etc. must be presented on Form No. 2 for approval by the Board prior to commencement of work.

8. A satisfactory drilling record must be kept for each tour, showing top and thickness of each and all formations drilled and all other information of value, one copy of which is to be kept at the rig while drilling is in progress for examination by any authorized agent of the Board.

9. All producing wells must be marked with name of the operator, number of the well and location, using reasonable precautions to preserve these markings at all times.

10. Delivery to the Board of two copies of all surveys, reports, analyses, logs, tests, samples and core descriptions, etc., as described in Rule 36.22.1013 and one copy of all cementing records as furnished by the cementing company and described in Rule 36.22.1241.

11. All work must be done in conformity with the regulations of the Board of Oil and Gas Conservation of the State of Montana, as contained in "General Rules and Regulations," and amendments thereto, as well as regulations prescribed in lieu thereof.

Table 2. Typical Conditions Attached to Drill Permit.

36.22.1001 (1) Suitable and safe surface casing shall be used in all wells. In all wells drilled in areas where pressure and formations are unknown, sufficient surface casing shall be run to reach a depth below all potable fresh water located at levels reasonably accessible for agricultural and domestic use. surface casing shall be set in or through an impervious formation and shall be cemented by the pump and plug or displacement method with sufficient cement to circulate to the top of the well. If it becomes necessary to run a production string, such string shall be cemented by the pump and plug method or any other recognized method and shall be properly tested by the pressure method before cement plugs are drilled.

36.22.1001 (5) Only freshwater based drilling fluid may be used when drilling through freshwater aquifers anywhere within the state of Montana.

36.22.1005 (1) The operator of a drilling well shall contain and dispose of all solid waste that accumulates during drilling operations. Said waste shall either be removed from the well site or buried at the well site to a minimum depth of 3 feet below the restored surface of the land.

(2) The operator of a drilling well shall construct his reserve pit in a manner adequate to prevent undue harm to the soil or natural water in the area. When a salt base mud system is used as the drilling medium, the reserve pit shall be sealed when necessary to prevent seepage.

ACTION UNDER A DRILL PERMIT

A drilling permit is valid for six months during which an operator is free to drill the well as approved under the conditions of the permit. If the well locates oil or gas, additional approval by the Board may or may not be required before production begins, as discussed later in the section on production.

The drilling permit does not specifically grant operators any rights not already granted under the terms of the mineral lease or provided by Montana law. For example, a valid drilling permit does not grant any right-of-way or easement to allow access to the drill site. Where the surface and mineral estates are held by one owner, a lease generally grants the oil and gas operator the right of access to the lease property. Similarly, where the surface estate is held by someone other than the owner of the mineral estate, a lease grants the oil and gas operator the right of surface access, but damages can be collected by the surface owner.

If other lands must be used for access, the operator negotiates with involved landowners. Under Montana's Constitution, state law, and court interpretation, adjoining landowners have the right to refuse access to the oil and gas operator. If a landowner and operator cannot reach agreement on access issues and payments, the matter is taken to district court. An oil and gas operation can condemn lands needed for access by making the required showings under the eminent domain provision of Montana's mining law. The applicability of the eminent domain law for lands not covered by a lease during exploratory drilling is less clear than when the presence of oil or gas has been proven. When determining condemnation actions, Montana courts have generally awarded individual damage to landowners and access to the oil and gas operator on a case-by-case basis. The courts generally decide such issues with a balancing test that considers two factors—the greatest public good and the least private injury.

The Board has taken the position that matters between the operator and the landowner are subject to negotiation and that state law provides surface owners with remedies and procedures to follow in making damage claims. The following sections discuss the role of the Board and others in determining and requiring the measures to be taken to prevent damage or contamination to surrounding land and underground strata by drilling operations and production.

DAMAGE AND COMPENSATION LAW

Montana's Surface Owner Damage and Disruption Compensation law (82-10-5 et. seq, MCA) was passed in 1981 to protect the surface owners of land underlain by oil and gas while allowing for necessary development of those reserves. This law places an obligation on the oil and gas operator to give surface owners advance written notice of the drilling operations he plans to undertake. This plan must be in sufficient detail to enable the surface owner to evaluate the effect of drilling operations on the surface owner's use of the property. The operator must compensate the surface owner for loss of agricultural production, lost land value and lost value of improvements caused by drilling operations and production. To receive compensation the surface owner must notify the operator within two years after injury occurs or becomes apparent. Within 60 days of receiving the notice the operator must make a written offer of settlement to the surface owner. The surface owner may accept or reject this offer. The surface owner may make a counter offer for settlement. If this is rejected by the company, the owner may also bring

action to seek compensation against the operator in the district court of the county involved. It is the current practice in Montana to use the notice period to negotiate payment for surface damage by the operator to the surface owner in advance of drilling or production activity. These payments are calculated in accordance with the value of the surface land and the size of the projected disturbance. Remedies provided by this section do not preclude any person from seeking other remedies allowed by law, or remove responsibilities of the operator to comply and state agencies to enforce the obligations imposed upon them by state law, rule, or regulation.

STATE PERMITS, LICENSES AND OTHER LEGAL REQUIREMENTS

Several state laws apply to oil and gas drilling and production operations under various circumstances. The requirements of each permit, license, or other performance standards are listed in the following section. The level of MEPA review performed by the various agencies when issuing permits or other approvals is determined on a case-by-case basis according to the degree of impacts associated with each permit. The discussion includes information requirements, provisions for exemptions from requirements, and the application of these requirements to oil and gas drilling.

DEPARTMENT OF HEALTH AND ENVIRONMENTAL SCIENCES (DHES)

The Environmental Sciences Division of DHES administers several laws related to oil and gas drilling activities which overlap the general responsibilities of the Board under 82-11-111, MCA.

Air Quality Permits. The Air Quality Bureau administers the Montana Clean Air Act. Normally, any proposed project that has the potential to emit more than 25 tons per year of any pollutant must obtain an air quality permit before beginning construction. The applicant must apply Best Available Control Technology (BACT) to each emission source. The applicant also must demonstrate that the project will not violate Montana or Federal Ambient Air Quality Standards (see Chapter Four). The air quality standards that typically would be relevant to oil and gas drilling and production include those for sulfur dioxide, nitrogen oxide, carbon monoxide, and fugitive particulates such as dust. Other air quality regulations include those regulating sources of nuisance odors, such as hydrogen sulfide.

Most drilling rigs are excluded from the permit requirement procedures if the combined emissions of various diesel engines and turbines used in the operation do not emit more than 100 tons per year of any pollutant (most notably nitrogen oxide) regulated under the Montana Clean Air Act. Drilling operations emissions are generally exempt from the air quality permit requirements because they are of short duration and are likely to be 100 tons or less. However, drilling operations that require larger rigs and greater horsepower and that will operate for longer periods of time may in certain instances require an air quality permit. Few air quality permits have been issued for drilling operations. An air quality permit was required for a well drilled near Red Lodge but not for a similar well near Bozeman (Dames and Moore 1986; System Technology, Inc. 1984). The two determinants of whether an air quality permit will be needed are the duration of the drilling operation and the horsepower of the engines used. For large drilling operations, a case-by-case analysis may be required to make this determination.

Water Quality Permits. The Water Quality Bureau administers the Montana Water Quality Act. The law defines "state waters" as any body of water, irrigation system, or drainage system, either surface or underground, except for irrigation water used up and not returned to any other state waters (75-5-103(9), MCA). This state law provides for classification of state waters and establishes water quality standards and two permit programs to control the discharge of pollutants into state waters. The law also contains a nondegradation policy to protect state surface- and groundwater from pollution. Under 75-5-106, MCA, "State, county, and municipal officers and employees, ...shall cooperate with...the department in furthering the purpose of the law insofar as is practicable and consistent with their other duties."

The Montana Pollutant Discharge Elimination System (MPDES) (ARM 16.20.901 through 919) provides for regulation of point sources discharging pollutants into state waters, including both surface and underground waters. Point sources are defined as any type of conveyance such as a pipe, ditch, conduit, or well from which pollutants may be discharged. The MPDES permit contains water quality limitations and requires self-monitoring of effluent by the permittee. While this program does not contain provisions for exemptions from the permit process, typical oil and gas drilling operations do not discharge wastes via a point source to state waters and therefore do not require MPDES permits.

The Montana Groundwater Pollution Control System (MGWPCS) (ARM 16.20.1001 through 1025) uses a permit system to regulate sources of process wastes or pollutants that may reasonably be expected to result in the discharge of pollutants to groundwaters. All sources must comply with groundwater quality standards. The terms used in the groundwater regulations are interpreted broadly to ensure coverage of all pollutant sources. The groundwater standards classify groundwater according to existing uses and are based on the principle of protecting those uses. Exclusions from the MGWPCS permit requirements (ARM 16.20.1012 1(e)) include water injection wells, reserve pits, and produced-water pits employed in oil and gas fields if the operations are approved pursuant to Board rules (ARM 16.22.1226 through 1234).

Refuse Disposal Requirements. The Solid and Hazardous Waste Bureau is responsible for administering both the Montana Solid Waste Management Act (75-10-201 et. seq, MCA) and the Montana Hazardous Waste Act (74-10-4 et. seq, MCA). A license from DHES is required for the operation of commercial disposal facilities for either solid waste or hazardous waste.

The Solid Waste Management Act does not allow disposal of waste except at licensed landfills, or in the case of one's own nonhazardous refuse, on one's own land. Most of the Bureau's program for disposal sites is directed towards licensing of municipal landfill sites.

Typical refuse generated by oil and gas drilling, including construction debris (boards and cardboard), office and lunchroom waste, and some waste motor oils or solvents, could be disposed of in a licensed Class II landfill. However, the law (75-10-214(1), MCA) allows persons to dispose of their own solid refuse upon land they own or lease as long as it does not create a nuisance or public health hazard. Some oil and gas operators transport these wastes to approved local landfills. Others incinerate combustible material at the drill site and bury the ash. Many use the reserve pit or a separate garbage pit and bury the refuse when operations are complete (see Table 2 for drill permit conditions).

Disposal of drilling mud and fluid from individual wells presents a different set of disposal problems. The Bureau has classified drilling muds and fluids generated at individual wells as "industrial wastes being disposed of on site." This classification gives drilling mud and fluid the same exemption that can be used for other wastes generated at the drill site. Further, drilling mud and fluid also are exempt from Montana's Hazardous Waste Program (ARM 16.44.304(2)(c)), and the Montana Hazardous Waste Act. This same exemption is found in federal rules dealing with waste disposal. The adequacy of disposal practices for drilling muds and fluids and the current systems regulating such disposal have been evaluated by the Environmental Protection Agency (EPA). EPA recently completed a study of oil and gas drilling fluids and muds and determined that these wastes did not warrant regulation as hazardous material. However, EPA did recommend that state programs regulating disposal of these wastes should be evaluated and improved (EPA 1987). The Interstate Oil Compact Commission also has recognized the need for improved state regulation of drilling waste (Dowd 1988).

In the past couple of years there has been a shift in landowner acceptance of on-site disposal of drilling muds and fluids with high concentrations of salts. The practical problems associated with disposal of large amounts of drilling muds and fluids, coupled with an uncoordinated program to regulate their disposal, has concerned some state and federal agencies and landowners in Montana (Anderson 1987).

A license for a commercial disposal site for drilling wastes from the Solid and Hazardous Waste Bureau would require certain measures, including groundwater monitoring, soil testing and waste testing. Over the last three years DHES has received several inquiries and applications for commercial disposal sites. Because of the costs associated with these requirements, the persons interested in commercial disposal sites have not actively pursued a license. DHES has found two commercial disposal sites operating without a permit in Montana.

North Dakota maintains the closest drilling waste disposal sites; one at Tioga and two at Williston. Inspectors for North Dakota's oil and gas agency evaluate each individual drilling site and determine on a case-by-case basis, usually early in the drilling process, whether the drill muds may be buried at the site. Off-site disposal at a central disposal facility has been required by North Dakota for 3-5 percent of drill sites permitted statewide over the past couple of years (Norton 1988, Murphy 1988).

Work Camp License. A $30 license from the Food and Consumer Safety Bureau is required when an oil or gas operator provides common housing for two or more employees. "Housing" is broadly defined to include bathrooms and facilities for eating and sleeping.

Applications for a license to operate a work camp must be made on forms provided by DHES. Licenses expire on December 31 of the year issued. Scaled layout plans of a proposed work camp must be prepared and submitted to DHES and the local health authority for approval prior to beginning construction.

DHES and county health officers review proposed work camps. Rules require each camp to provide facilities that meet standards for housing, water supply, sewage treatment and disposal, refuse disposal, and rodent and weed control.

The requirement for a work camp is most likely to be triggered during boom periods or when remote exploratory wells are proposed. During the oil boom in the 1980s, there were as many as eight such camps in Montana.

DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION (DNRC)

Under the Water Use Act, the Board has authority over water produced from oil and gas wells (85-2-510, MCA). The law defers to the Board regarding disposal of such water. In many producing basins, produced water is used to drill new oil and gas wells. In wildcat areas, other sources of water may be required. The act requires that a permit from DNRC be obtained under certain conditions when water is to be used during drilling (discussed below) and when an oil or gas well is to be converted to a water well (85-2-303, MCA).

Water Use Permit. A water right permit must be obtained before any surface water diversion or groundwater withdrawal of 100 or more gallons per minute. The withdrawal of groundwater less than 100 gallons per minute requires that notice of withdrawal be filed with DNRC within 60 days. In the Baker area, a permit is always required for any groundwater withdrawal.

There are three methods to obtain water for oil and gas drilling operations: (1) surface water temporary use permit, (2) a groundwater well permit, and (3) obtain water from other water right holders. Surface water permits are issued through DNRC's local water rights office under 85-2-310 to 312, MCA. Issuance of a temporary surface water right takes three to six months, depending on the amount of water requested and whether a hearing is required. The second method is to use groundwater under a water right issued through the area water rights office. For oil and gas drilling operations this would involve use of the small water rights exception (85-2-306, MCA) that requires filing for water rights within 60 days of completion of a well or developed spring. The third method is to obtain water from an existing water right holder. If water is purchased by the drilling operator, the person selling the water must have either a valid water right or a water use permit.

DEPARTMENT OF STATE LANDS (DSL)

Before surface disturbance begins on state-owned lands, a field review of the activity is conducted by personnel from one of DSL's six area land offices. This site inspection focuses on location of oil and gas drilling and production facilities to minimize conflicts with the surface use of the land. Although DSL has considerable authority to direct and control oil and gas activities under state leases, it rarely performs field monitoring during drilling or production to determine violations of lease provisions or stipulations. The agency has no full-time oil and gas inspectors.

In practice, DSL depends on the quality and integrity of the operators. It also relies on inspections made by the Board for seismic shot-hole plugging, during drilling and production, and for final reclamation after well abandonment. Communications between DSL staff and the Board's field staff on individual wells or drilling operations is generally good when situations require that corrective action be taken. Communications over routine inspections are generally minimal.

Although DSL has full bonding authority, concern by operators over the bonds required by the Board of Oil and Gas Conservation and DSL led the Board of Land Commissioners in the 1970s to suspend bonding on oil and gas leases involving state-owned land. Although two bonds were required, the activities covered by the bonds were much different. In contrast to the plugging and restoration bond of the Board of Oil and Gas Conservation, bonds imposed by DSL were general performance bonds covering all activities on a lease. Without performance bonds, DSL relies on the integrity of individual operators to perform according to the stipulations of a lease. If problems do occur, DSL can take certain administrative actions, such as shutting down an operation until a problem is addressed or canceling a lease, but it does not have authority to impose fines. While violations of the lease provisions or stipulations can result in the canceling of a lease, such action is not often taken. Although DSL has authority in its rules to correct damage and bill the oil and gas lessee for the costs, this action can have little success in cases where it is more economical for an operator to give up the lease rather than reimburse DSL. Finally, like other landowners, DSL can seek civil action for payment of damages.

FEDERAL AGENCY ACTIONS REGARDING DRILLING

U.S. BUREAU OF LAND MANAGEMENT

Once a lease is issued on federal land, BLM's involvement with oil and gas drilling operations and abandonment follows Department of the Interior regulations. These regulations are contained in code of federal regulations (Title 43 Part 3160) and specifically in Onshore Oil and Gas Order Number 1, Approval of Operations on Onshore Federal and Indian Oil and Gas Leases. The regulations require that before any well can be drilled, an Application for Permit to Drill, Deepen or Plug Back, known as an APD, must be submitted for review and approval (see Figure 25). During or following this review, an on-site inspection occurs and detailed requirements and conditions for approval of the APD are developed. Figures 26 and 27 show two options for APD approval and the timeframes required for each.

BLM has developed procedures and rules for evaluating APDs in light of the requirements imposed by the National Environmental Policy Act. All APDs are reviewed against planning documents and supporting environmental impact statements to ensure that the action complies with the plan and has received adequate environmental review. If an APD conforms to the planning document and previous environmental work is deemed adequate, BLM prepares a documentation sheet for the proposal. If the APD does not conform to the plan and adequate environmental analysis has not been prepared, an environmental analysis will be conducted. In very sensitive areas, this analysis is documented in a detailed environmental assessment or EIS. In the past, 95 percent of all APDs in Montana have been approved under the categorical exclusion process. BLM no longer uses the categorical exclusion process for approving APDs.

Most oil and gas drilling (APD) and production operations (sundry notices) will be reviewed by BLM according to a proposals compliance with existing resource management plans and supporting environmental impact statements. A review process known as a plan conformance

Form 3160–3
(November 1983)
(formerly 9–331C)

FIGURE 25

SUBMIT IN TRIPLICATE*
(Other instructions on reverse side)

Form approved.
Budget Bureau No. 1004–0136
Expires August 31, 1985

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL, DEEPEN, OR PLUG BACK

1a. TYPE OF WORK
DRILL ☐ DEEPEN ☐ PLUG BACK ☐

b. TYPE OF WELL
OIL WELL ☐ GAS WELL ☐ OTHER SINGLE ZONE ☐ MULTIPLE ZONE ☐

2. NAME OF OPERATOR

3. ADDRESS OF OPERATOR

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*)
At surface

At proposed prod. zone

5. LEASE DESIGNATION AND SERIAL NO.

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME

9. WELL NO.

10. FIELD AND POOL, OR WILDCAT

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA

14. DISTANCE IN MILES AND DIRECTION FROM NEAREST TOWN OR POST OFFICE*

12. COUNTY OR PARISH | 13. STATE

15. DISTANCE FROM PROPOSED* LOCATION TO NEAREST PROPERTY OR LEASE LINE, FT. (Also to nearest drlg. unit line, if any)	16. NO. OF ACRES IN LEASE	17. NO. OF ACRES ASSIGNED TO THIS WELL
18. DISTANCE FROM PROPOSED LOCATION* TO NEAREST WELL, DRILLING, COMPLETED, OR APPLIED FOR, ON THIS LEASE, FT.	19. PROPOSED DEPTH	20. ROTARY OR CABLE TOOLS

21. ELEVATIONS (Show whether DF, RT, GR, etc.)

22. APPROX. DATE WORK WILL START*

23. PROPOSED CASING AND CEMENTING PROGRAM

SIZE OF HOLE	SIZE OF CASING	WEIGHT PER FOOT	SETTING DEPTH	QUANTITY OF CEMENT

IN ABOVE SPACE DESCRIBE PROPOSED PROGRAM: If proposal is to deepen or plug back, give data on present productive zone and proposed new productive zone. If proposal is to drill or deepen directionally, give pertinent data on subsurface locations and measured and true vertical depths. Give blowout preventer program, if any.

24.

SIGNED _____ TITLE _____ DATE _____

(This space for Federal or State office use)

PERMIT NO. _____ APPROVAL DATE _____

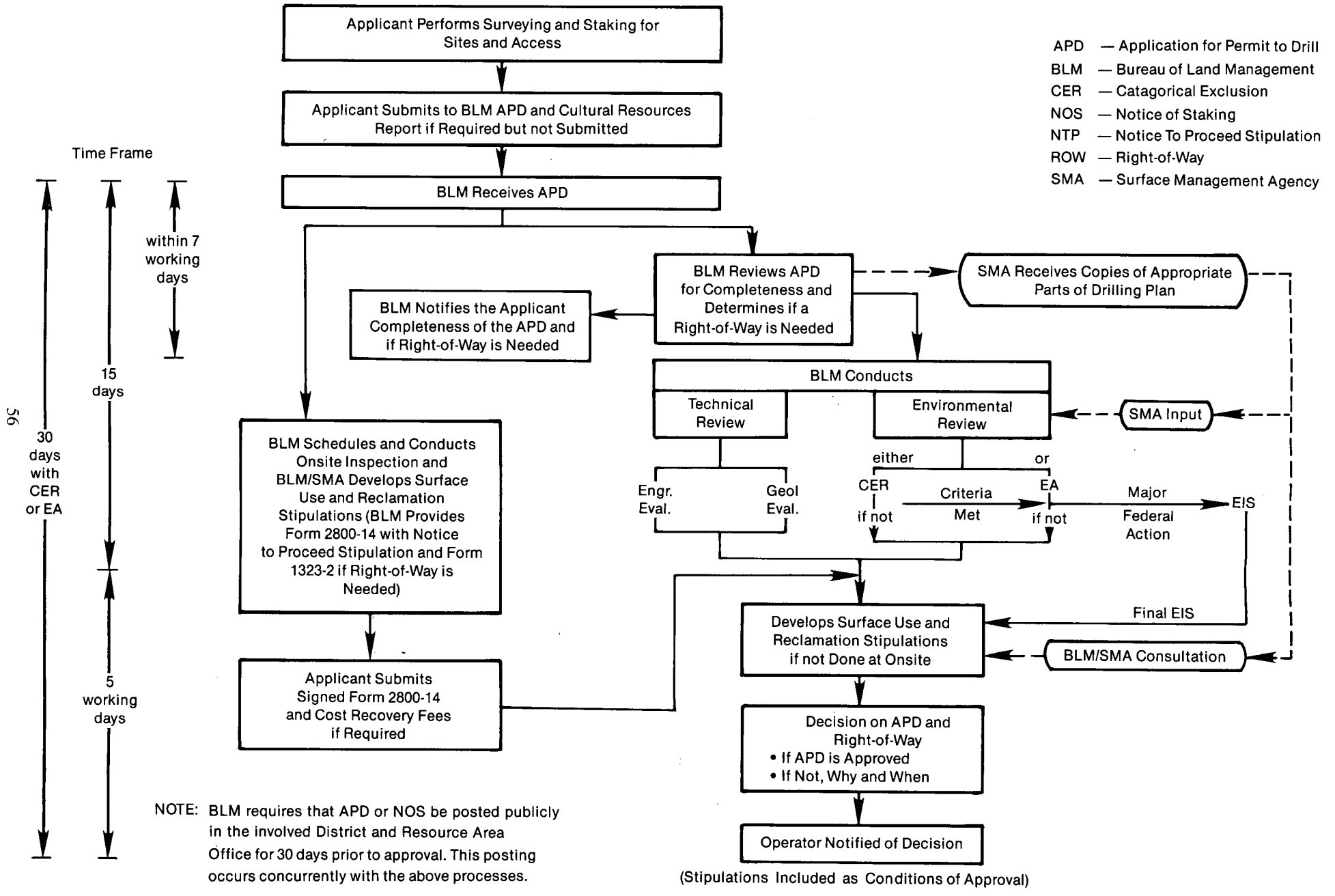
APPROVED BY _____ TITLE _____ DATE _____
CONDITIONS OF APPROVAL, IF ANY:

***See Instructions On Reverse Side**

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

FIGURE 26

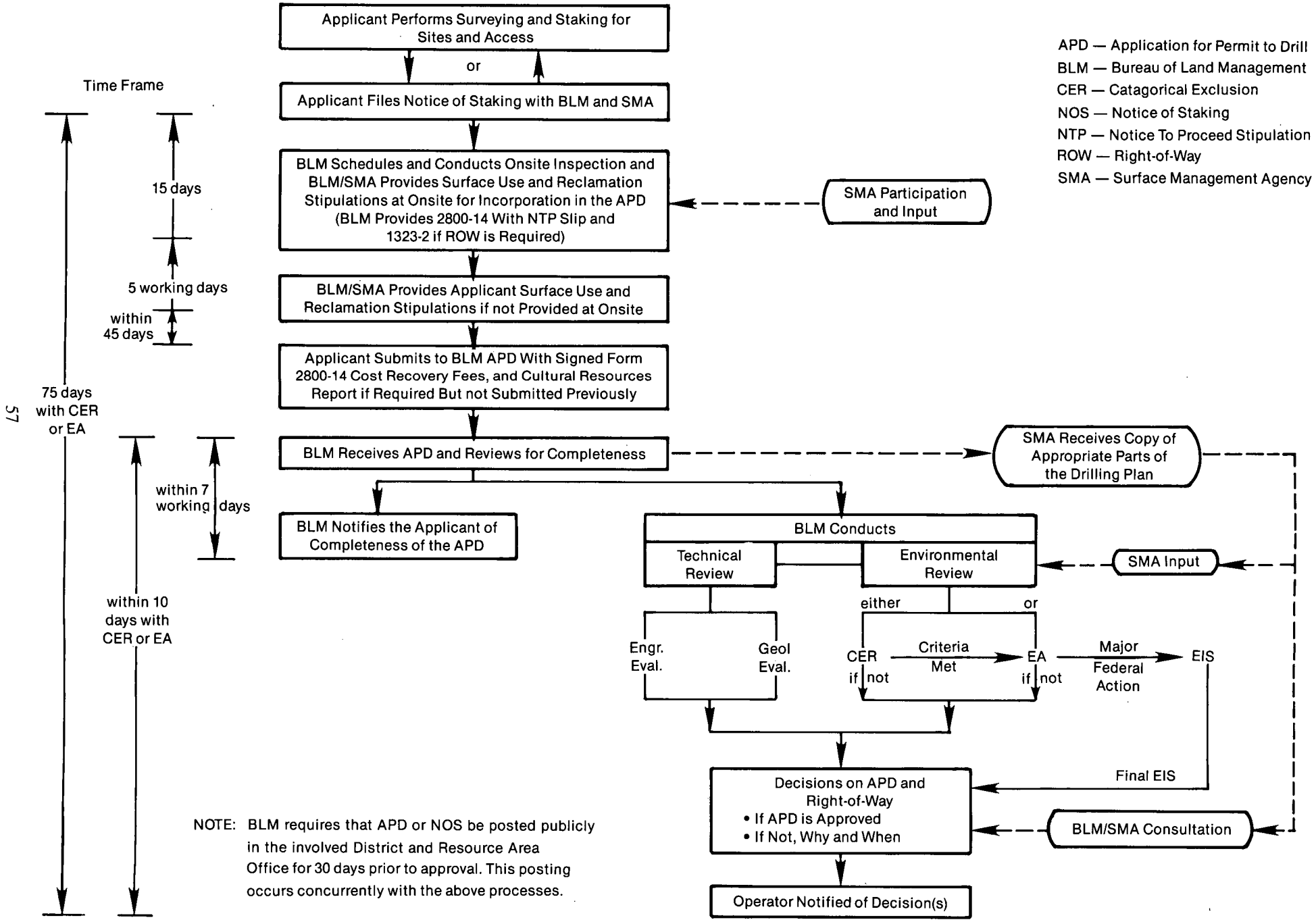
BLM APPLICATION FOR PERMIT TO DRILL (APD) OPTION - FLOW CHART



NOTE: BLM requires that APD or NOS be posted publicly in the involved District and Resource Area Office for 30 days prior to approval. This posting occurs concurrently with the above processes.

The Cultural Resources Report may be submitted not later than the 25th day of the 30-day processing period

FIGURE 27
BLM NOTICE OF STAKING (NOS) OPTION - FLOW CHART



NOTE: BLM requires that APD or NOS be posted publicly in the involved District and Resource Area Office for 30 days prior to approval. This posting occurs concurrently with the above processes.

and NEPA adequacy review is undertaken to ensure that a proposed action would not cause impacts beyond those already addressed in the resource plan or supporting environmental impact statements.

As part of the APD process, an applicant must submit detailed information regarding the use of the surface and proposed drilling program. Based on the information contained in the surface use program and an on-site visit, BLM develops measures it attaches as conditions for approval of individual APDs. The measures are designed to protect surface and subsurface resources located at or near the proposed drilling location. While BLM retains the flexibility to tailor required mitigation measures to fit individual site conditions, it has developed operating standards and guidelines in cooperation with the Forest Service for oil and gas activities on federal lands and when federal minerals are involved. The agencies have recently completed a draft set of "Surface Operating Standards for Oil and Gas Exploration and Development" (U.S. Bureau of Land Management and U.S. Forest Service 1988). These guidelines are to be used in the preparation of surface use and drilling programs, and establish acceptable operating practices and procedures for site preparation, drilling, reclamation, production, and abandonment.

BLM has adopted polices that require an environmental analysis, normally documented in an environmental assessment (EA), for each new field involving federal or Indian minerals. The EA process is used to determine the cumulative impacts of full field development and to develop necessary mitigation measures for adverse impacts. The operator(s) are asked to provide a conceptual development plan for the field to assist in this analysis.

U.S. FOREST SERVICE

The Forest Service typically reviews and approves the surface-use plan prior to BLM issuance of an APD affecting Forest Service lands.

The Forest Service is also responsible for issuing a number of permits, easements, and rights-of-way if oil and gas activities require crossing of forest lands in order to reach a lease or drill site. Also, the Forest Service has responsibilities for protecting archaeological, historical, and paleontological resources, and reviewing the impact of proposed actions on threatened and endangered fish, wildlife, and plant species.

PRODUCTION OPERATIONS

BOARD ACTIONS AND PRACTICES

For individual wells, various circumstances may require the operator to obtain additional Board approval beyond a drilling permit before oil or gas can be produced. Any well that is an exception to established location or spacing requirements receives an additional review to establish spacing requirements before production from the well can begin. Other conditions that require Board approval before production include instances where (1) hydrocarbons are found in two different zones and production is sought from both through one well; (2) an operator locates an unexpected pay zone; or (3) an operator is drilling for oil and encounters natural gas. All wells are required to comply with the Board's rules for oil and gas production, but other than in the above-listed cases, the Board has no further administrative approvals.

Production operations are discussed in sub-chapters 11 (safety) and 12 (production) of the Board's rules (ARM 36.22.1101 and 1201 et. seq). The rules are written from the perspective of efficient production, resource conservation, and prevention of waste. The rules only generally address contamination of air or water by liquid or gas leaking from wells, tanks, pipelines, and pits. While the rules discuss in general terms the proper equipment to be used for production, the Board has not established standards or guidelines concerning proper construction, selection, maintenance, or inspection of facilities used in producing oil or gas.

Although the Board continues to review and approve applications for waterflood and other enhanced recovery operations, these operations also must receive permits from EPA under the auspices of the Underground Injection Control Program.

The Board's rules concerning disposal of produced water in surface pits require that such pits may only be used when the site is underlain by tight soil such as heavy clay or hardpan. If the soil under the pit is porous or closely underlain by sand or gravel, impoundment of produced water is prohibited. The rule also authorizes the Board to condemn any pit that does not properly impound such water. The regulations do not establish minimum thickness or define tight clay soil or hardpan acceptable to prevent the seepage of waste constituents. No guidelines are provided concerning proper size of pits to contain water or method of construction. The Board staff relies on visual inspections to determine whether leaks are occurring.

INSPECTIONS BY BOARD STAFF

It is the goal of the Board's inspectors to visit each producing well once per year. These inspections are undertaken to detect operational problems and check for leaks, spills, and unauthorized venting of gas. Inspectors are given considerable flexibility for planning the necessary inspection work and are required to keep an inspection log. Each inspector relies on contacts with operators to learn about activity occurring in the various fields within his area. Complaints from operators or others regarding violations and problems are investigated as soon as possible. Typically, the Board's inspectors do not conduct joint inspections with other agencies unless requested to do so.

Deficiencies are recorded by the inspector and notice is given identifying the problem and giving the operator a period of time to correct it. A follow-up inspection is usually conducted once the inspector is notified that noted problems have been corrected. Inspectors rely a great deal on contact with operators to determine the extent of problems that may be noted during field inspections.

Any violations of Board rules or deficiencies in standard operating practice noted by the Board inspectors are typically handled by the staff. Inspectors do not have authority to shut down an operation for a major violation. That authority rests with the Oil and Gas Division Administrator and the Board. If a major violation is discovered by an inspector, the administrator makes a call followed by a letter to the operator and requires that the violation be corrected. The Board is occasionally involved when emergencies exist, if the staff is unable to persuade an operator to correct violations or if individuals wish to discuss problems with the Board. Violations of air or water quality standards are typically referred to DHES for action.

STATE AND FEDERAL AGENCY ACTIONS

AIR QUALITY PERMITS AND STANDARDS

Operational and emission characteristics of individual oil or gas wells during the production phase are more likely to trigger air quality permit requirements than drilling operations because pollutants can exceed established ambient air quality standards under certain circumstances, and exemptions from the permit requirements are not allowed.

DHES typically receives one or two complaints per year regarding air quality problems associated with oil and gas operations. Complaints pertain to operations that involve venting or flaring of gas, or leaks or faulty equipment at a well site. DHES has noted that during periods of increased drilling activity the number of complaints received also increases.

In some instances, it appears that both the Air Quality Bureau and the Oil and Gas Conservation Division have authority and may cooperate regarding certain issues related to air quality, even though each agency approaches such issues from a different regulatory perspective. For example, both agencies have regulatory interest in oil and gas ratio testing and preventing leaks from oil tanks and gas pipelines. The Board regulates these activities with the intent of conserving resources and preventing waste, while the Air Quality Bureau is concerned with how those activities affect air quality. DHES usually depends upon the operator's compliance with permit requirements and upon complaints from affected persons to detect violations of air quality standards.

Another, more restrictive air quality permit known as the Prevention of Significant Deterioration (PSD) permit would be required for major developments associated with oil or gas fields, such as oil refineries and gas sweetening plants. In rarer instances, an individual well could trigger such permit requirements if it were to emit 250 tons or more of pollutants into the air in a year (see Air Quality, Chapter Four).

WATER QUALITY PERMITS AND STANDARDS

The requirements for a Montana Pollutant Discharge Elimination System (MPDES) permit are more likely to be triggered by an oil and gas production operation than by drilling activities. In the past, overflows from oil/water collection units have entered state waters in some cases and MPDES permits were required. Presently, water produced from an oil or gas well can be discharged to the surface only for beneficial use, such as irrigation and stock watering, and such discharges may be authorized under the provisions of a general MPDES permit. The quality and volume of the receiving water, the quality and volume of the discharge, and water quality standards and classifications are considered on a case-by-case basis when discharge limits and monitoring requirements are established for a discharge permit. Each permit specifies discharge limitations and monitoring requirements to make certain that state waters are not degraded and that any violations of the limits are detected. Self-monitoring reports submitted by the permit holders are reviewed and compliance monitoring inspections are conducted to determine whether the operation is in compliance.

Direct discharges of wastes from oil and gas operations to surface water typically are not allowed because the discharge cannot meet water quality standards and nondegradation requirements. Surface discharge of water produced from oil and gas wells is permitted where a beneficial reuse of the water, such as stock watering, can be demonstrated. Water produced from an oil or gas well is sometimes as good as or better than surface waters. DHES usually allows such discharges if the landowner requests it and if the operator acquires a beneficial use permit from DNRC. Ten oil and gas production locations in Montana currently have MPDES permits that allow the discharge of

produced water for beneficial reuse. An alternative means of disposal is to discharge the water into other wells. These wells are regulated by the Environmental Protection Agency (see subsequent section).

Exemptions were included in the groundwater permit system to eliminate duplicative environmental permits for businesses operating in Montana. Facilities such as hazardous waste management facilities or large mining and milling operations are regulated by other permit programs which consider the potential for groundwater pollution. However, the WQB has oversight responsibilities to ensure water quality standards are met and the nondegradation policy is satisfied.

Exemption from the permit requirements for surface or groundwater discharges does not remove the responsibility of the Board or oil and gas operator to comply with DHES water quality standards and satisfy the nondegradation policy. In practice, DHES usually defers to the Board's rules and enforcement procedures to ensure compliance with the standards because these operations are permitted by the Board and both agencies have similar responsibilities to protect surface- and groundwaters. The Board's authority for water resource protection is contained in 82-11-111(2)(a) and 82-11-123(3), MCA.

The Water Quality Bureau has not taken an active role in the review of oil and gas drilling permits to determine if established water quality standards and the nondegradation policy are being satisfied. The Water Quality Bureau does investigate some complaints and water quality problems associated with discharges from oil and gas operations. When a violation is discovered, enforcement options available to DHES include administrative contact with the responsible party either by telephone or letter, issuance of an administrative order requiring that corrective action be taken, or court action to seek penalties. The level of enforcement action taken depends on the seriousness of the violation and the willingness of the responsible party to cooperate in correcting the problem.

The groundwater regulations (ARM 16.20.1025) describe emergency powers available to DHES in the case of spills or unanticipated discharges of toxic substances or any other materials that would violate groundwater below groundwater quality standards. Depending upon the severity of the spill or accidental discharge, DHES may require the person responsible for the spill to take appropriate remedial action including clean up, monitoring, and providing alternate water supplies to users whose activities are disrupted by the spill. Any release of contaminants due to transport, drilling or production operations would be subject to DHES requirements under this rule.

BUREAU OF LAND MANAGEMENT

BLM's Onshore Oil and Gas orders specify policies and measures required for production and abandonment activities for federal minerals. BLM's Montana State Office has compiled an oil and gas environmental program reference book which consolidates and describes BLM activities from leasing through abandonment and the measures to be taken by lessees. The measures are to be taken wherever activities could affect federal lands. Where the well site and access road surface are privately owned, BLM can require the operator to apply appropriate surface protection measures as a condition of the lease.

ENVIRONMENTAL PROTECTION AGENCY

Congress established the concept of the Underground Injection Control (UIC) program in 1974 under the authority of the Safe Drinking Water Act to protect underground sources of drinking water (USDW) from contamination due to the improper injection of fluids from a variety of sources, including the oil and gas industry. Oil and gas operations are regulated as "Class II" pollution sources and include wells which reinject brine or brackish wastewater brought to the surface with oil and gas, and wells used for underground storage of liquid hydrocarbons. In passing the initial legislation calling for the UIC program, Congress enjoined EPA from impeding or interfering with oil and gas production unless necessary to protect USDWs.

EPA began operating Montana's UIC program in June 1984. EPA's regional office in Denver handles administration and the technical functions relating to permit issuance and compliance. The Montana office located in Helena has lead responsibility for field inspections and emergency response. All new injection wells must have a permit from EPA before they can begin operation. "New" is defined as any injection well beginning operation in Montana after June 1984. All salt water disposal wells that were in existence as of June 1984 were required to receive a permit from EPA before June 1988. Enhanced recovery wells existing prior to June 1984 are not required to obtain a permit since they are authorized by rule, but must comply with all of the operational requirements imposed on new wells.

The Board has rules that were promulgated at the end of 1972 requiring operators to file applications and receive approval before commencing waterflood, secondary recovery, or saltwater disposal operations. Since EPA began operating the UIC program in Montana in 1984 the Board has not been involved in reviewing saltwater disposal wells, but applications for secondary recovery operations are still reviewed and approved.

ABANDONMENT, PLUGGING AND RESTORATION PROCEDURES

BOARD AUTHORITY AND PRACTICE

Operators are required to notify and obtain approval from the Board's staff prior to abandoning a well. Operators on federal or Indian lands also must obtain federal approval for abandonment procedures. Board rules provide an exemption to certain plugging requirements in the event that the landowner desires to use a well as a freshwater well. The Board must be notified in writing when a well is converted to fresh water use. Also, according to 85-2-303, MCA, the person desiring to convert an oil or gas well to a water well must file a notice of completion with DNRC or apply for a water-use permit, depending on the maximum volume of the well. Upon completion of plugging operations, the operator is required to restore the well location to its original grade and productive capabilities. The Board will accept a written request from the surface owner for a different restoration plan.

Under current Board rules, a well may be temporarily abandoned without being plugged if there is potential use for the well in future field operations such as enhanced oil recovery or as a disposal well. Unless the Board finds that such idle wells are causing damage to oil or gas reservoirs or to freshwater supplies, they may remain unused through the life of the field, or so long as productive wells also remain on the lease. Board rules are directed at restoration of individual well sites and do not address reclamation issues that occur off the well site.

After a location has been restored, it is inspected at least once, often twice, by one of the Board's field inspectors. The first inspection generally follows after filling of the pits, site recontouring and initial efforts at revegetation have occurred. The Board's rules require that waste must be removed or buried at the well site at least 3 feet below the restored surface of the land. Methods of final disposition of muds or fluids following drilling are not specified by rule and vary by regions of the state. The second site visit usually follows correction of any problems noted during the first inspection and after successful establishment of vegetation cover comparable to that on surrounding areas. If the location is adequately restored and all of the required reports, well logs, and other materials have been received by the local office of the Oil and Gas Division, the Board's Helena office is notified that the well may be removed from the operator's bond. Federal and Indian locations are not inspected by the Board's staff because surface restoration on these is monitored directly by the federal agencies. Under no circumstances are wells on state or private land removed from an operator's bond without inspection and approval by the Board's staff.

CHAPTER FOUR

DESCRIPTION OF IMPACTS AND MITIGATING MEASURES

INTRODUCTION

This chapter discusses the range of potential impacts that can be expected from oil and gas drilling and production in Montana based on data from available sources and personal communications with persons having experience in oil and gas drilling and production impacts. As required by Senate Bill 184, the information in this chapter is intended to provide a record of information and analysis for the Board of Oil and Gas Conservation to rely upon in responding to public and private concerns about drilling and production. This record would be used to assist the board when responding to public comments about and evaluating the environmental impacts that may exist with individual drilling proposals.

It is the purpose of this chapter to identify the environmental conditions or circumstances that could lead to potential adverse impacts from drilling and production in the major producing basins and ecosystems of Montana. A variety of factors play a role in defining the nature of the environmental concerns and the magnitude of potential impact resulting from individual drilling or production operations. Because of the wide variation of environmental conditions and resources and their different sensitivity to impact, it is important to obtain sufficient information about a proposed drilling operation and site to reasonably evaluate potential impacts. Factors such as the environmental characteristics at a drilling location and the nature of the drilling proposal (length and depth of drilling, size of rig, type of drilling fluids, etc.) should be considered when determining potential for impact. When drilling occurs in sensitive settings as defined by the criteria in this chapter, the potential for impact increases. However, the likelihood of significant adverse impacts actually occurring depends on measures taken to mitigate impacts. This chapter also identifies technical mitigation measures that can be taken to reduce or prevent adverse impacts.

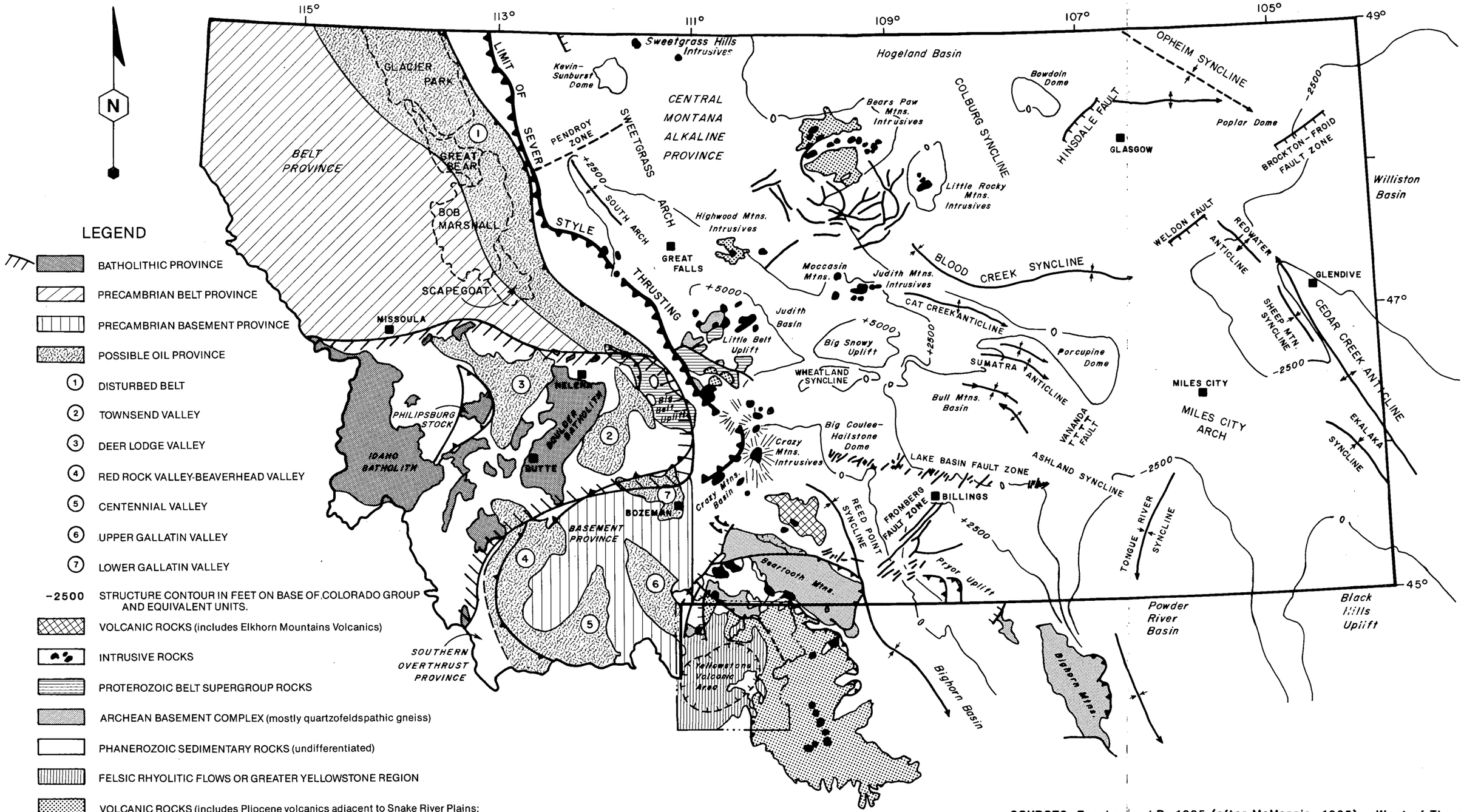
Chapter Five presents detailed discussion of the various alternatives available to the Board regarding a process for using the analysis contained here to evaluate the potential impact of individual drilling permits. As required by Senate Bill 184, Chapter Five also discusses possible measures that could be adopted to ensure that individual drilling proposals can be quickly reviewed and approved while ensuring that such operations occur in an environmentally safe and sound manner.

GEOLOGY AND SOILS CONCERNS

Montana's complex geologic history has resulted in a multitude of environments for oil and gas trapping, with consequent challenges to developers. A detailed description and a graphic illustration of Montana's geologic past can be found in Peterson 1985. Montana's geologic evolution has resulted in hydrocarbon traps ranging in variety from simple structures such as the Kevin-Sunburst Dome to the obscure Bell Creek embayment, and complex thrust-faulted traps of the Blackleaf and Knowlton gas fields. Figure 28 shows major geologic structures in Montana. Most of Montana's oil and gas production is associated with these features (see Figure 6, Chapter One). Oil production is not restricted to any specific geologic unit, but runs the gamut from the deep Ordovician Red River Formation of the Williston Basin to lower Cretaceous of the Bell Creek field in the Powder River Basin (see Figure 29). Most gas in Montana is found in Cretaceous sandstones of the Eagle and Judith River formations. On occasion, gas is produced in association with oil production but rarely in commercial quantities. Another feature in Montana, the Overthrust Belt, has had limited oil and gas production even though Alberta and Wyoming have been successful in developing major hydrocarbon resources along this feature.

As discussed in Chapter One, the level of drilling activity in Montana varies from year to year. About two-thirds of drilling activity (in any year) occurs in and near producing oil and gas fields. The remainder of drilling activity is categorized as wildcat, meaning exploratory drilling. As discussed in Chapter Two, a percentage of all wells drilled in any year are dry holes (see Figures 8 and 9). Wildcat drilling has the greatest uncertainty of success in

FIGURE 28
MAJOR GEOLOGIC STRUCTURES AND PROVINCES OF MONTANA



SOURCES: Fanshawe, J.R. 1985 (after McMannis, 1965) – West of Thrust
Taylor, R.L. and Ashley, J.M. 1985 – East of Thrust

FIGURE 29

GENERALIZED STRATIGRAPHIC CORRELATION CHART

SHOWING PRODUCTIVE FORMATIONS IN MONTANA OIL AND GAS FIELDS *

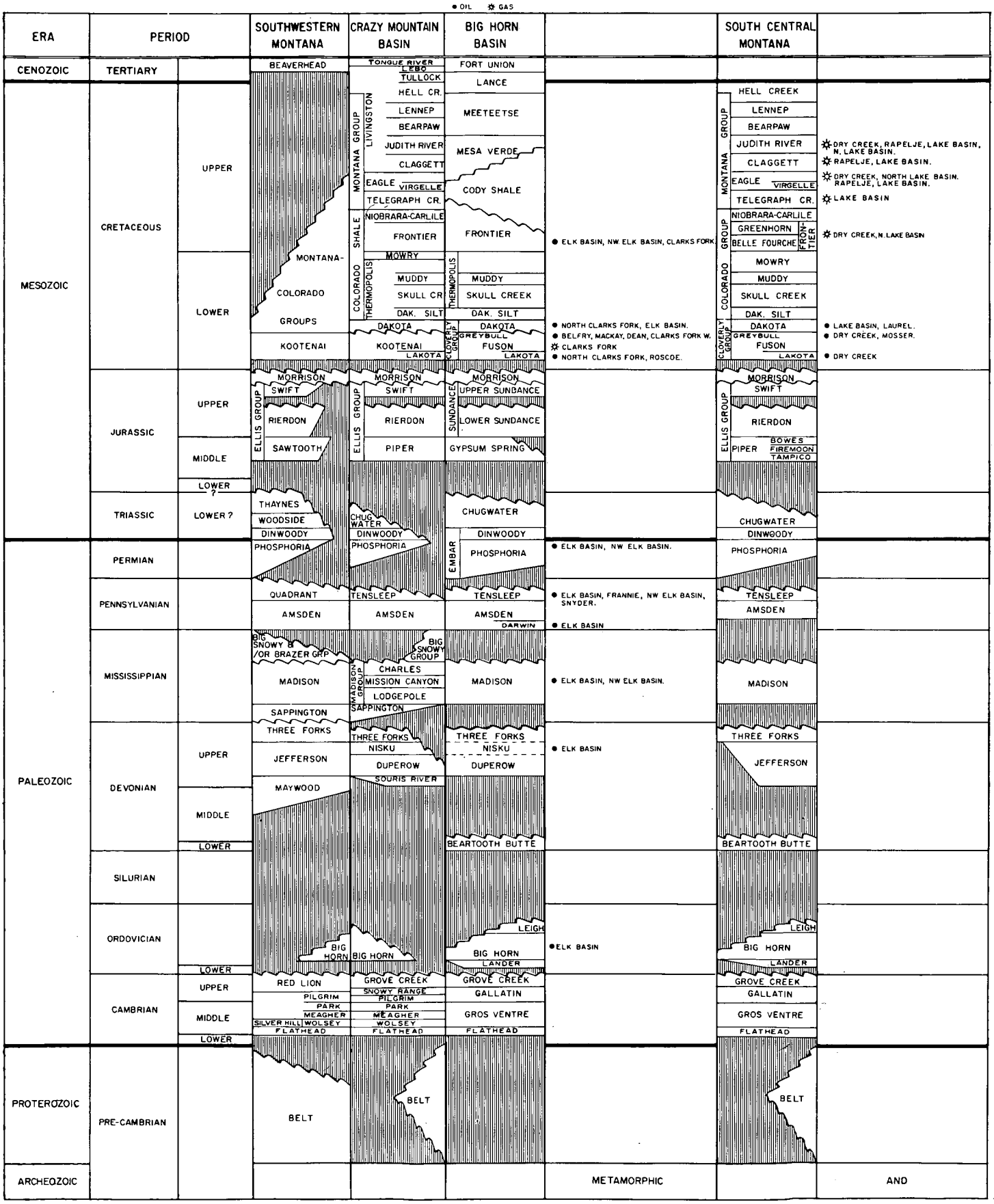


FIGURE 29 (Continued)

GENERALIZED STRATIGRAPHIC CORRELATION CHART

SHOWING PRODUCTIVE FORMATIONS IN MONTANA OIL AND GAS FIELDS *

● OIL ✡ GAS

ERA	PERIOD		CENTRAL MONTANA	SWEETGRASS ARCH	NORTH CENTRAL MONTANA	NORTH POWDER RIVER BASIN	WILLISTON BASIN	PERIOD	ERA
CENOZOIC	TERTIARY		FORT UNION / LEBO / TULLOCK	WILLOW CREEK / ST. MARY RIVER	FORT UNION / TULLOCK	FORT TONGUE RIVER / UNION / LEBO / TULLOCK	FORT TONGUE RIVER / UNION / LUDLOW / CANNON BALL		
MESOZOIC	CRETACEOUS	UPPER	LANCE GROUP: HELL CREEK / FOX HILLS; MONTANA GROUP: BEARPAW / JUDITH RIVER / CLAGGETT / EAGLE / VIRGELLE / TELEGRAPH CR / NIOBRARA-CARLILE / GREENHORN / BELLE FOURCHE; COLORADO GROUP: MOWRY / MUDDY / SKULL CREEK / BASAL COLO. SILT	LANCE GROUP: HELL CREEK / FOX HILLS; MONTANA GROUP: BEARPAW / HORSE THIEF / JUDITH RIVER / CLAGGETT / EAGLE / VIRGELLE / TELEGRAPH CREEK; COLORADO GROUP: MARIAS RIVER SHALE	LANCE GROUP: HELL CREEK / FOX HILLS; MONTANA GROUP: BEARPAW / JUDITH RIVER / CLAGGETT / EAGLE / VIRGELLE / TELEGRAPH CREEK; COLORADO GROUP: NIOBRARA-CARLILE / GREENHORN / BELLE FOURCHE / MOWRY / BOW IS. (MUDDY) / SKULL CREEK / BASAL COLO. SILT	LANCE GROUP: HELL CREEK / FOX HILLS; MONTANA GROUP: BEARPAW / JUDITH RIVER - PARKMAN / CLAGGETT / EAGLE - SHANNON / TELEGRAPH CREEK; COLORADO GROUP: NIOBRARA-CARLILE / GREENHORN / BELLE FOURCHE / MOWRY / MUDDY (NEWCASTLE) / SKULL CREEK / BASAL COLO. SILT	LANCE GROUP: HELL CREEK / FOX HILLS; MONTANA GROUP: BEARPAW / JUDITH RIVER / CLAGGETT / EAGLE / TELEGRAPH CREEK; COLORADO GROUP: NIOBRARA-CARLILE / GREENHORN / BELLE FOURCHE / MOWRY / MUDDY (NEWCASTLE) / SKULL CREEK / BASAL COLO. SILT	UPPER	CRETACEOUS	MESOZOIC
		LOWER	DAK.-1ST CAT CREEK / 2ND CAT CREEK / 3RD CAT CREEK; KOOTENAI	KOOTENAI: MOULTON / "LANDER" SUNBURST / CUT BANK	DAKOTA / KOOTENAI	DAKOTA / FUSON (KOOTENAI) / LAKOTA	DAKOTA / FUSON (KOOTENAI) / LAKOTA		
	JURASSIC	UPPER	ELLIS GROUP: MORRISON / SWIFT / RIERDON / PIPER / BOWES / FIREMOON / TAMPICO	MORRISON / SWIFT / RIERDON / SAWTOOTH	MORRISON / SWIFT / RIERDON / SAWTOOTH	MORRISON / SUNDANCE / GYPSUM SPRING	MORRISON / SWIFT / RIERDON / PIPER / NESSON / BOWES / FIREMOON / TAMPICO / KLINE / PICARD / SUE	UPPER	JURASSIC
		MIDDLE						MIDDLE	
		LOWER ?						LOWER ?	
	TRIASSIC	LOWER ?				CHUGWATER / SPEARFISH; GOOSE EGG: MINNEKAHTA / OPECHE	SPEARFISH / SAUDE / PINE SALT; MINNEKAHTA / OPECHE	LOWER ?	TRIASSIC
	PERMIAN					TENSLEEP	MINNELUSA / AMSDEN		PERMIAN
PALEOZOIC	PENNSYLVANIAN		AMSDEN / ALASKA BENCH / TYLER			MINNELUSA / AMSDEN	MINNELUSA / AMSDEN / TYLER		PENNSYLVANIAN
	MISSISSIPPIAN		BIG SNOWY GROUP: HEATH / OTTER / KIBBEY / CHARLES; MADISON GROUP: MISSION CANYON / LODGEPOLE / BAKKEN	SUN RIVER; MADISON GROUP: MISSION CANYON / LODGEPOLE	CHARLES; MADISON GROUP: MISSION CANYON / LODGEPOLE / BAKKEN	MADISON	BIG SNOWY GROUP: HEATH / OTTER / KIBBEY / CHARLES; MADISON GROUP: MISSION CANYON / LODGEPOLE / BAKKEN		MISSISSIPPIAN
	DEVONIAN	UPPER	THREE FORKS / DUPEROW / SOURIS RIVER	POTLATCH / THREE FORKS / NISKU / DUPEROW / SOURIS RIVER	THREE FORKS / NISKU / DUPEROW / SOURIS RIVER	JEFFERSON GROUP	JEFFERSON GROUP: THREE FORKS / BIRDBEAR (NISKU) / DUPEROW / SOURIS RIVER / DAWSON BAY / PRAIRIE EVAP / WINNIPEGOSIS / ASHERN	UPPER	DEVONIAN
		MIDDLE						MIDDLE	
		LOWER						LOWER	
	SILURIAN				INTERLAKE	INTERLAKE	INTERLAKE		SILURIAN
	ORDOVICIAN		RED RIVER	DEVILS GLEN DOL.	STONY MTN. / RED RIVER / WINNIPEG	STONY MTN. / RED RIVER / BIG HORN / WINNIPEG	STONY MTN. / RED RIVER / WINNIPEG		ORDOVICIAN
		LOWER	L. ORDO.			LOWER ORDOVICIAN: GROVE CREEK / GALLATIN / GROS VENTRE	LOWER ORDO.: DEADWOOD	LOWER	
	CAMBRIAN	UPPER	PILGRIM / PARK	SWITCHBACK SHALE / STEAMBOAT LIMESTONE / PAGODA LIMESTONE / DEARBORN LIMESTONE / DAMNATION LIMESTONE / GORDON SHALE / FLATHEAD	CAMBRIAN	DEADWOOD		UPPER	CAMBRIAN
		MIDDLE	MEAGHER / WOLSEY					MIDDLE	
		LOWER	FLATHEAD					LOWER	
PROTEROZOIC	PRE-CAMBRIAN		BELT	BELT: MISSOULA GR'P. — KINTLA ARGILLITE; SIYEH GR'P. — SHEPPARD DOL / PURCELL LAVA / UPPER SIYEH / SPOKANE SH. / LOWER SIYEH; RAVALLI GR'P. — GRINNELL SH. / APPEKUNNY QT. / ALTYN LS.						PRE-CAMBRIAN
ARCHEOZOIC			IGNEOUS		ROCKS				ARCHEOZOIC

- CENTRAL MONTANA: ● CAT CREEK. ● CAT CREEK, IVANHOE ✡ BIG COULEE ● MASON LAKE ✡● BIG COULEE, IVANHOE, CAT CREEK ● CAT CREEK (WEST, MOSBY, EAST & ANTELOPE DOMES) ✡ MUD CREEK ● BIG WALL, DELPHIA, GAGE, HIBBARD, SUMATRA, WOLF SPASS, POLE CR., WEDGE CR., CAT CR., WINNET, JCT., LITTLE & BIG WALL, HUAWATHA, INJUN CR., RUGGED PT., SUMATRA, RAINHOE, KEG C., MELSTONE, ● JIM G. KELLEY, STENSVAD, HOWARD C., SHEEPHERDER, ROBERUD, GUMBO RDG., BIG GULLY, KNOXLDE RANCH, RATTLER BUTTE, BREED CR., ● DEVIL'S BASIN ● RAGGED POINT
- SWEETGRASS ARCH: ✡ KINSOW C., O'BRIEN'S C., PRAIRIE DELL, E. KEITH, FLAT C., RATTLESNAKE C., ALMA ✡ KICKING HORSE, WHITLASH, GRANDVIEW, DEVON & S. WILLIAMS, BORTHOLOTE, HAYSTACK BUTTE, PRITCHARD CR., ARCH APEX, FITZPATRICK, MARIAS RV., SW. KEVIN, N. CONRAD ● S. CONRAD, M. BUTTE, ✡ PRAIRIE DELL, AMANDA, FITZPATRICK, SW. KEVIN, GRANDVIEW, CUT BANK, W. BUTTE, KEVIN-SUNBURST, FLAT C., SHELBY, TRAIL CR., E. KEITH, PHANTOM & W. ● BLACKFOOT, CUT BANK, RED CR., WHITLASH, GRABEN C., PHANTOM, MINERS C., RATTLESNAKE C., BUTTE CR. ✡ BEARS DEN, KEITH, WHITLASH & W., BLACK JACK, MINER'S C. ● BEARS DEN, KEVIN-SUNBURST, WHITLASH & W., CRUDEN C., BRADY, PRITCHARD CR., BERTHELOTE, FRED & GEORGE CR., BORDER ✡ MINER'S C., FLAT C., LAIRD CR., ETHRIDGE, BLACK JACK ● BANNATYNE, KEVIN-SUNBURST, WHITLASH, FLAT C., FRED & GEORGE, GRANDVIEW, LAIRD CR., ARCH APEX, HORSE CR., PHANTOM, AMANDA, PRAIRIE DELL & W., SW. KEVIN ● KEVIN-SUNBURST ✡ WHITLASH, KEITH, R. RIVARD, UTOPIA, FLAT C. W., BUTTE, BEARS DEN, KICKING HORSE, BLACK JACK, MINER'S C., ALMA, CANADIAN C. ✡ REAGAN, PONDERA C., LANDSLIDE BUTTE, PONDERA ✡ GRANDVIEW, KICKING HORSE, KEITH, WHITLASH, MT. LILLY, UTOPIA, BEARS DEN, HIGHVIEW ● BANNATYNE, BLACKFOOT, CUTBANK, KEVIN-SUNBURST, W. BUTTE, RED CR., GTYS. F. BASIN, GRABEN C. ✡ KEVIN-SUNBURST
- NORTH CENTRAL MONTANA: ✡ TIGER RDG., SHERARD, BROWNS C., BOWES, BULLWACKER, LEROY, SAWTOOTH MTN. ✡ BOWES, BOX ELDER, TIGER RDG., BLACK C., LARCO, SHERARD & W., BROWNS C., COAL C., BULLWACKER, FRESNO, SAWTOOTH MTN., CHIPS C., LEROY, LEHMAN, CHAIN LAKES ✡ BOWDOIN, SWANSON ✡ CANADIAN COULEE NORTH ● BOWES, TIGER RIDGE, RABBIT HILLS.
- NORTH POWDER RIVER BASIN: ● ASH CR. ✡ LISCOM CR., PUMPKIN CR. ✡ HARDIN ✡ HAMMOND ✡ BELL CR., HAMMOND ● BELL CR., WRIGHT CR., ROUGH CR., LEARY ✡ HAMMOND ● LODGE GRASS, SOAP CREEK, SNYDER ● SOAP CREEK.
- WILLISTON BASIN: ✡ CEDAR CREEK, PLEVNA. ✡ CEDAR CREEK ● WELDON, E. COW CR., FIAT L., SHOTGUN CR., SMOKE CR., KATY L., DWYER, POPLAR, COW CR., RICHEY, PRAIRIE ELK, VOLT, MINERAL BCH., GAS CITY, GOOSE LAKE, MEDICINE L., CLEAR L., RIPRAP C., RIDGELAWN, DIVIDE ● RED BANK, LUSTRE, AUTUMN ● SIDNEY, BRORSON, CABIN CR., MONARCH, PENNEL, POP. LAR, RED BANK, OUTLOOK, S. FIAT L., HARDSCRABBLE CR., SHOTGUN CR., SIOUX PASS, MONDAK W. ● PINE, PENNEL, LOOKOUT BUTTE, SALT L. ● TULE CR., S. & E., BENRUD, NE, & E., LONE TREE, SPRING L., VOLT, RED FOX, SALT L., CHELSEA CR., RAYMOND, CHARLIE CR., S. CLEAR L. ● OUTLOOK, MINERAL BCH., WOODROW, BOULDER ● SW. RICHEY, MONDAK W. ● RED STONE, OUTLOOK & W., FAIRVIEW, RESERVE, N. SIOUX PASS, RUSH MTN., RAYMOND & N.E., MONDAK W., MEDICINE L., N. BAINVILLE. ● BIG MUDDY CR., SIOUX PASS & N., DEER CR., MONARCH, PENNEL, PINE, OUTLOOK, SAND CR., SW. RICHEY, LOOKOUT BUTTE, VOLT, WILLS CR., WOODROW, RESERVE, CABIN CR., PUTNAM, MONDAK W., MEDICINE L. ● LOOKOUT BUTTE, GLENDIVE, PENNELL, WOODROW, MONDAK W. ● BURNS CR., MOHLY, RAYMOND & N.E., SECOND CR., CUPTON, DEER CR., CABIN CR., LITTLE BEAVER & E., MONARCH, OUTLOOK, PENNEL, PINE, REPEAT, SAND CR., WILLS CR., FERTILE PRAIRIE, LOOKOUT BUTTE, WOODROW, RESERVE, GAS CITY, BROWSON, BROWSON, RUSH MTN., SHERARD, BRUSH, BAINVILLE & W., OTIS CR., CULBERTSON, ENDEL, HAY CR., GIRARD, CANAL, FT. GILBERT, LONE TREE, SIOUX PASS, MIDDLE, & N., LONE BUTTE, PUTNAM, BIG MUDDY CR., MONDAK W., OXBOW, MEDICINE L., W. FOUR MILE, N. KATY L., CLEAR L. & S., CARLYLE, OLLIE, COMERTOWN, RED BANK, KRUG CR., MIDBY.

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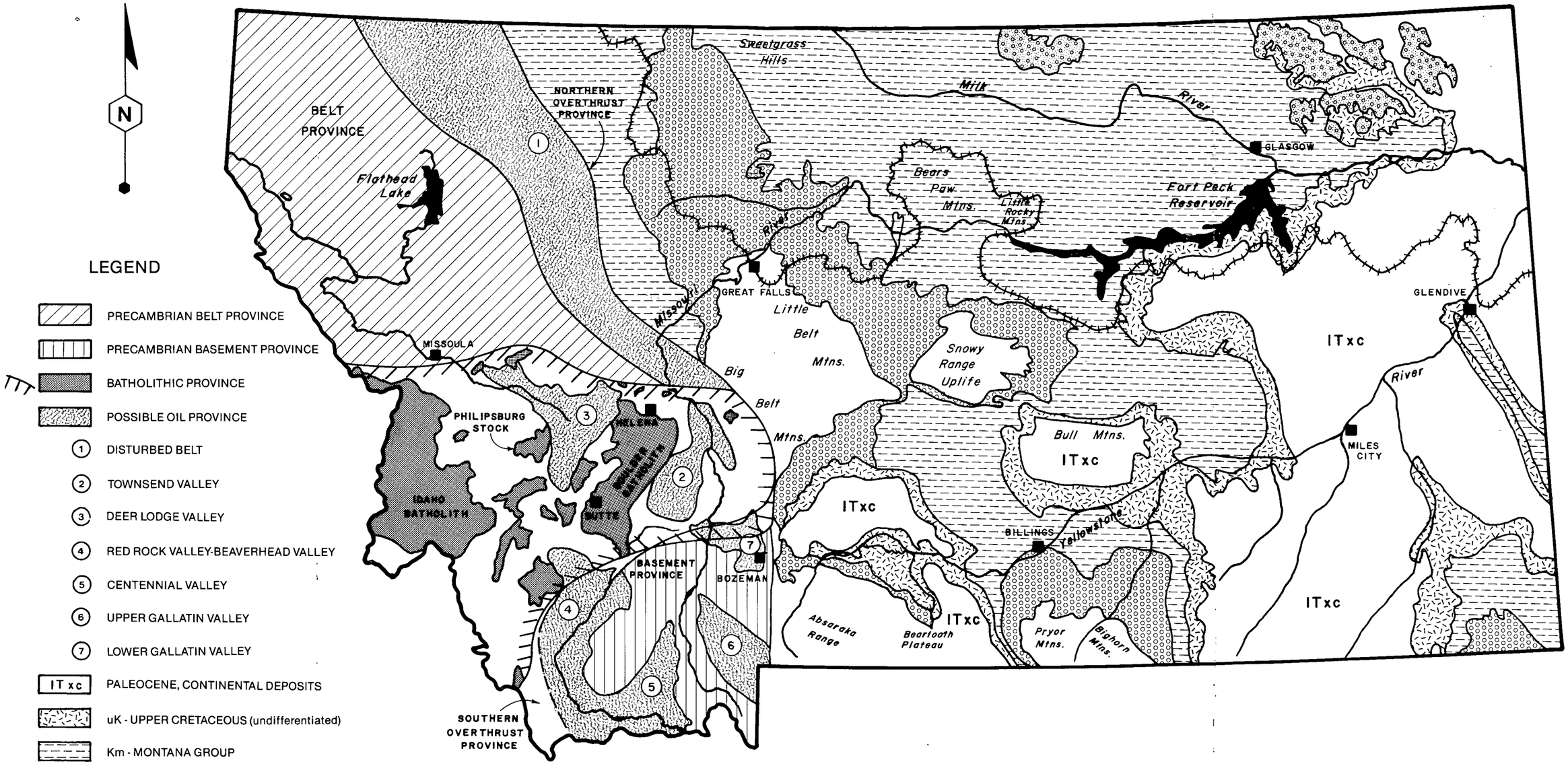
*SOME FIELDS SHOWN ARE DEPLETED OR NO LONGER PRODUCTIVE

FIGURE 30
GENERALIZED GEOLOGIC MAP OF MONTANA



SOURCES: Taylor, R.L. and Ashley, J.M. 1985, and Fanshawe, J.R. 1985
Edited by Griffith, E.

locating hydrocarbons. If a wildcat well finds oil or gas, additional drilling is necessary to determine the size of the reservoir capable of producing hydrocarbons. Once an oil or gas field is found, its development usually occurs over a period of years as individual wells are drilled. The spacing of wells is determined by spacing regulations and topographic tolerances established by the Board. These requirements are discussed in more detail in the land use section.

GEOLOGIC AND SOILS CONSTRAINTS

This section discusses constraints the physical environment places on oil and gas activity. The reader also is referred to the vegetation and water resources sections for additional information regarding how physical characteristics of a drilling site may lead to greater concern for water quality or revegetation. Table 3 lists the known constraints associated with geology, topography, soils, and subsurface characteristics in Montana's oil and gas regions.

Oil and gas site location and access road construction can be constrained in varying degrees by the physical environment of any given area. Frequently in areas of steep slopes (overthrust area and specific sites near outlying mountain ranges), solid bedrock can dictate site road location. Steep slopes can limit drill pad and access road construction where excavation requirements are excessive or would compromise slope stability. Slope aspect also influences site vegetation, soil moisture, and subsequent reclamation success. Soil parent materials and the soils themselves frequently determine the ease of pad and road construction, whether a reserve pit needs a liner, and reclamation success.

SURFICIAL GEOLOGY

Figure 30 is a generalized geologic map of Montana. Steep slopes, high elevation, wet sites, and moderate-to-heavy ground cover characterize the mountainous terrain. The northern section of the state presents a landscape modified by continental ice sheets and left with a thin veneer of mixed till, outwash gravels, and alluvium on eroded Tertiary and Cretaceous bedrock. South of the glaciated region, the geology material is a mix of deeply dissected Tertiary and Cretaceous bedrock of both marine and non-marine origin.

Steep terrain (the result of mountain building), complex geology, and extensive areas of exposed competent bedrock characterize the western third of the state. In addition to the problems of access road construction across steep terrain, flat or relatively flat terrain for sites is usually found in or near drainages. The glacial and alluvial materials, while easy to construct in, are generally quite permeable and subject to contamination if drilling fluids and produced water aren't properly contained. The steep terrain and mix of rock and soil material is usually stable if left undisturbed, but slope failure may result if slopes are cleared of vegetation and undercut by sites or roads. Between Browning and Augusta east of the mountain front, shale and sandstone of the Montana Group are known to contain important dinosaur fossils, presenting an additional important constraint. These particular units are very erodible and can be subject to slope failure if undercut.

East of the mountains, glaciation modified the Montana and Colorado group rocks and Tertiary stream sediments. Sandstone, siltstone, and shale predominate where not covered by a veneer of glacial till and outwash gravels. The tills and outwash gravels are important as local, shallow aquifers and are susceptible to impacts from surface activities. Any alluvial channel, regardless of its origin and nature of bank materials, should be regarded as a limiting factor, especially in selecting a site for oil and gas drilling and production activities.

Occasionally, site materials can aid in site construction. Shale units of the Cretaceous (Bearpaw, Mowry) are suitable for locating reserve pits because of inherent low permeability. Such units are not the best material for access roads, however. They are erodible, and slope failure may occur where till overlies these impermeable units.

In the central portion of Montana, surficial units are split almost evenly between Cretaceous and Tertiary with interspersed mountain ranges. Here, however, glaciation did not modify the landscape, which includes flat to rolling plains, deeply incised river channels, and isolated mountain ranges. The major constraints are easily erodible bedrock and potential for slope failure. Such failures may occur naturally from rapid snow melt. Even on slight-to-moderate slopes, road construction can be constrained by these geologic conditions.

SUBSURFACE GEOLOGY

Table 3 lists subsurface characteristics that are important in determining geological impacts of oil and gas drilling and production. While these constraints are less evident than those on the surface, they can be equally limiting for oil and gas activities.

Produced Water. The quality of produced water varies with its content of total dissolved solids (TDS). Table 4 provides a simple classification of groundwater and its uses based on TDS and salinity. Total dissolved solids is a measure of cations (calcium, sodium, magnesium, and potassium) and anions (sulfate, chloride, and bicarbonate). Table 3 lists ranges of TDS in produced waters from various oil and gas fields in Montana.

Hydrogen Sulfide Gas. A number of sources including API and BLM have identified hydrogen sulfide as a concern in drilling and producing oil or gas. This gas is a concern at low concentration (.005 ppm) due to its rotten egg smell. It can be fatal at concentrations of 500 ppm or greater. Additional information on the concerns with hydrogen sulfide during drilling and production are discussed in the Air Quality and Health and Safety sections.

Table 3. General Surface and Subsurface Characteristics in Montana Oil and Gas Regions.

	Subsurface Characteristics				Topography/Geology/Soils Characteristics						
Region	Geologic Trap	Depth (ft)	Hydrogen Sulfide	Formation Waters* (ppm)	Geology	Slope	Slope Stability	Mass Movement Potential	Soil Erosion Potential	Soil Compaction Potential	Soil Character
1. Overthrust Disturbed Belt	Thrust faulted Paleozoics. Numerous thrust planes can make drilling difficult.	6,000 to 18,000	Blackleaf at 0.58%; remainder of area unknown.	Area has little data to allow reliable estimates.	All units from pre-Cambrian to Quarternary glacial deposits.	Moderate in foothills. Very steep in mountain front areas.	Potentially unstable slopes along east front in Cretaceous surface units.	Moderate to high.	Low to high slope, vegetation and soil dependent.	Moderate to high; heavy equipment, wet soils, and loamy soils.	Thin alluvial colluvial soils, permeable soils in alluvial areas and on terraces.
2. Sweetgrass Arch	Stratigraphic dome structure, some structural control, Cretaceous-Devonian.	3,500 to 6,000	None to slight.	Slightly saline to very saline (20,000 TDS).	Glacial, Cretaceous bedrock.	Moderate to steep.	Stable to potentially unstable - slope and unit dependent.	Low to moderate (high on steep slopes of till underlain by shale).	Moderate to high.	Low to moderate, till soils high in silt and clay.	Varied; some areas of steep slopes on shale could be difficult to reclaim, particularly where soils are wet.
HiLine Bear Paw	Structural fault bounded stratigraphic traps (evaporite units).	1,500 to 3,500	None to very slight.	Fresh to briney <5,000 ppm CL to over 100,000 TDS - usually saline to briney.	Cretaceous shales, mixed glacial.	Moderate to steep.	Stable to potentially unstable.	Same as above.	Same as above.	Same as above.	Same as above.
3. Williston Basin	Structural, stratigraphic evaporite units.	5,000 to 13,000	Hydrogen sulfide to 30% in anhydrite units.	Very saline to briney--50,000 to 300,000.	Glacial till, Cretaceous shales.	Flat to rolling hills.	Generally very stable. Potentially unstable at cut slopes in shales with overlying till.	Low, flat terrain.	Moderate to high.	Low to moderate.	Varied, mixed till in the north on sedimentary shale, sandstone and siltstone.
Cedar Creek Anticline	Structural failed anticline, evaporite units.	7,000 to 10,000	Moderate to high potential, relatively deep high pressure with anhydritic units.	Very saline to briney.	Cretaceous shales.	Flat to moderate slopes.	Stable to potentially unstable steep slopes with Bearpaw shale; could fail if undercut.	Low to moderate.	Same as above.	Same as above.	Soils on sedimentary shales and sandstone, high clay soils difficult to reclaim, easily erodible.
4. Central Montana	Faulted anticlines and stratigraphic traps. Cretaceous to Permian.	2,000 to 5,000	None.	Slightly saline to briney--2,5000 TDS (Cat Creek) to 17,000 TDS (Sumatra).	Cretaceous bedrock dominates.	Flat to moderately steep.	Stable to potentially unstable, dependent on slope activity and material.	Low to moderate. Greatest on steeper slopes underlain by shale.	Moderate to high.	Low to moderate.	Variable. High clay soils on shale bedrock; erodible.

5. Big Horn Basin (Rapelje)	Structural, some stratigraphic control, Cretaceous (sweet gas).	550 to 1,250	None to slight.	Saline to briney; up to 230,000 TDS at Dry Creek.	Cretaceous and Fort Union shale, sandstone, siltstone.	Flat to moderately steep.	Stable to potentially unstable.	Low to moderate.	Moderate to high, greatest on steep slopes and high clay soils.	Low to moderate, fine grained soils.	Varied, some saline problems in closed basins with clay soils.
Elk Basin	Anticline. East area fault closure, some anhydrite, Cretaceous to Devonian.	1,300 to 6,500	Slight to moderate (6% hydrogen sulfide).	Moderately saline to very saline, improves with depth except for Jefferson (high SO4).	Tertiary Fort Union and Cretaceous.	Flat to steeply sloping.	Stable to unstable on steeper slopes of shale bedrock.	Moderate.	Same as above.	Same as above.	High clay, some with high sodium chloride in upper horizons.
6. Powder River Basin	Stratigraphic trap.	4,500 to 8,600	None.	Moderately saline, 4,000-6,000 TDS.	Cretaceous (Hell Creek)	Moderate to steep slopes.	Stable to potentially unstable.	Low to moderate.	Low to moderate.	Low to moderate.	Fair amount coarse fragments at Bell Creek; roads, etc. covered with crushed clinker.
(Hammond)	Stratigraphic Cretaceous. Muddy.	1,200 (average)	None.	None produced.	Cretaceous.	Flat to rolling hills.	Stable to potentially stable.	Moderate.	Moderate.	Moderate.	High clay, easily erodible, tough to reclaim.

*Formation water TDS are estimates based on Rw values (resistivity) from those listed in the 1985 Oil and Gas Symposium. TDS is approximately equal to 10,000/Rw.
Source: Compiled by Earl Griffith, DNRC.

Table 4. General Classification of Water Based on Dissolved Solids

Dissolved Solids Content (mg/l)	Salinity Classification	Comments
0-999	Fresh	Usually suitable for drinking by humans, depending on chemical constituents. No problem for any class of animal.
1,000-2,999	Slightly saline	Can be consumed by humans if no other source of supply available. These waters should be satisfactory for all classes of livestock, although they may cause temporary and mild diarrhea in livestock not accustomed to them.
3,000-4,999	Moderately saline	These waters should be satisfactory for all classes of livestock. They may cause temporary diarrhea or be refused for short periods.
5,000-6,999	Moderately saline	These waters can be used with reasonable safety for dairy and beef cattle, sheep, swine, and horses. It may be well to avoid using the higher levels for pregnant or lactating animals.
7,000-9,999	Moderately saline	In general, the use of these waters should be avoided. Older ruminants, horses and swine may subsist on them for prolonged periods of time under conditions of low stress.
10,000-35,000	Very saline	Not recommended for any agricultural use.
More than 35,000	Briney	Limited industrial uses.

Sources: National Research Council 1974 in Munshower 1986; Hem 1985.

Attempts to predict the probability and concentrations of hydrogen sulfide can be complicated by many factors such as pinpointing the source of the sulfur, predicting the form that the sulfur will be found in, predicting the natural scrubbing effect of rocks that the gas passes through to get from the source to its eventual storage reservoir, and the reactions that occur between hydrocarbons and their host rocks over millions of years. Scientists agree that sulfur is deposited in water-lain deposits, bound up in iron sulfide, gypsum, and organic debris, and is liberated in various forms along with oil and gas.

Although accurate predictions of hydrogen sulfide concentrations are difficult, certain assumptions can be made regarding whether a particular well location has the potential to yield hydrogen sulfide. First, any limestone or dolomite that the wellbore penetrates is likely to have toxic levels of hydrogen sulfide gas, beginning with the upper Jurassic, particularly the Ellis group of limey sandstones and fossiliferous limestones of western Montana, down through the deeper and older metamorphosed limestones and dolomite such as the Ordovician Red River formation of the Williston Basin. Second, as depth and temperature increase, hydrogen sulfide generally increases, and leakage into sandstones at greater depths tends to cause higher than expected levels of hydrogen sulfide. Lastly, any hydrocarbon reservoir in direct contact with anhydrite beds tends to have very high levels of hydrogen sulfide (Orr 1974).

Geologic settings with high hydrogen sulfide concentrations include the Paleozoics of the Big Horn Basin and Wind River Basin of Wyoming, Paleozoics of Alberta, and the Mississippian Mission Canyon Formation of the Williston Basin.

In the Williston Basin, evaporites dominate the lower part of the mid-Mississippian Charles Formation and are mixed with various limey and dolomitic units throughout the Devonian and Silurian formations. In the Ordovician Red River Formation, the evaporites are mixed with dolomites, especially in basin margin settings. Concentrations of hydrogen sulfide in the Duperow Formation of the Williston Basin have been reported at up to 30 percent.

Montana's portion of the Elk Basin field derives hydrogen sulfide from the Pennsylvanian Tensleep Formation (Smith 1985). An analysis by Orr (1974) indicates that primary oil and anhydrite were the sources for Elk Basin hydrogen sulfide. Hydrogen sulfide concentrations in the Tensleep Formation can range from 5 to 18 percent, with additional sour gas in the Madison and Jefferson formations (Montana Geological Society 1985).

Hydrogen sulfide concentrations also are known to occur in north central Montana, including the Sweetgrass Arch. Sour gas is associated with production from the Jurassic Sawtooth Formation. Most other formations in the area produce sweet gas.

Formation Pressure. Fluids in subsurface formations encountered during drilling are contained under natural pressure in the pore space of the rocks. This pressure is the result of the sedimentary and tectonic environment in which the rocks were laid down and the forces to which those rocks were subsequently subjected. Normal formation pressure is defined as being equal to the hydrostatic pressure gradient that would result from a column of water extending from the surface to the bottom of the hole. If a formation contains less pressure than would be generated by the column of water, it is said to be under-pressured or subnormally pressured. If the formation contains pressure greater than predicted, it is abnormally pressured. Most of the producing areas in Montana are under-pressured or normally pressured.

TOPOGRAPHY

The following topographic constraints are universal in extent, but obviously dominate the mountainous terrain and are more critical at higher elevations where sites are wetter and undergo freeze/thaw more frequently. Western Montana and the Overthrust/Disturbed Belt are severely constrained by these topographic limitations.

Slope Aspect. The orientation of a slope face relative to compass bearing is called its aspect. Slope aspect influences the microclimate of an area to such a degree that north slopes in mountainous areas are potentially unstable and exhibit surficial creep, while geologically equivalent but steeper south slopes are stable. Predominantly north-facing slopes retain snow longer than south slopes, have more available soil moisture and thus have a different vegetative assemblage (dense conifers, aspens, shrubs and forbes) than south slopes (range grasses and sagebrush). North slopes also maintain a lower average temperature and retain more water than south slopes. Difficulty of access and concurrent road maintenance costs due to snow accumulation and erosion are probably greater on north slopes than south slopes.

Slope Angle. Slopes greater than 15 percent are limiting to access roads and sites because: (1) earth-moving costs are greater than on lesser slopes, (2) more extensive preliminary surveys and cut and fill plans are needed, (3) more care and time must be taken to ensure equipment and personnel safety, and (4) the probability of slope failure increases with increasing slope angle. Increasing slope angle increases the magnitude of the downslope gravity force relative to the resisting shear forces. Many north aspect slopes exceeding fifteen percent exhibit active soil creep (slow downslope movement of soil by its own weight).

SOILS

Montana, with its wide mix of geologic parent material, has a vast array of different soil types. Parent material is one of the five soil forming factors, along with climate, vegetation, relief, and time (Brady 1974).

Glaciated plains soils vary greatly because of the mix of parent materials. Glacial till (a mix of sand, clay, gravel, and boulders), outwash gravels with few fines, and soils developed on Cretaceous and Tertiary bedrock can be found in glaciated areas of Montana's plains. Occasionally, along the southern margin of plains glaciation, there are extensive deposits of silt and clay developed in areas once covered by ice-dammed lakes.

South of the plains glaciation, soils developed on Cretaceous and Tertiary bedrock strongly reflect the mineralogy, chemistry, and texture of the clay parent material. It is easier to predict soil constraints here because of this strong relationship between parent materials and soils formed from them.

Mountainous soils also tend to reflect the parent material, but soil formation was strongly influenced by slope, climate, and vegetation. Soils in mountainous areas of Montana often have deeper alluvial and colluvial soils in alluvial valleys and on terraces. Soils on steep slopes are thinner and less well developed.

The complex soil relationship to geology, climate, and the other soil-forming factors precludes any attempt to describe in detail any soil for a given region. The Soil Conservation Service has produced a general soil map of Montana. This map has been adapted for general use and is presented in Technical Appendix 2.

IMPACTS AND MITIGATION

GEOLOGICAL CONSTRAINTS

Actions taken without knowledge of the limiting constraints posed by the physical environment can result in impacts to the environment. For example, surface disturbance can trigger slope failures, which can degrade water quality and have long-term consequences for aquatic species including fish.

The best mitigation is always avoidance of a potential problem. If, however, a problem area such as an unstable slope cannot be completely avoided, the developer can mitigate the problem through road or site relocation, or through least-impact construction and planned reclamation.

Region 1, the Overthrust/Disturbed Belt, has the greatest potential for physical science impacts because of complex geology, steep terrain, and extensive site requirements. Region 5, especially around Dry Creek, has a high potential for slope failure because of the rough terrain and failure-prone geologic units. Most of the rest of the oil-producing areas of the state do not have the unique slope/geologic conditions which contribute to slope failure (see Table 3). Nonetheless, construction on slopes greater than 30 percent should be avoided whenever possible, regardless of site geology.

SOILS

Soil erosion and compaction are generally unavoidable during oil and gas development. However, magnitude and significance of impacts can be minimized by appropriate measures.

Soil Erosion. Lack of vegetation, steep, long slopes, erodible soils, high winds, and heavy rainfall are the primary factors contributing to soil erosion. Elimination or a reduced influence of any factor will reduce erosion.

Equipment used in drilling oil wells is usually large and heavy enough to require an improved road, except in open terrain and rangeland. The largest equipment (deep hole rigs) is often restricted to well-built roads of moderate slope and width. Most oil development activity usually requires at least a bladed trail, and often a well-constructed, improved gravel road is needed. Minimal erosion would be expected from a shallow gas well (2,500 to 3,500 feet) on the Hi-Line, close to an existing road and using a small mobile rig with access across flat or gently sloping terrain on sodded loamy soils. The highest erosion potential would result at a well site several miles off the nearest road, across steep terrain in Cretaceous bedrock where road requirements are extensive and the terrain difficult.

Mitigating measures commonly applied to reduce soil erosion impacts are as follows:

1) Avoid riparian zones, wetlands and floodplains by a minimum of 100 feet exceptat stream crossings.
2) Minimize stream crossings.
3) Use best management practices and design construction to avoid stream contamination by sediment or petroleum.
4) Use special design measures for new cut-and-fill slopes where moderate-to-high water erosion hazards exist.
5) Promptly revegetate cut-and-fill slopes to control surface erosion by wind and water.
6) Whenever possible, avoid road construction on slopes greater than 60 percent. Also avoid construction of drill pads on slopes greater than 40 percent.
7) Minimize impacts resulting from increased road access by closing new roads to uses other than those required by oil and gas activity.
8) Obliteration activities will normally include removal of drainage structures and associated fill dirt to the extent necessary to pass expected flood flow. Use erosion prevention measures such as revegetation to make the road maintenance free.

BLM's construction standards, maintenance requirements, and road and pad reclamation standards for the Hall Creek APD are included in Technical Appendix 2. These mitigations could be applied for wells in similar type of terrain with associated deep-well drilling requirements.

Wind erosion is a problem in virtually every county east of the Continental Divide. The highest velocities generally are confined to the "Chinook" belt extending several tens of miles east of the Rockies and in the Yellowstone valley from Livingston to Big Timber. Eastern Montana also suffers from excessive wind erosion due primarily to dry soil, sparse vegetative cover, and erodible soils. Since wind erosion is influenced by vegetative cover, wind velocity, soil moisture, and soil surface roughness, mitigating measures may include water spraying (which is not always practical in water-short eastern Montana) and construction of windbreaks (fences or hedges).

Soil Compaction. Oil drilling activity, especially equipment transport, causes soil compaction. The degree of compaction is influenced by soil texture, moisture content, organic matter, and soil structure (Barnes et al. 1971). Soils with a mixture of sand, silt, and clay compacts more than a soil with more uniform particle size (Chancellor 1977). Coarse-textured sandy soils generally are more compactible than fine-grained soils (Larson et al. 1980). Soil moisture is the most critical factor in compaction. At field capacity (the amount of soil moisture remaining after a soil mass is saturated and allowed to drain freely for 24 hours), sufficient water remains in the pores to provide particle-to-particle lubrication and maximum compaction potential under load. Thus, moist, not wet, soils are most susceptible to compaction. Organic matter such as roots and humus can help reduce soil compaction. In general, the greater the organic matter content, the less compaction. Grassland soils tend to have greater organic matter content than forest soils and can withstand compaction pressures better, all other factors being equal. Coarse soils withstand compaction forces better than fine ones, especially at a heavy moisture content (Emerson 1978).

Compaction severely affects plant growth by inhibiting root penetration, limiting oxygen and carbon monoxide exchange between the root zone and the atmosphere, and severely limiting the rate of water infiltration into the soil. Compaction destroys the soil's ability to sustain plant growth and creates a soil surface with a high run-off potential.

Studies by Soehne (1958) showed that tires carrying different total loads but having the same surface pressure per inch of tire resulted in dramatically different compaction pressure curves. The heaviest load produced the deepest compaction pressure. Loads of oil field equipment may easily meet the 600-pound per inch of tire width requirement of the Montana Highway Department on hard surface roads, but the use of these same vehicle and wheel combinations on unimproved or unroaded areas can cause severe soil compaction, especially if the unimproved road is wet.

The following guidelines could be used to reduce the impact of soil compaction.

1) Confine travel to one roadway. Since most compaction occurs on the first pass, using many different access routes increases the area compacted.
2) Where possible, restrict travel during periods when the soil is moist or wet.
3) Construct access roads to accommodate the maximum loads. If necessary, use subgrade materials to distribute loads on access roads where the soils have inherently low-bearing strength.
4) Use tracked equipment or equipment with low-pressure tires rather than wheeled equipment for site preparation and recla-mation.
5) Remove vegetation only when necessary; any organic matter in the soil helps avoid compac-tion.
6) Compaction can best be remedied prior to reclamation by subsoiling or deep ripping when the soil is driest, usually late summer or early fall (Ferguson 1988). When compaction is shallow (the result of using large low-pressure tires or tracked vehicles), conven-tional tillage or scarifying equipment can be used.

SURFACE AND GROUNDWATER

The distribution and quality of water in Montana depends primarily on topography, climate, and geological conditions. The occurrence and distribution of water in Montana is described by the U.S. Geological Survey (USGS) in National Water Summaries (U.S. Geological Survey 1985 and 1986).

Generally the western mountain areas receive large amounts of precipitation that provides fresh water recharge to surface- and groundwater systems. Mountain streams and unconsolidated sand and gravel aquifers situated in the valleys yield large volumes of good quality water. Much of the unconsolidated materials that fill the intermontane valleys are composed of relatively insoluble granitic rock material. Minerals in this material do not readily dissolve into the water.

Much less precipitation falls on the eastern plains and thus less fresh water is available to recharge water resources. Streams in eastern Montana are turbid and of poorer quality because they drain lowland areas which contribute sediment and dissolved solids to runoff. Consolidated sedimentary aquifers in eastern Montana are finer grained than western alluvial aquifers and receive less recharge. Groundwater movement is slower in the fine-grained aquifers so the fine aquifer materials have a greater chance to dissolve into the water. Therefore, groundwater in the eastern aquifers is poorer in quality and well yields are less than in the western alluvial aquifers. The USGS (1986) estimates that recharge to groundwater from precipitation ranges from less than 1 inch in parts of the eastern plains to several inches in portions of the western mountains.

WATER QUALITY STANDARDS

Primary drinking water standards are intended to keep water pure enough to be safe for consumption. Secondary standards are intended to maintain acceptable taste and odor of drinking water. Water used for drinking must meet these standards (Table 5). In some cases, surface waters and groundwater will require treatment to meet the standards. EPA has established maximum allowable contamination levels for water used for various purposes. These guidelines are presented in Technical Appendix 3.

SURFACE WATER CLASSIFICATION

The classifications for each major river and its tributaries are based on the existing surface water quality. A summary of surface water classifications is presented in Table 6 and shown in Figure 31. DHES has adopted standards to limit the amount of various pollutants that can be released into surface waters. A permit is required when a source is likely to discharge to surface water. The permit regulates the concentrations and volumes that can legally be discharged to surface waters. The various water quality standards for each class of stream are established by administrative rules of DHES (see ARM 16.20.601 et. seq.).

GROUNDWATER CLASSIFICATION

The distribution and availability of groundwater varies greatly across the state. Descriptions of the principal aquifers in Montana are presented in reports published by the Montana Water Resources Board (1969), Montana Bureau of Mines and Geology (1982), and U.S. Geological Survey (1985). Maps showing the principal aquifers in Montana with adequate detail and scale are not available for inclusion in this report. Information obtained from the above documents has been compiled to generate a summary of the characteristics of the aquifers in Montana. Table 7 presents information on the name, descriptions and thickness of the principal aquifers; characteristics of typical water wells; and data on location, use, and total dissolved solids content of the groundwater.

The highest class groundwater, Class I, usually is considered suitable for drinking with little or no treatment. Groundwater in western Montana's alluvial and basin valley-fill aquifers and alluvial aquifers along major river valleys typically are considered Class I.

Table 5. Drinking Water Standards for Public Water Supplies

Primary Standards*	Maximum Contaminant Levels for Inorganic Chemicals (mg/l)
Arsenic	0.05
Barium	1.
Cadmium	0.010
Chromium	0.05
Lead	0.005
Mercury	0.002
Nitrate as N	10.00
Selenium	0.01
Silver	0.05
Fluoride	1.4 - 2.4
Endrine	0.0002
Lindane	0.004
Methoxychlor	0.1
Toxaphene	0.005
2, 4-D	0.1
2,4,5-TP Silvex	0.01

Secondary Standards**	Recommended Maximum Contaminant Levels (mg/l)
Chloride	250
Copper	1.0
Corrosivity	Non-corrosive
Iron	0.3
Manganese	0.005
pH	6.5 - 8.5 Std. Units
Sulfate	250
Zinc	5.0
Total dissolved Solids	500

* Primary standards are established to protect human health and define maximum permissible concentrations for each listed parameter.

**Secondary standards are developed to provide acceptable aesthetic and taste characteristics in drinking water. Recommended concentration limits have been established for the listed parameters.

Source: Title 16, Chapter 20, Subchapter 2, Administrative Rules of Montana.

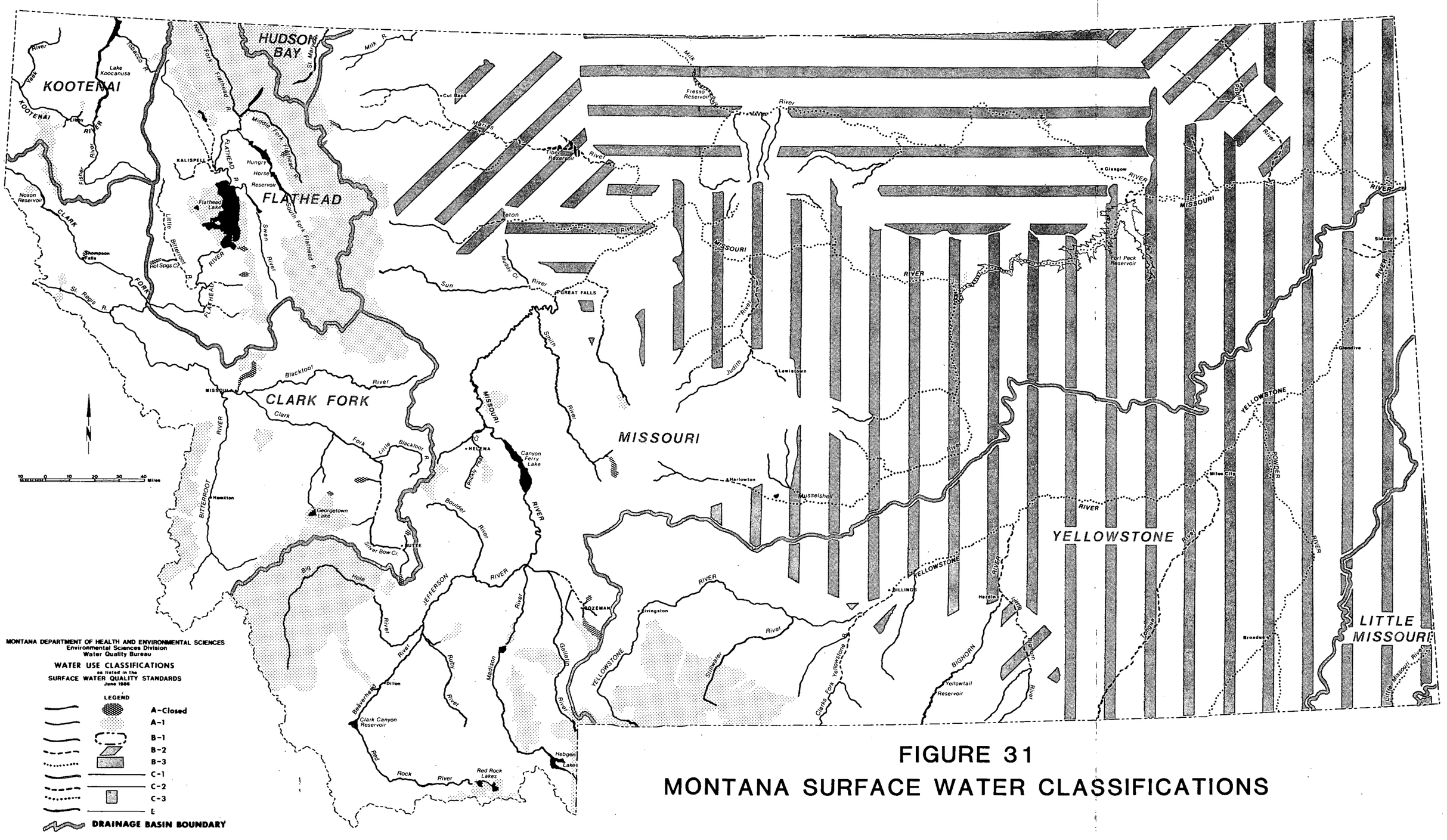
Class II groundwater is considered marginal for use as drinking water. Most groundwater in the eastern portion of the state is Class II.

Class III groundwater is generally limited to drinking water for livestock. Data on Class III aquifers are limited, but groundwater in some of the finer grained, highly soluble aquifers and some of the moderately deep aquifers meet this classification. In many areas, particularly in eastern Montana, surface water is absent and Class II and Class III groundwaters are the only economically available source of drinking water.

Class IV is the lowest groundwater classification, and such groundwaters may be suitable for some limited uses but for practical purposes are not treatable and are unsuitable for beneficial use. Class IV groundwater is contained in the very deep limestone aquifers of the Madison Group.

WASTES GENERATED BY DRILLING AND PRODUCTION ACTIVITIES

Although the chemical character of oil and gas wastes produced in Montana have not been studied in detail, the U.S. Environmental Protection Agency (EPA) (1987a) evaluated wastes produced by oil and gas exploration, development, and production nationwide to determine if they should be subject to hazardous waste regulations under the authority of the Resource Conservation and Recovery Act (RCRA). EPA concluded that wastes generated by oil and gas operations are not toxic enough to be regulated as hazardous wastes.



MONTANA DEPARTMENT OF HEALTH AND ENVIRONMENTAL SCIENCES
Environmental Sciences Division
Water Quality Bureau

WATER USE CLASSIFICATIONS
as listed in the
SURFACE WATER QUALITY STANDARDS
June 1986

LEGEND

- A-Closed
- A-1
- B-1
- B-2
- B-3
- C-1
- C-2
- C-3
- E
- DRAINAGE BASIN BOUNDARY

FIGURE 31
MONTANA SURFACE WATER CLASSIFICATIONS

Table 6. Summary of Surface Water Classifications in Montana.

A-Closed Classification: (1) Waters classified A-Closed are suitable for drinking, culinary, and food processing purposes after simple disinfection. Water quality is suitable for swimming, recreation, growth, and propagation of fishes and associated aquatic life, although access restrictions to protect public health may limit actual use of A-Closed waters for these uses.

A-1 Classification: (1) Waters classified A-1 are suitable for drinking, culinary and food processing purposes, after conventional treatment; bathing, swimming and recreation; growth and propagation of salmonid fishes and associated aquatic life, waterfowl and furbearers; and agricultural and industrial water supply.

B-1 Classification: (1) Waters classified B-1 are suitable for drinking, culinary and food processing purposes, after conventional treatment; bathing, swimming and recreation; growth and propagation of salmonid fishes and associated aquatic life, waterfowl and furbearers; and agricultural and industrial water supply.

B-2 Classification: (1) Waters classified B-2 are suitable for drinking, culinary and food processing purposes, after conventional treatment; bathing, swimming and recreation; growth and marginal propagation of salmonid fishes and associated aquatic life, waterfowl and furbearers; and agricultural and industrial water supply.

B-3 Classification: (1) Waters classified B-3 are suitable for drinking, culinary and food processing purposes, after conventional treatment; bathing, swimming and recreation; growth and propagation of non-salmonid fishes and associated aquatic life, waterfowl and furbearers; and agricultural and industrial water supply.

C-1 Classification: (1) Waters classified C-1 are suitable for bathing, swimming and recreation; growth and propagation of salmonid fishes and associated aquatic life, waterfowl and furbearers; and agricultural and industrial water supply.

C-2 Classification: (1) Waters classified C-2 are suitable bathing, swimming and recreation; growth and marginal propagation of salmonid fishes and associated aquatic life, waterfowl and furbearers; and agricultural and industrial water supply.

C-3 Classification: (1) Waters classified C-3 are suitable for bathing, swimming and recreation; growth and propagation of salmonid fishes and associated aquatic life, waterfowl and furbearers. The quality of these waters is naturally marginal for drinking, culinary and food processing purposes, agriculture and industrial water supply. Degradation which will impact established beneficial uses will not be allowed.

I Classification: (1) The goal of the State of Montana is to have these waters fully support the following uses: drinking, culinary, and food processing purposes after conventional treatment; bathing, swimming and recreation; growth and marginal propagation of fishes and associated aquatic life, waterfowl and furbearers; and agricultural and industrial water supply. An analysis will be performed for each of these waters during each triennial standards review period to determine the factors preventing or limiting attainment of the designated uses listed herein. Based on these analyses, the specific standards listed will be adjusted to reflect any improvements which have occurred in water quality as a result of water quality control of nonpoint-source pollution.

Source: Montana Water Quality Standards (ARM 16.20.616-623).

However, the study also indicated that proper disposal of these wastes was necessary to protect the quality of groundwater and surface water.

Drilling fluid and produced water constitute the largest volume of wastes produced by oil and gas exploration, development and production operations. Formation cuttings, drilling fluid additives, and petroleum compounds are returned to the surface with the drilling fluid. These materials are usually held in suspension or dissolved in the drilling fluid.

Drilling conditions, the quality and quantity of oil or gas, and the wastes produced by drilling operations are different with each field and sometimes differ between wells. Details on the quantities of drilling fluid additives used in Montana have not been compiled, although the types of additives are discussed in Chapter Two. The U.S. Environmental Protection Agency (1987a) and Davis (1987) indicate many of the additives, such as weighting materials, viscosifiers and lost circulation materials, are probably common to most deeper well drilling operations in Montana. The constituents of any particular drilling fluids will depend on the additives needed to drill a specific well. A list of the general purpose drilling fluid additives and their functions is presented in Table 8

The American Petroleum Institute (1987a) estimates that during 1985, an average of 7,334 bbls of drilling fluid (308,028 gallons) per well was generated in Montana. Other miscellaneous wastes related to the drilling operation are also produced on a regular basis. Lubricating oils, grease, and

Table 7. Summary of the Characteristics of Principle Aquifers and Their Use in Montana.

Aquifer Name and Description	Well Characteristics: Common Depth (ft.)	Well Characteristics: Common Yield (gal./min.)	Total Dissolved Solids Content of Groundwater	Locations Where Used	Primary Uses
Cenozoic aquifers: Western alluvial and basin-fill deposits: Unconsolidated sand, gravel, silt and clay. Generally unconfined. 30 to 500+ ft. thick.	20 - 40	5 - 50 est.	Dissolved solids concentration generally less than 300 mg/L near Helena and Missoula. Water quality in other areas probably similar	Western and southcentral Montana valleys.	Public supply, domestic, stock irrigation and industrial purposes.
Western glacial deposits: Unconsolidated sand, gravel, silt and clay. Unconfined to confined. 30 to 200 ft. thick.	50 - 300	5 - 50 est.	Dissolved solids concentration generally less than 200 mg/L in Northwestern Montana. Water quality in other areas probably similar.	Western and southcentral Montana valleys.	Public supply, domestic and stock purposes; limited irrigation and industrial use.
Eastern alluvial deposits and terrace gravels: Unconsolidated sand, gravel, silt and clay. Generally unconfined. 30 to 200 ft. thick.	20 - 50	5 - 50 est.	Dissolved solids concentration generally less than 2,000 mg/L.	Central and eastern Montana valleys.	Same as above.
Eastern glacial deposits: Unconsolidated sand, gravel, sil and clay. Unconfined to confined. 10 to 100 ft. thick.	20 - 60	5 - 10	Dissolved solids concentration generally less than 2,200 mg/L.	Northcentral Montana.	Same as above.
Fort Union Formation: Moderately consolidated and inter-bedded shale, siltstone, sandstone and coal. Unconfined to confined. Up to 2,200 ft. thick.	50 - 300	15 - 25	Dissolved solids concentration generally less than 1,800 mg/L.	Eastern and southcentral Montana.	Domestic and stock purposes; limited public supply, irrigation and industrial.
Mesozoic aquifers: Hell Creek and Fox Hills Formations: Sandstone with some siltstone and shale. Confined except near out-crop areas. 500 to 1,200 ft. thick.	150 - 500	5 - 20	Dissolved solids concentration generally less than 1,200 mg/L. Includes Fox Hills - lower Hell Creek aquifer.	Carter, Custer, Fallon and Prairie counties.	Same as above.
Judith River Formation: Sandstone with shale, siltstone, lignite and coal. Confined except near outcrop areas. 10 to 400 ft. thick.	200 - 600	5 - 15 est.	Dissolved solids concentration generally less than 2,300 mg/L in central Montana. Water quality in other areas of Montana relatively unknown.	Phillips, Blaine, Hill and Valley counties.	Domestic and stock purposes; limited public supply, irrigation and industrial.

Eagle Sandstone: Interbedded sand-stone and shale. Confined except near outcrop areas. 250 ft. thick.	100 - 800	10 - 20 est.	Dissolved solids concentration generally less than 2,300 mg/L in central Montana. Water quality in other areas of Montana relatively unknown.	Hill, Liberty, Chouteau, Glacier and Fergus counties and along mountain flanks.	Same as above.
Kootenai Formation: Sandstone, siltstone and shale. Confined except near outcrop areas. 400 to 500 ft. thick, basal sandstone 100 ft. thick.	100 - 900	10 - 30 est	Dissolved solids concentration generally less than 500 mg/L near outcrop areas in central Montana. Water quality in other areas of Montana relatively unknown.	Cascade, Judith Basin, Fergus and Petroleum Counties and along mountain flanks.	Same as above
Paleozoic aquifer: Madison Group: Limestone, dolomite, anhydrite and halite. Confined except near outcrop areas. 700 to 1,500 ft. thick.	500 - 3,000	- - - -	Dissolved solids concentration generally less than 5,000 mg/L but may exceed 300,000 mg/L in northeastern Montana.	Not widely used except along mountain flanks.	Not widely used except for localized domestic and stock purposes.

Source: (Modified after U.S. Geological Survey 1985).

Table 8. Function and General Purpose of Drilling Fluid Additives.

Function	General Purpose	Common Additives
Weighting material	Control formation pressure, check caving, facilitate pulling dry pipe, and well completion operations.	Barite, lead compounds, iron oxides.
Viscosifier	Viscosity builders for fluids, for a high viscosity-solids relationship.	Bentonite, attapulgite clays, all colloids, fibrous asbestos.
Thinner dispersant	Modify relationship between the viscosity and percentage of solids, vary gel strength, deflocculant.	Tannins (Quebracho), polyphosphates, lignitic materials.
Filtrate reducer	Cut the loss of the drilling fluid's liquid phase into the formation.	Bentonite clays, sodium carboxymethyl cellulose (CMC), pregelatinized starch, various lignosulfonates.
Lost circulation material	Primary function is to plug the zone of loss.	Walnut shells, shredded cellophane flakes, thixotropic cement, shredded cane fiber, pig hair, chicken feathers, etc.
Alkalinity, pH control	Control the degree of acidity or alkalinity of a fluid.	Lime, caustic soda, bicarbonate of soda.
Emulsifier	Create a heterogeneous mixture of two liquids.	Lignosulfonates, mud detergent, petroleum sulfonate.
Surfactant	Used to modify the degree of emulsification, aggregation, dispersion, interfacial tension, foaming, and defoaming (surface active agent).	Include additives used under emulsifier foamers, defoamers, and flocculators.
Corrosion inhibitor	Materials attempt to decrease the presence of such corrosive compounds as oxygen, carbon dioxide, and hydrogen sulfide.	Copper carbonate, sodium chromate, chromate-zinc solutions, chrome lignosulfonates, organic acids and amine polymers, sodium arsenite.
Defoamer	Reduce foaming action especially in saltwater-based muds.	Long chain alcohols, silicones, sulfonated.
Foamer	Surfactants which foam in the presence of water and thus permit air or gas drilling in formations producing water.	Organic sodium and sulfonates, alkyl benzene sulfonates.
Flocculants	Used commonly for increases in gel strength.	Salt, hydrated lime, gypsum, sodium tetraphosphates.
Bactericides	Reduce bacteria count.	Starch preservative, paraformaldehyde, caustic soda, lime, sodium pentachloraphenate.
Lubricants	Reduce torque and increase horsepower at the bit by reducing the coefficient of friction.	Graphite powder, soaps, certain oils
Calcium remover	Prevent and overcome the contamination effects of anhydrite and gypsum.	Caustic soda (NaOH), soda ash, bicarbonate of soda, barium carbonate.
Shale control inhibitors	Used to control caving by swelling or hydrous disintegration.	Gypsum, sodium silicate, calcium lignosulfonates, lime, salt.

Source: Wright 1978 and Collins 1975 in Murphy and Kehew 1984.

hydraulic fluids within drilling machinery must be periodically changed. Waste cleaning agents, solvents, and rags used for equipment degreasing and maintenance are discarded. Tanks that store fuel, oil, drilling fluid additives, and other materials must be emptied and cleaned. Drilling operations produce empty bags, cans, and barrels that have contained additives or other materials, and other miscellaneous refuse. These other wastes are either placed in a separate pit for on-site burial or transported off-site to a disposal area, such as a sanitary landfill. The volume of wastes generated is a function of two related factors--the depth of a well and the duration of the drilling operation.

Produced water and tank bottom sludges are produced during oil and gas production and treatment operations. The ratio of water to oil from a well increases over time. Secondary and tertiary recovery operations can increase the volume of water produced by a well. The quantity of produced water varies across Montana with individual oil and gas fields. Typically, gas wells produce little water (Syth 1988). Data for 1987 indicate that the 4,132 active oil wells in Montana produced an average of 2,600 bbls (109,200 gallons) of water (DNRC 1987). There is wide variation in produced water characteristics, depending on several factors, including the producing formation and the depth of the well.

Chemical constituents detected in drilling and production waste can be highly variable (U.S. Environmental Protection Agency 1987a; Davis 1987; Murphy and Kehew 1984; Beal et al. 1987). Table 9 lists representative chemical constituents most likely found in drilling and production wastes. These parameters probably are not prevalent in all wastes generated in Montana but are indicators, when present, of potential water quality concerns. Data from North Dakota and Wyoming where drilling activities are similar to those in Montana indicate that surface- and groundwater quality needs to be considered when determining measures required to protect water resources during drilling operations and when disposing of spent drilling fluids and production wastes (Davis 1987; EPA 1987a).

In eastern Montana, drilling fluid in the Williston Basin and portions of the Powder River Basin are typically very salty and produced water is high in TDS. Such wastes represent a significant source of contaminants that can degrade water quality. Wastes generated in other Montana fields may not present as great a threat to water quality, but improper management of wastes in any area may cause degradation of water quality.

FACTORS INFLUENCING IMPACTS TO WATER

The seriousness of impacts to Montana's water resources from wastes generated by oil and gas operations depends upon several factors. The hydrogeologic setting of a site largely determines the movement and severity of water pollution. Waste volume and the concentration and type of chemical constituents contained in the wastes are also important. Waste management practices and regulatory controls placed on oil and gas exploration, development, and production also influence the frequency and severity of impacts to water quality.

Surface water is readily susceptible to degradation from wastes directly discharged into a surface water body. The susceptibility of groundwater to pollution depends greatly on the characteristics of the aquifer.

SUSCEPTIBLE HYDROGEOLOGIC SETTINGS

Oil and gas facilities constructed and operated adjacent to surface water pose the greatest potential for surface water pollution. Facilities situated along streams, in drainage ways, or in steep terrain, increase the potential for surface water pollution. Wastes that escape the facility may directly discharge to surface water or drain downslope and join surface water bodies and cause degradation. Runoff from precipitation may transport wastes downslope into surface water.

Erosion at drilling or production sites can move sediment and waste materials into water resources. Contaminants that seep out of buried wastes are called leachate. Backfilled materials at reclaimed drilling or production sites can dry out and shrink, creating depressions that collect precipitation and runoff. Increased moisture can generate leachate that forms a long-term source of water pollution.

It is sometimes difficult to separate groundwater contamination from surface water contamination because surface and groundwater systems usually are connected. Either surface water systems leak into the subsurface and recharge groundwater, or groundwater systems discharge to the surface and contribute to surface water flow.

Groundwater is normally out of sight, so groundwater contamination often goes undetected until it affects an existing use. The subsurface migration of contaminants from oil and gas wastes depends greatly upon the permeability of the subsurface materials. Generally, groundwater movement is slower in fine-grained materials that have a high clay content. Migration of pollutants can be slowed by clay particles. Groundwater flow and the movement of pollution in coarse-grained materials, such as sand and gravel, is typically higher. The degree of saturation also is an important influence on the movement of groundwater and pollution below ground surface. Soluble pollutants can move with much greater ease through soil that is saturated. When the subsurface void spaces are completely filled with water, tensional forces are overcome and pollutants can migrate among subsurface particles.

Table 9. Water Quality Parameters of Concern in Montana Oil and Gas Wastes.

List of Parameters	Present in:*	
	Drilling Waste	Production Waste
Conventional Parameters		
Calcium		x
Chloride	x	x
Nitrate	x	
Sodium	x	x
Sulfate	x	x
Heavy Metals		
Arsenic	x	x
Antimony		x
Barium	x	x
Cadmium	x	
Chromium	x	
Fluoride	x	x
Iron	x	
Lead	x	
Manganese	x	
Magnesium		x
Zinc	x	
Organic Compounds		
Benzene	x	x
Ethylebenzene	x	
Phenanthrene		x
Toluene	x	
Ratios of Constituents		
Total dissolved solids	x	x
Total suspended solids	x	

* The presence of these parameters in sufficient quantities signals a concern for water quality degradation when disposing of drilling and production wastes, particularly in close proximity to surface- or groundwater resources.

Sources: Compiled by John Arrigo, DHES, based on data contained in Davis 1987; EPA 1987a; Murphy and Kehew 1984; and Beal et. al. 1987.

Aquifers near the surface are most susceptible to contamination from oil and gas wastes. Near-surface aquifers typically are composed of unconsolidated, highly permeable materials that can be tapped for water supplies. The depth to water in many of these aquifers is less than 50 feet. Near-surface aquifers susceptible to contamination from surface sources of pollution include alluvial, basin-fill, and glacial deposits in western Montana, and alluvial deposits, terrace gravel, and glacial sand and gravel in eastern Montana.

Sedimentary aquifers with an over layer of clay are less susceptible to contamination from the surface. However, where sedimentary aquifers are exposed at the surface or where vertical fractures are present in the rocks, ground-level pollutants can enter the aquifer. Groundwater can be degraded where oil and gas wells are not properly cased. Improper placement of casing in an oil or gas well may allow petroleum, drilling fluid, or produced water to enter the aquifer.

Because collecting site-specific data to determine water quality degradation often requires monitoring wells, many conclusions with respect to groundwater contamination must be inferred from known data. The Water Quality Act stipulates that it is unlawful to place wastes where they are likely to pollute state water. The release of wastes from the improper handling and disposal of wastes at oil and gas operations, particularly in susceptible hydrogeologic settings, creates the potential for water pollution and could be considered a violation of the Water Quality Act.

There has been no comprehensive study of the potential long-term effects of oil and gas drilling and production activity on Montana's water resources. Groundwater contamination from oil drilling and production has been recognized as a consequence of improper disposal and reclamation practices (Groundwater Advisory Council 1985). Two studies funded by Resource Indemnity Trust

funds are currently analyzing the extent of groundwater contamination from oil and gas waste disposal in north-central and eastern Montana. These studies focus on the Williston Basin, although the potential for groundwater contamination exists wherever drilling and production occurs in susceptible hydrogeologic settings. The degree of potential contamination depends on site characteristics: the nature and permeability of subsurface materials, the constituents of the drilling mud, produced water or other wastes, and the depth to underlying aquifers. It is likely that most disposal sites do not cause groundwater contamination; however, many, particularly those in sensitive settings, pose a threat to water quality in near-surface aquifers.

Table 10 summarizes the potential for oil and gas wastes to present concerns for water quality in the oil and gas regions.

Poplar River Problem. One area in Montana where water quality problems associated with oil and gas activities have been studied is the East Poplar oil field (U.S. Geological Survey 1984). Water produced from the field is brine, which is injected into subsurface formations or stored in evaporation ponds for disposal.

The area of the study covers approximately 20 square miles and is underlain by relatively impermeable Bearpaw shale covered with less than 50 feet of unconsolidated alluvial and glacial deposits of sand, gravel, and lesser amounts of silt and clay. Groundwater in the unconsolidated deposits that is tapped with wells for domestic and stock supply. The study indicates that groundwater discharges to the Poplar River, at least in some portions of the study area.

Results from the study suggest groundwater is being polluted because of produced water storage and injection operations. The concentrations of total dissolved solids (TDS), chloride, and sodium in groundwater varied significantly across the study area. The actual source for the contamination was not identified by the study, but leakage from injection pipes and produced water evaporation/storage ponds is suspected. It is not known if domestic or stock wells in the area were abandoned as a result of the pollution (USGS 1984).

North Dakota Studies. The North Dakota Geologic Survey conducted two studies (Murphy and Kehew 1984, and Beal et al. 1987) to evaluate impacts to groundwater from the burial of saltwater-based drilling mud.

The first study was conducted in western North Dakota and was aimed at evaluating the impacts of buried drilling wastes on shallow groundwater. Results of water analyses by Murphy and Kehew (1984) indicate that leachate is being generated from reclaimed reserve pits. Water obtained from the unsaturated zone (interval between the surface and the water table) beneath the buried drilling fluid at four study sites exceeds recommended concentration limits and maximum permissible concentration limits for trace elements and major ions (arsenic, chloride, lead, selenium, and nitrate). The concentration of these contaminants declined rapidly as the distance from the buried drilling fluid increased.

Two of the study sites were situated in geohydrologic settings that offered a great potential for leachate migration in the saturated zone (interval containing the water table). The chloride ion was chosen as an indicator of maximum leachate migration because of its high mobility and lack of attenuation other than by dispersion. The chloride concentrations returned to background levels within the saturated zone 200 to 300 feet downgradient of the buried drilling fluid at these two sites.

The shallow groundwater beneath one of the study sites exceeded maximum permissible concentration limits for cadmium, lead, and selenium, and was considered a danger to the health of anyone consuming it. These limits were exceeded in an area approximately 200 by 1,000 feet.

The second study (Beal et al. 1987) was conducted in north-central North Dakota and was directed at impacts to groundwater in glacial aquifers with characteristics similar to glacial aquifers in north-central Montana. Analysis indicated that leachate was being generated from buried drilling waste at the two sites selected for study. The impact of drilling fluid disposal in till depends upon the geologic setting. Migration of the drilling fluid constituents will occur along fractures in the till; widespread contamination could result if these contaminants intersect permeable subsurface sediments. Beal et al. concluded that drilling fluids should not be disposed of in glaciofluvial sediments.

WATER QUALITY BUREAU STUDY

In 1982 the Water Quality Bureau contracted for an evaluation of water quality problems associated with oil and gas development in eastern Montana. Dewey (1982) viewed 20 sites in Richland County where water quality problems were suspected. Some of the sites viewed by Dewey were associated with truck spills, illegal dumping and pipeline leaks. For some sites, not enough information was available to allow discussion in this report. Ten of the sites examined by Dewey are summarized in Table 11. Additional information is provided in Technical Appendix 3.

Dewey's evaluation was conducted shortly after oil and gas activities peaked in the late 1970s and early 1980s. All of the sites in the study were in the Williston Basin oil-producing area. Drilling fluids in this region typically have a very high salt content. Sites listed in Table 11 show examples of problems from improper reserve pit construction, maintenance, or reclamation which caused degradation of water quality or created the potential for water pollution. In one case investigated by Dewey (1982), drilling fluids that

Table 10. Sensitivity of Montana Water Resources to Contamination from Oil and Gas Wastes.

Region, Area or Producing Basin	Surface Geology	Soil Character	Sensitivity	Comments
1. Overthrust-Disturbed	All units from pre-Cambrian to Quaternary glacial deposits.	Thin alluvial colluvial soils, permeable soils in alluvial areas and on terraces.	High.	Very high potential to affect head-water areas due to confined sites, severe weather conditions, steep slopes, and porous alluvial soils. Water quality concerns may exist for both drilling and production.
2. Northern Sweetgrass Arch	Glacial units and Cretaceous shale bedrock.	Varied till; soils high in silt and clay.	Low to moderate.	Drilling and production wastes gener-ally not concern in areas of tight clay soil over shale bedrock. Exceptions may exist near wells and surface waters.
Hi-Line and Bear Paw Mountains	Cretaceous shales, mixed glacial units.	Varied; includes soils listed above; glacial outwash and alluvium.	Moderate.	Some concern may exist during drilling on case-by-case basis, particularly in areas of permeable soils, near wells, or in alluvium. Saline to briney-produced water also a concern in these areas.
3. Williston Basin	Glacial till, Cretaceous shales.	Varied; mixed till in the north on sedimentary shale, sandstone, and siltstone.	High.	Both drilling and production wastes are concern due to high salt and TDS content. Local water supplies gener-ally marginal and restricted to wells in shallow surface aquifers. Concern particularly important in areas of allu-vium and along areas of glacial limits.
Cedar Creek Anticline	Cretaceous shales and sandstones.	High clay and silt soils.	Moderate to high.	Drilling and production wastes may be concern in areas close to surface waters, water wells, and shallow acquifers.
4. Central	Cretaceous bedrock dominates.	Variable high clay soils predominate; more permeable soils present.	Low to moderate.	Drilling and production wastes generally not a concern except in areas of permeable soils or alluvium, near surface water or water wells, and when produced waters exceed 3,000 TDS.
5. Big Horn	Cretaceous and Tertiary (Fort Union) shale, sandstone, and siltstone.	Varied; similar to above.	Moderate.	Drilling wastes may be concern when drilling near surface- or groundwater, or areas of permeable materials. Area water sources generally of mar-ginal quality and can be easily affec-ted. Produced water also concern in such settings due to high TDS concentration.
6. Powder River	Cretaceous shales.	High silt and clay soils predominate.	Moderate.	Drilling wastes a concern near wells, areas of shallow groundwater (alluvium), or surface waters. Concern is greatest in such areas when saltwater muds used.

SOURCE: Compiled by Earl Griffith and Kevin Hart, DNRC.

Table 11. Summary of Ten Problem Sites Identified by Dewey in Richland County, Montana.

Site Number	Location Sec.	Twn.	Rng.	Date	Description of Problem	Comments
1	36	24	48	1982	Reserve pit constructed next to creek. Drilling fluids leaked into surface water via groundwater flows.	Surface water quality degraded. Chloride content elevated 3 miles downstream.
2	17	30	58	1980	Reserve pit liner torn, drilling fluids leaked into subsurface.	Chloride content of soil in vicinity of reserve pit elevated.
3	15	23	59	1980	Reserve pit constructed 300 feet from domestic well. Drilling fluids drained from pit onto surrounding area and allowed to soak into subsurface.	Groundwater contaminated with chloride, sodium, magnesium. Existing well had to be replaced.
4	36	24	59	1979-1982	Inadequately lined reserve pit constructed next to irrigation ditch.	Elevated chloride content detected in irrigation water sample. Levels returned to normal after 1 year.
5	32	27	54	1982	Reserve pit constructed in gravel deposit 200 feet from creek.	Potential for surface or groundwater contamination. No immediate contamination detected.
6	3	23	59	1092	Reserve pit liner torn, pit breached during reclamation to allow fluids to soak into subsurface.	Drilling fluids soaked into subsurface, creating potential for groundwater degradation.
7	23	23	55	1982	Reserve pit constructed in drainage way.	Pit placement disrupted surface water runoff, erosion contributed sediment to surface water.
8	17	24	59	1982	Torn reserve pit liner, site not reclaimed for 18 months.	Potential for drilling fluid to migrate into subsurface noted.
9	33	27	59	1982	Reserve pit not lined, shallow stock well and spring located downslope from drill site.	Potential for drilling fluid to soak into subsurface and contaminate nearby stock well and spring. Additional testing recommended.
10	27	35	57	1982	Brackish reserve pit fluids overflow onto surrounding land surface.	Disposal of drilling waste at site denied by landowner.

Source: Compiled by John Arrigo, DHES, based on data in Dewey 1982.

Table 12. Description of Oil- and Gas-Related Complaints Received by Water Quality Bureau.

Complaint No.	Location Sec.	Twn.	Rng.	County	Date	Description of Problem	Comments
1.	21	35	3	Toole	1-7-87	Circulation lost during drilling gas well near public water supply wells. City concerned that drilling fluids could contaminate water supply.	Loss of circulation occurred at a depth above that used as water supply. No contamination detected.
2.	35	31	42	Valley	3-24-87	Drilling fluid disposal pit constructed without a permit. Pit liner was torn. Citizen concerned about water quality in nearby stock and domestic wells.	Existing well located upgradient from pit. Soil contamination around leak detected. No analysis of groundwater under pit conducted.
3.	10	7	60	Fallon	3-31-87	Oil and chemicals spilled during well servicing and a pipeline break. Landowner concerned about surface and groundwater quality degradation.	Spilled oil and chemicals occurred over an aquifer utilized for domestic and stock purposes created potential for groundwater pollution. Cleanup and spill prevention measures implemented.
4.	9	9	59	Fallon	7-15-86	Produced water from abandoned flowing well used for stock watering was discharged without a MPDES permit to surface water.	Discharge of produced water to nearby surface water stopped.
5.	12	22	58	Richland	6-12-86	Commercial drilling fluid disposal pit constructed without a permit. Neighbors concerned about contamination of domestic wells 600 feet from pit.	Samples of pit contents taken. Investigation continues to assess potential for groundwater contamination of nearby wells.
6.	--	--	--	Richland	1-27-86	Oil company dumped waste crankcase oil in abandoned reserve pit. Stock ponds located downgradient. Landowner concerned about contamination of water.	Recommendation made that oil be removed and site properly reclaimed. Referred to BOGC.
7.	14	37	5	Glacier	1-2-86	Produced water evaporation pond overflowed and discharged to nearby creek. Overflow caused when snow melt raised water levels and eroded pond berm.	Corrective actions, including lowering water level in pond, repairing pond berm, and modifying liquid control structures at wellhead, were undertaken by operator.
8.	34	28	32	Sanders	9-17-85	Surface water runoff and spilled diesel fuel entered reserve pit and caused fluid to overflow pit and enter nearby stream.	Water quality of stream degraded as a result of spill. Corrective measures were taken during drilling such as removal of contaminated soil and construction of a diversion ditch to divert surface water from reserve pit. After drilling, fluids, muds and cuttings were removed prior to pit reclamation.

9.	19	35	1	Toole	6-28-85	Produced water and oil emulsion began flowing from improperly plugged and abandoned well.	Discharge from well created seeps in area downgradient from well contaminating surrounding soil and posing threat to nearby water. Problem referred to BOGC.
10.	7	34	1	Toole	2-22-85	Improperly plugged and abandoned well was producing water to the surface and draining into stock pond.	Quality of water and possible contamination of stock pond were not tested. Problem referred to BOGC.
11.	7	34	34	Toole	2-19-85	Storage tanks at oilfield service company were leaking and runoff from truck washing facilities was occurring.	Waste handling practices were considered a potential threat to groundwater quality. WQB sought application from company for MGWPCS permit and waste storage permit. Company did not respond.
12.	36 36	34 34	2 3	Toole Toole	2-14-85	Brackish water flowing from two abandoned oil wells was contaminating soil around each well.	Details on any measures taken are not known since action was handled by Soil Conservation Service personnel.
13.	--	34	3	Toole	1-23-85	Improperly plugged and abandoned oil well produced water that collected in a natural depression.	Landowner refused option to use water for stock. Company pursued permit to reinject water to the ground.
14.	7	34	34	Toole	11-20-84	Water from oil production operation was discharging to surface.	Requirements for MPDES permit were not met by company so permit was not issued. WOB requested that discharges be stopped.
15.	22	17	6	Lewis and Clark	5-16-84	Reserve pit located 600 feet from creek. Liner torn but pit not overflowing.	Potential contamination of creek prevented by modifying liner to eliminate chance of further tears to liner and possible leaks from pit.
16.	11	23	59	Richland	5-16-83	Reclaimed oil well and reserve pit 350 feet from shallow domestic well caused concern by landowner about contamination after noticing chemical taste and odor.	Drilling wastes buried on site could leak into subsurface and contaminate groundwater. Analysis of well samples prior and after drilling could not link chemical constituents of wastes and problems with well for the drilling operation.
17.	32	35	1	Toole	5-5-83	Produced water from several wells collected in central evaporation pond was discharged to surface and siphoned without a permit.	Improperly discharged water created erosion problems and interfered with use of land surface. Impacts to water resources were not studied. WOB requested operator obtain MPDES permit or stop the discharge.

Source: Compiled by John Arrigo from DHES files.

entered a nearby stream significantly elevated the chloride content of the stream at least 3 miles below the drilling site. These sites are representative of water quality impacts that result from improper or ineffective waste management practices in susceptible hydrogeologic settings.

COMPLAINTS RECEIVED BY WATER QUALITY BUREAU

The Water Quality Bureau records citizen complaints and inquiries regarding suspected water pollution problems. A review of the complaint files was conducted to obtain information on the severity and extent of water quality problems associated with oil and gas operations.

During the period from 1983 through 1987, 32 complaints relating to oil and gas activities were received. Detailed information on these problems is limited due to the process by which complaints were handled. A few of these complaints were referred to the Oil and Gas Division. Some of the complaints were channeled to county sanitarians who act as representatives of DHES and deal with threats to public health. Some of the complaints were handled by phone or letter where the party responsible for the problem was contacted and requested to correct the problem if necessary. Water Quality Bureau staff conducted field investigations at some of the sites.

Table 12 provides summary information on the date, location, and description of problems for 17 of these complaints.

The complaints represent a variety of problems associated with oil and gas activities. Complaints were received from many areas of the state, indicating that problems with oil and gas operations are not restricted to a few locations in Montana but can occur anywhere.

Spills and Leaks. Montana's groundwater regulations require that all spills or unanticipated releases of materials that would lower the quality of groundwater be reported to the Montana Hazardous Materials Response System. Water Quality Bureau files indicate that 74 reports of spills or unanticipated releases were received during 1987 from all types of sources. Half of these spill reports were related to leaks at oil and gas production and injection facilities. The principal wastes released in each of these incidents were produced water, crude oil, or oil and water emulsion. The reported volume of oil and gas waste discharges totaled over 400,000 gallons (an average of 12,500 gallons per spill), which is 70 percent of the recorded total volume of waste spilled in Montana during 1987.

Most of the spills leaked from piping at injection facilities in the Williston Basin. Many of the leaks were contained by skimmer ponds constructed downslope of production facilities. Accumulated oil, saltwater, and emulsion typically are recovered from the skimmer pond with a vacuum truck. Soil contaminated with salts and oil usually is not treated or removed because these wastes are not hazardous. However, soil contaminated with salts from produced water discharges is likely to be unproductive and salts may leach into the subsurface.

Disposal of produced water during oil and gas production also poses potential long-term threats to groundwater quality. Pipelines used to transport produced water from the producing well to a holding tank or injection well are not currently regulated by the state. Leaking saltwater collection pipelines buried in sand or gravel can leak for some time without being detected. There are no public records of the location, size, age, or type of materials used in saltwater collection and disposal systems (Smith 1988).

MITIGATION

The severity and frequency of impacts to water resources from oil and gas wastes can be reduced by adoption of certain measures and procedures, including better interagency coordination. Because of the wide variation in drilling wastes and quality of produced water in Montana, some flexibility will be required in establishing standards and guidelines.

The main areas of concern are: siting requirements with respect to surface and groundwater, location of existing uses of water, reserve pit construction, maintenance and reclamation, production facility operation, and abandoned wells.

SITING REQUIREMENTS

Surface Water Considerations. The proximity of reserve pits or evaporation ponds to water resources is a key determinant of the measures necessary to protect groundwater and surface water. Evaluation of the location of a well in relation to such features has not typically been done prior to the issuance of a drilling permit.

Considerations for both drilling and production activities include the proximity of the operation to surface water, wetlands, irrigation ditches, springs, stock ponds, or drainage ways that lead to surface water. These conditions can easily be determined by looking at topographic maps or by visiting the site.

Where possible, stipulation of a minimum allowable separation of drilling and production facilities from surface water would reduce potential impacts. BLM has specified a separation distance of 200 feet between live surface water and drilling and production facilities in some of its leases (Kruger 1988). Under 43 CFR 3101.1-2, BLM can require that an operator move drilling or production operations up to 200 meters (650 feet). Designation of an adequate separation

distance would prevent most releases, including unanticipated spills and leaks, from directly discharging into surface water. Variances could be granted where the company can demonstrate that wastes do not contain significant concentrations of contaminants, and containment structures can be built to control the escape of any wastes.

Groundwater Considerations. The aquifers most susceptible to contamination from surface pollution are the shallow alluvial aquifers in valleys, along rivers or streams, and on terraces. A minimum separation distance also could help prevent contamination in alluvial areas where surface and groundwater systems are interconnected. One possible measure to protect groundwater is to maintain 50 feet vertical separation between groundwater and reserve pits or evaporation ponds. Where such distances cannot be maintained, consideration of the soil permeability may indicate the need for a liner to protect groundwater. In areas of shallow groundwater, measures could be taken to prevent contamination during drilling and when disposing of wastes following completion of drilling, as discussed below.

Groundwater information can be obtained by several methods. Water well logs stored by the DNRC Water Rights Bureau and the Montana Bureau of Mines and Geology contain information on the depth to water and materials penetrated during well installation. Existing hydrogeologic reports and maps for many areas contain information on groundwater. Also, groundwater information can be collected when a spudder drill rig is used to start an oil or gas well. A site visit either by Board staff or oil company personnel could help to define the groundwater characteristics of a site. If groundwater information is not otherwise available, it can be obtained by drilling a test well.

An exemption from the minimum groundwater separation could be specified in the permit process for locations where the operator can demonstrate that wastes do not contain contaminants that can leach into groundwater or that the facility is constructed, maintained and reclaimed in such a manner to prevent groundwater contamination.

Existing and Potential Water Uses. The quality of water in all potable freshwater aquifers must be protected under Montana water quality law, whether the water is currently used or unused. The location of existing water wells in the vicinity of oil and gas drilling should be determined so that the wells can be protected from possible contamination. This information could be required as part of an application to drill, or could be collected by the Oil and Gas Division for use in evaluating individual permits to drill. If wells are located nearby, extra precaution should be taken during casing placement, correction of circulation problems, and construction, maintenance, and reclamation of reserve pits and evaporation ponds.

Potential impacts to domestic and public water supply wells could be minimized by designation of a minimum allowable separation distance, or a site-specific review to determine the need for other measures such as the lining of pits. Information on the location of existing wells is maintained by the DNRC Water Rights Bureau. Location information on public supply wells is also readily available from the Water Quality Bureau.

RESERVE PITS

The chemical quality of drilling fluid and the construction of reserve pits varies among the oil and gas fields in Montana. In some fields where drilling fluid is low in dissolved solids, many reserve pits are unlined. In areas where drilling fluid has high levels of dissolved solids, such as the Williston Basin, reserve pits typically are lined with a 12 to 14 mil reinforced polyethylene liner.

In areas other than the Williston Basin and portions of the Power River Basin where saltwater-based muds are used, the need to specify whether liners or other pit lining methods should be used may require a case-by-case evaluation. One option for protecting surface- and groundwater would be to require pit liners in all cases, unless the requirements were waived for individual wells where it could be demonstrated that drilling fluid does not pose a threat to water quality. Another approach would be to identify siting criteria for determining where liners are needed. The criteria could require consideration of the proximity of the reserve pit to water resources, existing uses of the water, the chemical characteristics of the drilling fluid, and waste disposal considerations. The chemical characteristics of the drilling fluid can be anticipated from other wells drilled in the area, or information about a proposed drilling program could be reviewed before issuing a drill permit. An approach based on siting criteria would require liners to be installed where specific conditions at the site require them. Such an approach could require the collection and processing of information that might cause the permitting process to take longer than it currently requires.

Obviously, reserve pits should be maintained leak free and not allowed to overflow for the life of the operation. Reclamation practices, including waste disposal methods, should be modified where necessary to protect water quality.

In areas where drilling fluid is high in dissolved solid content and water resources are susceptible to degradation, final disposal of drilling fluid wastes and reclamation is important. Consideration should be given to discontinuing trenching and squeezing of lined reserved pits as a disposal method. This practice entails use of a plastic pit liner during drilling. Upon start of reclamation, the pit liner is torn open. This method makes reclamation faster, but negates the function of the liner as a protective barrier against the downward migration of contaminants. Sensitive areas requiring pit liners could be identified during the permitting process by requiring companies to submit information on the soils and geologic characteristics of the site, the anticipated chemical content of the drilling fluid, and the proximity of the site to water.

Although off-site disposal is not practical for most wells, it may be necessary in certain sensitive hydrogeologic settings. Alternative methods of disposal on-site waste disposal may be appropriate in some cases. Such methods may include solidification of waste by natural or chemical means, encapsulation of waste in the liner, and placement of a bentonite cap over buried wastes. A case-by-case determination based on soil types, hydrogeologic setting, including depth to groundwater and proximity to surface waters, and chemical composition and volume of the drilling wastes is important when deciding on the most appropriate disposal method.

PRODUCTION FACILITY CONSTRUCTION AND RECLAMATION

The quality of produced water and methods of disposal vary widely across Montana. Currently there is no state permit requirement for production facilities to control the disposal of produced water.

Siting criteria that consider proximity to water also could be used for production facilities to protect surface and groundwater. One option would be to require plastic liners for all evaporation ponds where produced water is stored. This requirement could be waived if the company could demonstrate that the chemical character of the produced water would not pose a threat to nearby water. The waiver also might apply if the company could demonstrate that no water is susceptible to contamination or that introduction of produced water to the flow system would not cause degradation. Another option would be to define criteria for determining whether produced water could be stored in lined pits or would need to be disposed of by other means such as reinjection.

Requirements could be established to define the disposal methods for bottom sludge from storage tanks or separation vessels. These wastes should not be disposed of in ponds or at the well site, although they could be deposited in a suitable sanitary landfill.

Requirements could be established by the Board to report spills and leaks at production facilities to the Montana Hazardous Materials Emergency hotline [(406) 444-6911]. Rules and guidelines could be developed to provide adequate spill containment structures at production facilities near surface water or drainage ways to contain any unanticipated leaks.

AIR QUALITY

Air pollution is controlled through ambient air quality and emission standards and permit requirements established under the Federal Clean Air Act and the Montana Clean Air Act (DHES 1980). Montana has adopted federal ambient air standards and also has established stricter state standards for some pollutants. Table 13 lists the various state and federal standards that apply in Montana.

Terrain surrounding pollution sources greatly influences the effects of emissions. Topographic features such as mountains, valleys, or river drainages can combine to severely restrict or greatly enhance the dispersion capacity of a given airshed. These effects are highly localized and often determine how much air quality degradation may occur. Technical Appendix 4 summarizes the important features of Montana's five air quality regions.

AIR CONTAMINANTS FROM OIL AND GAS ACTIVITIES

The primary air contaminants associated with routine oil and gas drilling, production, and storage operations are: (1) airborne dust from construction or traffic on dirt roads; (2) diesel fumes from heavy equipment operations; (3) combustion byproducts from operation of heater/treaters, separators, and flaring; (4) fugitive emissions from product storage; and (5) venting or releasing of gases during well testing. Health and safety considerations resulting from accidental venting or releasing of gases during situations such as a well blowout or pipeline rupture are described in a separate section.

Table 14 is a listing of the various sources of air pollutants likely to be emitted during oil and gas drilling, production, and storage. The degree to which individual pollutants become concerns depends on several factors, including (1) the characteristics of the site within each air quality region; (2) the type of well and the composition of the gas or oil; and (3) whether the pollutant is generated during site preparation, drilling, testing, production, or abandonment.

Air pollution affects the respiratory, circulatory, and odor-sensing systems. Air pollutants usually enter the body through the respiratory system. The effects of various pollutants differ with both concentration levels during exposure and the length of the exposure.

PARTICULATE MATTER - TSP AND PM-10

Particulate matter can be generated by a number of activities during drilling and production. Engines generate small amounts of particulates compared to site and road construction. Once the stable ground cover is removed, dry and exposed soil becomes highly susceptible to wind erosion. Further, vehicle traffic creates turbulence which stirs up dust.

Table 13. Montana and National Air Quality Standards.

Pollutant	Montana Standard	Federal Primary Standard	Federal Secondary Standard
Deeply inhalable particulates (PM-10+)	50 ug/m^3 annual average 150 ug/m^3 24-hr average*	50 ug/m^3 annual average 150 ug/m^3 24-hr average*	None
Sulfur Dioxide	0.02 ppm annual average 0.10 ppm 24-hr average* 0.50 ppm 1-hr average**	0.03 ppm annual average 0.14 ppm 24-hr average*	0.5 ppm 3-24 average*
Carbon Monoxide	9 ppm 8-hr average*	9 ppm 8-hr average*	9 ppm 8-hr average*
Nitrogen Dioxide	0.05 ppm annual average 0.30 ppm hourly average*	0.05 ppm annual average	0.05 ppm annual average
Photochemical Oxidants (ozone)	0.10 hourly average*	0.12 ppm 1-hr average*	0.12 ppm 1-hr average*
Lead	1.5 ug/m^3 90-day average	1.5 ug/m^3 calendar quarter average	None
Foliar Fluoride	35 ug/g grazing season average 50 ug/g monthly average	None	None
Hydrogen Sulfide	0.05 ppm hourly average*	None	None
Settled Particulate (dustfall)	10 mg/m^2 30-day average	None	None
Visibility	Particle scattering coefficient of 3x10^{-5} per meter annual average***	None	None

Key: PM10 = particulate matter with an aerodynamic diameter less than 10 microns.
ug/m^3 = micrograms pollutant per cubic meter of sampled air.
ppm = parts pollutant per million parts of sampled air.
+Statistical standards based on three years of data.
*Not to be exceeded more than once per year.
**Not to be exceeded more than 18 times per year.
***Applies to PSD mandatory Class I areas.
Source: ARM 16.8.101 through 1602

The impact of dust depends on the type, quantity, and drift potential of the particles loosed into the atmosphere. Large dust particles settle out near the source, often creating a local nuisance. Fine particles are dispersed over a greater distance from the source. The potential drift distance of particles is governed by the height of the source, the size and density of the particle, and the degree of atmospheric turbulence. Tiny particulates can damage paint, reduce visibility, and carry poisonous chemicals into the lungs. Short-term exposure to respirable particulates can decrease lung function in children. Long-term exposure can result in increased respiratory distress symptoms and disease, and permanent reduction in lung function in children and adults. Persons with asthma are known to be more susceptible to respiratory problems caused by particulate emissions (U.S. Environmental Protection Agency 1987b).

NITROGEN OXIDES

Nitrogen oxides originate in high-temperature combustion processes such as the operation of diesel engines. These pollutants are a component of photochemical oxidants,

Table 14. Summary of Sources and Types of Air Pollutants from Oil and Gas Activity.

Pollutant	Drilling Sources	Production Sources	Storage Sources
Particulates (TSP/PM-10)	-site preparation and construction activities -diesel engine exhaust -access road dust	-fugitive dust from access road traffic -diesel engine exhaust	
Carbon Monoxide (CO)	-diesel engine exhaust -light duty vehicle exhaust	-light duty vehicle exhaust	
Nitrogen Oxide (NO_x)	-drilling rig diesel engine exhaust -other vehicular traffic exhaust	-diesel engine exhaust -vehicular engine exhaust	
Hydrogen Sulfide ($H2_s$)	-sour well gas venting -drill stem tests -gas/oil ratio (GOR) tests -production stabilization tests -uncontrolled (blow out)	-flaring (incomplete combustion) -fugitive losses from pipes, pumps, seals, flanges, etc. -sour oil disposition	storage tanks - oil/ water -breathing losses -working losses
Total Reduced Sulfur (TRS) compounds	-venting and flaring sour gas release	-sour gas venting and flaring -incomplete sour gas combustion	-storage tank working and breathing losses
Volatile Organic Compounds (VOCs) (nonmethane)	-drilling rig diesel engine exhaust	-light duty vehicle exhaust -diesel engine exhaust	-storage tank vaporization of crude oil condensates, distillates, etc.

Source: Compiled by Jim Hughes, DHES.

causing a stinking brown haze that irritates the nose and throat. Nitrogen oxide molecules occur in several different forms. The most common form found in the ambient air is nitrogen dioxide. Air quality standards are set to limit this form of nitrogen dioxide. Table 15 lists the affects from various concentrations of this pollutant in the air.

SULFUR DIOXIDE

Sulfur dioxide emissions result from the burning of fossil fuels containing sulfur, including gas or oil containing hydrogen sulfide. Sulfur dioxide is produced when gas is flared during well testing, or in order to dispose of gas not connected to a pipeline, or to convert or reduce hydrogen sulfide, during a blowout situation for example. Sulfur dioxide also would be produced if a well or associated facilities were to catch fire. Sulfur dioxide has an irritating effect on the eyes (at approximately 20 ppm), throat (about 5 ppm and greater), and respiratory tract (significant increase in lung resistance at 50 ppm for 10 minutes). Concentrations of 100 to 500 ppm are dangerous for exposures lasting for 30 minutes or more, and above 1,000 to 2,000 ppm they pose an immediate threat to life. The U.S. Environmental Protection Agency (1987b) reviewed its federal sulfur dioxide standard to determine if it was adequate to protect health. EPA concluded that there was no compelling need to revise the standard, although the study did confirm that sulfur dioxide in concentrations allowed by the standard irritates people with asthma (U.S. Environmental Protection Agency 1987b).

Table 15. Effects of Nitrogen Dioxide.

Concentration of Nitrogen Dioxide in air (ppm)	Exposure Time	Human Symptoms and Effects on Vegetation, Materials, & Visibility
300	---	Rapid death
150	---	Death after 2 or 3 weeks by bronchiolitis fibrosa obliterans.
50	---	Reversible, nonfatal bronchiolitis.
10	---	Impairment of ability to detect odor of nitrogen dioxide.
5	15 minutes	Impairment of normal transport of gases between the blood and lungs in healthy adults.
2.5	2 hours	Increased airway resistance in healthy adults.
2	4 hours	Foliar injury to vegetation.
1.0	15 minutes	Increased airway resistance in bronchitics.
1.0	48 hours	Slight leaf spotting of pinto bean, endive, and cotton.
0.3	---	Brownish color of target 1 km distant.
0.25	Growing season	Decrease of growth and yield of tomatoes and oranges.
0.2	8 hours	Yellowing of white fabrics.
0.12	---	Odor perception threshold of nitrogen dioxide.
0.1	12 weeks	Fading of dyes on nylon.
0.1	20 weeks	Reduction in growth of Kentucky bluegrass.
0.05	12 weeks	Fading of dyes on cotton and rayon.
0.03	---	Brownish color of target 10 km distant.
0.003	---	Brownish color of target 100 km distant.

Source: Stern et. al. 1984.

HYDROGEN SULFIDE

Hydrogen sulfide is found in gas from oil wells and in gas wells. It also is dissolved in the oil and water produced by such wells. This gas is found in various formations throughout Montana, most notably in the Overthrust Belt, Williston Basin, and in north-central Montana. Hydrogen sulfide can be released during drilling, production, or storage.

Hydrogen sulfide is colorless and flammable, and is about 20 percent heavier than air. It tends to sink or disassociate from the gas stream, and depending on meteorological conditions and how it is released, it may collect in low-lying areas such as drainages. At concentrations 0.004 to 0.007 ppm, hydrogen sulfide has an offensive odor comparable to that of rotten eggs and can cause annoyance. In higher concentrations, it is a highly toxic, reactive gas and will corrode metal.

Table 16 shows the odor threshold and toxic effects on humans associated with varying levels of hydrogen sulfide. These data are based on animal studies and human exposures. The literature on human health effects of hydrogen sulfide often categorizes the effects as acute, subacute, or chronic. Acute effects normally occur through very short term or single exposures to high concentrations of the gas with resulting

Table 16. Hydrogen Sulfide Effects on Humans.

Concentration in the air (parts per million)	Situation or Health Effect
5,000	Almost immediate death.
1,000	Initial rapid respiration leading to rapid intoxication in minutes, unconsciousness, death or permanent brain damage unless resuscitation occurs very promptly.
500	Unconscious after short exposure, cessation of breathing if not treated quickly.
200	Initial irritative phenomena--loss of smell, burning eyes, cough, shortness of breath; edema, headache, dizziness, and staggering gait may accompany. Usually complete recovery if exposure brief. Prolonged exposure (more than 30 minutes can lead to progressively more serious effects.)
50	Exposure over 1 hour may lead to headache, dizziness, and staggering. Shorter exposure characterized by conjunctivitis, cough. Recovery appears to be complete.
	Less than 50. Depending on duration may still have burning eyes, cough, etc. with rapid recovery.
14	"Spinner's eye" in 4 - 5 hours.
10	Occupational exposure limit "Spinner's eye" after 6 - 7 hours.
1 - 10	Conflicting reports. Workers not usually affected. Public experience eye irritation, nausea, vomiting, diarrhea, sleep disturbance.
0.3	Little objective evidence of disease but public complaints numerous.
0.005 - 0.05	Odor threshold.
0.001	Typical urban level of H2S.

Source: Petroleum Association for the Conservation of the Canadian Environment 1985.

effects on the central nervous system and respiratory system. Subacute effects refer to various irritations of the eyes and respiratory tract from intermediate concentrations and exposure time. Chronic effects reported in the literature are primarily odor annoyance and nerve disorders that result from longer exposure to lower concentrations. Hydrogen sulfide is considered a noncumulative poison because it rapidly oxidizes to nontoxic sulfates when absorbed into the blood. Unconsciousness and death can occur when hydrogen sulfide intake is greater than the body's capacity to oxidize it (Layton et al. 1983).

The scientific literature indicates that certain categories of individuals may have increased susceptibility to hydrogen sulfide toxicity. Susceptible persons include those with chronic eye inflammation, anemia, respiratory problems, psychiatric problems, and persons who have consumed alcohol within 24 hours prior to exposure (Layton et al. 1983). Elderly persons and infants may constitute a high risk group. Technical Appendix 4 contains additional data on effects of hydrogen sulfide.

In 1986, EPA conducted a review of scientific literature regarding the effects of hydrogen sulfide. This review was undertaken to determine whether a federal standard was needed for this pollutant. Following release of its preliminary draft report on hydrogen sulfide, EPA decided that a closer examination of the interactive nature of this pollutant with others was necessary before a recommendation could be made regarding the need and appropriate level for a federal standard.

Montana has a secondary standard limiting hydrogen sulfide to 0.050 parts per million. A secondary standard is set to protect property and vegetation from adverse effects of a pollutant. This concentration was selected to prevent the unpleasant odors associated with hydrogen sulfide at about this level. In avoiding secondary impact, this standard indirectly provides protection to the public from health effects which can begin to manifest themselves at higher concentrations.

MALODOROUS/NOXIOUS GASES

Minor amounts of odorous gases other than hydrogen sulfide can be present in oil and gas. Odorous sulfur compounds can be grouped into either total reduced sulfur or partially reduced sulfur compounds. A gas analysis must be performed to determine the content of these compounds for any given well.

Known as reduced organic sulfides, these sulfur compounds are typically associated with sour gas, and can be present in sour gas, oil, and produced water. They produce offensive odors even in minute concentrations.

AIR QUALITY IMPACTS

Chemical compounds vary widely in Montana oil and gas. Oil or gas from wells in a given formation in a field may be similar, but wells in the same field producing from different formations may produce different chemical constituents. Thus, without a gas analysis, the potential air quality impacts from venting, flaring, or on-site uses cannot accurately be determined in advance for individual wells. Only on rare occasions in Montana have oil or gas wells received air quality-related review. This usually results when there are complaints or when the operator contacts the Air Quality Bureau regarding pollution control requirements.

Air quality regulations define short-term impacts as having a duration from a few hours to a few months. Impacts that result from site preparation, road construction, heavy equipment operation, and pre-production activities usually are short term. Longer term impacts are associated with the production phase.

SITE PREPARATION AND CONSTRUCTION

Emissions during site preparation and rig set up are most likely to be vehicle exhaust from a number of mobile sources and dust from earth-moving activities during construction of roads, pads, and pits. The most common sources are diesel earth-moving equipment, diesel semi-trucks, delivery trucks, and gasoline-powered vehicles and trucks. Particulate matter is the pollutant most likely to significantly affect air quality.

Particulate emissions vary substantially from day to day depending on the level of activity, the specific operations, and the prevailing weather. Predicting the impacts involves compilation of a particulate emission inventory from construction and drilling activities. Particulate emissions from site and access road construction would depend upon total area disturbed. Other important determinants include the amount of silt in the soil and moisture content. Under worst case conditions, emissions of less than 25 tons per year can normally be expected from a single oil or gas well (BLM et al. 1983). Since site and road construction are usually short-term activities, access road use tends to be the major source of fugitive dust over the long term.

DRILLING

An air quality permit is required when emissions for any single pollutant exceed 100 tons per year (ARM 16.8.1102(1)(k)). Table 17 lists the ranges of emissions that can be expected from drilling engines and associated equipment based on duration of drilling and horsepower of engines in various oil and gas regions.

Table 17. Estimated Emissions from Drilling Operations in Montana*

Region	Rig horse-power	Drilling time (days)	Tons of Emissions: Nitrogen oxide (NOX)	Carbon monoxide (CO)	Sulfur Dioxide (SO2)	Particulate matter (TSP/PM-10)	Volatile compounds (VOC's)	Total rig engine emissions
Western MT	1500	90	31.1	8.3	3.6	3.1	0.9	47.0
	1500	180	62.2	16.6	7.3	6.2	1.7	94.0
	2000	180	82.9	22.1	9.7	8.3	2.2	125.3
	2000	365	168.2	44.9	19.6	16.8	4.6	254.0
Northern								
Oil	900	7	1.5	0.4	0.2	0.1	0.0	2.2
Gas	350	2	0.2	0.0	0.0	0.0	0.0	0.2
Williston	900	45	9.3	2.5	1.1	1.0	0.3	14.1
	1100	60	15.2	4.0	1.8	1.5	0.4	22.9
Central MT	900	10	2.1	0.6	0.2	0.2	0.1	3.1
Big Horn	900	20	4.1	1.1	0.5	0.4	0.1	6.3
6 Powder River	900	15	3.1	0.8	0.4	0.3	0.1	4.7

*Assumes that drilling rig and associated equipment are operating 80 percent of the drilling period.

Source: Compiled by Mark Kelley, DNRC, and Jim Hughes, DHES.

The Air Quality Bureau has determined that nitrogen oxides are a potential pollutant of concern for drilling rig engines greater than 1500 horsepower. As both engine horsepower and operating periods increase, the likelihood for nitrogen oxides impact also increases.

Several procedures have the potential to affect air quality while the drilling rig is on location or just before the start of production (see Technical Appendix 4). These include: (1) Gas and Oil Ratio (GOR) tests; (2) drill stem tests; and (3) stabilized production tests. The most significant pollutants likely to be emitted during these activities include hydrogen sulfide gas and sulfur dioxide, and volatile organic compounds. These pollutants can be emitted in varying quantities depending on the type of well and its potential flow volume.

Table 18. Sources and Types of Air Pollution from Producing Wells.

Pollutants	Oil Wells	Gas Wells	Oil-Gas Wells
Particulates	Traffic on access roads.	Traffic on access roads.	Traffic on access roads.
Nitrogen Oxides	Negligible.	Negligible.	Negligible.
Sulfur Dioxide	Negligible from sweet wells.	Negligible from sweet wells. For sour wells: Flaring sour gas; Burning sour gas in compressors or ancillary equipment.	Negligible from sweet wells. Flaring sour gas; Burning sour gas in heater-treaters, compressors, or ancillary equipment.
Hydrogen Sulfide	Negligible from sweet wells. For sour wells: Breathing and working losses from storage tanks; Fugitive losses from pipelines, pumps, seals, flanges, etc.	Negligible from sweet wells. Venting and flaring sour gas and fugitive losses from pipelines, pumps, seals, flanges, etc.	Negligible from sweet wells. Venting\flaring of sour associated gas; Burning gas in heater-treaters, separators, etc;. Breathing and working losses from storage tanks; Fugitive losses from pipelines, pumps, seals, flanges, etc.
Carbon Monoxide	Negligible.	Negligible.	Negligible.
Volatile Organic Compounds	Negligible.	Negligible from gas wells without condensates.	Breathing and working losses from storage tanks.

Source: Compiled by Jim Hughes, DHES.

PRODUCTION

The volume of air pollution generated over the life of an oil or gas well depends on the characteristics of the product and the production practices used. Oil and gas wells that produce hydrogen sulfide in the oil, gas, or associated gas are termed "sour wells." Sour wells are much more likely to cause air pollution than wells that do not produce hydrogen sulfide, termed "sweet wells." Table 18 lists the air pollutants and sources for wells that produce oil, gas, or both. An air quality permit is required when emissions for any single pollutant exceed 25 tons per year (ARM 16.8.1102(l)).

SUMMARY OF EXISTING COMPLAINTS

For the purpose of this programmatic statement, a review was conducted of complaints and problems DHES received between the years 1978-1988. The review focuses on counties in Montana where oil and gas development is concentrated (see Table 19). Complaints resulted mainly from (1) sour oil-gas wells; (2) malodorous fumes (nuisance odors) and vapors from storage tanks; and (3) malfunc-tioning flares. Problems resulted from stable (calm) atmospheric conditions, particularly in late evening to early morning hours and low wind speeds and prevailing wind direction from sour oil-gas wells. Complaints generally pertained to irritation of the respiratory systems and emotional and psychological disorders aggravated by the pollution. Complaints associated with gas processing (sweetening) plants were not considered, although several complaints resulted from the combined effects of sour oil-gas wells and gas processing plants near each other. The pattern of complaints in Montana is very similar to those identified in neighboring states (see Technical Appendix 4).

Table 19. Summary of Well Complaints in Montana by County.

County	Total # Years	Complaints	Remarks
Toole	1984, 1986	3	Sour oil-gas wells; odors
Glacier	1979, 1982, 1983	5	Tank odors; treater emissions
Dawson	1981, 1982	2	Hydrogen sulfide flaring; Bloomfield well blowout
Richland	1987-1988	6	Sour oil-gas well located in coulee drainage
	1984-1985	3	Sidney area, hydrogen sulfide; odors
	1983-1984	3	Reported small animal fatalities; sour oil-gas well odors
	1982	3	Area complaints by residents to county sanitarian
	1981	1	Hydrogen sulfide flaring; odors

Source: DHES files

To further determine potential air quality impacts associated with production of oil and gas in Montana, several case studies of wells in eastern Montana were analyzed. The results of these studies are shown in Technical Appendix 4 which describes the conditions that lead to air quality problems. The case studies indicate air quality impacts may exist with individual oil and gas wells. Quantity of hydrogen sulfide, the volume of gas produced by the well, terrain, and wind direction and speed interact to create air quality impacts extending beyond the well site.

Certain information can identify the potential for air quality impacts from a well containing hydrogen sulfide. The amount of sulfur dioxide produced depends on the percent of hydrogen sulfide in the gas and the quantity of gas being burned or flared. Most hydrogen sulfide wells in Montana are not evaluated unless a complaint is received by either the Oil and Gas Division or the Air Quality Bureau.

Figure 32 illustrates the sulfur dioxide emission levels that result when gas containing hydrogen sulfide is burned.

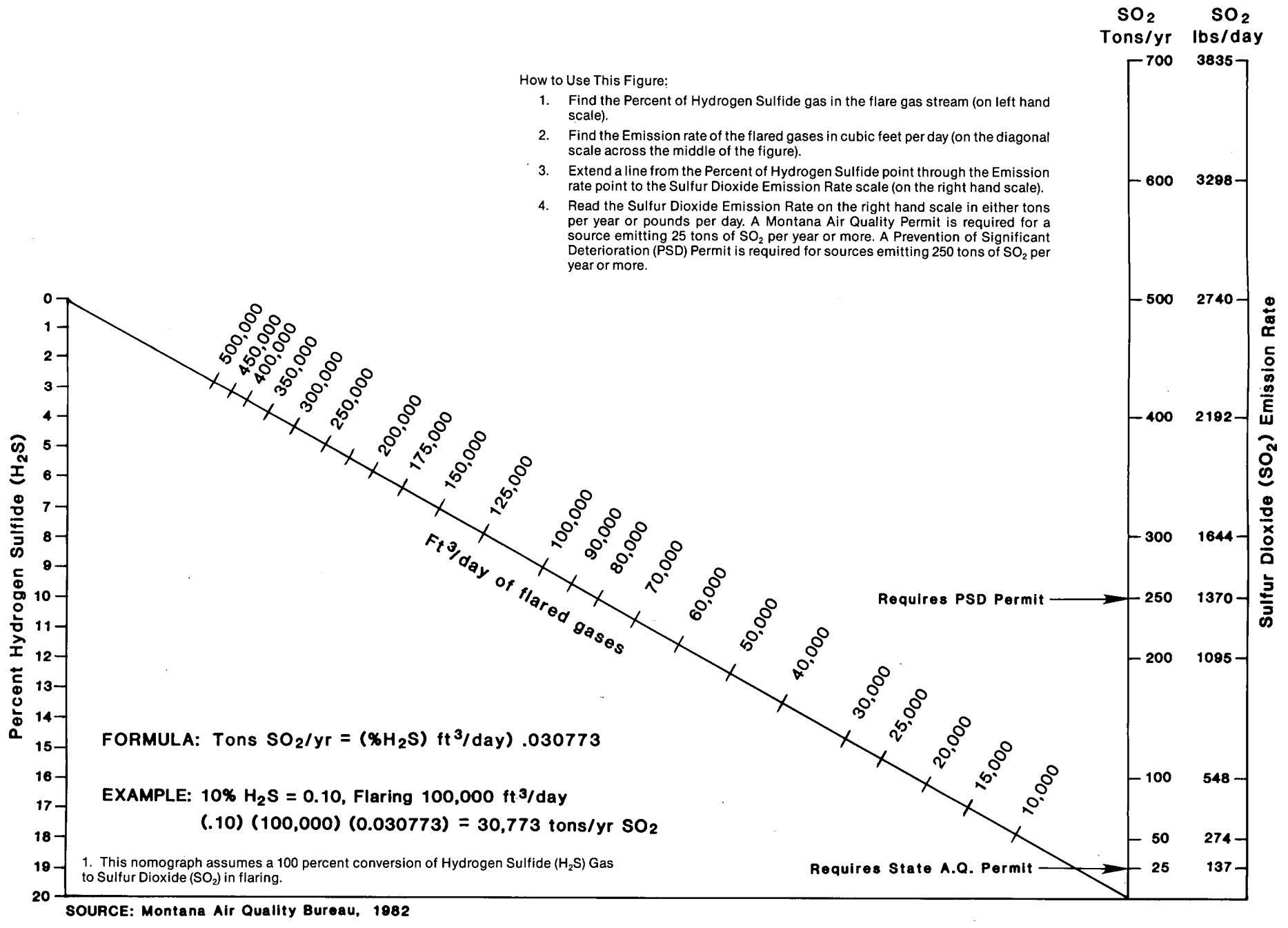
CUMULATIVE IMPACTS

The only available information regarding the cumulative air quality impacts caused by oil and gas development is from the Williston Basin in North Dakota. Cumulative regional air quality concerns were raised in the Custer National Forest Final EIS and Management Plan covering the Little Missouri National Grasslands (U.S. Forest Service 1986). Both the Medora and McKenzie ranger districts are experiencing elevated air pollution concentrations from oil and gas activity. Some smoke is visible from gas flaring in these areas, but there is greater concern over potential hydrogen sulfide releases. Similar cumulative air quality concerns in the basin were raised in the Theodore Roosevelt National Park Environmental Assessment and Management Plan (U.S. National Park Service 1986).

To date, about 1,500 producing oil and gas wells have been drilled in the two counties where Theodore Roosevelt National Park is located. Air pollution from this development includes hydrogen sulfide and sulfur dioxide from gas flaring; hydrogen sulfide emissions associated with venting and fugitive losses; and particulates from reserve pit burning and construction activities (U.S. National Park Service 1986).

Oil and gas development in formations with high hydrogen sulfide content is believed to contribute to cumulative air quality problems in North Dakota. As a result, BLM and North Dakota Department of Health have determined that an air quality study is necessary to determine the existing and reasonably foreseeable environmental impacts of the oil and gas development in western North Dakota and extreme eastern Montana. Montana has agreed to participate in this study. The objective of the Williston Basin

FIGURE 32
SULFUR DIOXIDE EMISSIONS FROM THE FLARING OF HYDROGEN SULFIDE GASES[1]



1. This nomograph assumes a 100 percent conversion of Hydrogen Sulfide (H_2S) Gas to Sulfur Dioxide (SO_2) in flaring.

SOURCE: Montana Air Quality Bureau, 1982

air quality study is to identify the management actions necessary to ensure adequate protection of air quality while allowing reasonable oil and gas development in eastern Montana and western North Dakota. If the initial study finds that air quality standards are not being met, an EIS will be prepared under provisions of 40 CFR 1506.5, the federal regulations implementing the National Environmental Policy Act. At present, only the Williston Basin has been identified as needing additional study and analysis.

MITIGATION

ADMINISTRATIVE MEASURES

Mitigation for air quality impacts will include both administrative process options and establishment of operating guidelines for oil and gas wells.

Screening Mechanism for Sour Wells. A mechanism is needed to determine the potential for each sour well to cause air quality problems either during drilling or production. Either the Air Quality Bureau or the Board could examine the potential of each sour well to produce a hydrogen sulfide hazard.

At the drilling stage, analysis could determine the potential radius of exposure and any possible public health and safety concerns from the well. These measures are discussed in detail in the health and safety section.

During production, review would identify wells requiring additional production equipment or the level of air quality analysis required to protect against potential hydrogen sulfide and sulfur dioxide impacts.

In other states, a review process is triggered by emission levels much below the 25 tons per year allowed in Montana. In Colorado, if total emissions of a well exceed 5 tons per year, those responsible for the source must perform computer modeling to predict impacts. In Wyoming, operators must perform continuous hydrogen sulfide measurements around a suspect source to determine compliance on and off the leased area. In North Dakota, compliance with hydrogen sulfide ambient standards is required off the leased area. North Dakota requires that any new well flaring gas be registerd with the State Department of Health. The registered information must contain a gas analysis and sufficient information to determine whether the well would comply with ambient standards and requirements for flaring equipment.

Gas Analysis. An analysis of gas in the gas stream may not be necessary for every well. However, such information would be important to estimate potential air quality concerns at the production stage. This information could be collected for all wells containing hydrogen sulfide, or only for wells containing hydrogen sulfide concentrations of 1 percent or greater.

DUST MITIGATION

Access roads are the major source of dust over the long term. Dust abatement measures include: watering, applying dust-suppressing chemicals, oiling, asphalt paving, and reducing vehicle speed. Watering of roads may reduce fugitive dust by about 50 percent; chemical suppressant achieves 75-85 percent reduction; oiling and asphalt paving could achieve 90-95 percent control. Other mitigating measures may include closure of roads to any use except drilling, production, or administrative purposes; providing a campsite at the well to reduce road use by workers, and carpooling in highly sensitive areas such as Class I airsheds. Production measures to reduce traffic could include the use of remote wellhead monitoring facilities.

NITROGEN OXIDES MITIGATION

Nitrogen oxides from internal combustion engines are the most difficult exhaust pollutant to control. Both vehicles and stationary drilling rig engines emit this pollutant. Good maintenance practices such as regular tune-ups and proper fuel-to-air settings should minimize these emissions. Under worst-case conditions, violations of the 1-hour and annual nitrogen oxide standards could be largely avoided by reducing operational hours or total engine horsepower rating.

During well production, some nitrogen oxides are emitted from combustion of well gas in flares and treaters, but these emissions are usually small. If an oil or gas well flares or consumes an average of 100 MCF per day per year, the nitrogen oxide emissions per well would average about 2.0 tons per year.

HYDROGEN SULFIDE MITIGATION

During well production, pipelines and connections are closely monitored with various kinds of sensors to detect minor leaks or major releases of sour gas. The sensors may be used to operate an alarm system and even shut in the well. An effective inspection and maintenance program is essential in identifying and preventing sulfide stress corrosion on collection pipelines, tubing, and fittings.

Wells producing sour gas should have an ignitable flare or incinerator plumbed such that gas released by a malfunction of the wellhead or associated pipeline can be routed to the flare. Elevated flares provide better atmospheric dispersion than ground-level or pit flares. Experience shows that pit flares are not efficient combustion devices and therefore are not effective in completely oxidizing hydrogen sulfide to sulfur oxide. An incinerator is far more efficient than a flare in oxidizing waste gases. In an incinerator, the waste gases are continually oxidized within a refractory-lined combustion tube. Flame quenching and back flashing are avoided and the kinetic requirements for thorough oxidation of hydrogen sulfide are met. If high

carbon dioxide concentrations are present in the waste gas, then an auxiliary fuel supply such as liquified petroleum gas or natural gas (LPG or LNG) may be necessary for adequate combustion. Incinerators could be used to burn odorous gases at wells in or near sensitive areas where odors would present a nuisance.

Gas blankets prevent odorous sulfur compounds such as hydrogen sulfide and other hydrocarbons (also called "volatile organic compounds," or "VOCs") from escaping to the atmosphere. Gas blankets are sometimes used on storage tank facilities to mitigate fugitive hydrogen sulfide losses. This strategy usually requires that sweet gas be available from nearby producing wells. The feasibility and practicality of gas blankets must be determined on a site-specific basis.

Vapor recovery may be used to mitigate odorous sulfur compounds emitted from storage tank facilities due to working and breathing losses. The collected vapors can either be flared or placed into a sales pipeline. The feasibility of vapor recovery systems depends on site-specific economics and production rates. Another measure to reduce hydrogen sulfide emissions is underground injection control (UIC). So far, this method has been little used in Montana. In other states, UIC is used often on federal leases, particularly in areas where secondary recovery is in progress on older fields and in cases where flaring is not allowed. Much more UIC is conducted in North Dakota than in Montana.

Another means of reducing sour gas is recompletion of sour gas wells to another zone that contains less hydrogen sulfide. This practice is not very common in Montana. Recompletion of wells normally is based on economic and production considerations, rather than to mitigate environmental impacts.

Sulfur can be removed from hydrogen sulfide by various chemical means. The practicality of using small-scale sulfur recovery plants on individual sour gas wells is determined by the production potential and economics. Gas sweetening plants can be constructed to serve a number of gas wells requiring removal of sulfur compounds and hydrogen sulfide. Often, the produced gas is piped some distance from the wells to be sweetened by the plant before it is sold. In Richland County, for example, four gas processing plants serve the Williston Basin area wells (see Figure 6).

SULFUR OXIDES MITIGATION

Sulfur dioxide emissions can originate from a number of operations, including certain testing activities performed before and just after well completion. Sulfur dioxide is produced when sour gas is flared for safety reasons during preproduction testing of the gas-to-oil ratio and production capacity. Mitigating measures could include constructing an elevated flare stack or temporary incinerator, installation of tail-gas scrubbers, or flue gas desulfurization. Desulfurization is expensive and may not be feasible or practical during testing activities.

For the production phase of oil and gas operations where sour gas is burned in heater-treaters or used to fuel other equipment, sulfur dioxide emissions can be limited by using LNG or LPG as fuel and installing tail-gas scrubbing facilities. Tail-gas scrubbing is too costly in most instances. If emissions are sufficient to require an air quality permit, an analysis would be required to determine the best available control technology (BACT) to reduce the sulfur dioxide emissions for a given well. The most likely and cost-effective approach to control sulfur dioxide emissions may be use of LNG or LPG for heater-treaters and other equipment. Elevated flares and stacks enhance atmospheric dispersion but don't reduce or control emissions. Most flare stacks in Montana are ground level or pit flares.

ODOR MITIGATION

Odorous compounds are controlled by the same measures used for hydrogen sulfide. Under good combustion conditions, burning or flaring of these compounds oxidizes them to carbon dioxide and sulfur dioxide. Since pit flares are not efficient combustion devices, a gas incinerator should be employed to thoroughly burn waste gases. A vapor recovery system can be used to collect vapors from storage tanks. The vapors can then be burned by the flare or incinerator. Where pipeline systems are in place, vapors can be piped to a nearby gas processing plant. In places where there is potential for nuisance odor annoyance, either an incinerator or vapor recovery system may be necessary to mitigate complaints from nearby residents or other affected persons. Gas vapors released from storage tanks or other low-pressure production vessels should be recovered when warranted.

HEALTH AND SAFETY

Health and safety hazards associated with oil and gas drilling and production include the following: (1) release of toxic or noxious gases from a well during drilling or production, from pipeline leaks or ruptures, and from storage tanks or other facilities including pits for mud and produced water; (2) fire at a well, or a fire spreading to a well site from another location; (3) employee use and handling of chemicals; and (4) employee use of machinery, heavy equipment and vehicles, including use of equipment under hazardous conditions such as high formation pressures.

Oil and gas drilling and production accidents result primarily from equipment failure, human error, or some combination of the two. The seriousness of any particular accident depends on a wide range of variables, including well-flow volume and pressure, meteorological conditions, presence of toxic gases such as hydrogen sulfide, proximity of the emission source to residences or roads, length of time that the hazardous situation exists, and availability of appropriate equipment and expertise to avoid or eliminate the hazard.

The remainder of the discussion in this section focuses on public health and safety concerns that would exist off the well site in the event of an emergency involving hydrogen sulfide gas. Technical Appendix 5 discusses aspects of worker safety which is under the jurisdiction of the National Occupational Health and Safety Administration.

The public could experience adverse health effects if a large volume of toxic gas is accidentally released, for example due to a well blowout or major pipeline rupture, or if toxic or noxious gases leak or escape from storage facilities, surface pits or pipelines. Chapter Two discusses conditions during drilling operations that can lead to potential for blow-out if the situation is not controlled.

Data from the Montana Board of Oil and Gas Conservation (BOGC) indicate that 4,242 wells were drilled in Montana between 1979 and 1983 with only one blowout. This occurred in Dawson County and did not involve hydrogen sulfide (Board of Oil and Gas Conservation 1985). An environmental assessment prepared for a recent drilling proposal indicated that two blowouts have occurred in Wyoming during a recent 10-year period when over 12,000 wells were drilled (Dames and Moore 1986).

Blowouts in Montana hve been even rarer than normal. The reasons have not been formally studied, but characteristics of the state's geology may offer a partial explanation, as discussed in the section on geology and in Technical Appendix 2. Technical Appendix 5 contains a discussion of blowout causes and statistics on well blowouts and pipeline ruptures throughout the United States. Case studies of well blowouts in Alberta, Canada, and Wyoming and notable differences between these locations and Montana also are discussed.

HEALTH RISK ANALYSIS METHODS

In 1983, Lawrence Livermore National Laboratory (LLNL) conducted an extensive study of the potential health and environmental risks associated with sour gas wells and collection pipelines in the Overthrust Belt. As part of this study, LLNL reviewed various methods for assessing health hazards associated with accidental sour gas releases. LLNL said that the ultimate use of risk assessments is for decision-making regarding safety measures to protect nearby residents (Layton et al. 1983). A commonly used technique for analyzing potential hazards is to calculate the size and boundaries of possible "danger zones" around sour gas wells where harmful levels of hydrogen sulfide could be present if a major well blowout were to occur.

A key factor affecting the complexity of health risk analysis is whether it is necessary to calculate where, within the danger zone, the risk of high hydrogen sulfide concentrations is greatest (Layton et al. 1983). This level of information would generally be more important in populated areas or areas where future development is anticipated. It would be used to tailor contingency plans to the population living or working in relatively specific areas (schools, hospitals, subdivisions, factories, or other public facilities) where the hazard would be greatest.

Risk analyses have been done for a number of well-drilling and field development proposals on federal leases in Montana and Wyoming. Examples include the Blackleaf field west of Choteau (U.S. Bureau of Land Management 1987), a well drilled south of Red Lodge by Amoco (Dames and Moore 1986), and the Riley Ridge field in western Wyoming (Environmental Research and Technology, Inc. 1983b). The assumptions used to define an emergency planning zone varied considerably among these analyses. For example, estimated hydrogen sulfide concentrations in the gas stream ranged from 3.2 percent to 15 percent and estimates concerning the probable duration of any uncontrolled release ranged from 12 hours to three days. Also, the hydrogen sulfide concentration levels considered sufficient to trigger emergency response action by the company or government officials ranged from 15 ppm to 300 ppm at the wellsite. The ultimate size of the emergency planning zones identified for these wells ranged from 1 to 2 miles downwind from the well sites.

Alberta's Energy Resources Conservation Board (ERCB) requires operators to calculate the maximum potential release rate of hydrogen sulfide when proposing to drill into formations that are known or suspected to contain the gas (Alberta Energy Resources Conservation Board 1987a). Data from other drilling or producing wells in the same geological setting as the proposed well are used to calculate the radius of exposure for the purpose of developing contingency plans in the event of an emergency at the well (see Technical Appendix 5).

MITIGATION - HEALTH AND SAFETY

BLOWOUT PREVENTION AND SAFETY PROCEDURES

Table 20 summarizes major safety considerations that apply to the design and operation of wells that may produce hydrogen sulfide. As noted in the table, many of the safety measures are standard for worker protection and control for most wells, even if hydrogen sulfide is not present. Figure 33

shows examples of specific methods of controlling kicks and how judgments are made about what to do if a kick occurs.

The oil and gas industry has been responsible for developing the safety measures and equipment used to protect workers and the public. The American Petroleum Institute (API) has written extensively on these subjects in a series of "recommended practice" reports that are updated on a periodic basis. A few examples include "Recommended Practices for Well Control Operations" (API 1987b), "Recommended Practices for Blowout Prevention Equipment

Table 20. Summary of Options Available to Limit or Prevent Adverse Health Effects from an Accidental Release of Hydrogen Sulfide.

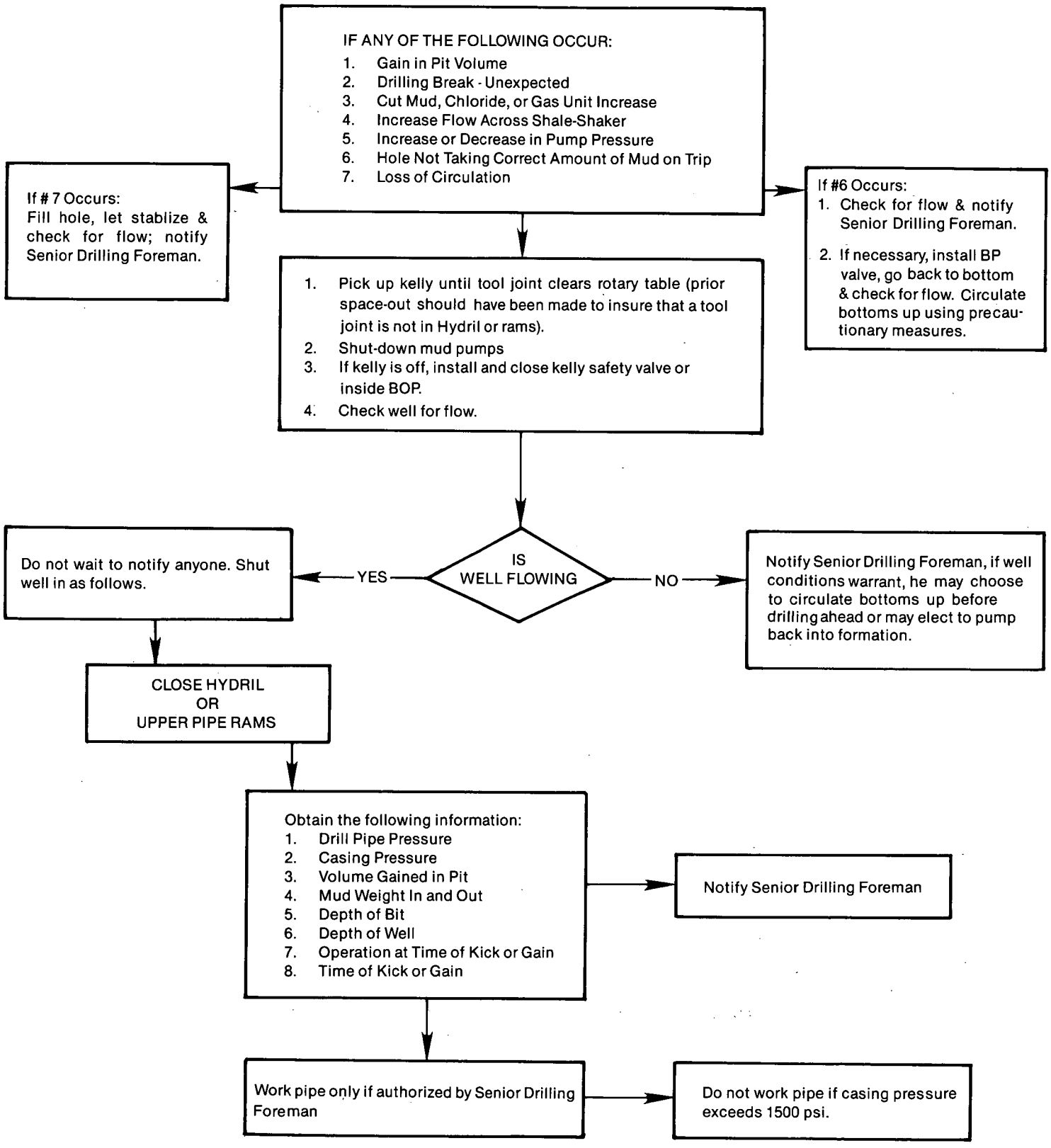
On-site Safety Measures	Safety Equipment and Quality Control	Drill Crew Training	Equipment Testing	Public Safety
Layout of drilling rig and ancillary equipment.	Hydrogen sulfide detectors and alarms.	Use of blowout preventers.+	Testing of blowout preventers.+	Identification of population at risk. Notification and evacuation of residents.
Identification of escape routes for different wind directions.	Instrumentation for determining wind direction.	Kick control procedures.+	Testing hydrogen sulfide sensors and alarms.	Ignition of released gases.
Location of safety facilities.	Warning flags and signs.*+	First aid.+	Maintenance of rescue equipment.+	Post-release monitoring.
Procedures for dealing with well control problem.*	Communications.+	Rescue techniques.+	Materials specifications, e.g. hardness and. corrosion resistance.	Site security.+
Chemical scavengers to remove hydrogen sulfide in drilling mud.	Blowout preventers and safety valves; specifications and quality control.+	Escape routes.	Audits for compliance with regulations or company procedures.+	Preemptive land ownership.
Special precautions drill stem tests and coring.	Resuscitators/ breathing devices.			
	First aid kits.+			
	Mud degasser and flare system.			

* ph of drill mud.
+ equipment or procedures common to most wells regardless of whether hydrogen sulfide is present.

Source: Layton and Cederwall 1987 (adapted from Layton et al. 1983)

FIGURE 33

PROCEDURES FOR WELL CONTROL



Source: Sohio 1986

Systems for Drilling Wells" (API 1984), "Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide" (API 1987c), and "Recommended Practice for Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations" (API 1981b). The recommendations and guidance in these reports establish what is generally regarded as "standard practice" within the industry.

BLM identifies site-specific requirements regarding safety and well control in stipulations that are attached on a case-by-case basis to permits to drill for oil and gas on federal and Indian land. However, over approximately the last two years the agency has been developing general well control and safety regulations that all oil and gas operators will be expected to follow. In most cases, BLM's requirements and the criteria used to identify equipment and safety practices closely parallel the recommendations and guidance contained in the API reports. The Alberta ERCB also has specific regulations identifying appropriate well control equipment and procedures, with special emphasis on sour gas wells.

A detailed discussion of each specific technical provision for safety and well control required by API, BLM, and the Alberta ERCB is beyond the scope of this document. The major types of well control equipment, safety procedures, and the regulatory approaches employed by BLM and Alberta are discussed in Technical Appendix 5. Current regulations of the Wyoming and Utah state oil and gas agencies and the Montana Board of Oil and Gas Conservation are also discussed. Montana rules could be strenghtened by specifying in greater detail the minimum types of equipment and procedures necessary to ensure proper control of wells, with special provisions, if appropriate, and identifying areas or formations where conditions warrant greater precautions (see Chapter 5).

WILDLIFE

Montana's large land area has a diversity of wildlife habitats. The relatively moist western portion of the state supports coniferous forests, montane grasslands, and riparian forests which seasonably become critical to wildlife as wintering areas, mating and reproduction habitats, migration corridors, security areas, and foraging areas.

East of the Continental Divide, the drier grasslands and shrublands are dominant with breaks, badlands, coulees, wooded draws, open conifer forests, and riparian shrub and forest communities providing topographic relief and important habitat values. The rolling grasslands and shrublands of central and eastern Montana are extremely productive as evidenced by their capacity to support large herds of native and domestic animals.

There are 502 species of mammals, birds, and reptiles in Montana. This wildlife provides the public with diverse, highly-sought outdoor recreational opportunities. Hunting has been and continues to be a tradition in Montana with 219,000 residents (27 percent of the population) and 29,000 nonresidents purchasing hunting licenses in the state annually. More than 2.4 million days were spent hunting big game and game birds in Montana in 1984 (Mussehl et al. 1986).

Photographing and observing wildlife in natural surroundings are popular both with Montana residents and nonresidents. Over 21 percent of Montanans participate in wildlife-related recreation other than hunting (Frost and McCool 1986).

The Department of Fish, Wildlife and Parks (DFWP) has determined that a small number of these species could be seriously affected by oil and gas development. Big game species, including mule and white-tail deer, elk, moose, big horn sheep, mountain goat, antelope, and black bear, are valued species whose seasonal habitats may be adversely affected by oil and gas activities. Sage grouse, sharp-tail grouse, and waterfowl also could be affected by oil and gas activity in Montana.

Currently, eight Montana species are classified under the Endangered Species Act as either endangered or threatened. Endangered species are those determined to be in danger of extinction throughout all or a significant portion of their range, whereas threatened species are likely to become endangered within the foreseeable future. Endangered species in Montana are the peregrine falcon, whooping crane, gray wolf, black-footed ferret, bald eagle, and least tern. The grizzly bear and piping plover are classified as threatened. Habitat destruction and loss of individual animals could lead to the extinction of threatened and endangered species.

Technical Appendix 6 contains additional data on game animal and bird species distribution. It also contains a review of technical literature regarding impacts to terrestrial and aquatic ecosystems from oil and gas drilling and production. This information forms the basis for analysis contained in the following pages.

WILDLIFE IMPACTS IN OIL AND GAS DEVELOPMENT REGIONS

DFWP analyzed the potential impacts of oil and gas development for the six oil and gas regions and ranked them on their relative susceptibility to various impacts. Besides the six regions, impacts are discussed for mountainous and

nonmountainous terrain. Impact significance is a measure of how an impact would affect individual animals, populations, and the species as a whole. It also is a measure of how humans would be affected by the long-term or short-term reduction or loss in a species or its habitat.

A general discussion of possible wildlife impacts in the various oil and gas regions is difficult because the regions vary so much in topography, habitat, species distribution, and potential for impact. Generally, the region boundaries follow county lines. Counties are not appropriate land units for evaluating potential impacts to fish and wildlife.

The ecological variation of the oil and gas regions is particularly evident in the Northern, Central, and Big Horn regions. The Northern Region, for example, includes the Rocky Mountain Front with its rugged topography, high gradient streams, rich species diversity, and relatively high sensitivity to impact. The region also includes the native grasslands, breaks, agricultural lands, and arid prairie which have vastly different ecological characteristics and potential for oil and gas impacts. The potential for impacts with a given level of oil and gas development varies considerably within the region, depending on whether mountainous or nonmountainous areas would be affected.

Similarly, the Big Horn Region includes the Beartooth and Absaroka ranges which are the highest mountain ranges in the state, and also include the arid, near-desert Big Horn Canyon and the area south of the Pryor Mountains. There is extreme heterogeneity in wildlife species, distribution, and use of habitat.

FACTORS INFLUENCING POTENTIAL FOR WILDLIFE IMPACT

The responses of wildlife to activities associated with oil and gas development are complex and difficult to predict on a statewide basis. Tolerance to various types of environmental disturbances varies among species and among individuals of the same species. The potential for impact is related to the timing of disturbance, severity of winter, location in the state, physiological status of the animal, hunting pressure, and predictability of the disturbance. The scale of oil and gas development, number of associated roads and other facilities, and implementation of measures to avoid or reduce impacts also greatly influence the probability and severity of impacts on wildlife. Table 21 summarizes the vulnerability of wildlife species to potential adverse impacts based on the items discussed in the following sections. The vulnerability of a species to a particular impact must be considered in relation to a number of site-specific factors or conditions that can be highly variable within and between Montana's oil and gas regions.

Winter Range. Winter ranges are especially important when assessing impacts because wildlife populations are concentrated in the winter and are highly dependent upon obtaining sufficient forage. Ihsle (1983) concluded that the greatest opportunity for conflict between mule deer and oil and gas development occurs on winter range.

Although the relative impact potential in the various oil and gas development regions is associated with the amounts of seasonally important habitat, the different oil and gas development regions vary in their susceptibility to similar levels of development. The difference in susceptibility to impact on winter ranges in various regions of the state relates directly to the topography of the land, amount of snowfall, size of individual parcels of winter range, number of animals present, and the resiliency or adaptability of animals to development in a given area. In mountainous portions of the state, for example, development on big game winter ranges would exert greater impacts than would similar levels of development on winter ranges in eastern Montana.

Winter range in western Montana generally is in narrow bands bounded by high snowfall areas in the mountains upslope and valley bottoms with urban and agricultural activities at the lower elevations. Animals have little capacity to withstand long-term displacement from winter habitat. In eastern Montana, however, the characteristics of the winter range are different. Most winter range in eastern Montana is on relatively large areas of land with a diversity of slopes, aspects, and topographic features. Winter range is often part of year-round habitat. Animals displaced by oil and gas development in eastern Montana usually would have more land where they could go in response to disturbance than would animals in western Montana. The difference between animals on winter range in the mountains or on the prairie is supported by data from several studies. The Riley Ridge gas field developed in Wyoming is on elk winter range in foothills adjacent to the Rocky Mountain Front. Development of the gas field caused a precipitous decline in elk populations and abandonment of winter range (Harju 1985; Johnson 1985).

In contrast to the impacts of the Riley Ridge Project, large scale coal development near Decker in eastern Montana had little impact on the wildlife species studied. Phillips et al. (1986) spent 10 years in an extensive study of wildlife thought to be especially sensitive to development. Specific studies focused upon mule deer, antelope, sage grouse, and golden eagles. The studies found that mule deer and antelope populations thrived throughout the study despite increased levels of mining and human disturbance. The mule deer herd increased from an estimated 90 animals in 1977 to over 600 in 1984. During the same period, the antelope herd increased from 20 to over 188 animals. Sage grouse habitat was lost, but mitigation efforts were successful. Golden eagle numbers remained stable over the 10-year study period. The only detrimental impact documented during the study was increased numbers of deer road-killed or poached.

Table 21. Vulnerability of Wildlife Species to Categories of Impacts.

Wildlife Species	Probability that Wildlife Species Would Be Adversely Affected by Major Oil and Gas Impacts. Vehicle Collisions	Increased Hunting	Increased Poaching	Displacement from Winter Range	Stress During Breeding Season or Young-Rearing Season	Habituation to Humans
Mule Deer	3	3	3	3	1	2
Elk	2	3	3	3	1	2
Antelope	2	2	2	2	1	1
Bighorn Sheep	2	1	3	3	1	1
Mountain Goat	2	1	3	3	1	1
Grizzly Bear	1	1	3	0	2	3
Black Bear	1	3	3	0	2	3
White-tailed Deer	3	2	3	3	1	2
Gray Wolf	1	0	2	0	3	2
Sage Grouse	3	3	1	2	2	0
Sharp-tailed Grouse	3	3	1	2	2	0
Bald Eagle	1	0	1	2	3	1
Peregrine Falcon	1	0	0	0	0	0
Least Tern	0	0	0	0	0	0
Piping Plover	0	0	0	0	1	0
Whooping Crane	0	0	1	0	0	1
Black-footed Ferret	1	0	0	0	0	0
Waterfowl	1	2	1	0	0	0

Key: 0 = Little or no probability
1 = Low probability
2 = Moderate probability
3 = High probability

*NOTE: The vulnerability of a species to impact must be considered in conjunction with a wide range of factors. Tolerance as to various environmental disturbances varies among species and among individuals of the same species. The potential for impact is related to the timing of disturbance, severity of winter, location in the state, physiological status of the animal, hunting pressure, and predictability of the disturbance. Refer to text for discussion.

Source: Compiled by Joe Elliott, DFWP.

Access Roads. Various publications, discussions with biologists, and consideration of DFWP management policy indicate that the construction of new roads and upgrading of existing roads would have a high potential to cause direct and indirect long- and short-term adverse impacts on wildlife.

As part of this study, road density on winter range was analyzed. The average miles of road per township and per section for 46 representative townships in winter ranges throughout Montana were tabulated. The average road density varied from .74 to .98 mile of roads per section, ranging from a low of .28 mile per section to a high of 1.36 miles of road per section.

The road densities on winter ranges are about the same for all of the oil and gas development regions. This is probably because winter ranges are relatively accessible. In western Montana, for example, winter ranges are adjacent to valleys where rural and suburban development is typically dense. In nonmountainous parts of Montana, the rolling terrain is crossed by roads for agricultural and recreational purposes. Although there are no data by which to evaluate the quality of winter range as a function of road density, it is assumed that the existing density of roads on winter ranges is not sufficiently high to eliminate the use of the areas by wildlife.

Impacts of road construction on wildlife and wildlife habitat have been well documented for oil and gas projects and other natural resource developments. Impacts include biological effects, such as displacement and stress, and other effects related to changes in hunting opportunity.

In general, the most severe impacts from oil and gas development would result from construction and use of roads in winter range. These impacts would generally be most

pronounced in winter ranges adjacent to mountainous summer-fall range, and their severity would depend upon location of the roads, degree of screening of the roads by terrain and vegetation, severity of the winter, density and species of animals present, and ability of animals to avoid roads and yet have sufficient forage and cover. The potential for impact due to roads also is related to traffic volumes, timing of use (both daily and seasonally), and management of road access. The potential for impacts from these sources depends to some degree on the ownership of land affected (see land ownership factors) and phase of development of an oil or gas project.

Although the precise correlation between roads and quality of winter range is not known, it is certain that at some level, new roads reduce the carrying capacity of winter range. The decrease would be due to direct habitat loss, displacement or stress reactions, or combinations of these.

Despite the lack of information concerning the precise nature of the relationship between carrying capacity losses on winter range and increased roads, existing roads were studied and the number of roads likely to accompany oil and gas development were predicted. The estimates of roads likely to result from oil and gas development were derived by measuring roads in the Cedar Creek Anticline oil and gas field and by reviewing reports on oil and gas projects.

Roads in the Cedar Creek Anticline were measured for 26 sections of land that have one to eight wells per section. There does not appear to be a consistent correlation between the amount of road and number of wells per section; however, the most road per well is required when there are only one or two wells per section. The average road length in the Cedar Creek Anticline for all sections with one to eight wells per section is 2.3 miles (see Technical Appendix 6).

It appears that in nonmountainous terrain such as the Cedar Creek Anticline, the miles of new road required per section and per well are less than required in mountainous terrain. Technical Appendix 1 projects that oil and gas development in the mountainous western region would require an average of 1 to 5 miles of new access road per well. According to the U.S. Bureau of Land Management (1981a), an oil field with 40 acres per well and 16 wells per section requires at least 4 miles of access road per section.

In mountainous terrain, the amount of new road needed for well development is quite variable, depending on several factors including existing access and terrain in an area. For example, construction of a single gas well in the Badger-Two Medicine area of the Rocky Mountain Front would require from 4.6 to 9.2 miles of new road (U.S. Bureau of Land Management and U.S. Forest Service 1985).

Proposed oil and gas field development (10 wells in 10 sections) in southwestern Wyoming would require only 8.1 miles of new access road, less than 1 mile per well (U.S. Bureau of Land Management and U.S. Forest Service 1987). The large Riley Ridge gas project in Wyoming, with approximately 207 wells spread over approximately 180 square miles, would require 76 miles of new road and 135 miles of road upgrading (U.S. Bureau of Land Management and U.S. Forest Service 1983).

The data indicate that in mountainous terrain at least 2 to 3 miles of new road per section may be necessary. Development in nonmountainous terrain would probably require 1 to 2 miles of new road per section, with less road per well as the number of wells increases.

In mountainous terrain, this amounts to doubling the existing road length recorded for any winter range in Montana. Although the ecological significance of such an increase is not known, it is possible that roads built to accommodate oil and gas development could significantly reduce the carrying capacity of winter ranges adjacent to mountainous summer-fall habitat.

Roads in security habitat would have a different type of impact. Unlike impacts of roads on winter range, road impacts to security habitat are related to increased hunting kills rather than stress or nutritional effects. A Road Management Policy adopted by the Montana Fish and Game Commission (1982) was developed to maintain security habitat for elk and deer during the summer and fall so that the quality of hunting would be maintained. Table 22 presents the relationship between hiding, covert, and open-road densities recommended in this policy to maintain current hunting opportunities in forested areas of Montana.

Table 22. Recommended Road Density Limits in Forested Areas.

Existing Percent Hiding Cover*	Open Road Density Range
80	0.0 - 2.4 mi/mi^2
70	0.0 - 1.9 mi/mi^2
60	0.0 - 1.2 mi/mi^2
50	0.0 - 0.1 mi/mi^2

* Hiding cover is defined as any timber stand with 40 percent of more crown canopy coverage.

Source: Department of Fish, Wildlife and Parks 1982.

Because 2 to 3 miles per section of new road would be required for oil and gas development in mountainous terrain, it is possible that some developments would degrade summer-fall security habitat below levels specified in the DFWP Road Management Policy. More road could lead to more hunting kills of big game. The increased vulnerability of big game due to losses in habitat security would require shorter hunting

seasons and other restrictions, with the ultimate result being a decline in hunting opportunity and recreation. Hunter opportunity relates to season length and quality of the hunting experience. Such impacts could last for as long as roads are present and used, with impact reduction depending on the degree to which hunter access could be controlled.

Species Present. The potential for impacts to be caused by oil and gas development is closely related to the presence of sensitive wildlife species and magnitude of oil and gas activity. The potential for impacts also is associated with the relative effectiveness of measures to avoid animals and habitat. Implementation of measures to avoid animals and habitat during sensitive seasonal periods can effectively avoid some impacts to elk, bighorn sheep, mountain goat, whitetails, and mule deer. Impacts will have different degrees of significance and mitigation, depending on levels of activity, size, and phase of development, and a number of other interrelated factors.

The presence or absence of occupied grizzly bear habitat is a major consideration when evaluating the potential for significant impacts in various areas of the state. Grizzlies are sensitive to displacement, habituation, and illegal shooting in the spring, summer, and fall, over a wide range of elevations and habitats. They are even sensitive to disturbance while hibernating during the winter and spring. Their low population densities, large home ranges, and activity patterns during darkness make them difficult to detect. The removal of a small number of bears from a local population would be of much greater significance than would the loss of a similar number of white-tailed deer or other numerous species more capable of adapting to habitat changes and disturbance.

Land Ownership. The land ownership and management objectives for land affected by oil and gas development could influence the potential for impacts to wildlife. On both public and private land, direct habitat losses to road construction would be approximately 2.3 to 8.7 acres of habitat lost per mile of road (U.S. Bureau of Land Management 1980). The indirect effects on wildlife and habitat from roads could differ between public and private lands.

On public lands, road management policies can restrict public access during certain times of the year. Road policies for public land often include the provision that roads be obliterated and reclaimed after use. Wildlife values are usually a primary consideration of road management on public lands.

On private lands, the primary objective of road management may or may not be based on concern for wildlife and wildlife habitat. It is probable that road management on many private lands would focus on the use of the roads for agriculture rather than concern for wildlife. Although landowners often restrict public access on private lands, they rarely obliterate and reclaim all-weather roads after oil and gas related use has ceased.

In general, private lands usually do not have the levels of vehicular traffic and dispersed use that occur on public lands. A new road on public land may be open to unlimited traffic, whereas a new road on private land is not necessarily available for public access.

Although the road management policy on public lands has often included provisions for restricting public access, the success of maintaining restricted vehicle access is variable. Gates and barriers blocking access on public lands are often illegally breached, and political pressure may result in roads being opened.

If a private landowner would choose to restrict access on a road to protect wildlife, the restriction probably would be more effective than a similar restriction on public land. Private landowners usually detect trespass violations quite efficiently.

DRILLING AND PRODUCTION IMPACTS

Different phases in development of oil and gas projects have different impacts. The impacts that could result from exploratory drilling could be considerably less severe and shorter term than impacts associated with the production phase, primarily depending on whether the access road is reclaimed. Although the duration of an exploratory drilling operation in the Overthrust Region would be relatively long (60 to 220 days), the direct impacts on wildlife at the drill site would be minimal if the drilling was not conducted during critical periods on winter ranges.

Peck et al. (1987) said that the direct effects of exploration on grizzly bear are probably much more insignificant than the secondary effects of increased bear habituation, road construction, and human presence. Ihsle-Pac (1985) reported that the short-term impacts to mule deer on the Rocky Mountain Front as a result of drilling may be minimal. Although her database was limited, Ihsle-Pac reported that mule deer showed no obvious avoidance of well sites in the Blackleaf-Teton Unit. She qualified her research results by explaining that impacts during her study were difficult to assess due to low intensity of oil and gas activity, mild winter conditions, and low density of deer populations in the vicinity of active well sites.

In contrast to the observations from research conducted along the Rocky Mountain Front, Johnson (1985 and 1986) reported that one well drilled on elk winter range at the Riley Ridge Project in Wyoming caused elk to abandon the area and to move several miles away. The drilling of three wells caused elk to abandon 6,000 acres of winter range. After drilling and human activity at the well site were over, elk began to return to the area.

In contrast to the relatively insignificant impacts expected from exploratory drilling, development of a large field with relatively close spacing of wells could significantly reduce available grizzly bear habitat, at least temporarily (Aune and Stivers 1983). Ihsle (1983) concurs that development of dense well fields may lead to physical habitat loss and deterioration which could increase mortality to mule deer. Ihsle said that detrimental effects of oil and gas development may be accentuated if it occurs in conjunction with other land use such as livestock grazing, housing development, recreation, or severe winters.

The production phase requires a higher level of development than drilling. For example, the U.S. Bureau of Land Management (1980) reported that in Wyoming development of 1,437 oil and gas wells required 1,208 miles of new road, 86 miles of powerlines, and 1,406 miles of pipeline. Total acreage disturbed was 5,101 acres for drilling and production locations, 4,096 acres for roads, 206 acres for powerlines, and 3,374 acres for pipelines.

Direct loss of habitat due to all types of development greatly increases with the transition from drilling to production. The potential for increased sedimentation in surface waters also increases. Powerlines near waterfowl habitat can kill birds that collide with wires. Impacts may increase in old well fields due to injection of brine or other materials into wells to recover additional oil and gas. These production activities increase the potential for ruptures and spills of chemicals and solutions that could be toxic to wildlife and harmful to habitat. A crude oil spill from a ruptured pipeline released an estimated 6,500 barrels of oil into the North Platte River in Wyoming (Travsky 1986). Over 60 miles of the river were contaminated, killing at least 350 birds and 33 mammals. The spill depressed wildlife reproduction for a 1-2 year period.

Although some individual animals or types of animals can become accustomed to a production site, sensitive species will experience long-term disturbance from year-round production that lasts several years. Some habitat may be lost for the life of the oil and gas field.

Animals such as bighorn sheep and elk use the same migration routes and seasonal ranges every year. This consistent use is a learned behavior pattern that is acquired by young animals following older animals. If a herd is prevented from using the established ranges or migration routes for a sufficiently long period, knowledge of the routes and ranges could be lost. Range or habitat use patterns that have been abandoned are often very slow to become reestablished.

Seasonal timing would be effective in minimizing wildlife/human interactions during drilling, but it may not be practical to impose strict seasonal constraints on production-related human activity. Production would be continuous, and it might not be feasible to significantly limit human activity at well sites and on access roads in seasonally important wildlife habitats.

Oil and gas activity on the Blackleaf Game Management Area was an example of how wildlife conflicts can be avoided (U.S. Bureau of Land Management 1983). This area is an important winter range and spring-summer grizzly habitat. Drilling was timed to avoid wildlife impacts. If a well field is developed on the Management Area, it might not be possible to restrict production activities to periods when wildlife would not be affected.

Although the impacts from one well probably would be negligible, two or three wells in the same area might increase impacts to significant levels.

CUMULATIVE IMPACTS

A cumulative effect of oil and gas drilling results from the additional development that occurs if petroleum or natural gas are found. The discovery of gas or oil in one location often stimulates more intense exploration in that immediate area and adjacent areas.

The impacts of oil and gas development could act cumulatively with other resource uses and developments to adversely affect fish and wildlife. Logging, mining, hydroelectric development, and livestock grazing are the principal resource developments likely to interact with oil and gas development to exert wildlife impacts.

Construction of roads for oil and gas exploration and development may increase timber harvest in some areas where logging had previously not been economically feasible. A significant cost of logging is road construction for access to timber. If oil and gas developments construct roads into unlogged areas, the cost of timber harvest could be reduced. Road development, if followed by increased logging with its attendant impacts, would increase impacts.

Mining of metals and talc is expanding in the Overthrust Region. Impacts from mining would be similar to those from oil and gas development. If both were to occur in the same area, the impacts would be increased.

Coal mining in eastern Montana has altered wildlife habitat, particularly around Decker and Colstrip. Although few impacts of coal mining to wildlife have been demonstrated, oil and gas development in coal mining areas could further reduce habitat availability and use. With continued development, the disruption of habitat use could become sufficiently widespread to reduce the carrying capacity of winter ranges and breeding areas, which could reduce wildlife populations.

Livestock grazing can reduce the carrying capacity of winter ranges for elk and bighorn sheep. Oil and gas development on winter ranges shared by cattle, elk, or bighorn sheep could displace the wildlife.

AREAS WITH HIGH WILDLIFE IMPACT POTENTIAL

Significant impacts are most likely to occur when two or more wells are drilled in mountainous portions of the state where sensitive, highly-valued species would be affected.

The areas with the greatest potential for significant impacts are the Rocky Mountain Front; the Cabinet, Mission, Swan, Beartooth, and Absaroka mountains; and the Madison and Centennial ranges. These areas are in the Overthrust, Northern, and Big Horn oil and gas regions. Habitat in these areas supports bighorn sheep, mountain goats, elk, mule deer, and grizzly bear. These animals are susceptible to short-term and long-term activities that would affect winter range or increase the frequency of encounters between grizzlies and humans.

Construction and use of roads pose the greatest potential for direct and indirect impacts to wildlife. More roads increase collisions between vehicles and wildlife, particularly where roads are constructed in migration routes, winter range, near salt licks, and in areas where animals move daily between feeding and resting habitat. New roads into spring habitat would increase human access with accompanying increases in both legal and illegal bear hunting.

Wolves could be affected by oil and gas development around the borders of Glacier National Park. They would be susceptible to disturbance if roads, wells, or other activities were constructed and operated close to dens where young are being reared in the spring.

Currently in Montana, the only known nests of endangered peregrine falcon are in the southwestern part of the state. Oil and gas activities within a mile of a peregrine nest could cause nest abandonment or interfere with the rearing of young birds (Suter and Jones 1981).

Most bald eagles in Montana nest in the Western Region. Oil and gas development near nesting birds could reduce reproduction success.

Oil and gas development in the Western Region of the state would have the greatest potential for adverse impact on fish and wildlife. The miles of new road that would have to be constructed is greatest (1 to 5 miles per well), the duration of exploratory operation would be greatest (60 to 220 days), and the reserve pit size would be largest. Based on data from Alberta in the Overthrust Belt (Horejsi 1987), as many as 16 oil wells may be drilled per square mile. One gas well is typically drilled per square mile (U.S. Bureau of Land Management and U.S. Forest Service 1983)

Work camps in remote mountainous areas could create impacts on wildlife. Portable facilities for sleeping, cooking, eating, food storage, and waste disposal would be needed. Work camps would reduce vehicle traffic on access roads, but camps in remote areas probably would be in undeveloped habitat. The potential for wildlife to be displaced by human activity or habituated to humans would be great, given the relatively long period of operation of a typical drilling operation in the Western Region.

Both grizzly and black bear are susceptible to habituation, particularly where food and garbage are present. Some bears could become habituated to work camps or might be intentionally attracted to camps by workers for amusement or photography. When bears and humans are in close proximity, the inevitable result is that some bears are killed through legal and illegal shooting and the removal of problem bears. Reductions in grizzly bear numbers, particularly in the Cabinet-Yaak Ecosystem where bear numbers are very low (less than one bear per 100 square miles), could result in eradication of the populations in those areas.

Grizzly bear move during the spring from higher snow-covered areas to the foothills and grasslands along the Rocky Mountain Front. Bears move onto the plains as far as Choteau and Bynum in search of food and regularly use spring and summer habitat on the Sun River, Ear Mountain, Blackleaf Game Management Area, and the Pine Butte Swamp Preserve. Increased access and human activity along the Rocky Mountain Front could displace bears, increase the potential for conflicts between bears and humans, and increase illegal bear shooting. Increased hunter access into spring grizzly bear habitat along the Rocky Mountain Front would increase the potential for hunters to shoot grizzlies during the black bear season, mistaking them for black bear.

In the absence of hunting, bighorn sheep also can become habituated to humans (MacArthur et al. 1979). However, sheep are hunted in the Western Region of the state, so habituation would be unlikely. Rather than becoming habituated to work camps and well sites, bighorn sheep probably would be displaced if the camps and wells were located in either summer or winter ranges. Displacement could increase stress on the animals and render them susceptible to predation, disease, and reduced reproductive capacity.

Bighorn sheep are consistent in the use of the same summer and winter habitats, lambing areas, migration routes, and salt licks year after year. If displaced, they do not readily adapt to new habitat, use patterns, and behavioral habits. If work camps, well sites, or heavily traveled roads intrude into sheep habitat, displacement probably would occur. Although displacement of individual animals probably would be a short-term response to a specific disturbance or activity, the effects of displacement on the local population or herd due to field development could be long term. Increased predation and disease, combined with reduced reproduction due to displacement and stress, could affect population numbers and vigor for many years.

Elk and mule deer would be most susceptible to displacement during the winter and spring. There are 8,461,500 acres of winter range in the Western Region (see Technical Appendix 6). Traffic on roads and human activity at wells and work camps could displace wintering animals, reducing available habitat and possibly the carrying capacity of the range.

Large reserve pits could trap and drown both large and small animals. In mountainous terrain with dense vegetation, it is probable that animals would accidentally enter these pits while foraging at night. The depth of the pits could prevent even the largest animals such as moose and elk from escaping.

Although oil and gas development has been limited along the Rocky Mountain Front, Joslin (1986) suggested that recent population declines in mountain goat populations may have been caused by oil and gas exploration activities. Additional oil and gas development may cause further declines in mountain goat populations by increasing stress which predisposes goats to disease.

AREAS WITH LOW TO MODERATE IMPACT POTENTIAL FOR WILDLIFE

Portions of Montana that would have moderate impact potential are mountainous areas with elk, mule deer, bighorn sheep, and mountain goat, but occupied by few or no grizzly bears. Such areas would include the Belt, Sapphire, Garnet, Castle, Highwood, Tobacco Root, Gravelly, and Flint Creek mountain ranges. These ranges provide excellent summer and fall habitat for big game species with winter ranges in adjacent foothills.

Areas with low potential for oil and gas impacts to elk, mule deer, antelope, white-tailed deer, and bighorn sheep would be nonmountainous portions of the state, generally east of the Continental Divide. Although the prairies, breaks, and forested areas in central and eastern Montana have substantial populations of these species, these animals are less susceptible to impacts.

In nonmountainous portions of Montana, sage grouse and sharptails would be vulnerable to oil and gas activity in the spring when the birds are concentrated on strutting grounds (Baydack and Hein 1987; Braun 1986). Construction and use of roads near strutting grounds could displace birds, resulting in a decrease in local reproduction. Roads close to strutting grounds could result in birds being killed by vehicles. Because birds fly to and from strutting grounds in early morning when visibility is poor, the risk of collisions between birds and vehicles is relatively high.

Roads and other facilities that would displace birds would cause short-term impacts to local populations during the drilling phase of oil and gas development. If oil or gas were not found, the site would be abandoned, and impacts on birds would cease. If the well proves productive, development of that well and other wells in the area could affect local bird populations for the life of the project. The construction of powerlines, particularly near strutting grounds, could cause sharptails and sage grouse to die in collisions with wires.

Waterfowl would be most likely to be affected during the drilling phase when reserve pits are present at the well. Petroleum residue and chemicals in the pits could kill ducks and shore birds. Oil and brine spills also could adversely affect waterfowl and shore birds by collecting in natural depressions and potholes. Oil coming in contact with birds would directly affect them by reducing the insulating properties of their feathers. Brine and oil in surface water would kill aquatic vegetation and aquatic invertebrates. Aquatic vegetation provides both food and cover for waterfowl.

During the production phase of development, reserve pits would no longer be necessary and could be reclaimed. Removal of the reserve pits would eliminate the potential for impacts to waterfowl unless "skimmer pits" were constructed to separate oil-water mixtures. Skimmer pits could attract and kill waterfowl.

The Northern Region of oil and gas development has numerous potholes that are highly productive waterfowl areas. The Poplar River drainage of the Williston Basin also provides important breeding habitat for waterfowl and shore birds.

Threatened or endangered species found at least seasonally on the prairie include the bald eagle, piping plover, least tern, whooping crane, and possibly the black-footed ferret. Bald eagles nest along the Yellowstone River and in southeastern Montana.

The Northeastern Region provides nesting habitat for threatened piping plover and endangered least tern. The piping plover nests around Medicine Lake and the least tern nests on an island in the eastern part of Fort Peck Lake. Endangered whooping cranes periodically stop at Medicine Lake during migration. The greatest risk that oil and gas development would pose for these species would be from oil spills or major blowouts with hydrogen sulfide. Contamination of wetlands from an oil spill could destroy habitat and nests and kill birds.

The last sighting of the black-footed ferret in Montana was in the Powder River Region in 1979. It is not known whether ferrets still live in Montana. Oil and gas development would affect ferret habitat only if it disturbs large colonies of prairie dog, the primary food of the black-footed ferret.

Although major oil spills and well blowouts are not common, their possible occurrence close to habitat occupied

or potentially occupied by threatened or endangered species is a concern. The loss of even a very small number of individuals from a threatened or endangered species would be a significant biological impact.

MITIGATION OF WILDLIFE IMPACTS

Mitigation is an effort to reduce, abate, or alleviate adverse impacts. Generally, mitigation does not totally eliminate impact but it makes losses of the resource less severe (Bromley 1985).

Usually, avoidance of impacts is the most effective and economical means of mitigation. The Interagency Rocky Mountain Front Wildlife Monitoring/Evaluation Program (1987) recognized impact avoidance as a mitigation measure and formulated specific management guidelines for oil and gas development with the objectives of preventing:

1) physical destruction of wildlife habitat;
2) human disturbance that would displace various wildlife species from important seasonal use areas;
3) direct human-caused death of animals;
4) death or physical impairment of animals from chemical contamination of the environment;
5) increased wildlife and human interactions caused by human intrusion and animal displacement.

ROADS

Displacement and stress resulting from roads can be mitigated by timing construction and use to avoid seasonally important habitats, such as big game winter range, migration corridors, calving or lambing areas, salt licks, spring grizzly bear habitat, grizzly denning areas, and grouse strutting grounds. Seasonal and daily management of road traffic can reduce impacts. Besides reducing or eliminating traffic during the sensitive winter and spring periods, traffic should avoid daily peak wildlife activity periods, such as the hours near dawn and dusk.

Reduction in habitat quality due to roads can be avoided in mountainous areas by building roads where they are screened from view and not on ridge tops. In non-mountainous terrain, roads should avoid riparian areas, woody draws, and wetlands. Where roads are built in dense cover, avoid where possible straight stretches of road that exceed 1/4 mile. Visual barriers or "dog-legs" help preserve security for wildlife.

Where big game summer-fall security areas would be affected, limit project-related access and prevent access during hunting season by signs and locked gates restricting all but authorized access.

During drilling in sensitive areas, traffic can be minimized by hauling workers in a bus. During production, electronic monitoring equipment can be installed at drill sites to prevent the need for frequent visits. Site visits could be as infrequent and brief as possible. To reduce the potential for poaching, place reasonable restrictions regarding use of firearms during work periods or when carrying them in vehicles traveling to and from work locations.

Sedimentation can be avoided by constructing roads on nonerodible soils and gentle slopes as far from water as possible. Undisturbed zones of vegetation could be left between roads and streams to trap sediment. Revegetation of areas disturbed during drilling and production, including road margins, can help to reduce potential fish and wildlife impacts (see Revegetation section).

HABITUATION

Habituation of animals to humans can be avoided by discouraging workers from feeding any wildlife. Avoid construction camps in important occupied grizzly bear habitat. At any construction camps in or near grizzly or black bear habitat, incinerate or haul garbage each day to acceptable landfills. Report the presence of any bears in the vicinity of oil and gas activities to the DFWP area biologist or warden.

TOXICITY

Take action to clean up spills of chemicals, oil, or brine immediately. Dispose of any toxic chemicals, including materials contained in reserve pits used during drilling, at approved sites in accordance with state and federal regulations.

Contingency plans for dealing with spills of oil, brine, and chemicals could be prepared and approved by the company, Board, or DHES before drilling and production begins in sensitive wildlife locations. Site-specific measures could specify how spills would be handled and affected areas reclaimed in the event of an accident. Dust suppression should not include the application of chloride salts or other materials toxic to vegetation or wildlife.

BIRD BREEDING AND NESTING

In sharp-tailed grouse and sage grouse habitats, preserve a 1/4-mile buffer strip around known strutting grounds and restrict activities in the early morning hours of spring when the grouse are active on the strutting grounds. Operators could be encouraged to contact DFWP biologists to determine the location of strutting grounds.

Preserve a 1-mile buffer strip around the nests of bald eagles, golden eagles, prairie falcons, peregrine falcons, and ferruginous hawks during the nesting and brood-rearing period (April through July). If a 1-mile buffer strip cannot be maintained, avoid oil and gas activities within 1/2 mile or less from nests and plan activities to take advantage of trees and terrain to provide visual barriers.

WELLS, PIPELINES, AND OTHER FACILITIES

In forested habitats, install an 8-foot high woven wire fence around reserve pits to exclude wildlife. In important waterfowl migration and breeding areas, cover pits with wire mesh. In sensitive settings, the design and location of pits can be tailored to the sites to prevent contamination of ground and surface water and protect wildlife that uses the area.

Construct the reserve pit so that 75 percent of its capacity would hold all fluids and cuttings from the drill hole. Construct the site to provide proper drainage to control erosion and runoff, including a 2-foot high berm around the perimeter of the drill site.

Site powerlines to avoid, where possible, the potential for bird collisions with wires. In areas with high collision potential, the wires could be buried.

Whenever possible, pipelines should avoid rivers and streams. In areas with saline or corrosive soils, measures can be taken to prevent deterioration of pipelines. Possibilities of lining the pipe with corrosion-resistant material, increasing pipe thickness, and installing cathodic protection could be evaluated and implemented on a site-specific basis where Class I streams or important spawning areas would be affected. Pipelines could be located along existing rights-of-way to minimize disturbance.

Noise levels can be kept at a minimum in sensitive wildlife habitat by muffling engines, generators, and energy production facilities (seeNoise section)

ADMINISTRATION

Cumulative impacts can be mitigated by providing for continued administrative review of oil and gas developments which exceed certain sizes or would cause significant impacts not easily mitigated. The potential for adverse impacts could result from (1) any oil or gas well development including roads and other associated facilities in occupied grizzly bear habitat; (2) any fields of two or more wells in mountainous areas in or near sensitive habitats; (3) any fields of six or more wells in or near sensitive habitats in prairie regions; (4) any wells that would affect significant wetlands; and (5) any well with 1/2 mile of active bald eagle or peregrine falcon nests.

FISHERIES

Montana waters support 80 species of fish, some adapted to cold waters of western Montana and others to the warmer waters of the eastern part of the state. Stream fishing for trout is popular with both residents and nonresidents and generates considerable revenue from license sales and for businesses that provide goods and services. A recent study (Duffield et al. 1987) estimated the value of cold-water fishing in Montana to be approximately $215 million annually. Angler use of Montana rivers and streams is more than 1,365,000 days per year and is expected to increase to more than 1,531,500 days per year by 1990.

COLD-WATER FISH

Salmonid fish (trout, salmon, grayling, and whitefish) are the dominant species in cold lakes and streams in the western part of the state. In major streams, trout populations range from 700 to 3,000 catchable-sized fish per mile. Smaller tributary streams have from less than 100 to more than 600 catchable-sized fish per mile. Whitefish numbers equal or surpass trout in some waters. Salmon are not native to Montana, but they have been stocked in rivers, lakes, and reservoirs in the state. Kokanee have established reproducing populations, heavily harvested by anglers, in a number of locations in the state.

COOL- AND WARM-WATER FISH

Most of the rivers, streams, and lakes in the eastern part of the state support species adapted to cool and warm water. The most sought by anglers include sauger, walleye, northern pike, bass, channel catfish, burbot (ling), and paddlefish.

The cool- and warm-water fishery is found in approximately 4,400 miles of stream and in 240 ponds, lakes, and reservoirs. Resident anglers spent about 90 percent of their fishing time seeking warm- and cool-water species in 1984.

SPECIES OF SPECIAL CONCERN

DFWP has designated fish species of "special concern" in Montana. These species have been designated on the basis of their relative rarity or concern for their continued existence in their current range. Table 23 lists fish species of special concern and their occurrence in the oil and gas development regions.

GENERAL IMPACTS TO AQUATIC ECOSYSTEMS

BLM and the U.S. Forest Service (1983) identified impacts of oil and gas development to fish and other aquatic organisms for the Riley Ridge Project in Wyoming. These impacts include: (1) direct removal of habitat, and habitat degradation from sedimentation; (2) altered spawning and seasonal migration due to stream obstructions such as misaligned culverts; (3) premature siltation of pools and beaver ponds; (4) direct loss of fish from accidental spills or

Table 23. Fish Species of Special Concern Found in Montana Oil and Gas Regions.

Species	Oil and Gas Development Region					
	Overthrust	Northern	Williston Basin	Central	Big Horn	Powder River
Cutthroat Trout	P	P	NP	NP	NP	NP
Bull Trout	P	NP	NP	NP	NP	NP
Arctic Grayling	P	P	NP	NP	NP	NP
Paddlefish	NP	P	P	P	NP	P
Pallid Sturgeon	NP	P	P	NP	NP	P
White Sturgeon	P	NP	NP	NP	NP	NP
Sturgeon Chub	NP	P	P	NP	NP	P
Sicklefin Chub	NP	P	NP	NP	NP	NP
Shortnose Gar	NP	P	P	NP	NP	NP
Pearl Dace	NP	P	P	P	NP	P
Shorthead Sculpin	P	NP	NP	NP	NP	NP

Key: NP = Not present
P = Present

Source: Compiled by Joe Elliott, DFWP.

pipeline ruptures releasing toxic substances; and (5) increased legal and illegal harvests of fish due to increased human access.

The U.S. Forest Service (1981a) reported that adverse impacts to water quality could occur due to well blowouts, oil spills, mud pit failure, and downhole contamination of fresh water strata. Because trout and other cold-water species require clean, well-oxygenated gravels for spawning and egg development, the greatest potential for aquatic impacts from oil and gas development would come from sediments generated during road construction.

Studies by the Flathead National Forest (Martin et al. 1987) show that most of the sediments generated by logging operations come from roads. Both suspended and deposited sediments in streams originate from roads and enter the streams from land runoff. Martin et al. (1987) presented an extensive literature review on stream sediments and concluded that fine sediments deposited in stream gravels in the North Fork of the Flathead River could require 10 to 40 years or more to be removed by high river flows.

Suspended and deposited sediments are detrimental to salmonids and their habitat. Deposited sediments reduce habitat by filling pools and spaces in gravel which are critical to young fish. Fine sediments in stream gravels affect incubating eggs and developing embryos by inhibiting dissipation of metabolic wastes (Phillips 1971). Fine sediments in stream gravels also abrade developing embryos and emerging fry (Weaver and White 1985), delay the rate of egg hatching, and reduce survival rates during incubation (Martin et al. 1987). The movement of sediments also abrades aquatic insects (important fish food) and reduce both the numbers and species.

Berg (1981) reported that water in the Marias River drainage has been contaminated by oil seeps from drill holes in pothole lakes near Cut Bank, Montana. Berg also noted that saltwater from deep drilling can be a detrimental pollutant. He advised that oil pipelines not be allowed to cross rivers in the vicinity of critical paddlefish spawning areas. Garvin and Botz (1975) reported that oil has leaked from wells and contaminated Cut Bank Creek in Montana, but no data have been presented concerning the impacts of oil on the environment.

FACTORS INFLUENCING POTENTIAL FOR IMPACTS TO AQUATIC ENVIRONMENTS

The potential for impacts to aquatic environments in Montana is related to the size of the river or stream, terrain, hydrology, species present, and existing water quality. Fishery values also are directly related to whether a river or stream flows through mountainous or prairie habitat. Streams in mountain regions typically support cold-water salmonid species and have high flow gradients, whereas prairie rivers and streams have warm- and cool-water species, low flow

gradients, and broad floodplains. In general, the mountainous areas of Montana have the highest potential for aquatic impacts.

According to Hobbs and Halbach (1981), riparian vegetation stabilizes streambanks and controls erosion, filters out sediments and reduces downstream siltation, shades the water to keep it cool, it provides organic debris to feed fish and aquatic insects.

The Stream Classification Map prepared by the U.S. Fish and Wildlife Service and DFWP shows that most Class I, II, and III streams are in mountainous regions of the state (U.S. Fish and Wildlife Service 1980). The stream classification is based on the value of a given stream in providing habitat for relatively rare species or for providing important habitat for fish of special recreational and aesthetic value. Class I streams provide exceptional habitat for populations of high interest species. Class II streams provide moderate habitat for highly valued species and exceptional habitat for less highly valued species. Class III streams provide substantial habitat for highly valued species and moderate habitat for less valued species. Technical Appendix 6 lists the class of streams in each oil and gas region.

Salmonid species would be most affected by oil and gas activities in mountainous areas of the state. Recreationally valued species such as rainbow and brown trout are the most numerous game fishes, but there are also populations of special concern species such as the Westslope and Yellowstone cutthroat and arctic grayling.

The greatest potential for impact would result from road construction and road upgrading for both drilling and production. Typically, in mountainous terrain, roads and pipelines are constructed close to streams where slopes are less steep. Construction and use of roads near streams increases suspended and deposited sediment in the streams. Culvert and bridge construction may hinder fish movement and alter stream hydraulics. Perched culverts or small-diameter culverts with high current velocity effectively block spawning migrations of trout. Increased access from new roads could increase both legal and illegal harvest of fish. With development of oil and gas production facilities, the number of roads would increase, pipelines would be constructed, and more wells would be drilled, increasing sedimentation.

The development of oil wells and fields could affect fish and other aquatic organisms directly through spills of oil, chemicals, and drilling fluids. Although major oil spills would be infrequent, minor spills from collection pipelines and at well heads would be fairly common. Because many high quality streams, such as headwater spawning streams, have low flow volumes, even relatively small spills could do serious damage. In mountainous terrain, oil spills would be difficult to contain because soils in such areas are often porous and runoff to streams is direct and rapid.

In nonmountainous portions of the state, precipitation is lower, terrain is less steep, and there are fewer streams. Water is warmer in prairie streams and fish are adapted to more sediment and turbidity.

Because of the aridity of central and eastern Montana, some streams are dry part of the year, and sediments from construction activities do not immediately find their way into major rivers. Disturbance of soil may result in local erosion, but sediments settle out before reaching major drainages. Similarly, if oil spills were to occur in eastern and central Montana, it would take a relatively long time for oil to reach a major stream. The opportunities for containing or reducing the effects of an oil spill in a prairie region would be greater than in the mountains because there would be more time to detect and react to the spill.

POTENTIAL FOR FISHERIES IMPACTS IN OIL AND GAS REGIONS

Western Montana has numerous Class I streams, whereas the eastern two-thirds of the state have relatively few. In the Northern Region, the Missouri River from above Fort Benton downstream to Wolf Point and the Milk River have populations of paddlefish and cool- and warm-water fishes. The fish populations in these rivers would be relatively tolerant of increased sediment from oil and gas development. Rarely, there might be impacts from major oil spills near streams.

The major streams of the Williston Basin are the Missouri River (Class I), Poplar River (Class II and III), and Big Muddy Creek. Major oil spills in the Poplar River could affect two species of special concern, paddlefish and pearl dace, and other warm-water fishes. The Missouri River also has paddlefish, pallid sturgeon, and shortnose gar, all species of special concern in Montana. Due to the large size and flow volume of the Missouri River, it would take a catastrophic oil or chemical spill to affect these fish.

The Powder River (Class II), Tongue River (Class II and III), and Yellowstone River (Class I) are the major rivers in the Powder River Region. The Powder River has populations of the sturgeon chub and other native species. The Tongue River supports populations of both the sturgeon chub and paddlefish, along with numerous other fish species. The Yellowstone River has paddlefish, pallid sturgeon, pearl dace, sturgeon chub, sauger, walleye, and numerous nongame fishes. As in the Williston Basin, the streams in the Powder River Region probably could only be affected by a major oil or chemical spill.

The Central Region has fewer miles of Class I and II streams than any other region. The Musselshell, Judith, and Yellowstone rivers are the principal streams. Impact potential from oil and gas development is low for this region.

The Yellowstone River (Class I, II, and III) is the major river in the Big Horn Region. The Yellowstone upstream from Columbus is a Class I stream with high fishery values for brown trout. Downstream, reaches are populated by populations of cool- and warm-water species. No species of special concern exist in this region (see Table 23).

MITIGATION OF FISHERIES IMPACTS

Culverts and bridges can be constructed to permit fish movement. Size culverts to keep flow velocities low enough to allow fish passage even during high flow periods. Placement of culverts and bridges should occur through the 310 Permit process where perennial streams would be affected. Additional measures related to protection of fisheries values include those to prevent erosion and sedimentation impacts and those related to water quality. The reader is referred to the mitigation measures designed to address these impacts and discussed in the soils, water quality, wildlife, and revegetation sections of this chapter.

NOISE EFFECTS

The perceived sound level from oil and gas operations are determined by the loudness and pitch of the sound at the source, the listener's distance from the source, air temperatures, humidity and turbulence, wind gradients, and any screening effects from terrain or vegetation (Engineering Dynamics 1984). Over distances greater than 1/5 mile, these conditions can be constantly changing, causing sounds to wax and wane. Evenings with still, humid air provide near optimal conditions for sound to carry, while turbulent, dry-air conditions dampen sound transmittance. Technical Appendix 7 summarizes the noise characteristics and sound levels most likely to be found in Montana.

Noise levels as they affect people and animals are most commonly measured using the A-weighted decibel scale which approximates the auditory perceptions of the human ear at moderate sound levels (Harrison et al. 1980). Figure 34 shows the relative loudness of different noise levels.

The Environmental Protection Agency (1974) uses 55 dBA during the day and 45 dBA at night as the levels below which there are no documented adverse effects to human health or welfare (National Academy of Sciences 1977). The 55 dBA guideline applies to long-term continuous noise exposure. In comparison, a sound level of 35 dBA is approximately the background noise level in rural areas and is the level where sleep interference begins (Toole 1979; Golden et al. 1979). Persons in rural areas expect lower background noise levels than those in urban and developed areas (Stolen 1980; Toole 1979). The magnitude of this rural "peace and quiet" factor varies by location, but the expected background rural sound levels are generally 5 to 20 dBA quieter than those in urban areas (Harrison et al. 1980). Rural Montana areas have low (30-35 dBA) background sound levels characterized by wind, water, animals, and other natural sounds (Krueger 1987; Stolen 1980).

The occupational health and safety standard for 8 hour per day exposure to protect worker hearing damage is 90 dBA (National Institute for Occupational Safety and Health 1978). However, "even at this noise level, hearing damage can be expected in some individuals" (National Institute for Occupational Safety and Health 1978) (See Figure 35).

NOISE IMPACTS AND MITIGATION

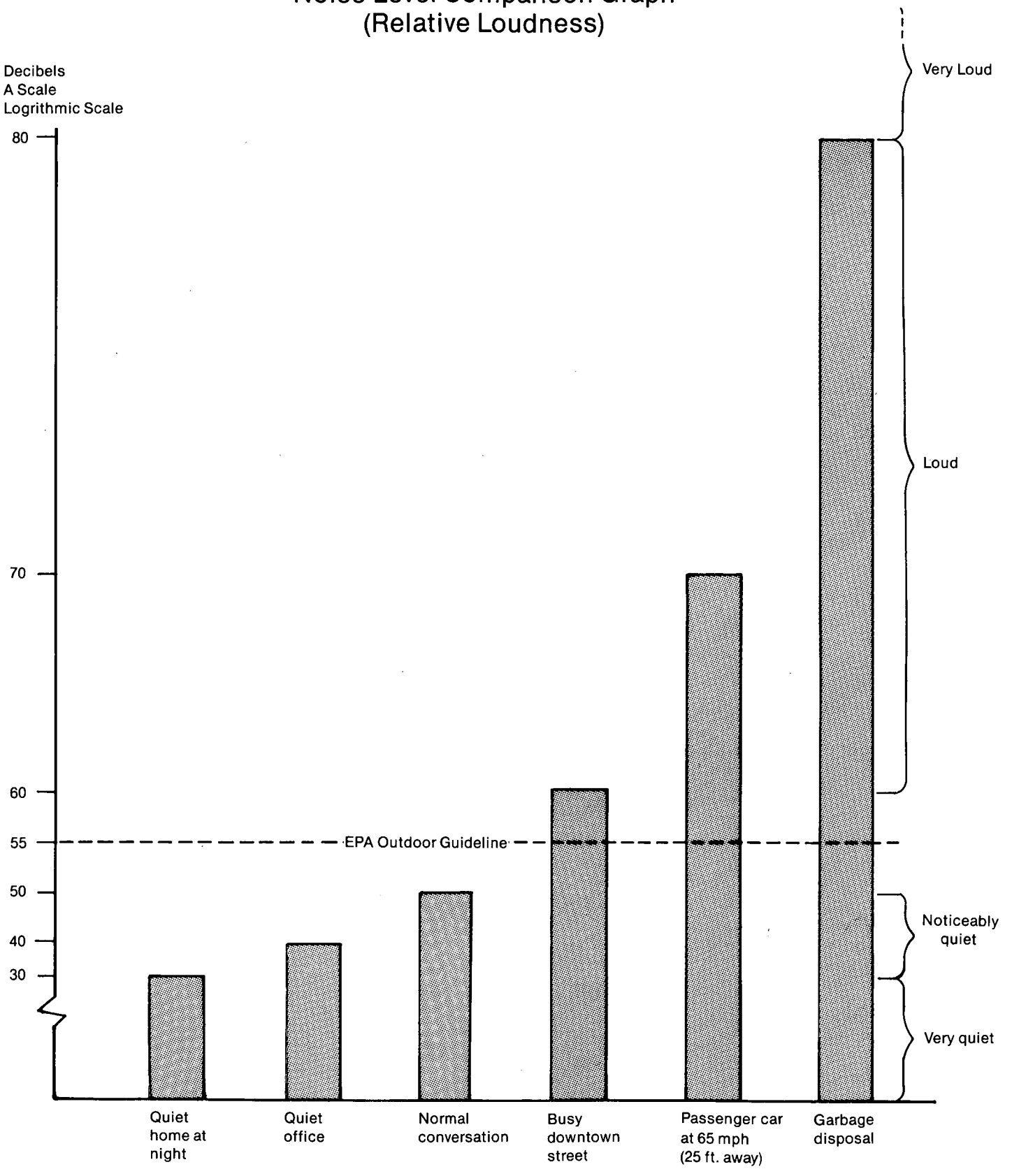
The drilling and operation of an oil or gas well generates noise through drill pad construction activity, vehicle traffic, drilling operations, site rehabilitation, and production activities. These noises are most intense near the drill site, along transportation corridors, and at petroleum-processing locations. Measured sound levels from current oilfield operations can be used to estimate noise levels from future wells and other field facilities. Sounds generally decrease 6 dBA for every doubling in the sound travel distance (Engineering Dynamics 1984). The important factor in determining noise impacts is the distance of the noise source from people. Table 24 lists the various noise sources associated with drilling and production and the distances from the source where noise levels reach 55 dBA and 35 dBA. Technical Appendix 7 contains a description of the drilling and production activities that contribute noise.

Noise ranges from intense levels at which hearing can be quickly impaired, to long-term background noise that disrupts nighttime sleep. While less is known regarding noise impacts on wildlife than noise impacts on humans, EPA suggests that "the most simple approach is to assume that animals will be at least partially protected by application of maximum levels identified for human exposure" (U.S. Environmental Protection Agency 1974).

The on-site noise levels produced by road and drill pad construction equipment, drilling equipment, and pumping stations often exceed health standards for short-term workroom exposure to noise (National Institute for Occupational Safety and Health 1978). Drill rig noise normally exceeds 90 dBA, so unprotected workers with long-term exposure can expect hearing damage.

FIGURE 34

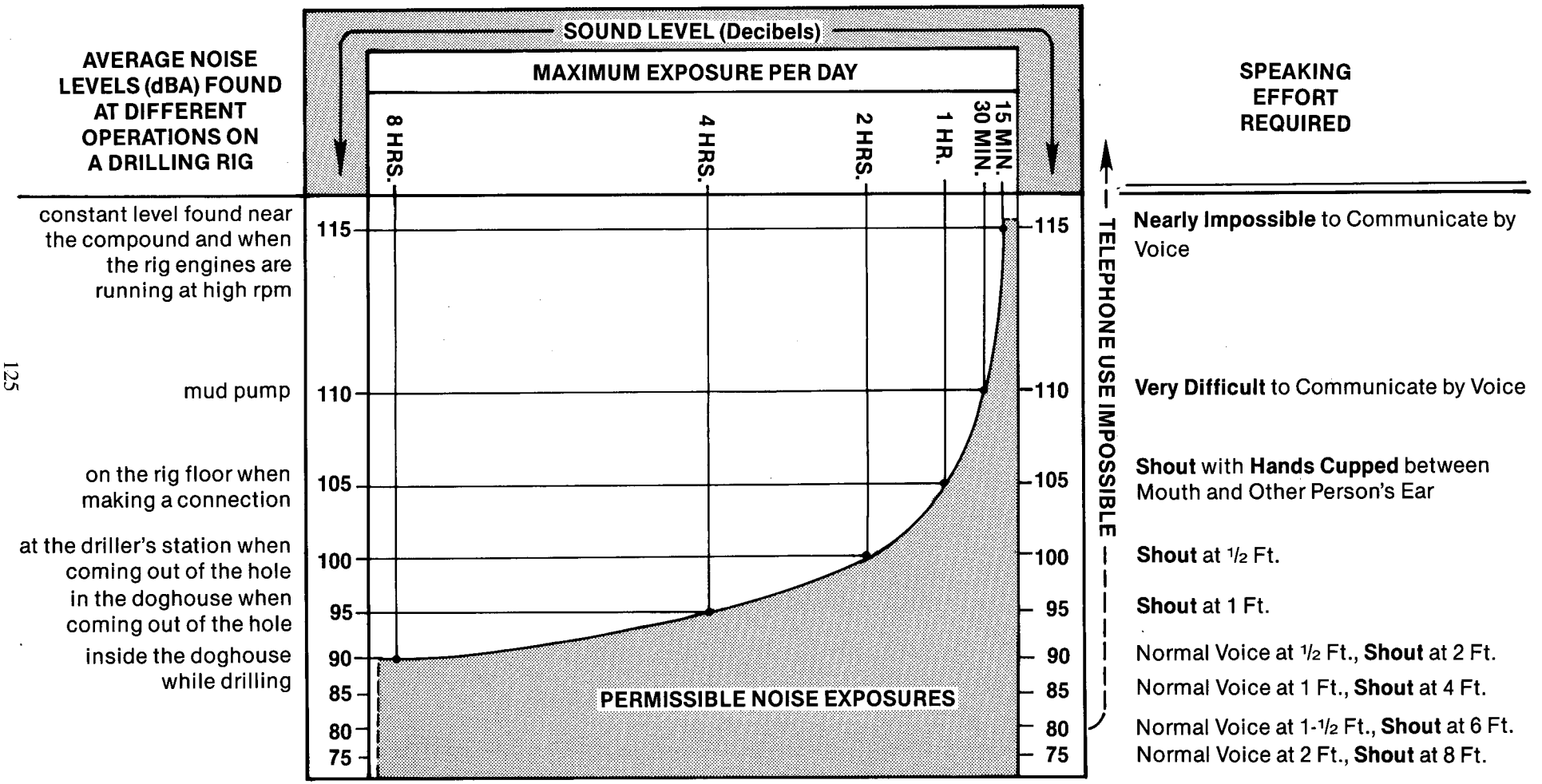
Noise Level Comparison Graph
(Relative Loudness)



SOURCE: Engineering Dynamics, 1984, and Dames and Moore, 1986

FIGURE 35

PERMISSIBLE NOISE EXPOSURES



SOURCE: National Institute for Occupational Safety and Health, 1978

Table 24. Summary of Drilling and Production Noise Levels and Mitigation.

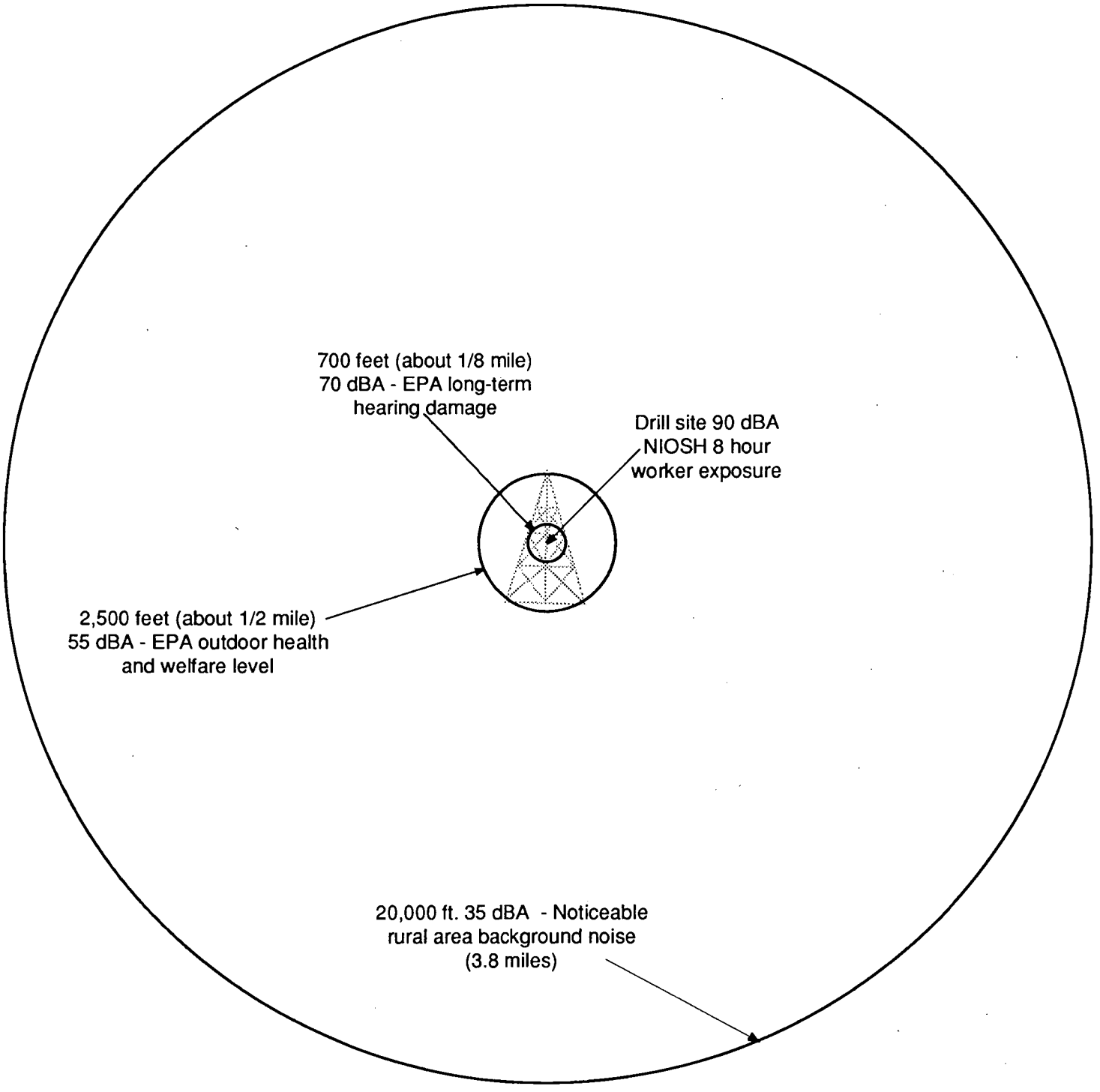
Equipment	Unmitigated Source Noise Level	Noise Impact Distance[2] (55 dBA)	Mitigation Measure(s)	Estimated Mitigated Noise Level[1]	Estimated Mitigated Noise Impact Distances[1] 55 dBA[2]	35 dBA[3]
Diesel trucks	95 dBA (intermittent)	1,500 ft.	Mufflers, improved operation	90 dBA	1,000 ft (.2 mile)	8,000 ft (1.5 miles)
Earthmoving equipment	115 dBA (intermittent short-term)	3,500 ft.	Special mufflers	115 dBA	3,500 ft (2/3 mile)	35,000 ft (6.5 miles)
Diesel drilling rigs	100-115 dBA (short-term)	2,500 ft.	Residential mufflers, sound screens, orientation	75-90 dBA	~ 500 ft (.1 mile)	4,000 ft (.75 mile)
Diesel-electric drilling rig	100-115 dBA (short-term)	2,500 ft.	Residential mufflers, sound screens, orientation	75-90 dBA	~ 500 ft (.1 mile)	4,000 ft (.75 mile)
Drill rig operations, (trips, braking, and pipe movement)	Up to 115 dBA (intermittent)	3,500 ft.	Sound absorbers, sound screens, operating changes (use auxilliary brake)	about 80 dBA	500 ft (.1 mile)	4,000 ft (.75 mile)
Production testing and test flaring	95 dBA (occasional short-term)	1,500 ft.		95 dBA	1,500 ft (.3 mile)	12,000 ft (2.3 miles)
Compressor stations	105 dBA (long-term)	2,500 ft.	Mufflers, sound screens	80 dBA	500 ft (.1 mile)	4,000 ft (.75 mile)
Pump unit						
- gas engine	95-100 dBA (long-term)	2,000 ft.	Mufflers	70-75 dBA	300 ft (.05 mile)	2,500 ft (.45 mile)
- electric	65 dBA (long-term)	100 ft.		65 dBA	100 ft (.02 mile)	800 ft (.15 mile)

[1] These estimated sound levels and distances are only approximate estimates because individual locations, drill rigs, equipment type and weather conditions all affect transmitted sound levels.
[2] EPA health and welfare level.
[3] Noticeable noise level slightly above rural area background environmental noise and the threshold for slight sleep interference.

Source: Compiled by Mark Kelley, DNRC, after Engineering Dynamics 1984 and Kruger 1987.

FIGURE 36

AVERAGE NOISE LEVELS AROUND A DRILLING RIG (100-115 dBA Noise Source)



Mitigation Measures - Require the use of Diesel-Electric type drilling rigs which produce constant noise levels over long periods of time as opposed to Direct Drive diesel engines which produce highly variable noise levels. Use drilling rig engine mufflers capable of a 25 dBA reduction in engine noise levels.

SOURCE: Kruger, 1987

WORK-SITE NOISE MITIGATION

Measures to mitigate noise on the work site include shielding and isolation of noise sources, retrofitting with sound-absorbing equipment, bumpers, sound shields, sound blankets and sound boards, changes in operating procedures, full machinery lubrication, and use of mufflers on engines and compressor equipment (National Institute for Occupational Safety and Health 1978; Montana Department of State Lands 1984). If these measures are not feasible or sufficient, hearing protection equipment such as earmuffs and earplugs can be used to protect workers.

OFF-SITE NOISE MITIGATION

Drilling-related noises create an elevated sound zone around the site. Typical drill rig operations cause noise levels greater than 55 dBA up to approximately 1/2 mile from the drill site, and may cause sleep interference (35 dBA) up to 4 miles from the site (Figure 36). Pipeline compressor stations will have a similar impact for the life of the field (up to 30 years). Within these areas of elevated noise, human and wildlife activities can be adversely affected (U.S. Environmental Protection Agency 1974). These impacts can include sleep loss, behavioral effects, psychological effects, land use and property value effects, and loss of wildlife habitat (U.S. Bureau of Land Management 1982).

There is a wide variety of measures for reducing noise impacts at the site (see Table 24). Other measures may include relocation or timing of activity in sensitive areas. The easiest mitigation approach may be to schedule drilling activities to avoid impacts on people or wildlife. Most of the site preparation activities can be scheduled during daytime hours when noise is less of a problem. In exceptional situations, drilling activities can be scheduled to avoid sensitive seasons of the year, such as the peak summer tourism season (Dames and Moore 1986) or wildlife feeding, migration, or birthing times (Kruger 1987).

More commonly used noise mitigation measures include residential noise mufflers, sound screens, and directional orientation of the drill rig (which can decrease noise levels at least 25 dBA) (Montana Department of State Lands 1984); improved drill rig operations (including use of auxiliary brake when stopping the draw works); and use of diesel-electric drilling rigs which produce a more consistent and less annoying noise (see Table 24 for specifics).

If oil or gas are discovered, production testing and flaring at the well generate noise up to 95 dBA (Kruger 1987). These activities are short-term and intermittent, and the noise is difficult to mitigate.

In producing natural gas fields, the most noise (105 dBA) usually comes from collection compressor stations. Compressor station noises are of special concern because they are continuous for the life of the field (up to 30 years). Compressor stations can be equipped with mufflers, surrounded with acoustic barriers, berms or screens, or relocated to less sensitive locations. The mufflers, barriers, and screens normally can provide a 25 dBA noise reduction (Stolen 1980; Kruger 1987). Compressor station noise reductions of up to 85 dBA have been achieved in Great Britain, where noise increases greater than 5 dBA are not permitted at any human residence (Stolen 1980). Because compressor station siting is somewhat flexible, stations can be placed to avoid homes in the 35 dBA impact zone.

For producing oil fields, the major noise mitigation at the wellhead is to use electric pump jacks, which are at least 30 dBA quieter than gas-powered engines. Gas-powered engines can be equipped with mufflers that reduce their noise levels by up to 25 dBA (Dames and Moore 1986). In remote fields, it may be uneconomical to construct electrical powerlines, so muffler-equipped gas engines may be the least noisy feasible alternative.

LAND USE

Surface ownership patterns vary greatly among the oil-producing regions of Montana. The western portion of the state is characterized by federally administered National Forest lands at higher elevations and private land in the valleys. Northern Montana is largely privately owned rangeland, except for extensive federal BLM lands in the eastern half, and three extensive Indian reservations. The northeastern Montana oil-producing region is an approximate split between private rangeland and the Fort Peck Indian Reservation. The central and south central Montana regions are mostly private lands surrounding large parcels of National Forest lands. The central region contains extensive BLM lands along its northern edge, and the south central region includes the Crow and Northern Cheyenne Indian reservations. Southeastern Montana is a mix of private and BLM lands, with four additional federal parcels comprising the Custer National Forest.

State lands are scattered fairly evenly across the state as a result of the granting of two sections of land per township at statehood. Denser concentrations of state land exist where in-lieu land selections were made by the state to replace other lands. The state completed in-lieu selection of surface ownership in 1983. Selection of mineral ownership is

continuing. Of the 6,185,276 acres of state land, 82 percent are leased for oil and gas. Technical Appendix 8 contains information on surface ownership for each oil and gas region.

Ownership of subsurface minerals, including oil and gas reserves, generally follows surface ownership patterns. Split-estate ownership, in which the surface owner does not own the subsurface minerals, is the exception rather than the rule. Still, split-estates are fairly common and are generally found where past land sales or exchanges have conveyed only the surface estate. This situation is the most common in older oil-producing areas, such as the Cut Bank/Kevin area of northern Montana, where past land sales have recognized that the mineral rights are often more valuable than the surface ownership. Split-estates are also common along Burlington Northern rights-of-way, where BN has retained mineral rights in surface sales. Split-estate is common on BLM and state land, where land sales and exchanges sometimes split the ownership estate (Hagener 1988).

AGRICULTURE AND THE PETROLEUM INDUSTRY

Agriculture accounts for nearly a third of the total receipts earned by Montana's primary industries. About two-thirds of Montana's agricultural lands are rangeland and pasture that support the livestock industry. Crop land comprises about another one-fourth of all the state's agricultural lands. In 1985, Montana farmers harvested 1.6 million acres of irrigated crops and nearly 6 million acres of nonirrigated crops (Montana Department of Agriculture 1986). These figures indicate irrigated acreage declined 10 percent from the previous year, and nonirrigated acres were down 20 percent. This decline is in part a continuation of the statewide downward trend in number of farms and total farm acreage that has been occurring for the last 50 years.

Table 25. Disturbed Acreage Estimates for Producing Oil and Gas Wells.

Region	Total Producing Wells (1985)	Total Long-term Disturbance (through 1985) Acres	1986 New Wells Drilled	1986 Initial Disturbance Acres	Total Disturbed Acres
1. Overthrust	0	0	2	29	29
2. Northern Montana	2,803	7,007	235	587	7,594
3. Williston Basin	1,540	4,620	80	640	5,260
4. Central Montana	417	1,251	48	168	1,419
5. Big Horn	141	423	14	49	472
6. Powder River Basin	216	648	29	130	778
Total	5,117	13,949	408	1,603	15,552

* These estimates are based on data about "typical wells" in each oil and gas region (see Technical Appendix 1).
Source: Compiled by Art Compton, DNRC.

The oil-producing regions of the state exhibit differing degrees of petroleum development. Northeastern Montana accounts for nearly three-fourths of the state's oil production, while the south central area accounts for 3 percent and southeastern Montana for about 5 percent (see Figure 3). Table 25 shows the estimated acreage disturbed by producing oil and gas wells and associated facilities up to 1985, and by new wells drilled in 1986.

LOCAL LAND-USE PLANNING

Thirty-two of Montana's 56 counties have adopted comprehensive land-use plans. Another nine counties have cities with comprehensive plans that include provisions for influencing land use in an area extending up to about 4 1/2 miles from the city limits. The Montana Land Resource and Use Act (76-1-101 et. seq, MCA) explicitly precludes county planning boards from authorizing an ordinance or resolution that prevents complete recovery of a mineral resource by its owner. The same law, however, authorizes the creation of planning and zoning districts upon petition of 60 percent of the landowners of parcels 40 acres or more. After creation of such districts, county commissioners appoint a five-member commission to administer them. This commission has greater authority to restrict mineral entry or development. For example, the Bridger Canyon Planning and Zoning District in Gallatin County (western Montana region) required a Conditional Use Permit before approving drilling an oil and

gas well in Bridger Canyon. The District has used its powers to deny conditional use permits for gravel pits in the past (Peck 1988a).

WELL SPACING

The Board is responsible for establishing how much space must exist between wells in a given field. The Board generally selects a spacing unit that represents the geologic area expected to be drained by each well. This spacing is then translated to a minimum ground surface distance between wells. Normally, this spacing requires that only one permitted well may produce from the same formation within the spacing or drilling unit.

The Board establishes well spacing in two ways. The first is by adopting a "field" rule that applies to a specific oil or gas field above a particular producing formation. The field rule is adopted following a public notice and hearing process. About half of the producing fields in Montana have designated spacing units.

In the absence of a field rule established for a particular field, the "statewide" spacing criteria apply. The size of statewide spacing units depend upon the depth of the target formation. Table 26 summarizes the Board's statewide spacing rule requirements. All wildcat wells and the remaining half of the producing fields are regulated under statewide spacing requirements.

Actual well locations may vary from the statewide spacing unit criteria by a designated "tolerance" distance of 75 to 150 feet. This distance is designed to accommodate siting of a well in rough terrain. Tolerance distances also are sometimes used to avoid surface agricultural facilities such as irrigation canals and other improvements (Richmond 1988).

Table 26. Statewide Spacing Requirements for Well Drilling.

	Depth(ft)	Spacing(acres)	Tolerance(ft)	Comments*
Stratigraphic test	6,000 or less	40	75	Exceptions require site inspection and approval.
Wildcat wells: either oil or gas	6,000 to11,000	160	150	Exceptions require site inspection and approval.
	11,000 or more	320		
Oil wells	6,000 or less	40	—	Exception requires hearing
	6,000 to11,000	160	—	Only one well may produce from the reservoir in the spacing unit.
	11,000 or more	320	—	
Gas wells	any depth	640	—	Only one producing well in spacing unit. Exception requires hearing.

* In order to drill a wildcat well that does not meet statewide spacing requirements, the operator must receive permission from the Board of Oil and Gas Conservation.
Source: Administrative Rule of Montana 36.22.702(1)-(10)

IMPACTS COMMON TO ALL PRODUCING REGIONS

Technical Appendix 8 summarizes land use impacts in producing regions of Montana. The following sections describe in general terms the impacts from drilling and production activities.

PETROLEUM DEVELOPMENT AND CATTLE

The oil and gas-producing regions of Montana are used extensively for cattle grazing. Livestock forage and petroleum development are generally compatible because exploration activity is only temporary. Grazing of livestock on rangeland continues during oil and gas development. Well density in oil fields can vary from one well per 40 acres to one well per 320 acres, and one or two wells per section in gas fields. Access roads remove some land from the grazing base, but generally these impacts are not great. It is not until maximum existing well densities are reached that grazing can become uneconomical. The Kevin-Sunburst field in northern Montana, for example, supports nine wells per 40 acres. As much as 50 percent of the surface area is unavailable for forage production.

The relatively high volumes of exploration vehicle traffic present a hazard to livestock. Heavy traffic on temporary access roads increases the risk of collision with stock, resulting in injury or death of the animals (U.S. Bureau of Land Management 1980). Airborne dust stirred up by heavy exploration vehicles settles on grass along the road. The dust can affect the palatability of grass and forbs up to 1/4 mile from the road (U.S. Bureau of Land Management 1980). Decreased palatability can force cattle to other grazing areas decreasing efficient distribution and resulting in overgrazing. Rain washes the dust from the vegetation periodically.

Drill pad sites and reserve pits can contain toxic compounds, such as thread compound used to treat drill pipe joints, crude oil, salt water, and a number of chemical and base metal additives used with drilling muds. Although outright poisoning of livestock is rare, animals that ingest these materials can lose weight. This thinness is often diagnosed as the result of parasites or poor nutrition. Cattle are most likely to drink salt water from reserve pits in the Williston Basin during the winter when fresh water sources are frozen (Edwards 1985). Cattle can also enter unfenced reserve pits and drown or become mired in the soft drilling muds.

The noise from temporary exploration activity can drive livestock away, causing inefficient stock distribution and overgrazing on other parts of the range (U.S. Bureau of Land Management 1980).

Livestock forage also can be killed by accidental spills of crude oil, saline-produced water, or drilling fluid. Such spills often follow drainages and can affect the most productive areas of the range, including water sources (U.S. Bureau of Land Management 1980).

Water availability can limit livestock operations in any region of the state. Petroleum exploration can provide a benefit to grazing when an exploration well produces water and subsequently is abandoned for petroleum production. Such a well provides a convenient source of stock water. The conversion to a water well requires negotiation and agreement between the private landowner (or the surface managing agency) and the well driller, and approval by the Board and other state agencies.

Oil field access roads can give ranchers access to more remote areas of their property and provide for easier winter feeding, range improvement and maintenance, and stock supervision. However, road systems also can interfere with livestock dispersal and cause decreased forage efficiency, because cattle tend to congregate and travel along roads. Access road networks, drill pads, and other surface facilities remove livestock forage from production. The amount of surface affected depends upon the field size and producing region (see Vegetation section).

PETROLEUM DEVELOPMENT AND CULTIVATION

Oil and gas production does not exclude agricultural uses, although different farm and ranch lands differ in their capability to sustain petroleum development and remain agriculturally productive. Cultivated land is more vulnerable than grazing land to impacts from petroleum exploration and development. This greater vulnerability is due to the hindrance to farm equipment caused by oil and gas facilities, soil compaction on access roads, and the greater inherent value of cultivated land.

Oil and gas exploration and development on cultivated land generally has a greater impact than on rangeland for the same reason that production has greater impact on such land. Oil and gas exploration is generally a temporary activity and its disruptive effects on agriculture tend to be short term. Drill pads and access trails remove ground from production only during drilling. Also, since most cultivated land is relatively flat, access trails do not require a great deal of cut-and-fill. The impacts that remain from unsuccessful drilling operations are generally repairable. They result mainly from soil compaction under the drill pad and access trails and soil contamination caused by escape of oil or drilling fluids from the drill pad or reserve pit. Soil compaction may be remedied by ripping at least 36 inches deep following removal of drilling facilities and before the field is harrowed for planting.

New technologies and treatments have been developed to reclaim croplands contaminated by oil spills. These lands often can be brought back into production in several years rather than the decades that have been required in the past. Oil is broken down by bacterial action in topsoil and subsoil. Cultivation contributes to increased aeration of subsoil horizons. The increased aeration enhances bacterial decomposition of oil and speeds up the reclamation process (McGill and Bergstrom 1983). Studies into the amount of time required for biological decomposition of oil spills in grain fields in Alberta indicate that petroleum has a half-life of about 1 year with optimum soil management, which includes mechanical cultivation and the addition of nitrogen fertilizers. Spill areas usually supported a cover crop of native grasses and weeds within one year and could support cereal grain (albeit with decreased crop yields) after two or three years (McGill and Bergstrom 1983).

A successful exploration well may lead to long-term production facilities with a life of 20-30 years. The agricultural operator will find it necessary to maneuver cultivation machinery around the well pads and other surface facilities. These facilities may require a change in cropping and cultivation patterns. Additional passes by cultivation equipment is necessary to farm around such obstructions. This increases the operators' time demands and fuel costs and can contribute to compaction of soils around the obstacles. Compacted soils are less productive. Other potential

production impacts to cultivation include seepage from reclaimed reserve pits and pipelines.

The Surface Owner Damage and Disruption Compensation Act (MCA 82-10-501 et seq) provides for damage payments and advance notification of landowners by oil and gas operators. The law establishes the agricultural operator's right to receive reimbursement from drillers for loss of agricultural production and income, lost land value, and lost value of improvements. The damage payments are to be based upon a mutually agreeable formula and must consider the period of time over which the impacts occur. The payments usually are made in lump sum for exploration impacts or annual installments for production impacts. The Act also requires the drilling operator to provide advance written notice of planned activities so that the landowner can plan his agricultural operations around them (82-10-501 et. seq, MCA).

Although the Surface Damage Compensation Act provides some protection for agricultural interests, some landowners have complained that the enforcement of the Act's provisions is difficult (Coon 1981; Henderson 1981; Nordhagen 1981). Landowners have had to seek enforcement of the Act through the courts (Brunner 1981). This can be time consuming and expensive, and often goes "against the grain" of the independent values of some Montana landowners.

Landowners who also own the subsurface estate beneath their property generally benefit financially from oil and gas production on their land. In some cases, proceeds from drilling and production activities is an important source of income for families beleaguered by a depressed farm economy. Landowners who do not own the underlying mineral estate are the most vulnerable to economic loss caused by the impacts of petroleum production on agricultural land.

PETROLEUM AND RESIDENTIAL AREAS

Residential areas can be particularly vulnerable to impact from any type of industrial development occurring nearby. This vulnerability results from the high sensitivity of some residential dwellers to their surroundings and expectations concerning the safety and aesthetic quality of those surroundings. These expectations vary in different areas of Montana. Residential dwellers near urban areas, industrial areas, or major transportation corridors may have lower sensitivity and expectations about some aspects of their surroundings, such as aesthetics, quiet, and solitude, than people who live in more scenic or rural areas.

Impacts to residential dwellers from petroleum development generally result from one or more of five causes—noise, dust from roads, visual and aesthetic impacts, concerns over human health and safety, and potential decline in property value. Most of these areas involve the greatest potential impacts at the exploration phase.

The residential impact of noise produced by petroleum exploration equipment and vehicles depends largely upon the existing residential setting. Subdivisions and other residential developments in rural areas are characterized by noise levels below 35 decibels. Rural residents expect lower background noise levels than those in urban and developed areas, where background noise levels are in the 40-55 decibel range (see Noise section). These background noise levels can be exceeded by conventional drilling rig operations up to 1/2 mile from the drill pad. Shouse (1985) suggests 4,000 feet as the worst-case noise impact distance in a rural setting. Measures to mitigate noise impacts are described in the section on Noise Effects.

Unpaved rural roads are sources of dust (Smith 1988a; U.S. Bureau of Land Management 1981a). Dust can be a nuisance to residences within 1/4 mile of the road. Some residents are forced to keep their windows closed because of the dust (Smith 1988a; Hammer 1988).

Exploration drilling equipment and soil disturbance around a drill site can intrude on the view from residences. Visual impacts are increased by the sensitivity of many rural residents who have selected homesites for their aesthetic qualities. The visual impact of a drilling operation is highly dependent on site-specific conditions such as setting, orientation, and distance to the viewer (see Visuals section).

Exploratory drilling can present moderate hazards to nearby residents through the possible escape of toxic substances from the drill pad or reserve pit. These substances can be airborne toxins in produced gas, or liquids such as drilling or production fluids. Fires originating at drilling operations could be a source of airborne pollutants and conceivably could spread to nearby residential areas.

Some rural dwellers may to be opposed to oil and gas development because they see no benefits that may accrue to them as adjacent landowners. Since most rural residential dwellers live on small parcels of land and may or may not own the underlying mineral estate, they generally do not benefit financially from exploration efforts. Frequently, the owner of the parcel on which exploration is proposed does not live on that parcel, so nearby residents see themselves as shouldering nearly all of the impact burden with no opportunity to benefit. This attitude may be modified to a moderate or major degree in the case of persons who feel that their jobs or livelihoods are stabilized or improved by oil and gas activity.

A successful exploration well generally results in additional exploration wells to identify the extent of the

producing formation. Each additional well will usually present the same type of impacts as the first one, effectively extending the temporary nature of exploration drilling over a longer period. This increased duration increases the significance of exploration impacts.

Production-related noise impacts include short-term production testing and test flaring operations, which are difficult to mitigate. Longer term impacts are associated with gas compression stations and gas-powered pumping units for production oil wells (see Noise section).

In small producing fields, dust kicked up by daily maintenance and vehicle traffic is fairly minor. However, if development results in large-scale production, the impacts to residences could be long term (20-30 years).

Health and safety issues during the production phase generally relate to accidental spills of petroleum from tank trucks or pipelines, and accidental and fugitive releases of hydrogen sulfide gas. Gas and oil transport and delivery pipelines criss-cross many nonproducing areas of the state, so potential impacts are not necessarily limited to residences close to producing areas.

The visual and aesthetic impacts of petroleum production facilities are relatively long term and should not be dismissed as a temporary phenomenon. However, production facilities such as pumps and tank batteries usually are smaller and quieter than exploration facilities. If development expands from a single producing well to a full field, however, the sheer number of additional facilities and access roads can lend an industrial flavor to otherwise pastoral settings.

IMPACTS UNIQUE TO WESTERN MONTANA

Exploration and development in the Overthrust district will generally require more land disturbance per well than in other regions of the state. Exploration wells in remote locations may require trailer camp facilities, including sleeping quarters, kitchen and dining facilities, septic systems, and refrigerated food storage. Wells could require tree clearing and site leveling and grading.

Wildcat wells also have generally greater access road requirements and in steeper terrain usually will require cut-and-fill. However, the amount of new road construction in any area depends on the availability and condition of existing roads. Single-lane roads built on hillsides generally will require disturbance of about 20 feet of right-of-way and cover 2.2 acres per mile. Total road disturbance for an exploratory wildcat well could run from 7 to 15 acres or more, depending on road length.

Exploratory drilling in the Overthrust district could encounter hydrogen sulfide gas and probably would require precautions to protect workers and residents if people live nearby (see Health and Safety section).

In forested areas, marketable timber would be removed from the well site and access road routes and sold. Depending on agency reclamation stipulations, the access road also may be left available for more intensive management of surrounding timber resources. Many roadless tracts of timber in western Montana are not economical to harvest, and the development of access for oil or gas exploration could make these tracts more attractive to lumber interests. Increased timber harvest can result in high cost to non-commodity values such as wildlife, watershed, and primitive recreation.

Sometimes it is possible to use directional drilling to decrease disturbance in steep or remote terrain. With directional drilling, the drill site can be located on flatter ground not directly above the target formation, which minimizes cut-and-fill construction and access road requirements. However, other more intensive land uses such as road corridors and cultivation also occur in valleys, and in some cases directional drilling may preempt productive agricultural activities.

Oil and gas production in the western region also is likely to cause greater impacts than in other regions. The spacing of individual wells may depend on the depth drilled, although spacing of 320 acres or greater per well is likely. The size of individual well pads would be reduced from 5 to 2 acres when wells go into production. Access roads would be required between well sites, and tank batteries and heater treater facilities could expand the surface disturbance beyond the amount required for drilling. The level of development required to extract a large reserve in this region could include numerous wells and a collection pipeline system rather than tank batteries (see Technical Appendix 1).

Proper reclamation of unsuccessful exploration wells includes recontouring and revegetation of the site. Improper reclamation can result in soil erosion on slopes and access roads. Due to the higher quality and number of streams and aquifers in the Overthrust district, stringent waste disposal practices will be important to protect surface- and groundwater quality. The metal additives to the drilling muds used in the Overthrust district could have a detrimental effect on the productivity of soils around the reclaimed pit (Shouse 1985). Proper reclamation would be particularly important when drill sites are on valley floors that are used for pasture or cultivation.

MITIGATION

The Board is responsible for requiring measures to prevent drilling and production operations from damaging or contaminating underground strata or the surface around the drill site. Through its rulemaking authority, the Board can address a range of potential adverse impacts caused by petroleum exploration and production. Rulemaking and enforcement by the Board could benefit both private and public resources on land affected by drilling or production.

A major shortcoming of the Surface Owner Damage and Disruption Compensation Act is that it is directed at damage payments without providing a means to prevent impacts. While landowner damage compensation is an important element of Montana law, emphasis could be shifted from negotiated levels of acceptable damage to impact prevention or limitation. Rulemaking by the Board to address specific environmental issues associated with drilling and production could be one means of providing protection.

Rulemaking and enforcement by the Board may have the added benefit of promoting the protection of public resources such as air, water, and wildlife on private lands. The protection of these public values is an issue distinct from the compensation payments an individual landowner might receive. Board adoption and enforcement of rules concerning impact mitigation and monitoring might work to increase the Board's role in ensuring that permitted activities associated with oil and gas drilling and production (such as reserve pit construction, solid waste disposal, and flaring of gas) do not lead to violations of existing air and water quality laws or unnecessary impacts from development.

DRILLING

In order to avoid waste of timber resources, saleable timber cleared from access roads and well sites on public land should be decked and sold or, on private land, should be disposed of at the landowner's discretion. Noncommercial timber on public lands should be decked separate from saleable timber, and public access should be provided to firewood gatherers during a season that will not conflict with wildlife or other resource concerns. These measures are commonly used by public land-managing agencies.

In order to protect the quality and productivity of agricultural land, operators planning directional drilling from private lands in productive valley bottoms should cooperate with the landowner in locating the drill pad and other surface facilities, and in scheduling operations. This can help avoid disturbance of especially productive acreage or improvements such as irrigation facilities. This measure also is an effective means to ensure that surrounding surface is not contaminated by drilling or production fluids, and that the pit will not fill up and overflow due to heavy precipitation. Such measures are routinely required by federal land management agencies for drilling on federal land.

The metal additives in the drilling mud used in the Overthrust district and the brine used in and produced by drilling in the Williston Basin can contaminate soils and impair agricultural productivity. Removal of pit fluids containing these contaminants is effective in protecting soil and shallow aquifers.

In order to protect livestock, reserve and workover pits in grazing areas could be fenced to protect livestock from drowning or being mired. Fences also help prevent livestock from drinking chemicals or salt water. This measure is not commonly required on rangeland. It is occasionally required on federal land to protect wildlife.

Operators could perform regular dust abatement on unimproved public roads that pass within 500 feet of residences and subdivisions. On roads used by more than one operator, all operators could be required to cooperate and participate in regular applications of abatement measures.

Temporary school enrollment increases can be accommodated in temporary classroom facilities such as trailers. This approach will minimize the capital investment required to respond to temporary enrollment fluctuations typical of a petroleum boom.

Landowners negotiating with drillers and well service and supply companies should avoid use of prime or productive agricultural land for access routes or materials storage or handling.

RECREATION AND AESTHETICS

VISUAL MANAGEMENT SYSTEMS

The Forest Service and BLM treat scenic values as one of several land resources managed on an equal basis with other resources.

Technical Appendix 9 describes the objectives of federal land managers in maintaining visual quality. These management objectives provide the standards for measuring changes expected to result from proposed development. They will guide the selection of measures to mitigate visual impacts.

VISUAL CONCERNS FOR PRIVATELY OWNED LAND

Non-federal land is not under any visual management system, although there often is concern for scenic values. These concerns may surface when proposed developments are perceived as likely to disrupt or change the visual character of an area. Where concerns are strong, local groups may organize to voice their concerns and influence the decision on whether to approve the project, and if so, under what conditions.

Areas that could be sensitive include residential areas, recreation sites, or any setting where the existing character or visual quality is valued. Such areas are found throughout the state, typically in private ownership. Individual residences, residential clusters, small unincorporated communities, and semi-developed areas adjoining large cities are among these potentially sensitive areas. Privately owned campgrounds and recreation sites, undeveloped rivers and streams, dude ranches, and resorts also are potentially sensitive. The sensitivity of any area is determined by the perceptions and values of residents and visitors in regard to the visual intrusion from any proposed development.

RECREATION ON PUBLIC LANDS IN MONTANA

Recreation in Montana covers a wide spectrum of activities. Developed recreation sites for camping, picnicking, relaxation, and water-based activities are located on national forests, BLM land, and state-owned land. State parks, monuments, recreation areas, and fishing access sites are all part of the state park system managed by the Department of Fish, Wildlife and Parks. Numerous county and city parks and recreation sites provide opportunities for both outdoor and indoor recreation. A significant portion of recreation in Montana is dispersed use of state and federal lands. Popular activities include hunting, fishing, back-packing, camping, cross-country skiing, and snowmobiling. Technical Appendix 9 summarizes the existing recreational activities and use levels in Montana.

RECREATION ON PRIVATELY OWNED LANDS IN MONTANA

Recreation settings and opportunities on privately owned lands in Montana also are diverse. They range from developed sites such as private campgrounds, recreational vehicle parks, or KOAs, to large dude ranches and resorts that offer trail rides, fishing, hiking, and many other activities on both privately owned land and adjacent public land. Outfitters also may use both private and public land for dispersed activities such as hunting and back-country pack trips. Whatever the activity or location, recreation on privately owned land requires the landowner's consent.

IMPACTS TO RECREATION

Potential impacts to recreation from oil and gas exploration and production activities can be grouped into four categories: (1) changes in recreational opportunities; (2) changes in recreational access; (3) changes in the quality of recreational experiences; and (4) changes in the number of users (Dames and Moore 1986). The type, magnitude, and significance of these impacts will differ with the project and the location.

Some effects of development may be perceived as beneficial by some types of recreationists and detrimental by others who desire different types of recreational experiences. For example, improved access to remote areas could be perceived as a benefit by recreationists desiring additional motorized opportunities. Other recreationists desiring more primitive experiences could perceive improved access as an adverse impact.

Some impacts will be short term, lasting only for the duration of exploratory activities, while others may extend beyond this stage, with indirect effects lasting for several years or decades. Impacts associated with development and production activities will be more long term. The following sections discuss these potential impacts by category.

CHANGES IN RECREATIONAL OPPORTUNITIES

Recreation settings may vary from semi-primitive roadless areas managed for their natural quality and roadless character, to more developed areas having extensive access road networks. This range of possible recreation settings creates a wide spectrum of possible impacts. Recreation opportunities may change when oil and gas exploration and development affect developed recreation sites or where there is a change in the mix of dispersed uses in an area.

Developed recreation sites could be directly affected by location of drilling facilities on or near the sites, changing the activities and opportunities at those locations.

Areas with dispersed recreation use may contain scattered locations of concentrated use that could be affected by oil and gas drilling. Examples of these areas are undeveloped campsites, outfitter base camps, trail head facilities, or special attraction features such as waterfalls, unique rock formations, or scenic overlooks.

Recreation at these sites and areas would be temporarily disrupted by exploratory drilling or permanently displaced if development and production is undertaken. The magnitude of impact will depend on the nature of the existing site, its current use, the degree of intrusion from oil and gas activity, and the availability of substitute sites or areas for displaced activities. Where existing uses depend on a primitive setting and solitude, potential impacts may be more severe than in more developed settings.

Where conflicts occur between recreational uses and oil and gas development, recreation may shift to other areas when nearby areas have similar attributes and qualities (U.S. Forest Service 1981b). Shifting use patterns can overload nearby areas, creating management problems from overuse or potential conflicts among user groups.

Short-term changes in recreational opportunities could occur during exploratory drilling, lasting anywhere from a few days in some areas of the state to several months in western Montana. When an exploratory well is a dry hole,

pre-drilling levels of recreation may resume after the termination of drilling. Successful reclamation and revegetation of the drill pad and access road would return the project area to its approximate pre-drilling condition. Long-term changes in recreational opportunities could result primarily from changes in recreational access (see next section).

CHANGES IN RECREATIONAL ACCESS

Changes in recreational access may vary from temporary disruption of access due to drilling activities to broader changes in recreational use patterns due to new or upgraded access roads (U.S. Forest Service 1981b). While the first category may result in short-term disruption of recreation activities or the relocation of an existing road into a site or area, more long-term and potentially severe impacts are possible from the second category. This section focuses primarily on the second category of impact.

Developing new access to currently unroaded sections of public lands probably would change the present character and use of that land. New or upgraded roads can allow increased access and recreational use by hunters, campers, and other dispersed recreationists. Motorized recreationists may value the increased access that oil and gas development can provide, opening up previously remote areas for use, while recreationists valuing the more remote and unroaded areas will perceive access road construction as a detrimental effect (U.S. Bureau of Land Management 1981b). New access in areas of intermingled public and private ownership also can change use of these lands.

If road access is not controlled and recreation use becomes established, later efforts to close roads, restrict travel, or reclaim an area become more difficult (U.S. Bureau of Land Management 1981b). Even when roads are closed after completion of drilling, they can sometimes still be used by horseback riders, hikers, bikers, snowmobilers, and all-terrain vehicles. Increased vehicle use can lead to several indirect impacts. These include increased erosion, hunting pressure and game harvest, game harassment, and landscape scarring. (Refer to other sections for discussion of these impacts.)

CHANGES IN THE QUALITY OF RECREATIONAL EXPERIENCES

During exploratory drilling, the presence of the drilling rig and other equipment, drilling personnel, and increased traffic can contribute to both direct and indirect impacts, changing undeveloped areas to industrial sites (Dames and Moore 1986). Additional background noise, dust, and human activity can contribute to a change in recreational setting and experience. These impacts are likely to be short term and indirect, lasting from set-up to take-down for the exploratory drilling phase, then decreasing to lower levels during production. The magnitude of impacts will vary with the type of setting present before drilling, the scale and visibility of drilling operations in any given setting, and the perceptions of recreation visitors to the area.

Aesthetic impacts can contribute to changes in the quality of recreational experiences, depending on the degree of intrusion and visibility of oil and gas activities. These effects are the same as those discussed above in the section on changes in recreational opportunities, and contribute to changes in recreational experience.

Aesthetic impacts will be severe in areas of high scenic quality, high viewer sensitivity to intrusions, and high potential for landscape alteration. The severity of impacts will vary with the degree of naturalness or scenic quality of an area, its designated visual management objectives (if in a managed area), the sensitivity of viewers to change, and how well the landscape can absorb visual change (U.S. Bureau of Land Management and U.S. Forest Service 1983).

The scale of potential impacts associated with field development typically will be greater for oil production than for gas production. Oil production will have more surface facilities with wells closer together than gas wells. Surface facilities for oil production can include pumping units, a tank battery, heater treater, and dirt dike for containing spills. In contrast, surface facilities for gas production usually are limited to the wellhead and meter house, with subsurface pipelines used for transport. Spacing for oil wells varies, with the densities higher in shallow fields. Spacing for gas wells is typically greater than for oil wells. Impacts associated with field development are long term, lasting for the life of the field, which can range from a few years to several decades.

CHANGES IN USER NUMBERS

Any of the impact categories discussed above can contribute to an increase or decrease in the number of users at a given recreation site or area. Where activity displacement occurs only during exploratory drilling, impacts will be short term. Field development could result in more significant long-term impacts if existing uses were disrupted or displaced for the life of the field. The magnitude of these impacts will vary with their length, the number and type of activities affected, and the availability of nearby substitute areas for use. Indirect impacts also could occur where shifting uses affect adjacent areas, overloading the capacity of those areas to absorb additional users or creating conflicts among user groups.

AESTHETIC IMPACTS FOR PRIVATELY OWNED LANDS

Private landowners owning both surface and mineral rights implicitly choose to incur some visual impacts on their property when they lease oil and gas resources. In some

cases, these visual impacts will not be limited to the immediate area of the drill pad but will extend off-site, potentially affecting views from other, possibly more sensitive areas. Only a case-by-case analysis can determine the severity of such impacts.

The magnitude of visual impact will be influenced by landscape, the nature of viewers, and project-related variables. Visual impacts typically will be greatest in areas with high scenic quality and few man-made developments. Potential visual impacts also will be high in areas with steep terrain, uniform vegetation, high contrast between the appearance of disturbed soil and surface features, or poor potential for reclamation. Impacts in previously unroaded areas may be more noticeable during exploratory drilling when access roads are constructed to drill sites.

The scale of project facilities also will influence visual impact, with less impact for development limited to a few acres and requiring no access roads and greater impact for larger scale drilling activity requiring several miles of access roads.

Impacts could range from short term for exploratory activities that last only a few weeks or months, to long term for field development and production activities that extend over several decades. Impacts increase with the presence of more drill rigs and support facilities. Where production facilities remain following exploration, visual impacts will continue over the life of the well or field, though at a level somewhat below that of the exploratory drilling stage, due to the smaller scale of production facilities. Landscape alteration may remain evident for years in areas where reclamation and revegetation are difficult.

FACTORS INFLUENCING POTENTIAL FOR IMPACTS

Developed recreation sites are most common in the western third of the state, with decreasing numbers across central and eastern Montana (see Technical Appendix 9). A higher number of recreation sites increases the potential for impacts from oil and gas activities. When drilling activities occur within 1 mile of a developed site, the potential for impact may exist. Factors influencing impact potential include the distance between the activity and the recreation site, and the degree of visibility between.

The presence of existing oil and gas development facilities in an area reduces the chance that additional developments would cause serious impacts. In contrast, areas with little or no oil- and gas-related activity are more likely to be affected. Generally, development in the western part of the state would have the highest potential to cause impacts.

The types of dispersed recreation occurring in any given area influences the potential for impact. Potential for impact will be greater where dispersed uses depend more on retention of the natural, undeveloped quality of an area. Total dispersed recreation use on national forests and BLM lands is seven to eight times higher in western Montana than in the eastern part of the state (see Technical Appendix 9). Specially managed areas are more common in western Montana.

SELECTING MITIGATION MEASURES

In most cases, the types of recreation sites and uses in a given area and the visibility of project facilities from sensitive viewing areas will guide the selection of appropriate mitigating measures. Examples of potentially sensitive recreation areas and sites include national, state and local parks and recreation areas; wild, scenic, and recreational rivers; established trail systems; private campgrounds, resorts and dude ranches; fishing access sites; rivers and streams with high quality fishing; natural areas; and areas with unique habitats.

Other sensitive viewing areas are residential areas—towns, communities, outlying residential clusters, individual residences—and highways and roads. In general, close proximity of any of these sensitive viewing areas may signal the need for more evaluation and visual mitigation. Typically, foreground viewing (0-1/2 mile) in natural, undisturbed settings will indicate the need for a detailed evaluation of potential visual impacts. In most situations, a combination of setting, viewer location, and project location will determine visibility and degree of impact. Other factors that may influence impact levels include number of viewers and viewer sensitivity to intrusions. Landform and vegetation patterns and the existing visual character also will affect the magnitude of visual impact. Measures for reducing or avoiding impacts to recreation and aesthetics should be selected and implemented following consultation among oil and gas operators, recreation managers, surface owners, and other affected parties.

The following measures could be effective in avoiding or reducing impacts. While most drilling phase mitigation measures will be more appropriate for wildcat wells, new wells in existing fields may be near designated recreation sites, special management areas, or sensitive viewing areas, which may require some measures. Most measures are suitable for both public and private lands.

MEASURES FOR DEVELOPED RECREATION SITES

1) To reduce impacts associated with the close proximity of developed recreation sites and oil and gas activities:

(drilling phase)- to the extent possible, avoid location of oil and gas facilities on recreation sites or areas, leased sites, or undeveloped sites

having concentrated use;- as appropriate, establish a buffer zone considering recreation uses, projec visibility, and use levels between sensitive recreational sites and drilling activities.
2)To reduce use conflicts between recreation activities and oil and gas activities:(drilling phase)
- coordinate timing of exploration activities to minimize conflicts during periods of peak recreation use; for example, no set-up or breakdown of equipment during peak use periods;
- to the extent possible, avoid heavily usedrecreational roads and trails;
- provide substitute access of equal quality where oil and gas activity creates conflicts or results in closure of recreational roads or trails.

(full field development)
- in cases where oil and gas employees overload existing recreation facilities such as parks, pools, playing fields, and other developed sites, oil and gas companies could provide funds to park and recreation departments or districts for additional programs or site development.

MEASURES FOR DISPERSED RECREATION

- coordinate timing of activities to avoid periods of peak recreation use (see example for developed recreation sites).

MITIGATION - AESTHETICS

1)To reduce potential impacts resulting from landscape alteration and vegetation removal:

(drilling)
- use flat slopes rather than steep slopes;
- avoid clearing vegetation in uniform, dense stands.

(production)
- use natural topographic, landform, or vegetation breaks for siting pipelines and electric utilities out of sight as much as possible;
- avoid rocky areas where excavation would cause irreversible landscape alteration;
- use minimum road widths and minimum vegetation clearing adjacent to roads.

2) To reduce the visibility of exploration facilities from sensitive viewing areas such as residential areas, recreation sites and travel routes:

- locate pads, structures, and roads away from open areas to the extent possible when facilities are visible within 1/2 mile of potential observers;
- retain existing vegetation around the perimeter of drill pads and along access roads for screening;
- use existing topography for screening of oi and gas facilities where possible;- orient drilling rig and/or lights so lights are not directly visible from nearby residential areas during night drilling;
- avoid locating drill rigs on ridges where they would be skylined;
- use native rather than exotic species in revegetation efforts.

3)To reduce the visibility of production activities and facilities from sensitive viewing areas such as residential areas, recreation sites, and travel routes:

(production)
- reclaim and revegetate portions of the drill pad not needed for production;
- reclaim and revegetate cut-and-fill slopes of access roads;
- paint or camouflage permanent production facilities;
- plant screening vegetation near sensitive viewing areas;
- avoid locating permanent facilities on the skyline;
- bury transmission lines to reduce cumulative effects of overhead lines;
- where transmission lines will be overhead rather than underground, use darkened wood poles and dull-surface conductors;
- where clearing of dense, uniform vegetation for pipelines, utilities, and roads is required, right-of-way edge should be feathered rather than a straight line.

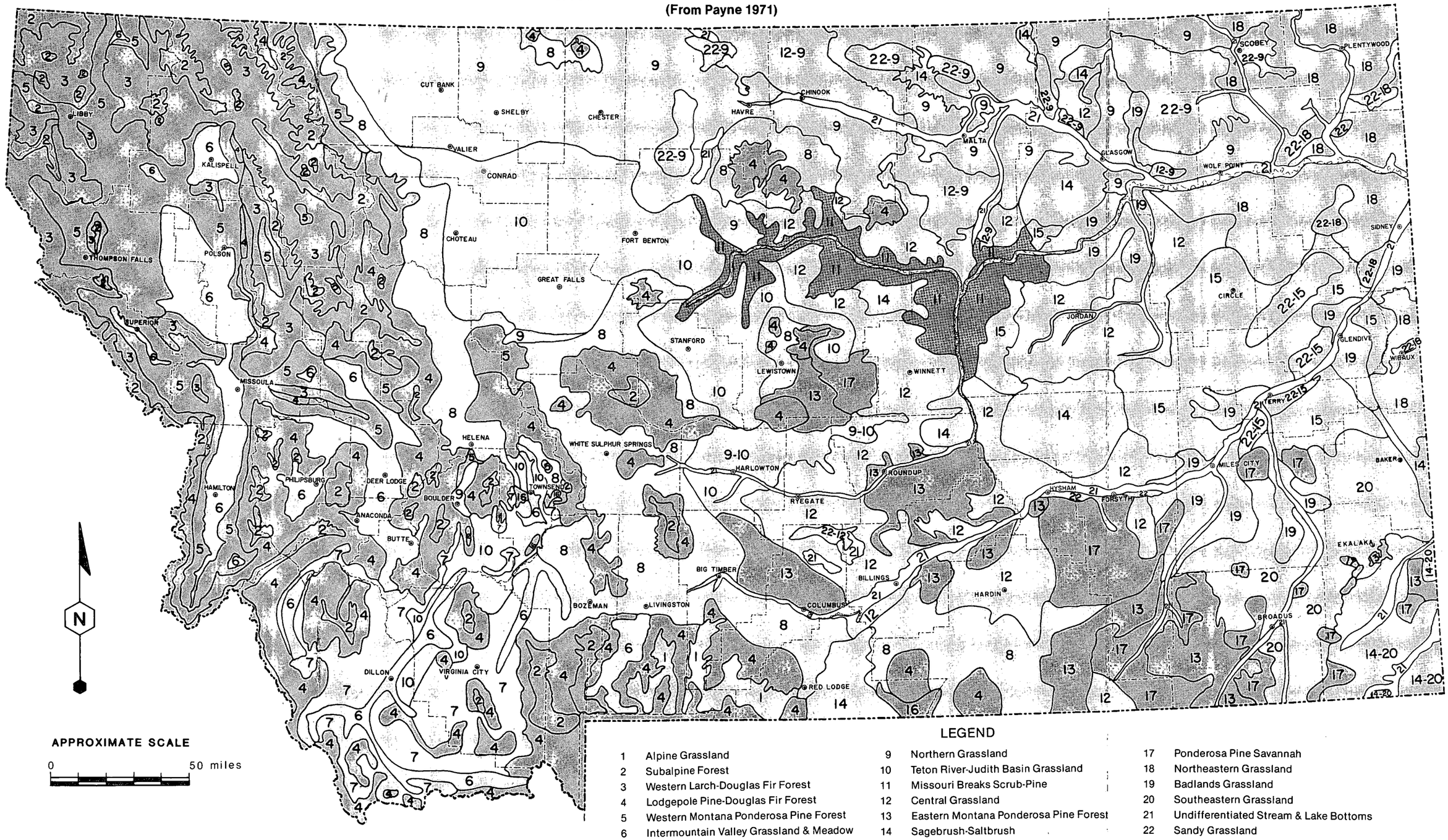
VEGETATION

The 22 vegetation types found in Montana are characterized in Appendix 10 and shown on Figure 37. This information is from Paine (1973).

NOXIOUS WEEDS AND THEIR CONTROL

Weeds are generally thought of as: (1) plants growing where they are not wanted, or (2) plants that are more harmful than beneficial. Most weeds are able to spread rapidly and out-compete other plants (Montana Department of Agriculture 1981). Thus, weeds limit the growth of desirable vegetation such as cultivated crops and range plants used by livestock and wildlife. Most weed species have at least some of the following characteristics:

FIGURE 37
MONTANA VEGETATION TYPES
INTER-AGENCY RANGE COMMITTEE
(From Payne 1971)



APPROXIMATE SCALE

0 — 50 miles

LEGEND

1	Alpine Grassland	9	Northern Grassland	17	Ponderosa Pine Savannah
2	Subalpine Forest	10	Teton River-Judith Basin Grassland	18	Northeastern Grassland
3	Western Larch-Douglas Fir Forest	11	Missouri Breaks Scrub-Pine	19	Badlands Grassland
4	Lodgepole Pine-Douglas Fir Forest	12	Central Grassland	20	Southeastern Grassland
5	Western Montana Ponderosa Pine Forest	13	Eastern Montana Ponderosa Pine Forest	21	Undifferentiated Stream & Lake Bottoms
6	Intermountain Valley Grassland & Meadow	14	Sagebrush-Saltbrush	22	Sandy Grassland
7	Foothill Sagebrush	15	Prairie County Grassland		
8	Foothill Grassland	16	Beartooth Juniper-Limber Pine		

1. continuous seed production during the growing season;
2. highly efficient seed dispersal;
3. persistent banks of seeds or seedlings;
4. capability for growth in adverse climates and soils; and
5. capability to reproduce through seeds, sprouts, and rhizomes (Montana Department of Agriculture 1981; McDonald and Tappeiner 1986).

Several agents are responsible for disseminating weeds and accelerating their spread. Wind may spread weeds over great distances. Seeds or entire plants (such as Russian thistle or "tumbleweed") may be specially adapted to wind dispersal. Water running in streams or irrigation canals also transports weeds. Weed seeds can be dispersed by livestock and wildlife. These seeds usually attach to animal hair or pass through digestive tracts (Montana Department of Agriculture 1981).

Humans are the most active agent in the spread of weeds (Montana Department of Agriculture 1981). Weed seeds or parts attach directly to people or machinery. People also spread weeds by planting crop seeds that are contaminated with weed seeds. Developments that leave disturbed, barren soils encourage weed growth. The human role in the spread of weeds is evidenced by infestations around roads, railroads, powerlines, irrigation canals, and construction sites.

Concern over growing weed infestations in Montana led to the enactment of the County Noxious Weed Control Act of 1985 (MCA, 7-22-2201 through 7-22-2153). This act defines a weed (also called a noxious weed) as any exotic plant species established or that may be introduced in the state which may render land unfit for agriculture, forestry, livestock, or other beneficial uses. Table 27 lists the species that have been classified as weeds throughout Montana. Each weed control district (usually a county) may add other species to these lists.

Table 27. Weed Species Classified in Montana.

Category 1 (currently established in Montana)

Canada thistle	(Cirsium arvense)
Field bindweed	(Convolvulus arvensis)
Whitetop	(Cardaria draba)
Leafy spurge	(Euphorbia esula)
Russian knapweed	(Centaurea repens)
Spotted knapweed	(Centaurea maculosa)
Diffuse knapweed	(Centaurea diffusa)
Dalmatian toadflax	(Limaria dalmatica)
St. Johnswort	(Hypericum peforatum)

Category 2 (recently introduced or not yet detected in Montana)

Dyers woad	(Isatis tinetoria)
Yellow starthistle	(Centaurea solstitialis)
Common crupina	(Crupina vulgaris)
Tansy ragwort	(Senecio jacobaea)
Rush skeletonweed	(Chondrilla juncea)

Source: Administrative Rules of Montana 4.5.201-203 et. seq.

Acreages infested with listed weeds are shown in Table 28. Table 29 gives average rates of spread and reductions in livestock carrying capacity across five northwestern states.

As of 1987, spotted knapweed was the most extensive weed problem in Montana covering 4,718,180 acres (Table 28). Spotted knapweed was first reported in Ravalli County in 1920 and has since spread to every county (Lacey et al. 1986). However, the most extensive infestations are still in western Montana (Figure 38). Chicoine (1984) identified areas of the state where there is a high probability that spotted knapweed will grow (Figure 39). His research was based on the climatic and soil characteristics in areas of present infestations. Disturbed soil and seed transport on vehicles and machinery do much to encourage knapweed infestations.

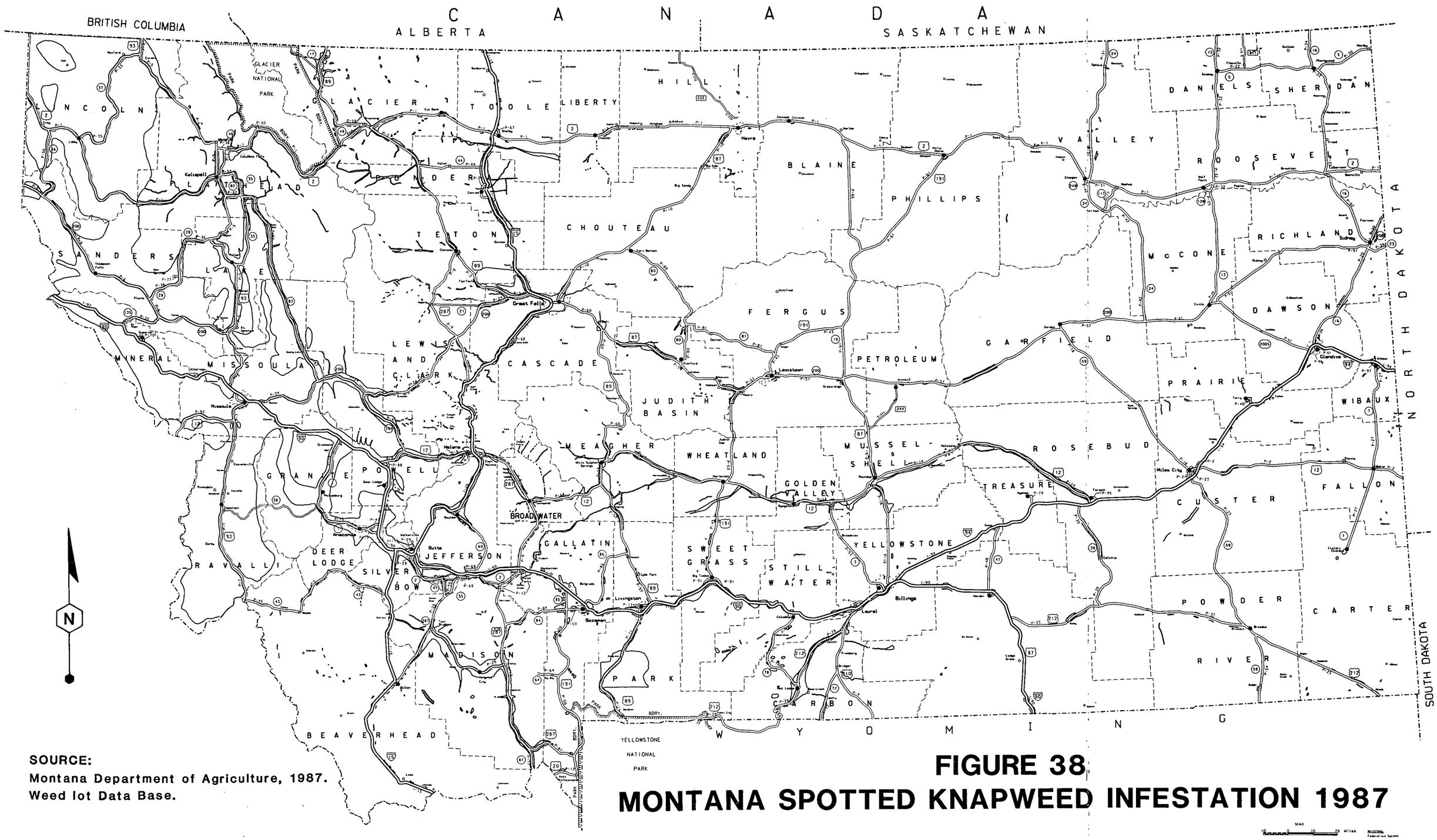
Knapweed reduces forage for livestock and wildlife in Montana. In 1983, an estimated $4.5 million of range forage for livestock was lost to spotted knapweed. At the present rate of spread, annual forage loss to spotted knapweed will reach $155 million by 2008 (Lacey et al. 1986). Lolo National

Table 28. Acres of Land in Montana Infested with Listed Weed Species.

Region	Weed Species										Total
	Spotted Knapweed	Leafy Spurge	Canada Thistle	Dalmatian Toadflax	Diffuse Knapweed	Russian Knapweed	Field Bindweed	Whitetop	St. Johnswort	Dyers Woad	
1	4,412,986	248,739	704,454	50,445	5,786	4,696	7,568	17,490	514,029	43	5,966,236
2	213,440	63,576	211,900	3,339	263	34,022	20,664	22,237	11	1	569,453
3	113	46,992	28,894	503	12	2,781	197,400	89	1	0	276,785
4	71,741	149,535	306,360	7,351	50	2,351	168,610	11,233	52	0	717,283
5	19,600	101,100	455,016	35,150	4,583	3,330	263,030	7,120	5	1	888,935
6	300	12,000	6,500	0	0	200	7,000	32	0	0	26,032
Total	4,718,180	621,942	1,713,124	96,788	10,694	47,380	664,27	58,201	514,098	45	8,444,724

NOTE: Rush skeletonweed, common cripina, and tansy ragwort are listed weeds (Category 2) that have not been found in Montana. Yellow starthistle is occasionally found in Gallatin, Liberty, Carbon and Ravalli counties (B. Mullin, MDOA, pers. com. April 1, 1988).

Source: Montana Department of Agriculture 1987 and Mullin 1988.

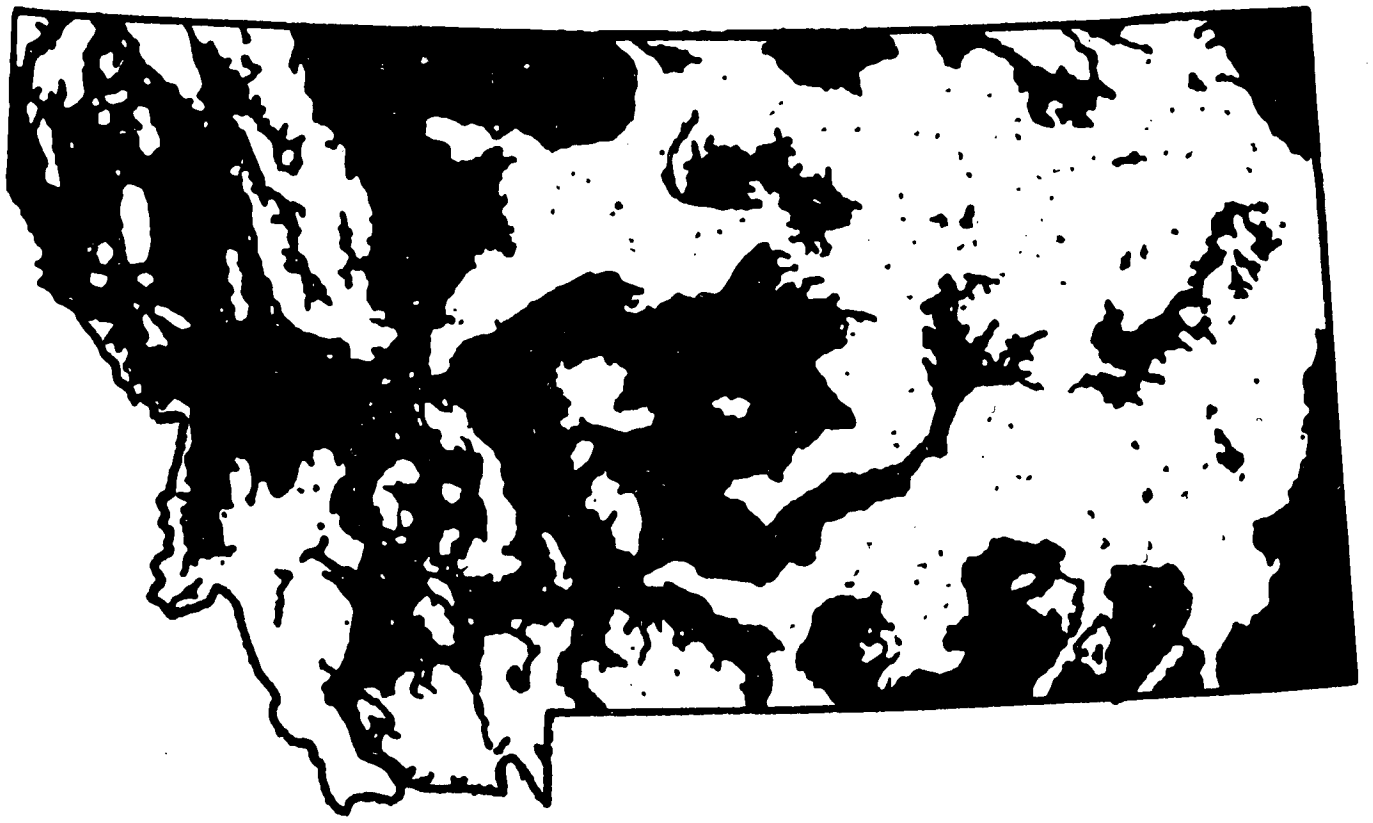


SOURCE:
Montana Department of Agriculture, 1987.
Weed lot Data Base.

FIGURE 38
MONTANA SPOTTED KNAPWEED INFESTATION 1987

FIGURE 39

AREAS WITH HIGH VULNERABILITY TO KNAPWEED INFESTATION



High probability areas based upon the conditions found in 116 knapweed infestations.

Source: Chicoine, 1984

Table 29. Rates of Spread and Reductions in Livestock Carrying Capacity of Selected Weed Species.

Weed Name	Average Annual % of Spread	Average Annual % Reduction of Carrying Capacity of Infested Areas*
Spotted knapweed	24	80
Leafy spurge	12	59**
Canada thistle	10	42
Whitetop	9	55
Russian knapweed	8	55
Diffuse knapweed	18	59
Dalmatian toadflax	8	46
Tansy ragwort	16	45
Dyers wood	14	38
Yellow starthistle	17	65***

* Based on use by sheep, cattle, or horses.
** Use by cattle and horses is zero.
*** Use after bud formation is zero.
NOTE: Average estimated over a 5-state region (Wyoming, Montana, Idaho, Oregon, and Washington).

Source: Appendix C-1, page 152 in BLM 1985.

Forest's capacity to support elk is expected to decline by 200 animals annually by 1998 (Spoon et al. 1983 in Lacey et al. 1986).

Although leafy spurge affects fewer acres than some other weed species (Table 28, Figure 40), it is extremely difficult to eradicate (Lacey et al. 1985). Like spotted knapweed, spurge is found in every county in Montana. In 1979, annual loss of livestock forage due to leafy spurge infestation was estimated at $1.4 million (Reilly and Kaufman 1979; in Lacey et al. 1985).

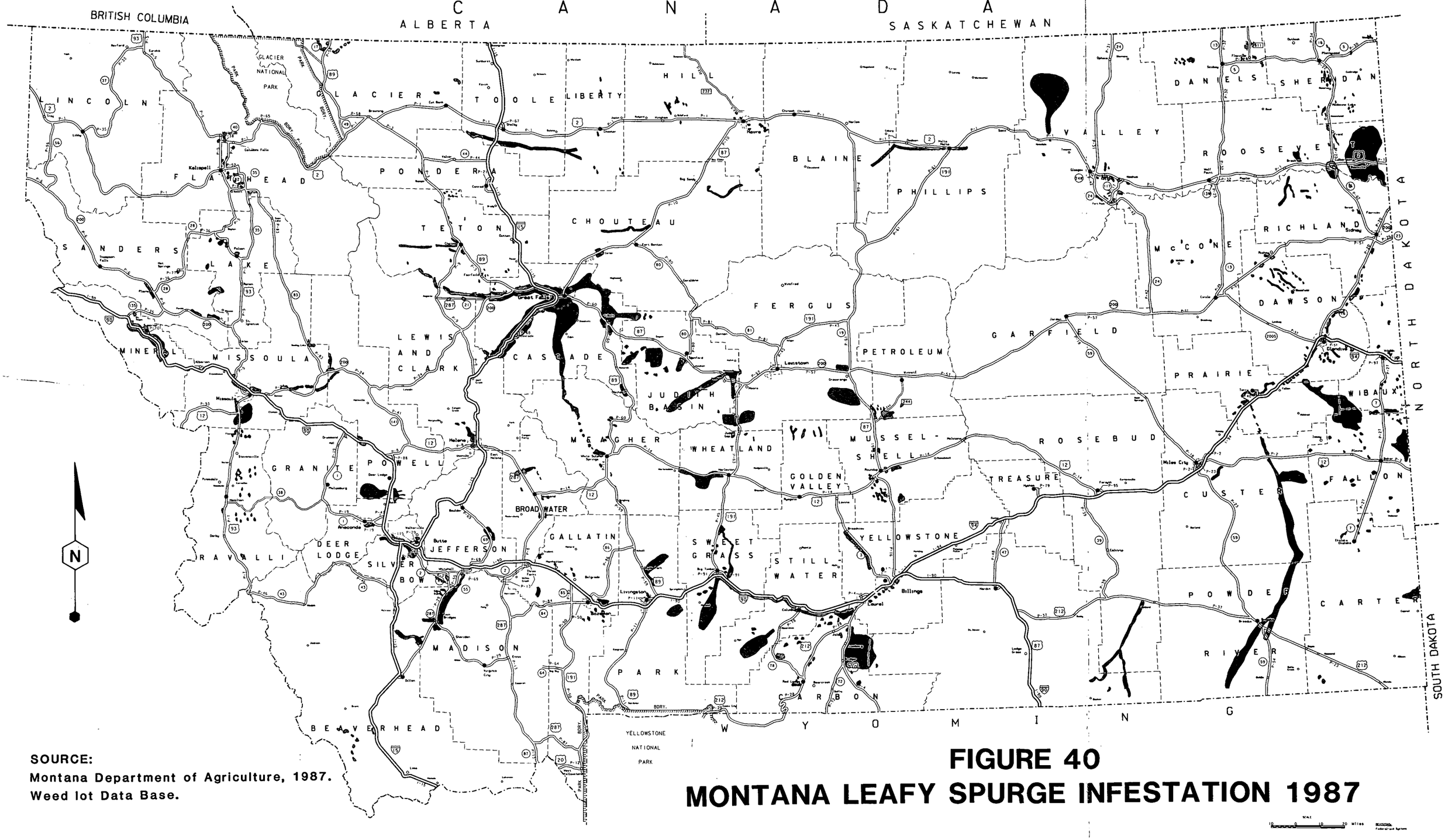
The weed law centers on Section 7-22-2116: "It is unlawful for any person to permit any noxious weed to propagate or go to seed on his land, except that any person who adheres to the noxious weed management program of his district or who has entered into and is in compliance with a noxious weed management agreement is considered to be in compliance with this section." As used in this section, "person" also refers to partnerships, corporations, associations, and state and local governments.

Landowners therefore may choose from three courses of action with respect to weed control, including: (1) eradicate all weeds on their property. If the property is being leased, the landowner could use the lease to hold the lessee responsible for weed control; (2) agree to comply with the district weed control plan; and (3) develop and comply with their own weed control plan, subject to the district's approval.

Weed control plans should describe the most effective methods of controlling weeds given the species, soil type, environmental conditions, and infestation size. The goal of these plans is to keep weeds from spreading and to eventually reduce infestations. Examples of methods often found in plans include spraying herbicides and cleaning weed parts from vehicles. Specific contents of plans are the responsibility of district weed boards (Mullin 1988).

The weed control act also addresses the revegetation of right-of-way and disturbed areas (Section 7-22-2152). Persons disturbing vegetation within a right-of-way or easement (roads and pipelines are specifically noted) must reestablish a cover of beneficial plants. This revegetation plan must be approved by the district and must include weed management procedures. Section 7-22-2153 provides for the development of cooperative agreements between landowners and districts for roadside weed control.

All weed control techniques may be grouped into five basic categories: (1) preventive, (2) cultural, (3) mechanical or physical, (4) biological, and (5) chemical. Preventive control includes the use of weed-free crop seed, and cleaning weeds from machines and clothing before entering weed-free areas. Cultural control is based on good land management practices (such as proper grazing, rotating crops, and maintaining vigorous, competitive crops). Mechanical control includes hoeing, pulling, mowing, tilling, and burning



SOURCE:
Montana Department of Agriculture, 1987.
Weed lot Data Base.

FIGURE 40
MONTANA LEAFY SPURGE INFESTATION 1987

(Montana Department of Agriculture 1981 and Weed Management Standards).

Biological control uses a weed's natural enemies to control infestations. Biological control shows promise but is still in developmental stages (Montana Department of Agriculture 1981 and Weed Management Standards). Due to the extent of weed infestations, chemical control (use of herbicides) is currently the most important control method.

SPECIAL STATUS PLANTS

Plant species found in Montana are "threatened or endangered" as classified by the U.S. Fish and Wildlife Service (USFWS). However, some plants are on the USFWS list of candidate species (Table 30). Candidate plants are species for which "current information indicates that proposing to list as endangered or threatened is possibly appropriate, but substantial biological information is not on file to support an immediate ruling." The USFWS can neither protect candidate plants nor estimate when such plants might receive protection under the Endangered Species Act. However, federal land management agencies have adopted policies that help to preserve candidate species.

BLM policy is to "carry out management consistent with multiple use for the conservation of candidate species and their habitats" and "ensure that actions authorized, funded, or carried out do not contribute to the need to list any species as threatened or endangered." The U.S. Forest Service classifies 51 Montana plants, including seven candidate plants, as sensitive species. Policy directs the Forest Service to determine the effects of their programs and actions on sensitive species. Impacts to sensitive species are to be avoided or minimized.

Montana organizations also have developed lists of special status plants. Lesica et al. (1984) assessed species of limited distribution in Montana. Although commonly called rare plants, listed species are more correctly categorized as rare, threatened, endangered, extinct, or undetermined. More recently, the Montana Natural Heritage Program (MNHP) has published an updated list of "Plant Species of Special Concern." Plants on this list are ranked according to their state or global population status, ranging from critically imperiled to demonstrably secure. For example, some species may be imperiled in Montana but secure globally. Species listed by Lesica and MNHP are not protected by law. It is possible that certain statutes may, in the future, be interpreted as providing protection to such species.

Region 1 contains the most special status plant species (Table 31). This large number is due to the size of the region and the diversity of habitats. Conversely, the more homogenous landscape of Region 3 contains the fewest of these species.

VEGETATION IMPACTS

Construction of facilities and roads would cause the primary effects on vegetation. Vegetation would be removed for the life of the operation. For a successful well, a site about 40 percent of the original drill site would remain disturbed for the life of the well. However, unsuccessful drill sites can be reclaimed. Reclamation generally includes spreading topsoil and reseeding per the landowner's request (see Chapter 2). Access roads cause a significant part of the disturbance resulting from drilling and production. Roads to unsuccessful drill sites can be reclaimed. Roads to productive wells might be upgraded for oil transport. Oil from large fields would be transported by pipeline. Pipelines would require varying amounts of disturbance based on the size of line. Reclamation of disturbed areas would minimize impacts from pipeline construction.

DRILLING IMPACTS

Small amounts of vegetation would be lost to roads and drill sites. Dust and vehicle emissions could reduce growth of minor amounts of adjacent vegetation. If disturbed areas are prepared and seeded properly, reclamation will further reduce impacts. The effects of drilling on vegetation would be a concern (1) when drill sites or roads are in riparian areas, wooded drainages, or wetlands; (2) where drill sites or roads would cause sedimentation or channel downcutting in riparian areas; (3) when drill sites or roads would be in areas that contain populations of special status plants; (4) where operations could spread or encourage the growth of weeds; (5) in case of reserve pit leakage; and (6) in the event of blowouts or wildfire.

Drilling sometimes may occur in areas that support riparian vegetation or special status plants. If located in or at the head of drainages, drill sites and access roads can add sediment to streams and wetlands. Channel degradation also can occur. Heavy sediment loads or severe degradation would affect riparian vegetation. If relocation of the drill site is possible, these impacts can be reduced. Access routes can be located to avoid sensitive areas.

Soil disturbance associated with drilling can cause weeds to spread. Of even greater concern is the long-distance transport of certain weed species by drilling equipment and vehicles. For example, spotted knapweed seeds clinging to vehicles used in western Montana could be carried to previously uninfested areas in the east (Figure 38).

Weed spread is reduced if disturbed areas are revegetated during the season of disturbance or the next growing season. All well drilling operations are covered by the County Noxious Weed Control Act which holds landowners responsible for weed control. Adherence to the act and strict enforcement by weed districts could nearly

Table 30. Plant Species in Montana Proposed for Protection under the Endangered Species Act.

Scientific Name	Common Name	U.S. Forest Service Sensitive Species	Expected or Known Occurrence
1. Antennaria aromatica[1]	Aromatic pussy-toes	yes	High mountain ranges in western Montana, such as Absaroka, Madison, Pioneer, and Rocky Mountain Front.
2. Arabis fecunda	Sapphire rockcress	No	Steep slopes of sagebrush/grassland communities in Sapphire Mountains, Ravalli County.
3. Aster mollis[2]	None	No	No specific information.
4. Astragalus barrii	Barr's milkvetch	Yes	Known to occur in Rosebud, Big Horn, and Powder River Counties. Histori- cally known in Carter County.
5. A. scaphoides	Bitterroot milkvetch	No	Occurs in sagebrush/bunchgrass communities in southwest Montana.
6. Botrychium crenulatum	Wavy moonwort	No	Moist habitats in the Swan Valley, Montana.
7. B. paradoxum	Peculiar moonwort	Yes	Deerlodge, Glacier, Pondera, and Flathead Counties.
8. Calamagrostis tweedyl	Cascade reedgrass	Yes	Forested and clearcut areas in Mineral County.
9. Carex lenticularis var. dolia	Goose-grass sedge	No	High elevation, wet meadows, and lake shores in Glacier National Park in northwest Montana.
10. Claytonia lanceolata var. flava	Yellow springbeauty	Yes	Moist Montana meadows in Deerlodge, Gallatin, Silver Bow, Powell, and Beaverhead Counties.
11. Erigonum lagopus	Rabbit wildbuckwheat	No	Barren hills in the Pryor Mounains of Carbon County and possibly Big Horn County.
12. Grinella howellii	Howell's gumweed	Yes	Coniferous forest openings in western Montana.
13. Howellia aquatilis	Howellia	Yes	Shallow glacial potholes and river oxbow pools in the Swan Valley.
14. Penstemon lemhiensis	Lemhi beardtongue	Yes	Sagebrush grassland and forest edges in southwest Montana.
15. Rorippa calycina	Persistent sepal yellowcress	No	Alluvial areas - sandy river - banks and shores. Known or suspected to occur in southeast Montana and McCone and Cascade Counties.
16. Shoshonea pulvinata	None	Yes	Limestone substrates and gravelly soils along ridge tops and barren areas in the Beartooth and Pryor Mountains.
17. Silene spaldingii	Spalding's silene	No	Grasslands of the Flathead Valley and Lincoln County.
18. Trisetum orthochaetum	Bitterroot trisetum	No	Boggy meadows in Bitterroot Mountains of Missoula County.

[1] Antennaria aromatica was recommended for removal from the list (October 1987). The Montana Natural Heritage Program believes the species is more abundant than was previously thought.

[2] Aster mollis was recommended for removal from the Montana list (1987). The Montana Natural Heritage Program has no records for this species in Montana.

Source: Compiled by Scott McCollough, DNRC, after Lesica et al. 1984.

Table 31. Number of species and occurances of special status plants in Oil and Gas Regions.

	USFWS Candidate Plants[1]		USFS Sensitive Plants[1]		MNHP Plants[3]	
	Species Count	Occurrences[2]	Species Count	Occurrences	Species Count	Occurrences
Region 1	12	169	39	239	121	320
Region 2	3	5	7	14	27	50
Region 3	1	1	0	0	7	8
Region 4	1	3	1	3	12	24
Region 5	4	10	4	10	52	105
Region 6	2	7	2	7	11	14

[1] Some species fall in both categories.
[2] An occurrence is a site at which a species is found. Each occurrence may contain one or more plants.
[3] Does not include candidate or sensitive plants.
NOTE: Statewide species counts differ from the state lists due to the presence of some species in more than one region.

Source: Montana National Heritage Program 1988.

eliminate weed spread by well drilling activities. The contribution of oil and gas drilling to weed spread is comparable to other types of construction.

If improperly constructed, reserve pits can leak mineralized water or oily residue. If this leakage enters a streambed or drainageway, it can damage nearby vegetation or off-site vegetation.

Soil contamination from oil and gas development in Montana results mainly from leaking and improperly reclaimed reserve/brine pits. Regions 2 and 4 with brackish water and Region 3 with very briney water are the regions of most concern. Region 1 should be viewed with caution because of a lack of down-hole data, thin, coarse-grained soils, steep slopes, and proximity of drill sites to high quality headwater streams. Produced hydrocarbons and fuel spills occasionally cause impacts. Spills generally are not large and the materials are relatively immobile.

Blowouts are rare accidents (see Health and Safety) that can have substantial effects on vegetation. They expose vegetation to harmful gases, oil, and drilling fluids. Nearby vegetation is most severely affected, although some harmful gases travel significant distances. A 1982 blowout in Alberta provides an example of the effects of a large blowout (Energy Resources Canada Board 1984). Oil condensate killed many trees near the drill site. Farther from the site, oil deposits reduced tree growth for two or three years. After the blowout, many trees were cut or burned to reduce wildfire hazard. Sulfur was deposited over a wider area and interrupted normal growth rates of trees for two or three years. The damaging effects of these substances are discussed below.

The presence of petroleum products and chemicals at drill sites creates a fire hazard. Depending on its size, wildfire can have major impacts on vegetation.

PRODUCTION IMPACTS

Several types of impacts result both from drilling and production of oil and gas. These impacts result from removal of existing vegetation, placement of fields in sensitive areas, creation of conditions favorable for weed growth, and creating a potential source of wildfire.

The amount of vegetation removed varies with the size of the development (Table 32). Vegetation removal for oil fields and roads usually is not significant unless riparian areas or special status plants are disturbed. However, large fields with numerous wells and roads could remove substantial amounts of vegetation. The amount of land required for existing and new fields is discussed in the Land Use section.

Table 32. Acres of Vegetation Disturbance by Typical Oil and Gas Facilities and Roads.

Region	Single Drill Site	Single Well Site	Average Field
1 (oil or gas)	6.2 to 16*	4.2 to 13	8.4 to 39
2 (oil or gas)	1.75 (oil)	1.15 (oil)	3.45 to 5.75 (oil)
	1.25 (gas)	0.95 (gas)	2.85 to 9.5 (gas)
3 (oil with gas)	5.5 to 6.5	3.5	7.0 to 10.5
4 (oil only)	3.5	2.3	2.3 to 17.5
5 (oil, some gas)	3.5 to 4.5	2.7	5.4 to 13.5
6 (oil, some gas)	3.5 to 4.5	2.7	2.7 to 13.5

* A work camp may be required and would remove additional vegetation. Region 1 roads are high standard; all other regions use bladed trails.
NOTE: Estimates are based on data regarding "typical wells" in each oil and gas region.

Source: Compiled by Scott McCollough, DNRC.

Reclamation of depleted oil and gas fields could restore most disturbed vegetation. Vegetation removed to install pipelines can be restored to original condition during operation of the pipelines. However, reclamation of an oil field can be difficult because of soil compaction and accumulated oil and brine around wellheads and tank batteries. Intensive reclamation methods (such as site drainage, fertilization, application of calcium, and discing) are usually required.

Weeds may grow around buildings and roads associated with oil and gas fields. As with drilling, the Weed Control Act holds the landowner responsible for weed control. McCollough (1988) interviewed 11 district weed supervisors to determine the extent of weeds in existing Montana oil and gas fields. None of the supervisors reported any major problems with state-listed weeds. Oil and gas development seems to be no worse than other soil-disturbing activities for causing weeds.

Certain air pollutants associated with oil and gas fields may affect vegetation. Hydrogen sulfide and sulfur dioxide are noted pollutants. Hydrogen sulfide discharged from wells is often intentionally ignited to convert it to sulfur dioxide. However, combustion commonly is incomplete and both gases are released. The gases also can leak from tanks and wellheads (see Air Quality).

Hydrogen sulfide tends to settle in depressions on the ground and can increase sulfur content of plants. Elevated sulfur levels can kill portions of the leaves and reduce growth of plants. Experiments by Thompson and Kats (1978) indicated that these symptoms occur in some species continuously exposed to 0.3 to 3.0 parts per million of hydrogen sulfide. However, in a natural setting, impacts to vegetation would depend on site-specific and highly variable factors. These factors include topography, meteorological conditions, plant species, and dosage of hydrogen sulfide (dosage is determined by emission rate, duration, and above-ground height of release).

Sulfur dioxide is also bad for plants. Exposure to sulfur dioxide eventually could reduce plant cover and diversity (Dodd et al. 1979; Rice et al. 1980a; Rice et al. 1980b). As with drilling, excessive dust and vehicle emissions could harm adjacent vegetation.

Accidental spills of oil and brine can damage vegetation. Spills most commonly occur at tank batteries or wellheads and at corrosion points in pipelines. Pipeline spills are more frequent in older fields where pipes are weakened by corrosion (DeJong 1980). Oil spills generally reduce plant growth. Reductions in growth are caused by direct toxic effects of oils on plants, reduced germination, lack of seed stocks, or by making soil unfavorable for plant growth (DeJong 1980; Baker 1970). The severity of toxic effects (reduced transpiration and photosynthesis and increased respiration) depends on the constituents and amount of oil, environmental conditions (such as light and moisture), and species of plant involved (Baker 1970). Conifer species appear to be more susceptible to sprays of oil than deciduous species. Oil changes the soil by decreasing pore space or increasing the activity of soil microbes. As a result, soil wetability declines and microbes out-compete plants for nutrients. Oil spills in Alberta affected an average of 1.25 acres of vegetation. Effects last from 1 to 20 years (DeJong 1980; McGill and Bergstrom 1983).

Oil in the soil is eventually degraded by microbes. The rate of degradation is accelerated by reclamation practices such as burning off the surface oil, discing, fertilizing, and seeding (McGill and Bergstrom 1983). With reclamation, oil-contaminated topsoil may support vegetation within five years (DeJong 1980). Legumes are effective reclamation species due to their nitrogen-fixing capability (Gudin and Syratt 1975). This capacity removes them from direct competition with the soil microbes for soil nitrogen. Oil that reaches the subsoil can present insurmountable reclamation problems due to limited aeration, low temperatures, and difficulty of adding fertilizer (DeJong 1980; McGill and Bergstrom 1983).

Older hydrocarbon fields produce larger proportions of brine per volume of oil produced. The brine spills that may occur are more damaging than oil spills because salts are not biodegradable. High levels of sodium chloride can kill plants, and sodium ions may break down soil structure and prevent movement of air or water in the soil (DeJong 1980).

Brine spills typically are treated with a calcium compound (such as gypsum) or manure. Spill sites are then disced, fertilized, and seeded. This treatment usually is successful on well-drained, non-saline soils. However, naturally saline and poorly drained soils often cannot be reclaimed (DeJong 1980).

REGIONAL COMPARISON

In most cases, vegetation impacts will depend on the amount of vegetation removed. Therefore, regional differences in levels of oil and gas activity will determine regional differences in vegetation impacts. However, enough information is available to make the following assessment.

1) Impacts of drilling for oil or gas would be greatest in Region 1. The larger drill pads and longer roads required in this region would affect more vegetation per well (Table 32). The amount of vegetation affected by an average hydrocarbon field also would be greatest in Region 1. High standard roads would be needed and would affect vegetation more severely than the bladed trails of other regions. Furthermore, camps might be needed for drill crews and these would affect additional vegetation.

2) Hydrogen sulfide is most likely to be encountered in Region 3 (see Geology). Therefore, vegetation near a well in this region stands the greatest chance of being damaged by hydrogen sulfide. Impacts from this gas also could occur in Region 5 and Region 1. Other regions appear free of this hazard.

3) Region 1 contains the most coniferous forest and special status plant species (Table 31), increasing the potential for impact. The risk of facilities and roads disturbing populations of special status plants is greater in Region 1 than in other regions.

4) Pipelines could disturb vegetation in any region.

MITIGATION

The following measures have been determined to reduce potential impacts to vegetation from oil and gas drilling and production.

1) Preparation of a revegetation plan before a site is disturbed would enhance the likelihood of successful reclamation. The plan could be subject to the approval of both the Board of Oil and Gas Conservation and the landowner. At a minimum, thistype of plan should address:

(a) areas to be revegetated;
(b) topsoil salvage, preferably the 'A' and 'B horizons, and redistribution;
(c) revegetation goals;
(d) seed mixtures;
(e) methods of soil preparation;
(f) fertilizers, mulches, and other amendments; and
(g) contingency plans in the event revegetation fails.

2) Trees and shrubs should be planted on reclamation areas when requested by the landowner or when necessary to return the land to its approximate original land use.

3) Before disturbing any soil, oil and gas developers could consult with the district weed supervisor. The supervisor will identify weed infestation areas and suggest weed control methods. The supervisor may consider it nece-ssary to wash vehicles and equipment to remove weed seeds and parts.

4) The Board of Oil and Gas Conservation could ensure that the oil and gas companies comply with the County Noxious Weed Control Act of1985 (7-22-2101 et seq, MCA).

5) The length and number of access roads could be kept to a minimum. Minimum standard roadsshould be used where possible.

6) Access road crossings of wooded drainages, riparian areas, and wetlands could be minimized. Wooded drainages should be avoided as routes for access roads. Routes should avoid populations of special status plants to the extent feasible.

7) Drill pads should be kept as small asfeasible.

8) Drill pad locations should be adjusted as much as possible to avoid wooded drainages, riparian

areas, wetlands, and populations of special status plants.

9) Unless the landowner specifies that an access road should be kept open, roads no longer needed for oil and gas activity should be regraded to approximate original contours and revegetated.

10) Measures should be taken to prevent blowouts and spills (see Health and Safety).

11) Blowouts and spill sites should be reclaimed using appropriate and site-specific reclamation. The goal of reclamation would be to restore the land to its original use.

12) Reserve pits should be properly designed and regularly inspected (see Water Quality).

13) Deep rip areas of compacted soil prior to reseeding.

14) If necessary, fence grazing animals out of revegetated areas to allow grasses one or two seasons to stablish roots.

SOCIAL AND ECONOMIC EFFECTS

ECONOMIC EFFECTS

Oil and gas exploration and development are an important part of Montana's economy. More than Montana's other major basic industries, the oil and gas industry has been subject to major shifts that had noticeable effects on the overall performance of the statewide economy. These changes have, in some instances, profoundly influenced economic conditions in areas of the state where major exploration and production have occurred.

The economic effects of oil and gas development tend to be more changeable than the effects of most other types of energy and natural resource developments that occur in Montana, for the following reasons: (1) activity in the oil and gas extraction industry tends to be cyclical, with a decade or more separating periods of intensive development; (2) the most employment associated with oil and gas development occurs during exploration activities, with smaller workforce needed once wells and production facilities are in place; (3) work associated with oil and gas exploration is most often dispersed over a region rather than being concentrated at a central location; (4) activities are carried out by numerous different companies, often acting independently of each other, rather than one large developer or one coordinated development; (5) workforce tasks are often short term and many oil workers tend to be transient, moving from job site to job site; (6) the timing, scale, and duration of intensive development activities is not predictable; and (7) boom/bust cycles tend to be more abrupt than for most other resource developments.

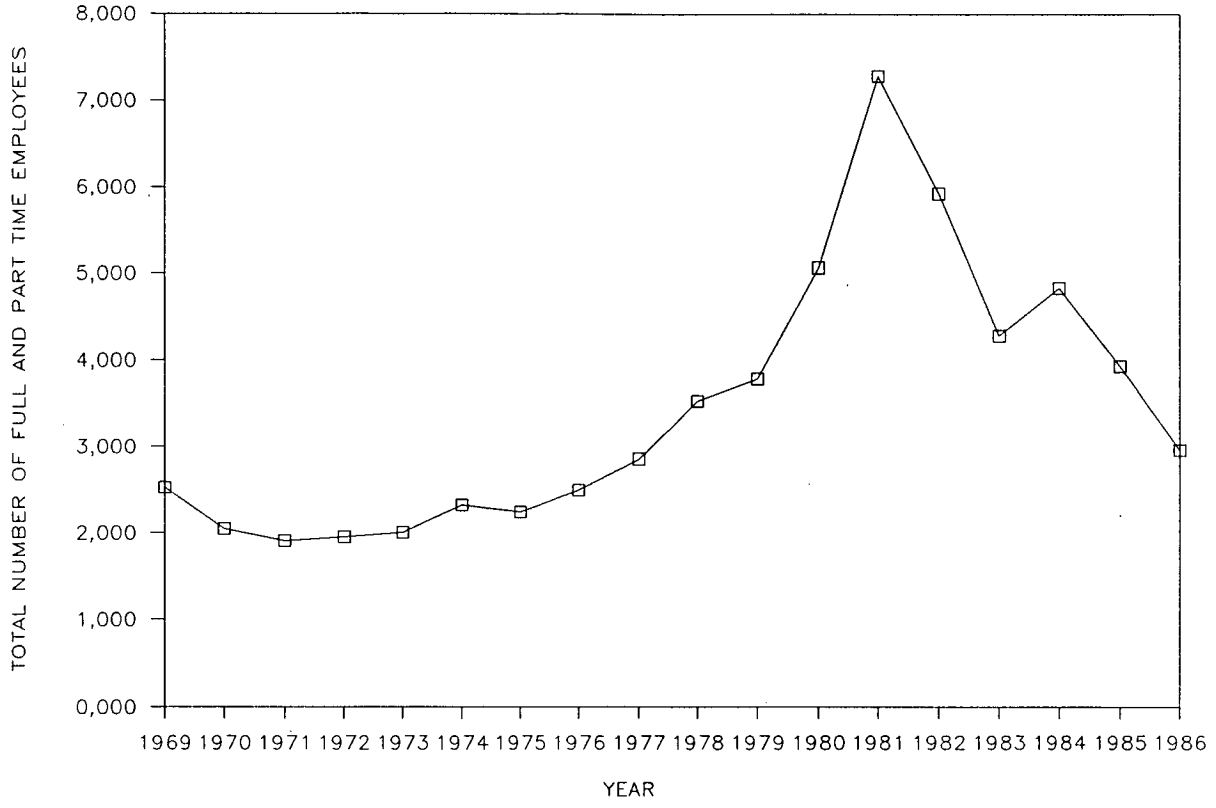
DIRECT EMPLOYMENT AND INCOME

Most of the direct and indirect employment and income created by the oil and gas industries consist of short-term jobs during exploration activities and well development. A smaller labor force is required to operate oil and gas wells during production phases (Polzin 1988). Wages and salaries paid by the oil and gas industry are considerably above the state average. As an example, in 1986 the average earnings for persons working in the oil and gas sector were about $27,900 compared to an average of $15,800 for all economic sectors (Montana Department of Labor and Industry 1986). Employment and income received by persons working in the oil and gas sector fluctuates considerably from year to year, reflecting the ups and downs in the oil and gas market. When employment in the sector is high, the industry makes a notable improvement on the statewide, regional, and local economies of Montana. Figures 41 and 42 show the statewide jobs and earnings directly attributable to oil and gas activities.

Discovery of major new oil-producing areas motivated short-term booms in Montana's oil and gas industry in the 1940s, 1950s, and 1960s. These booms tended to be localized in areas where the new discoveries were made. The more recent employment boom of the late 1970s and early 1980s was different from previous booms because it was motivated by favorable oil prices. The economic effects of exploration were felt at differing levels of intensity in many areas of Montana. At the peak of the boom, over 7,000 persons were employed by the industry and annual wage and salary earnings were estimated to be $186 million. At its peak, employment in the sector accounted for 1.9 percent of total jobs and over 3.4 percent of employment earnings within the state.

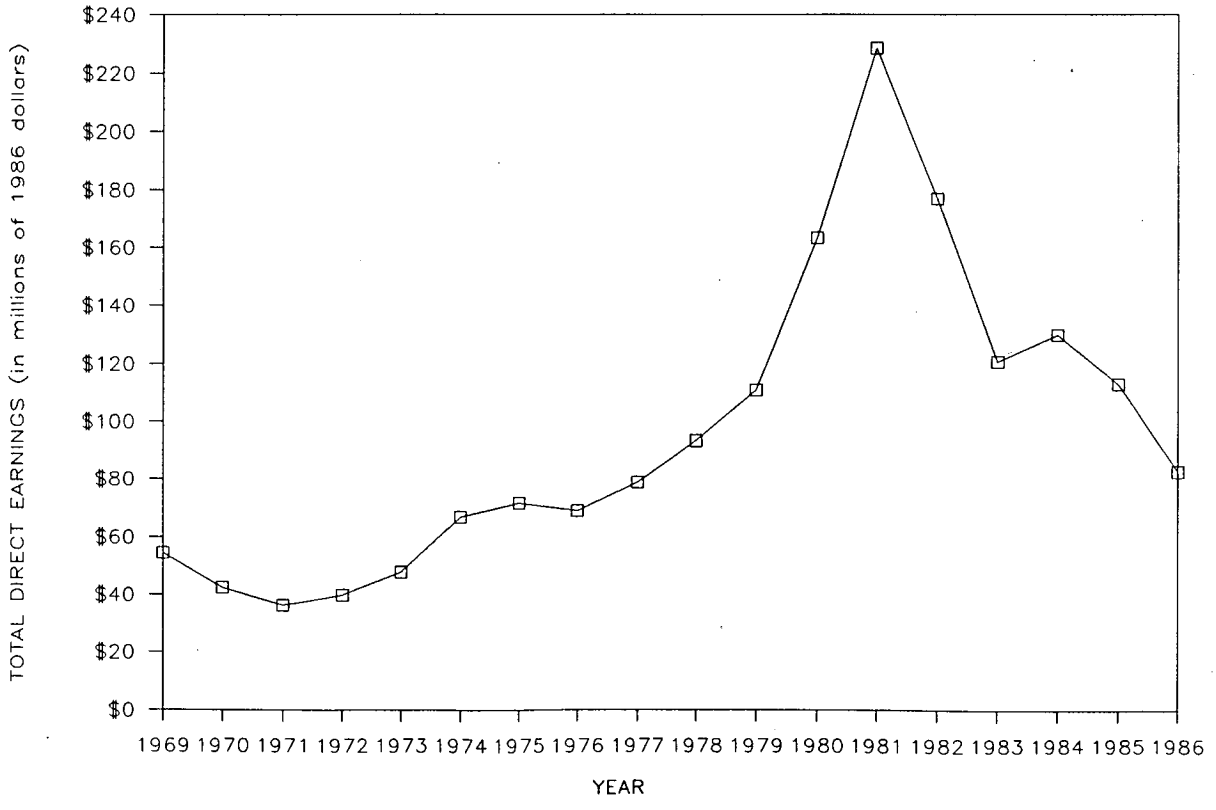
Decreases in oil prices in the mid-1980s quickly reduced exploration activity and employment and earnings in the sector (U.S. Bureau of Economic Analysis 1988a and b). Still, even during periods of relatively low levels of exploration, the oil and gas industry employs a substantial number of Montana residents. In 1986, about 3,000 persons worked in the oil and gas extraction industry in Montana and annual earnings in the sector were estimated at $82 million (U.S. Bureau of Economic Analysis 1988b). In that year, direct employment accounted for 0.7 percent of total jobs and 1.3 percent of employment-related earnings in Montana.

FIGURE 41
MONTANA OIL AND GAS EXTRACTION INDUSTRY EMPLOYMENT



SOURCE: U.S. Bureau of Economic Analysis, 1988a

FIGURE 42
DIRECT EARNINGS IN THE OIL AND GAS EXTRACTION INDUSTRY



SOURCE: U.S. Bureau of Economic Analysis, 1988b

LEASE AND ROYALTY PAYMENTS

Many Montana residents, particularly ranching and farming households, have benefitted from lease and royalty payments made by oil and gas developers. In 1986, an estimated 47 percent of the land in Montana was leased for mineral development (Montana Petroleum Association 1987). Competition for oil and gas leases results in relatively high lease payments to mineral owners during intensive development periods. During periods of lesser exploration activity, leasing declines and amounts paid for exploration and development rights also are much lower (Smith 1988b).

Royalty payments made by oil and gas developers to Montana residents are influenced both by production levels and prices received for oil and gas produced in the state. Royalty payments are based on percentage of the gross value of the oil or gas recovered. In recent years, the royalty payments made on Montana oil and gas production have been reduced by the low market prices for crude oil (see Figure 43).

Most private royalty interests in Montana oil and gas are held by state residents (Olsen 1988). Royalty payments made to farming and ranching households have helped to maintain family ownership of farms and ranches in oil and gas-producing areas (Smith 1988b). While royalty payments have decreased considerably from the $110 million paid out during 1981, this source of income continues to benefit residents of the oil and gas-producing areas (Mercer 1988, Stoner 1988).

When surface and mineral rights are owned by different parties, surface owners do not receive royalty income but do receive "damage" payments from developers for physical damages, road use, and inconveniences associated with development activities on their property. The amount of the damage payments also has varied with exploration activity levels (Nelson 1988).

SECONDARY ECONOMIC EFFECTS

Secondary economic effects are the employment and income benefits resulting from the expenditure and recirculation of oil and gas-related income. During boom periods, the expenditures of the industry and its employees contribute to expansion of employment and increased income in activities such as trade and service businesses, and public education and government services.

In the late 1970s and early 1980s, oil and gas activities motivated economic growth in all of the petroleum-producing regions of Montana. The economic growth was most substantial in the Williston Basin area of northeastern Montana and the Billings area, which evolved into a statewide management center for the industry (Moller 1988). To a lesser but still notable extent, local businesses and employment opportunities in the northern, central, and southeastern oil and gas regions expanded during the growth period.

The mid-1980s decline in exploration activity, lowering of lease and royalty payments to private individuals, and significant decline in industry tax and royalty payments to public agencies resulted in an abrupt reduction of the abilities of the regional and local economies to support the levels of commercial and public service that developed during the boom.

Because the economic bases of Montana's small communities are concentrated in a few key industries, the precipitous decrease in the oil and gas activity quickly resulted in loss of jobs and income in many areas of Montana. The effects of the slowdown were most notable in northeastern Montana, and particularly Richland County, which was strongly influenced by oil money (Haugen 1988).

Between 1975 and 1981, oil and gas employment in Richland County increased from less than 100 jobs to over 2,000, and then by 1986, fell back to about 600. During the same years, total employment in the county went from about 4,800 jobs to 8,300 and back to 6,100 (U.S. Bureau of Economic Analysis 1988a).

It is notable that more people are employed in Richland County now than before the oil boom. This suggests that oil and gas development has resulted in some long-term growth in the area's economy (Haugen 1988). The county's continuing high unemployment rate (9.1 percent in 1987), indicates that the local economy is still adjusting to downturn in the oil industry activity (Montana Department of Labor and Industry 1988). The county experienced 15 business or personal bankruptcies in 1981 and 50 in 1987 (U.S. District Courts 1988).

OTHER ECONOMIC EFFECTS

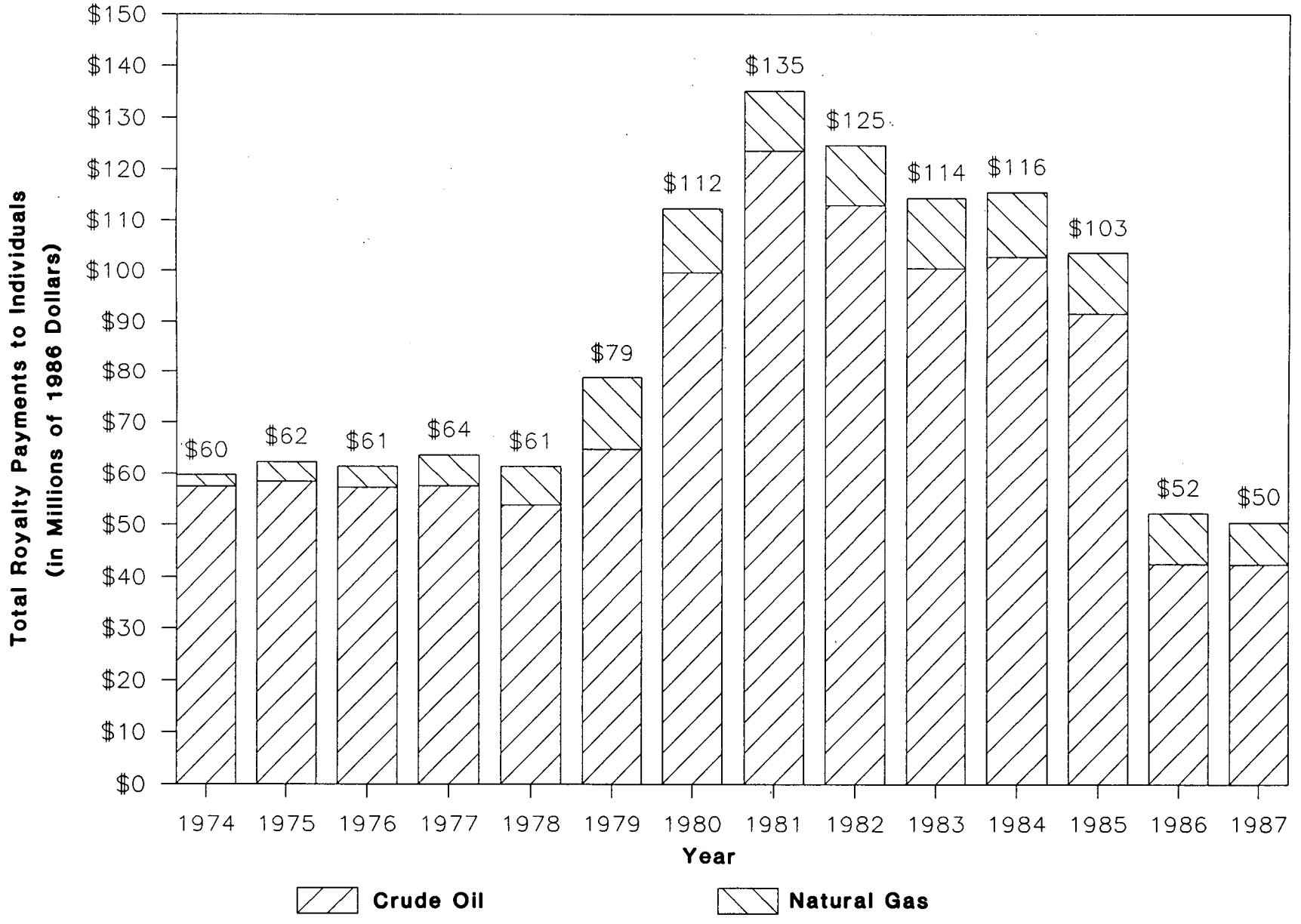
Other economic effects also may occur in areas experiencing intensive oil and gas exploration. In northeastern Montana, the in-migration of workers contributed to rapid population growth and shortages of goods and services, causing local inflationary effects (see later sections on community services). Most notable were affects on housing costs which rose by a third or more. A tight labor market and the high wages paid by the oil and gas industry also contributed to the increases in the costs of local labor. Persons in many different occupations benefited from the higher wages resulting from competition for labor (Haugen 1988). Additional detail on these effects is provided in the section on population and community services.

PUBLIC REVENUE COLLECTIONS

Taxes and royalties resulting from oil and gas development and production are important sources of revenue

FIGURE 43

OIL AND GAS ROYALTY PAYMENTS TO INDIVIDUALS



SOURCE: Montana Department of Revenue Biennial Reports, 1975 – 1987

for state government, local governments, and public education systems of Montana. Categories of revenue derived from taxes and lease and royalty payments made to Montana include:

- Natural Resource Taxes:
  - Oil and Gas Severance Tax
  - Oil and Gas Producers' Privilege and License Tax
- Resource Indemnity Tax
- Property Taxes:
  - Net Proceeds Tax
  - Real Property and Other Business Property Taxes
- Income Taxes:
  - Corporate License and Income Taxes
  - Personal Income Taxes
- Lease and Royalty Receipts:
  - Lease Payments
  - Royalty Collections from State Lands
  - Royalty Collections from Federal Lands

Technical Appendix 11 describes in greater detail mechanisms for collecting these taxes and how portions of the revenues are used to fund operations of state government and Montana schools. In recent years, lower crude oil prices have reduced government revenue. Increases in oil and gas exploration and the rise in the market values of crude oil and natural gas production in the 1970s and early 1980s contributed to rapid and substantial growth in public revenue collections. Conversely, curtailment of exploration and the sharp fall in prices for crude oil in the mid-1980s contributed to the fiscal difficulties which currently beset state and local government and public education in Montana.

Most of the oil and natural gas revenue collected by various levels of government in Montana depends directly or indirectly on the value of oil and gas produced. Volumes of production and market prices for oil and gas determine the value of the oil and gas production. Figures 44 and 45 show the relationships between market prices and volumes of production for Montana oil and gas over a 12-year period. Fluctuations in production volumes have affected public revenue collections, but far more influential have been changes in the market prices for the commodities, particularly crude oil.

Summary of State Government Revenue Collections In the mid-1970s and early 1980s, State of Montana tax and royalty revenue collections increased significantly due, in part, to major growth in the taxes paid directly and indirectly by the oil and gas extraction industry. Increased revenues contributed to a period of expansion in state government services and employment (Johnson 1988). State revenue decreases occurring in the mid-1980s reflect the decreases in taxes and royalties paid directly and indirectly by the oil and gas industry.

As shown by Table 33, state government revenue collections from the oil and gas industry rose precipitously in the late 1970s and early 1980s. Revenues peaked in 1982, a result of the peak prices received for oil production in 1981. When oil prices fell in the mid-1980s, state collections dropped abruptly.

Technical Appendix 11 describes in greater detail the various taxes applied to oil and gas activities and the role the revenue plays in state and local spending on schools and other governmental programs.

Local Government and Local Public School Revenue Collections. Property taxes are the single most important revenue source for Montana local governments and schools. Property taxes are levied against the net proceeds and royalty values of oil and gas production. The revenues from property taxes on the net proceeds value of production accrue primarily to counties and school systems where oil and gas fields are located. Figure 46 shows the trends in income from net proceed taxes collected through county and school district levies.

After adjusting for inflation, county tax revenues from oil and gas production are actually lower in the mid-1980s than they were a decade earlier; county income from oil and gas production is estimated to be 26 percent lower in 1986 than it was in 1977. For the same comparison years, school levy revenues increased by an estimated 24 percent. Dissimilarities in revenue trends result from differences in county government and school taxing policies. County government levies in oil and gas producing areas have tended to decrease since the beginning of the oil boom; whereas, school levies have increased.

POPULATION EFFECTS

The population effects of oil and gas development are most dramatic at the regional and local levels (see Table 34). Most counties experiencing noteworthy oil or gas activity in the 1970s and 1980s experienced some level of population growth. Nearly all of the major oil and gas-producing counties are estimated to have experienced population decreases after the mid-1980s.

The population effects of the recent boom/bust cycle in Montana were most noticeable in the Williston Basin. The industry also influenced population patterns in the Billings metropolitan area and, to a lesser extent, the populations of Montana's other oil and gas-producing regions.

Population estimates from non-census years are not precise but do provide a general indication of recent

Table 33. Annual Revenue Collections by State of Montana from the Oil and Gas Extraction 1976 - 1987 (in 1986 dollars)

Year	Severence & Privilege Taxes	RIT Trust Fund	Corporate Income Tax	Personal Income Tax	University Mill Levy	Lease and Bonus Pay	Royalties from State Lands	Royalties from Federal Lands	Total Taxes and Collections
1976	12.5	3.6	5.0*	4.3*	2.1*	5.5	4.1	5.0*	42.2*
1977	12.6	3.7	5.6*	4.6*	2.0*	6.0	5.6	7.0*	47.1*
1978	12.4	3.5	5.9*	5.1*	2.1*	9.0	6.4	7.9*	52.3*
1979	12.0	3.1	6.8	5.6*	1.8*	11.3	6.0	7.3	53.9*
1980	16.0	5.0	6.6	7.7*	2.2*	18.4	7.9	9.6	73.4*
1981	26.6	6.1	9.3	10.9*	3.2*	47.5	13.5	15.2	132.4*
1982	61.3	8.2	11.3	10.0*	4.2*	22.6	10.2	11.9	139.7*
1983	52.7	8.5	10.3	7.9*	4.0*	11.3	9.5	10.8	115.0*
1984	55.2	7.1	5.8	7.9*	3.7*	14.0	8.8	10.9	113.5*
1985	53.8	6.5	6.8	7.4*	3.7*	10.8	8.4	8.7	106.1*
1986	38.1	6.0	6.5	6.0*	3.3*	8.2	6.2	5.0	79.3*
1987	18.7	2.4	3.9	0.0*	1.7*	4.9	5.6	4.5	46.0*

* Indicates estimated value.

Source: Developed from information provided by Montana Department of Revenue 1976-1986; Montana Department of State Lands 1988; and Department of Interior, Bureau of Land Management 1977-1988.

Table 34. Recent Population Trends for Selected Montana Counties (in thousands of people)

County	Representative Years						
	1970	1975	1980	1982	1984	1986	1987
Blaine	6.7	6.7	7.0	6.9	7.1	7.0	6.9
Carbon	7.1	7.8	8.1	8.3	8.7	8.5	8.3
Fallon	4.1	3.9	3.8	3.8	3.8	3.6	3.5
Glacier	10.8	10.5	10.6	11.1	11.4	11.1	11.2
Hill	17.4	17.8	18.0	18.5	18.5	17.8	17.8
Liberty	2.4	2.4	2.3	2.4	2.6	2.3	2.3
Musselshell	3.7	4.2	4.4	4.6	4.8	4.7	4.5
Pondera	6.6	6.7	6.7	6.9	7.0	6.7	6.6
Phillips	5.4	5.2	5.4	5.4	5.7	5.5	5.4
Powder River	2.9	2.4	2.5	2.5	2.5	2.4	2.3
Richland	9.8	10.2	12.2	14.9	14.3	13.4	12.1
Roosevelt	10.4	10.1	10.5	11.3	11.6	11.3	11.2
Rosebud*	6.0	9.7	9.9	12.2	13.5	12.6	12.3
Sheridan	5.8	5.6	5.4	6.0	5.9	5.5	5.3
Toole	5.8	5.6	5.6	5.7	5.8	5.4	5.2
Wibaux	1.5	1.5	1.5	1.6	1.5	1.3	1.3
Yellowstone	87.4	98.9	108.0	113.5	119.1	120.0	118.1

* Population changes in Rosebud County are attributable to coal-related development.
Sources: U.S. Census of Population. 1970 and 1980, and Interim Population Estimates, 1981, 1987, and 1988; U.S. Bureau of the Census,U.S. Department of Commerce. Washington, D.C.

population patterns. These estimates probably understate the shifts in population, especially in rural counties. For instance, Richland County's population is believed to have peaked at about 15,500 in 1981-1982 and then decreased back to about 12,200 (Haugen 1988). Figures shown for Sheridan County probably also understate both the amount of population growth and subsequent population decline (Smith 1988b).

Population effects of oil and gas exploration parallel the settlement patterns of industry employees. Because of the absence of housing and public and private services in rural areas of Montana, the settlement of industry workers tends to concentrate in the larger communities in oil and gas-producing regions.

The city of Sidney in Richland County became the hub of oil and gas activity in northeastern Montana. The city's population is estimated to have grown from 4,000 to 7,000 during the oil boom, and dropped to between 5,000 and 6,000 during the post-boom era (Mercer 1988).

New settlement did occur in other smaller communities of northeastern Montana. In some instances, the new settlement severely strained local housing supplies and public service delivery systems (Smith 1988b, Haugen 1988).

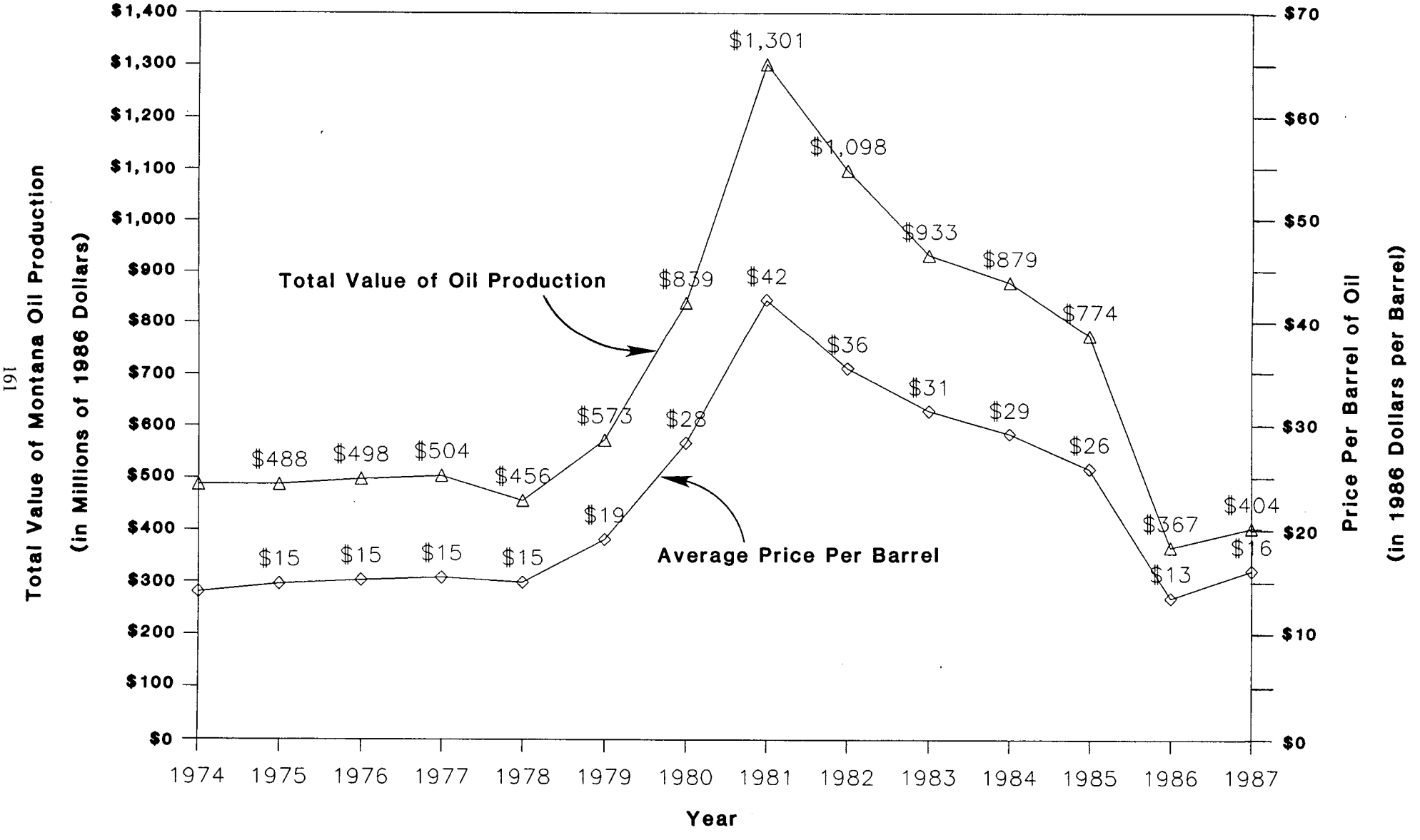
Many residents of the area believed that oil and gas development had caused a long-term increase in northeastern Montana's population. A high level of oil and gas employment was maintained for several years, long enough to encourage individuals to purchase new homes, local businesses to expand to meet the demands created by enlarged markets, and local governments and schools to invest in improvements to provide services to larger populations.

Though Yellowstone County is not a major oil or gas producing county, its role as Montana's management and regional service center for the oil and gas industry causes its population to be affected by oil and gas development in the state (Moller 1988).

DEMOGRAPHIC AND SOCIAL EFFECTS

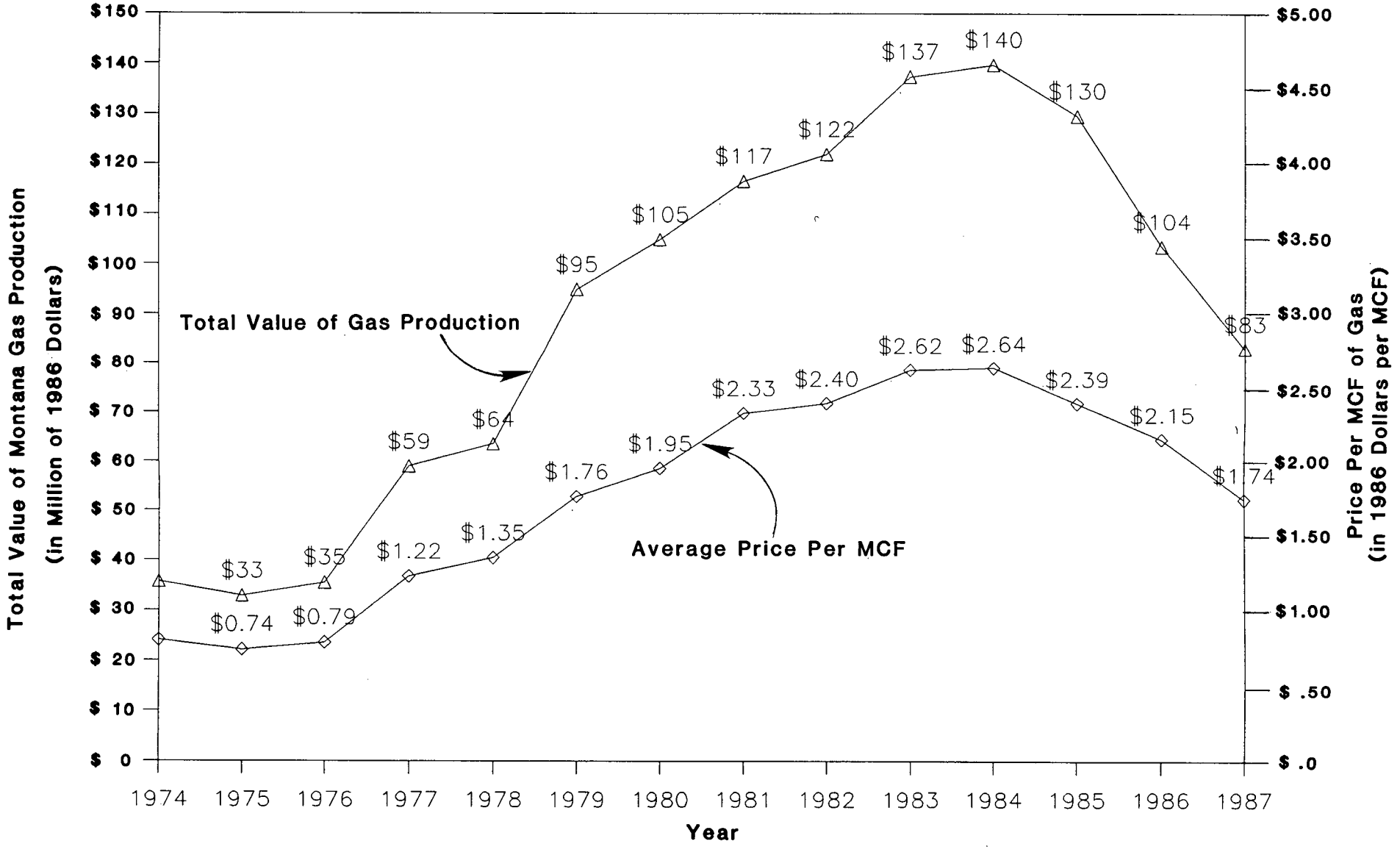
Besides influencing the numbers of people able to live in Montana, the employment opportunities offered by the oil and gas industry influence the demographic and social characteristics of the state and local populations. When the industry stimulates a population influx into an area of Montana, the effects of the increase depend on the type and number of people coming in, the rapidness of the population growth, and the characteristics of the preexisting population.

FIGURE 44
RELATIONSHIP BETWEEN THE PRICE PER BARREL OF OIL AND TOTAL VALUE OF OIL PRODUCTION



SOURCE: Montana Department of Natural Resources and Conservation, 1975 - 1987

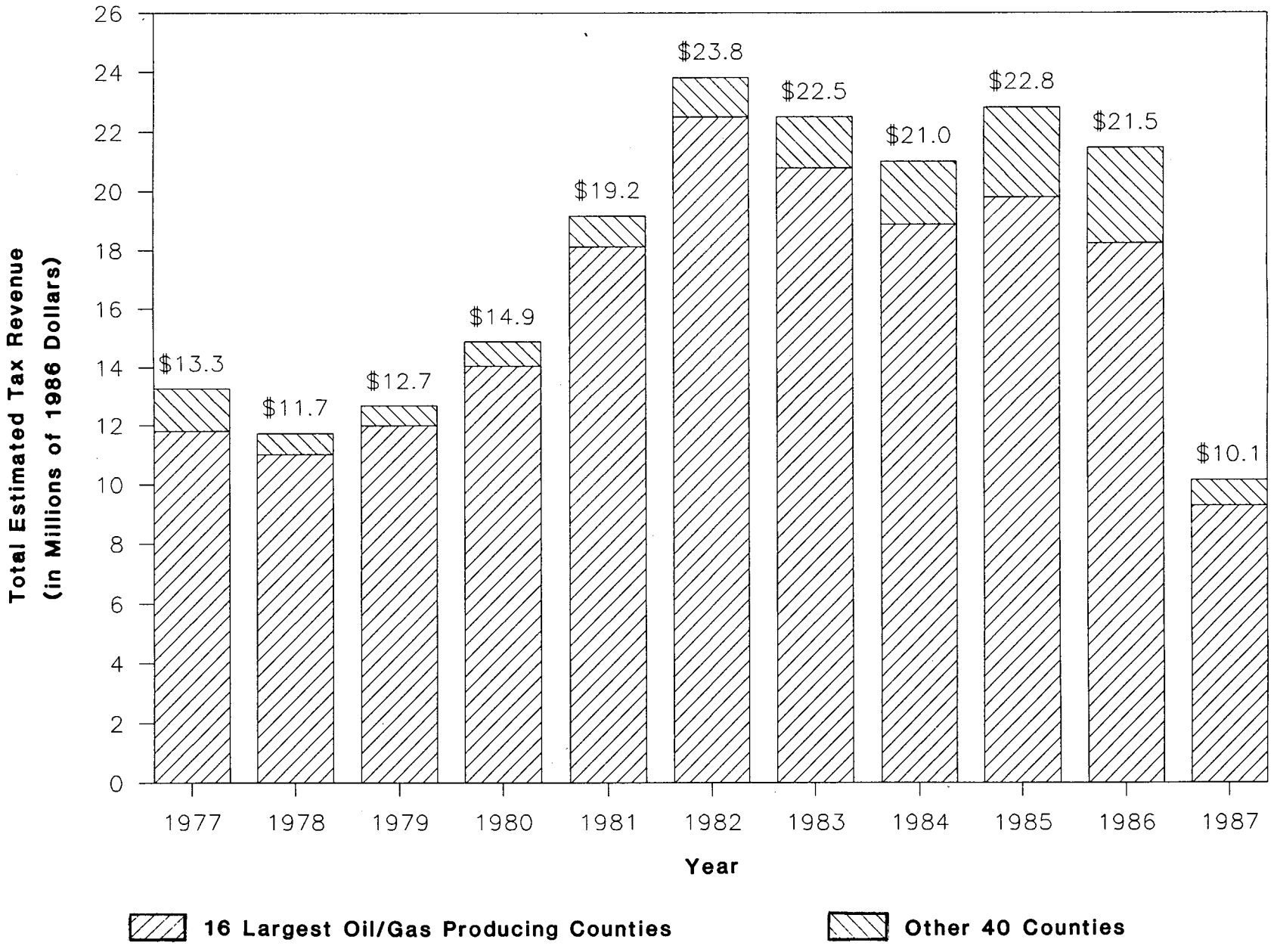
FIGURE 45
RELATIONSHIP BETWEEN THE PRICE PER MCF OF GAS AND TOTAL VALUE OF GAS PRODUCTION



SOURCE: Montana Department of Natural Resources and Conservation, 1975 - 1987

FIGURE 46

COUNTY REVENUE FROM THE OIL AND GAS NET PROCEEDS TAX



SOURCE: Developed from Montana Department of Revenue Biennial Reports, 1977 - 1987

A study of persons working during the oil boom in North Dakota's section of the Williston Basin found that half or more of the workers employed by the oil and gas industry were from outside the region. Further, the study found that the nonlocal workers tended to be young males, with smaller families than typical of local residents (Chase and Leistritz 1983).

The percentage of nonlocal workers working in Montana's portion of the Williston Basin was probably greater than in North Dakota because of the smaller local labor pool and limited number of pre-existing oil and gas service companies operating in this region of Montana (Leistritz 1988).

The temporary addition of a few people has little impact on the social and public and private service characteristics of Montana communities. For example, drilling a deep well in Gallatin County had little impact in this area (Peck 1988b).

Rapid migration of substantial number of people to rural Montana could cause substantial changes to living patterns and social interrelationships and also stress public and private services (Gilmore and Duff 1975). In northeastern Montana, the economic effects of a major boom changed the fundamental operation of the regional and local economies. The frenzied economic growth during a boom changed the pace and personality of business and personal interactions (Stoner 1988).

The characteristics of new arrivals will influence the types of public and private service impacts likely to occur within a community. The preponderance of males (unaccompanied by family members) during initial periods of oil and gas activity creates demand for transient-type housing (trailer spaces, motel rooms, small apartments). In the case of Sidney, the influx of young males increased demand for law enforcement and certain types of entertainment and recreation services (Mercer 1988). However, the early arrivals had little impact on enrollments in local schools.

When a period of oil development is extended, family members join oil workers, and the demand for family-type housing increases, as do demands for services such as water and sewer systems and public schools. School enrollments did increase in northeastern Montana, but growth in enrollments did not correspond to the overall increase in the area's population. This suggests that even over several years of intensive development, some oil and gas workers were not joined by their families.

A notable social benefit of oil development in northeastern Montana was the supplemental income it provided to family farms and ranching operations in the form of lease, royalty, and right-of-entry payments. Farmers and ranchers also earned supplemental income by selling materials and services to the oil and gas industry. The additional income helped some family agricultural operations stay in business. Jobs and income created during the period of oil development allowed local people to remain in the region who otherwise would have left (Mercer 1988; Smith 1988b; and Haugen 1988).

COMMUNITY SERVICES

Montana counties, cities, and towns provide most of the community services upon which oil and gas employees depend. Most workers live in housing in existing communities, and they require local services such as police and fire protection, health care, water and sewer service, garbage disposal, and city street maintenance. The workers' children are enrolled in local schools.

The two largest sources of funding for local services are locally levied property taxes (40 percent) and transfers from federal and state government (31 percent). The remaining 29 percent is provided by fees and charges for such items as special districts and miscellaneous resources (Montana Department of Revenue 1987). Locally levied taxes fund a wide range of services, such as road and bridge maintenance and repair, district courts, libraries, and airports. However, most (59 percent) local property taxes go to support local schools. State tax transfers include the gasoline tax, which also contributes to repair of county roads and city streets; the insurance premium tax, used to fund police and firefighter retirement programs; and taxes on alcoholic beverages, which support local chemical-dependency programs, law enforcement, and public health agencies. The state general fund also supports local schools.

The oil and gas industry supports the tax base through the payment of property tax on drilling and production equipment. The industry also is assessed a net proceeds tax based on the value of the oil and gas produced. Finally, federal mineral royalty payments are referred to the state to meet the impacts resulting from development of minerals on federal land. The royalty funds go to the school equalization program.

In the most active oil-producing regions of the state, such as the Williston Basin in northeastern Montana, tax revenues from oil development sometimes have not been great enough, available soon enough, or available to the jurisdictions where they are needed to offset impacts to community services.

Montana counties have a cap on the maximum levy that can be assessed for road and bridge repair. During the oil boom of the early 1980s, some counties found that the levies

were insufficient to keep up with deterioration of county roads and bridges in oil-producing areas.

Revenues generated through mill levies, oil severance, and royalty are generally available one to two years after the oil that generated them is produced, so there is a time lag that can leave some community service impacts unmet. This delay is especially significant on the upswing side of oil development cycles when the influx of workers to the producing regions is the most pronounced.

The taxable value of oil and gas production can dramatically increase the taxable valuation in jurisdictions where the production is located. Increased taxable valuations have allowed county school districts and special districts to increase tax revenues while decreasing mill levies. The residents of these jurisdictions benefit from the low individual property tax rates brought about as a result of the significant contribution of the oil and gas industry to their county or district. However, the industry's labor force often requires community services and schooling in other jurisdictions, often the towns and small communities of the counties. These towns usually share little of the revenue associated with petroleum production, because the wells are not within their taxing jurisdiction. The communities do not receive the net proceeds tax, and they have to rely on a residential tax base to fund most of the services they provide. Smaller towns generally have the greatest problems in providing services to fluctuating populations. Small communities have less flexibility in absorbing increased demand for services than larger towns and cities with larger service structures in place.

The most critical of the services the communities provide are capital services, such as water supply, sewer, and sewage treatment facilities. These services require large investments by community residents and long-term debt is usually required to finance them. The eventual decline of employment levels and resulting departure of workers can leave long-term residents of communities "holding the bag" on the debt incurred to provide capital services to temporary worker populations.

Road Impacts. Oil and gas development has not generally affected the level of service on the state's primary and secondary highways. Minor, temporary slowdown in traffic sometimes occurs when drill rig components or a number of cement trucks or other well service vehicles are being moved along a highway together (Cromer 1988).

Gravel-surfaced county roads are subject to damage by traffic to and from existing oil and gas development. Frequent travel of heavy equipment tends to break down the surface of gravel roads. The road surface can be restored through regrading, although the surface is soft immediately after such maintenance. The need for maintenance will be more frequent when traffic volumes are high. Unimproved roads generally do not lend themselves to grading and other maintenance because they do not have an established roadbed. Gravel roads are less susceptible than unimproved roads to damage during wet weather or high soil moisture. Unimproved roads sometimes become impassable in wet weather because of severe rutting by heavy oil field equipment. In dry weather, deteriorating road surfaces sometimes become a source of dust problems for rural residences. Wooden bridges covering streams or irrigation canals crossed by county roads often cannot support trucks hauling drilling equipment, mud, crude oil, or produced water. Although the oil-producing counties generally have very large taxable valuations during high oil production years, state law limits tax money that can be spent on roads to 12 mills. This amount often has been insufficient to maintain existing unimproved gravel roads around oil fields. Replacement of wooden bridges with pre-stressed concrete structures capable of supporting oil field traffic has further depleted county road funds (Smith 1988a).

Table 35 shows per capita spending on county roads for 16 representative oil and gas counties. The low population of these rural counties causes relatively high per capita spending compared with the more populous counties of the state. However, the spending trend closely follows the up-and-down nature of the oil and gas development cycle that occurred between 1977 and 1987.

The average per capita spending among the representative petroleum- producing counties increased between 1977 and the height of the oil boom in 1982, as counties were required to increase their county road maintenance because of oil field drilling and production vehicles (Smith 1988a). Per capita spending decreased in many cases, returning to approximately the same level or a level lower than the pre-boom level following the decline in oil production over the period ending in 1987.

Table 36 provides an estimate of total vehicle trips required on primary, secondary, and county roads to establish a well site in each of the petroleum-producing regions. The vehicle counts are based upon a typical number of vehicle trips required to move drill rigs, casing material for the mud system, and other equipment to the well site, including rig/ support crew and other worker commuting. The vehicle count figures take into account the reduced transportation requirements that result when field well service and equipment companies establish materials storage and shop facilities close to producing areas. The production column includes the vehicle trips required for equipment and workers involved in well completion and production facility installation (except pipeline construction).

School Impacts. Public schools in many rural Montana counties, including the petroleum-producing counties, have experienced declining enrollments for several decades. Table 37 shows total (elementary and high school) enrollments for the 16 most productive oil and gas counties in Montana for 1977, 1982, and 1987.

Table 35. Per Capita Spending on County Roads in Selected Montana Counties (in 1986 dollars)

County	1977	1982	1987
Blaine	61.00	79.00	66.00
Carbon	51.00	40.00	27.00
Fallon	182.00	401.00	47.00
Glacier	54.00	64.00	36.00
Hill	22.00	33.00	27.00
Liberty	107.00	175.00	80.00
Musselshell	24.00	57.00	26.00
Phillips	49.00	95.00	78.00
Pondera	58.00	49.00	32.00
Powder River	440.00	274.00	83.00
Richland	54.00	150.00	58.00
Roosevelt	119.00	164.00	108.00
Sheridan	78.00	204.00	77.00
Toole	66.00	127.00	59.00
Wibaux	124.00	312.00	153.00
Average	$103.00	$148.00	$ 64.00

Source: Montana Department of Revenue, Research Bureau, 1976-1986Biennial Reports, Helena; and U.S. Bureau of the Census,Provisional Estimates of the Population of Counties,Series P-26, U.S. Department of Commerce, Washington, D.C.

The boom-bust cycle in petroleum development is not generally reflected in school enrollment figures. Fallon County, for instance, saw its taxable valuation triple as a result of oil and gas net proceeds revenues between 1977 and 1982, but experienced a decrease in both elementary and high school enrollment. Several other counties experienced dramatic increases in taxable valuation during the peak of oil and gas activity in the early 1980s. These same counties experienced similarly drastic declines in taxable valuation by the end of the boom in 1987. School enrollments declined gradually throughout the boom, suggesting that continuing population losses were greater than oil-caused population gains in most areas.

Richland County is the one notable exception to the decline in school enrollments. The county experienced an increase of 258 students (11 percent) during the boom years of the early 1980s and gained another 31 students during the period of decline in oil production ending in 1987. Richland County was temporarily able to buck the trend in declining school enrollments because Sidney, the county seat, was an oil field development center where oil producers and supporting field service companies set up branch operations. The development of oil field supply and service companies and warehouses provided stability that enabled Sidney to compensate for the declining population trend apparent in other rural Montana counties. Sidney's capital services such as water and sewer systems probably also influenced the settlement and commuting patterns of the petroleum work force.

Long-term declining enrollments have left most public schools in the petroleum producing counties with adequate facilities to accommodate another upswing in oil and gas production (Isbell 1988; Ritter 1988; Bourquin 1988; and Smith 1988a). Several counties report that some hiring of additional teachers would be necessary if enrollment increases (Ritter 1988; Bourquin 1988).

Housing Impacts. The dramatic increase in petroleum development in the late 1970s caused an influx of workers into some of the communities of the oil and gas producing counties. The number of workers arriving and the impact they had on the housing structure of communities varied greatly among the regions.

Northeastern Montana experienced an increase of nearly 5,000 jobs during the oil boom. Leistritz (1982) reports that oil development in Williston Basin counties in North Dakota provided new job opportunities for a nearly equal proportion of local (48 percent) and non-local (52 percent) workers. The local/non-local worker ratio may have been similar in Montana's Williston Basin communities, but this topic has not received specific study.

Table 36. Estimates of Total Vehicle Trips Required Per Well

		Vehicle Trips per Well per Year			Total Vehicle Trips per Field				
			Days		Per	Small Field		Full Field	
Region		Drilling	duration	Production	well	# well	trips (year)	# wells	trips (year)
1	Oil	2445	90	195	2640	2	4620	10	21,120
2	Oil	72	7	22	94	3	235	10	752
	Gas	28	2	8	36	3	90	19	540
3	Oil	2030	60	100	2130	2	3730	10	17,040
4	Oil	90	10	30	120	3	300	8	750
5,6	Oil	180	15	35	215	2	376	8	1,343

* Estimates were derived using data contained in typical well fact sheets found in Technical Appendix 1.

Table 37. Public School Enrollment in Selected Montana Counties.

Numbers of Full-time Students

County	1977	1982	% change (1977-1982)	1987	% change (1982-1987)
Blaine	1821	1593	-12.5	1567	- 1.7
Carbon	1705	1555	- 8.8	1630	+ 4.8
Fallon	998	823	-17.5	793	- 3.7
Glacier	3006	2733	- 9.1	2786	+ 1.9
Hill	3964	3387	-14.6	3187	- 5.9
Liberty	534	474	-11.2	461	- 2.7
Musselshell	944	876	- 7.3	932	+ 6.4
Phillips	1177	1108	- 5.9	1068	+ 5.4
Pondera	1688	1458	-13.6	1329	- 8.9
Powder River	596	548	- 8.1	481	-12.2
Richland	2420	2658	+ 9.8	2689	+ 1.1
Roosevelt	2733	2558	- 6.4	2690	+ 5.2
Rosebud	2131	2760	+29.5	2780	+ 0.7
Sheridan	1191	1078	- 9.5	1050	- 2.6
Toole	1242	1045	-15.9	1003	- 4.0
Wibaux	389	367	- 5.7	285	-23.3

Source: Montana Public School Enrollment Data, Fall annual reports for Montana Office of Public Instruction 1977-1987.

Many of the new petroleum workers settled in the larger towns of Sidney and Glendive, and these towns seemed to experience the greatest housing impacts (Smith 1988a; Groshart 1988). Sidney was the most heavily affected community.

Five new subdivisions were developed around Sidney, three of which were on cultivated agricultural land. The largest subdivision was designed to accommodate 130 houses. Seventy houses were built before the downturn in oil production began. Ground instability and soils problems caused shifting and breakup of house foundations, necessitating the removal of most of these homes; about 20 now remain. Three large eight-plexes were built near Savage in Richland County. The departure of workers during declining petroleum production in the mid 1980s has left those units vacant (Groshart 1988).

Chase and Leistritz (1983) report that 25 percent of locals and 37 percent of nonlocal petroleum workers in North Dakota's Williston Basin counties live in mobile homes. Such temporary housing patterns have some detrimental consequences for communities, in part because trailers have a much smaller taxable value than single family dwellings, and therefore don't contribute as much to the community's tax base. However, mobile home parks provide the opportunity for the community to largely avoid the heavy capital investment needed to install extensive water and sewer networks in new subdivisions occupied by conventional housing. This reduces the financial burden on the community during periods of high growth.

City ordinances in Sidney prevented a large influx of mobile homes within the city limits. Most mobile homes were situated in several new trailer parks. Many of these homes have been repossessed and moved, but three parks remain. The largest of these was designed to accommodate 130 trailers; it now contains 14. Of the two remaining mobile home parks, one was designed to accommodate 112 trailers and now holds 60, while the other, designed to hold 15 trailers, now contains 4 (Groshart 1988; Mercer 1988).

The departure of petroleum workers has had long-term financial effects on Sidney. The city has acquired 106 lots through tax defaults, and holds between $400,000 and $500,000 of bonded debt on the Special Improvement District (SIDs) on these and other parcels. As a result of the 1987 appraisal, the city is also experiencing a 14 percent reduction in taxable valuation because of a drop in property values (Mercer 1988). Many traditionally agriculture-based communities in Montana are also experiencing decreases in valuation, but not to the same extent as Sidney. The decline in market values on residential and other property has persisted since about 1983.

Efforts to accommodate an influx of petroleum workers in Sheridan County included the construction of apartment buildings in Plentywood. A number of single family dwelling owners also converted basements to apartments (Smith 1988a). Most of the communities in Sheridan County experienced an influx of trailer homes, some of them sited on vacant city lots with no sewer service. Public health problems resulted. The towns of Antelope and Outlook incurred long-term debts when they invested in sewer and water systems (Smith 1988a).

Impacts to housing were less dramatic in the other petroleum producing regions of the state. Most of these regions experienced a slight-to-moderate increase in home construction during the boom years of the late 1970s. As workers and their families left the area in the early to mid-1980s, vacancy rates and the number of homes for sale increased. Virtually all county officials now report that housing capacity is adequate to accommodate another substantial increase in petroleum employment and production without some of the growing pains experienced during the last cycle (Wiedeman 1988; Mercer 1988; Groshart 1988).

Law Enforcement Impacts Petroleum development in rural communities may increase the demand on law officers and jail facilities. Total annual incarcerations in the Sheridan County jail over a 10-year period are summarized in Table 38, and may be typical of the most heavily affected counties.

The number of incarcerations in a given year is one indictor of the load placed on local law enforcement services. The number of incarcerations peaks at the height of the oil development cycle in 1981. By 1987, the demand on the jail

Table 38. Total Incarcerations in Sheridan County, Montana.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Annual incarcerations (all offenses)	102	193	224	284	243	205	161	123	113	101

Source: Smith 1988a.

facilities had returned to the pre-boom level of about 100 incarcerations per year.

Richland County, another area which saw a substantial increase in petroleum production between 1977 and 1981, saw it's crime rate jump from 1,458 per 100,000 population (ranked 37th out of 56 Montana counties) to 4,506 (ranked 10th) during the height of the boom in 1981. By the end of the cycle in 1986, the county's crime rate dropped to 2626 (ranked 23rd in the state) (Montana Board of Crime Control 1988).

Richland County's average income from fines assessed for parking, speeding, and other offenses has averaged $40,000 per year over the last seven years. At the height of the oil boom in 1981, however, the county assessed $170,000 in such fines (Mercer 1988).

CHARACTERISTICS OF FUTURE SOCIAL AND ECONOMIC IMPACTS

The future influence of the oil and gas extraction industry will be influenced by a number of interrelated factors discussed below. Although development of natural gas has contributed and will continue to contribute to the state's economy, its economic influence on Montana probably will continue to be less substantial but more stable than that of oil development.

MAJOR NEW DISCOVERY

A new oil or gas discovery would stimulate increases in exploration activity in the area of Montana where the discovery was made. As with discoveries in the past, direct employment and income effects would occur mainly in the region near the new oil-producing area. Success in making discoveries also would increase exploration and development interest in an area. Billings, because of its role as the industry's management center, probably would experience some oil oriented employment growth from a major new development anywhere in Montana.

The growth in oil industry employment and earnings would be temporary. When the areas surrounding the new producing area were leased and explored to the satisfaction of the industry, given the economics of the time, employment in the sector would decrease substantially. Remaining jobs would be involved in developing new wells and production and well maintenance activities.

CRUDE OIL PRICES

Price increases for crude oil could improve the economic feasibility of otherwise marginal oil exploration activities and would motivate exploration for new oil discoveries in many different areas of Montana. The intensity of development would be determined by how much the price increases improve the economics of exploration activities. The oil boom of the early 1980s was motivated by unprecedented increases in the price of oil. Development activities were greatest in the established oil-producing areas, such as in the Williston Basin. The return of favorable prices probably would renew industry activity in there areas. In addition, some "rank wildcat" drilling would occur in geographic areas with promising geologic formations but no history of oil production.

EMPLOYMENT CHARACTERISTICS

Employment levels during oil and gas exploration depend primarily on the nature and the number of wells drilled. Well depth influences both the number of persons employed and the duration of employment. Wells 9,000 feet or deeper require larger work forces for longer periods of time and have much greater employment and income effects than shallow wells.

Surface and subsurface characteristics also affect the manpower requirements and length of time necessary for drilling. Developing access roads to remote mountainous areas is likely to be expensive and time consuming, providing jobs and income for road builders. Drilling deep wells in the complex geology of the Rocky Mountains is likely to take longer than in nonmountainous areas.

Because of the specific skills needed, many persons employed in exploration activities in Montana are from out of state or from other areas of the state (Leistritz 1988). Nonresidents of the state or the local area tend to spend less of their incomes near the drilling activity than do permanent residents.

Montana's populous areas are most capable of providing support services desired by the oil industry because of their larger and more diversified array of businesses and workforce skills. Development activities near Montana's major cities are likely to employ a higher percentage of local and Montana residents than are developments in rural areas.

In less populated areas, contracted services are often provided by nonlocal labor. A study in North Dakota's section of the Williston Basin found that over half the persons employed in exploration were nonlocal workers (Chase and Leistritz 1983). Nonlocal workers probably comprise an even larger share of industry employment in Montana's portion of the basin, because of the small population of northeastern Montana and the few local oilfield services available (Leistritz 1988).

SCALE AND DURATION OF DEVELOPMENT

Any increase in the level of oil and gas exploration will provide economic stimulation at state, regional, and local levels. The economic effects of small increases in exploration jobs for periods less than a year are likely to be minor. Montanans hired to perform exploration activities will benefit personally from the income provided by the jobs, but small-scale short-term activity would not significantly increase secondary employment or income. Discontinuation of low level exploration activities would not have important adverse affects on Montana.

If the number of jobs in oil and gas exploration were to increase, the industry's potential to create secondary income and employment would climb also. Even at significant levels of employment, the secondary effects of short duration exploration are likely to be limited to small and temporary increases in service jobs and increased income for local businesses.

Short duration activities by the oil and gas industry are not likely to motivate major new investments in local businesses, or such things as personal investments in new housing. Discontinuation of intensive but short term exploration activities would cause some decrease in employment and income but would not have major area-wide economic effects.

The longer oil and gas exploration continues in an area, the more likely it is to cause secondary economic impacts. Even 20-30 jobs for a year or two will stimulate growth in secondary employment. If exploration activity lasts for a number of years, it is likely to increase secondary employment and business and personal investments.

NATURE OF AFFECTED ECONOMIES

The sizes of the regional and local economies experiencing the effects of oil and gas activity will influence the extent to which jobs and income in secondary economic activities are likely to occur. The size and diversity of an area's economic base also are likely to affect its vulnerability to the bust effects that tend to follow an expansion in oil and gas activity.

Larger economies with more diversified economic bases and providing wider arrays of goods and services are likely to experience greater secondary employment and income benefits from a given level of oil and gas development than are smaller economies. Larger economies also will be better able to absorb the shock effects resulting from major reductions in exploration activities.

Small economies lack the versatility necessary to quickly respond to new markets for goods and services created by exploration workers and are likely to be limited in their ability to provide support services for exploration companies. Exploration activities will create proportionately fewer jobs and stimulate less new investment in smaller economies than in larger economies.

Major and relatively long duration exploration activity can make a small economy vulnerable to a "bust-type" contraction of secondary business activity. Sudden reductions in employment and expenditures by oil and gas developers can severely affect operation of small economies that depend on the performance of a few basic industries.

The oil boom in northeastern Montana was big enough and lasted long enough to stimulate significant expansion of secondary business employment and new investment in government and business facilities. When industry activities were cut back, the remaining economic base could no longer support the elevated levels of secondary economic development. The experience in northeastern Montana could be repeated in just about any medium or small economy in Montana where intensive and relatively long-duration exploration occurs.

No regional or local economy in Montana is large enough to be unaffected by major long-term shifts in the oil and gas industry. Because of its size and diversity, the Billings economy was able to better cope with the changes in industry activity levels occurring in the recent boom and bust cycle.

Billings did experience perceptible economic growth during the oil boom and the Billings economy was adversely affected by the bust. However, the adverse effects were somewhat diminished by other key basic industries contributing to the area's overall economy. The Billings area did not experience unusually high rates of unemployment or business failure as a result of the decline in oil industry activities (Moller 1988). The economies of the state's larger urban centers, such as Billings, Great Falls, Missoula, Helena and Bozeman, would be best able to manage the effects of major oil and gas developments in the future.

SOCIOECONOMIC MITIGATION

Social and economic impacts caused by oil and gas development differ from the impacts of most other natural resource developments. Major impacts from oil and gas development are likely to be the cumulative effects of numerous activities occurring simultaneously, rather than the result of a single centralized operation. Further, the location, timing, duration, and intensity of oil and gas development activities are less predictable than most other types of resource developments.

Local governments and schools have primary responsibility for coping with the social and economic impacts of oil and gas development. Actions by local governments and schools lessen the need for long-term capital improvements and reduce the socially disruptive effects of rapid population changes. Policies affecting residential and

commercial development patterns, public facility improvement, and the delivery of human services can lessen the short- and long-term costs of public services and the impact on local living conditions.

Actions by local governments and schools should be based on the best available information about planned industry activities and an understanding of the cyclical nature of oil and gas development patterns.

State agencies can assist local governments and school systems by compiling and circulating timely information regarding the location and magnitude of oil and gas development activities. Information on the status and location of leases and permits, development schedules, locations of activities, and crew size would help public agencies anticipate and respond to changing demands. Direct technical assistance of funding by state agencies could help local government cope with complex planning and human service delivery problems.

Montana State government's assistance programs for communities affected by coal and hard rock mines are examples of legislatively established programs that help local governments and schools deal with financial problems resulting from population growth. Montana's Coal Board provides grants and loans to public entities experiencing population growth as a result of coal development. The tax base sharing provisions in Montana's hard rock mining impact program allow property taxes to be distributed in a manner to ensure that the jurisdictions experiencing mining's impacts to schools and public services also receive tax funds for compensation.

Aspects of the impact assistance programs for coal and hard rock mining could be adapted to oil and gas operations.

The movement of heavy vehicles and equipment to and from oil and gas sites can cause major damage to public roads and bridges, and may warrant statute changes to help repair the damage. Even when counties have imposed maximum levies for road and bridges, funds have sometimes been insufficient to maintain adequate road and bridge services. In such cases, it may be necessary for the Legislature to allow counties to increase mill levies to fund these services. the Legislature might wish to require voter approval and demonstrated urgency for increased funding.

Initiative 105 (the property tax freeze) created special problems for county governments and school systems in oil-producing areas. Also, lower oil prices resulted in sizeable decreases in taxable valuation for local governments and school systems. Some legislative action may be needed to allow local governments and schools to raise mill levies where local tax valuations have experienced major decreases.

HISTORICAL, ARCHAEOLOGICAL AND PALEONTOLOGICAL RESOURCES

By definition, significant paleontological, archaeological, and historical resources are those that contain information that can be interpreted to provide further understanding of Montana's past. While a number of fossil-bearing formations exist in Montana, those yielding large vertebrate fossils have the greatest scientific value (U.S. Bureau of Land Management 1984). Technical Appendix 12 lists the areas known to contain important paleontological resources. Significant vertebrate fossils include complete skeletons of large and small animals or reptiles and individual or groups of bones from dinosaurs.

Prehistoric (archaeological) and historical resources consist of (1) physical remains, (2) areas where significant human events occurred, even if evidence of an event no longer remains, and (3) the environment immediately surrounding the actual resource. The value of a site consists of the information about a past society's way of life that potentially could result from analyzing the remains and the site's environmental factors. Each site is a finite nonrenewable resource with unique potential for significance. As established by the National Park Service, Table 39 lists the criteria for evaluating a given archaeological or historical site for significance.

Some 28,000 archaeological or historical sites have been recorded in Montana. These sites represent a range of activities covering broad periods of Montana's past. A small number of these sites have been evaluated for inclusion on the National Register of Historic Places. The majority of sites have not received detailed evaluation to determine whether they are eligible for listing on the National Register. Sites that have one or more of the qualities described in Table 39 are potentially eligible for listing on the National Register of Historic Places. There are certain requirements for identification and protection of archaeological and historical resources in Montana. Any surface disturbing activity involving federal and state-owned lands or minerals requires that consideration be given to historical and archaeological sites. There are no corresponding requirements for identification and protection of paleontological resources on federal lands (National Research Council 1987; Spielman 1988).

Approximately 10 percent of Montana has actually been surveyed to determine location of historical or archaeological sites (Schwab 1988). In much of Montana,

Table 39. Criteria for Evaluating Significance of Historical and Archaeological Resources.

36.CFR 606. The quality of significance in American history, architecture, archaeology, engineering, and culture is present in districts, sites, buildings, structures, and objects that possess integrity of location, design, setting, materials, workmanship, feeling, and association, and:

(1) that are associated with events that have made a significant contribution to the broad patterns of our history; or

(2) that are associated with the lives of persons significant in our past; or

(3) that embody the distinctive characteristics of a type, period, or method of construction, or that represent the work of a master, or that possess high artistic values, or that represent a significant and distinguishable entity whose components may lack individual distinction; or

(4) that have yielded, or may be likely to yield, information important to prehistory or history.

data regarding historical and archaeological sites are obtained through on-the-ground surveys of areas proposed for disturbance on federal and state lands or where federal or state minerals are involved. The State Historic Preservation Office (SHPO) maintains records of all sites identified by various surveys. These records generally describe the location and type of site identified, but further evaluation is normally required to determine whether a particular site contains information or exhibits qualities that would make it eligible for listing on the National Register of Historic Places. SHPO maintains a roster of sites listed on the National Register of Historic Places, or eligible for such listing, in each of Montana's counties. This roster is constantly being updated as evaluation by SHPO in consultation with other federal and state agencies identifies additional sites for listing.

Although little is known about the potential number of sites in Montana, past survey efforts indicate that certain topographic and environmental features are particularly likely to hold archaeological remains. Major river valleys and adjacent uplands and areas where major tributaries meet frequently have evidence of use by prehistoric people. Early people tended to select locations that were relatively flat, preferring ridges and benches that offered a view of the surroundings. Access to resources such as food, water, shelter, or raw materials for tools also are notable factors to consider in determining potential site locations. For example, in both eastern and western Montana, sites are often found in association with creek bottoms and adjacent upland settings near sources of stone that is suitable for tool making (Schwab 1988).

IMPACTS TO HISTORICAL AND ARCHAEOLOGICAL RESOURCES

Surface-disturbing activities associated with construction of access roads, drill sites, and reserve pits pose the greatest potential for direct impacts to historical or archaeological resources. Such activities could destroy archaeological and historical remains. During construction, previously unknown sites could be discovered. While such discoveries would be a beneficial aspect of construction, sites could be disturbed and information contained in them could be lost. The loss of information at a site would be an irreversible loss of opportunity to learn more about some aspect of human history or prehistory. The significance of this loss would depend on the site's value. Indirect impacts on a site's value would involve the alteration of a setting which might be essential to qualities that would make a site eligible for listing on the National Register of Historic Places.

Sites also could be devalued if unauthorized personnel remove artifacts. The likelihood of such impacts is increased when roads constructed for oil and gas wells provide access to inaccessible sites.

The impacts that would occur as a result of oil and gas development in any particular location would be influenced by the number and type of archaeological or historical sites present. It is likely that reliable information about historical or archaeological sites at many potential drilling locations in Montana may not be known without a survey.

IMPACTS TO PALEONTOLOGICAL RESOURCES

Impacts to paleontological resources could result from surface-disturbing activities in areas where geologic formations contain important fossils. Such activities could result in both beneficial and detrimental consequences, including the destruction or disturbance of significant fossils, or the discovery of fossil remains. Increased access could lead to unauthorized collection of fossils at known sites.

MITIGATION

Several measures could reduce potential for impacts to known archaeological, historical, and paleontological resources. Requirements imposed on federal and state agencies by various laws provide protection against loss of information obtained through analysis of archaeological and historical remains. In areas where similar procedures to not apply, the following measures have been identified.

Impacts can be avoided most effectively by avoiding areas known or suspected to contain archaeological and historical remains, but this may not be practical where an oil or gas lease is held.

Minor relocation of a proposed drill site to avoid a sensitive feature is sometimes possible.

Consultation with groups such as SHPO or the Museum of the Rockies can identify areas of known archaeological, historical, or paleontological value. A formal agreement such as a memorandum of understanding could be written between the Board and these agencies detailing procedures for consultation and methods for advising on the significance of potential impacts.

A survey to determine the presence of historical, archaeological, or paleontological resources could be considered as a possible measure to mitigate against potential impacts. As an alternative, sites discovered during construction could be evaluated by a qualified archaeologist or paleontologist in order to collect information that otherwise may be lost.

CHAPTER FIVE
PROGRAM ALTERNATIVES

INTRODUCTION

A major purpose of this programmatic environmental impact statement is to help determine a process the Board could use in evaluating the environmental impacts associated with individual drilling proposals. This process would include a method for incorporating environmental review considerations into the Board's rules and drill permitting process. Chapter Four provides a record of information for the Board to rely on when evaluating individual permits to drill. This record of information identifies the range of environmental impacts associated with oil and gas development in the major producing basins and ecosystems of Montana and methods to mitigate long-term impacts and avoid permanent environmental impairment.

This chapter (1) summarizes the major findings of Chapter Four concerning environmental impacts associated with drilling and production; (2) summarizes mitigation options presented in Chapter Four; (3) discusses alternatives available to the Board for incorporating environmental review into its rules and drill permitting process; and (4) discusses the administrative alternatives available to the Board to expediently determine the level of environmental review necessary in the context of individual drilling proposals.

SUMMARY OF IMPACTS AND AVAILABLE MITIGATION

A primary value of Chapter Four is that it identifies the range of impacts that can occur to a particular resource such as water or wildlife and the site-specific circumstances or conditions that could result in potential for impact. The analysis in Chapter Four thereby provides both substantive information about the nature of the impacts and a method for analyzing their likelihood of occurrence. The Board's task is to decide what portions of the broad range of possible impacts covered in the programmatic are potentially applicable to an individual project. The main indicators are the presence of sensitive environmental features or constraints and the characteristics of the drilling project itself. Another contribution of the programmatic is the identification of certain types of drilling projects which, in combination with certain locational characteristics, are not likely to create any serious environmental problems and that warrant only a minimum level of individual study to document the Board's evaluation. This evaluation assumes that measures are applied to reduce adverse impacts.

Based on the analysis in Chapter Four, potential adverse impacts from oil and gas activities may differ with the type of drilling operation, the environmental sensitivity of a location, and the short-term, long-term and cumulative nature of impacts attributable to either drilling or production.

In most cases, the drilling of an individual oil or gas well will not result in major adverse impacts on the environment if proper care is taken in the siting and construction of the drilling location and access road, if drilling muds and fluids and any other wastes are disposed of in an appropriate manner, if safe drilling practices are observed, and if the site and road are properly reclaimed. Other than these considerations which are applicable to all drilling operations, the potential for adverse impacts is almost entirely dependent on the sensitivity of individual drilling locations. Factors such as the length of time and size of drilling rig necessary to drill a particular well increase the potential for impact, particularly in sensitive settings. In some cases, an environmental feature will signal the need for special precautions because it represents a constraint (e.g., geologic features such as rugged topography and unstable slopes, hydrogen sulfide). In other cases, a sensitive feature may have characteristics that are particularly vulnerable to the disturbance or changes caused by oil and gas activity.

The situation where major adverse environmental effects are most likely is when a wildcat drilling operation leads to discovery of a commercially producible oil and/or gas reservoir and full field production commences in a previously undeveloped area. Even under these circumstances, the impacts are highly dependent upon the location where the development takes place, but the impacts are inherently more serious than during drilling due to the long-term nature of production activities.

The following summary of impacts is condensed from the analysis contained in Chapter Four. While potential for some impact may exist with any particular well, decisions about the magnitude and significance of an impact primarily depends on the location where drilling is proposed and measures applied to mitigate against adverse impacts.

Additional detail regarding how the Board would make these judgments for any particular drilling proposal are discussed in a later section on review of drilling proposals.

GEOLOGY AND SOILS

The characteristics of geology and soil most likely to present constraints to oil and gas drilling and production include areas of rugged topography and unstable soils, and problematic characteristics of oil and gas formations, including hydrogen sulfide, salt zones, and water with high concentrations of sodium chlorides and total dissolved solids. These features usually require special site construction and reclamation methods, special equipment and operating procedures, and careful waste disposal practices.

AIR QUALITY

The air quality impacts most commonly associated with the drilling of individual oil and gas wells include the following: (1) increased dust and airborne particulates created by site and road construction and generated by vehicles; and (2) increased nitrous oxides due to the operation of the drilling rig and other engines. Except in rare situations where a number of wells are simultaneously drilled in close proximity or where the drilling location is in an area of constrained topography (for example, a narrow mountain valley), these air pollutants are not likely to reach levels that trigger permit requirements or violate ambient standards. The exception for nitrogen oxide would be a drilling operation lasting several months and using a drilling rig of 1,500 horsepower or greater capacity and other associated engines. Increased particulates would generally be a short-term construction impact that could be successfully minimized if efforts (watering the roads, for example) are made to suppress dust, especially in residential areas or other locations frequented by the public.

The air pollutants associated with oil and gas production with the greatest likelihood of causing adverse impacts include hydrogen sulfide, sulfur dioxide, and other sulfur compounds. Most individual wells do not produce these pollutants in quantities or concentrations that would violate ambient air quality standards or trigger the need for an air quality permit. The situation most likely to cause impacts or trigger regulatory requirements would be the venting or flaring of hydrogen sulfide over an indefinite period of time by a number of wells in a single field or series of adjoining fields. Activities such as drill stem tests, gas/oil ratio tests, and production stabilization tests also can create or contribute to adverse impacts, but usually only on a short-term basis. Sulfur dioxide would typically occur in concentrations or volumes sufficient to cause problems only if high volumes of gas were being flared to convert hydrogen sulfide, and when on-site uses of gas containing hydrogen sulfide are substantial.

The severity of adverse impacts depends on the concentration of hydrogen sulfide in the gas, associated gas, or oil; the volume of production; proximity of residences, public roads or areas accessible to the public; proximity of Class I or other sensitive areas where air quality degradation is especially problematic; and local terrain and meteorological conditions. At present, neither the Board nor any state agency routinely collects gas analysis data or has a procedure for determining which production wells may potentially cause air quality impacts, either individually or in association with other wells in a given area. Problems are currently discovered only when a complaint is received and investigated.

Analysis in Chapter Four shows that the Board's current rule limiting flaring to an average of 100,000 cubic feet per day each calendar month can trigger the requirement for an air quality permit, and may result in violations of ambient air quality standards in some situations. In some cases, special emission control technologies and procedures might be necessary to avoid violations, while in other situations it might not be possible to flare up to the limits of the Board's rule without causing violations. Consultation between the Board and the Air Quality Bureau when variances from the Board's flaring rule are requested would allow problem situations to be detected and addressed.

HEALTH, SAFETY AND NOISE

The potential for adverse affects on human health and safety from oil and gas drilling and production results primarily from loss of control of a well and, where hydrogen sulfide is present, the possibility of a major blowout or pipeline rupture exposing the public to elevated and possibly lethal concentrations of the gas. Loss of control of a well where no hydrogen sulfide is present normally would not pose a threat to the public, but workers could be endangered. Hydrogen sulfide blowouts are rare occurrences, but where concentrations of the gas and flow volumes are relatively high, and where residences or urban centers are relatively close to a well, the consequences of a blowout could be highly adverse.

The oil and gas industry has developed an extensive array of specialized equipment and procedures to ensure proper control and operation of wells. Also, contingency plans may be prepared in sensitive locations to identify the actions that would be taken to respond to a hydrogen sulfide emergency and protect the public. The discussion in Chapter Four indicates that Board rules could be strengthened by specifying in greater detail the minimum types of equipment and procedures necessary to ensure proper control of wells, with special provisions, if appropriate, and identifying areas or formations where conditions warrant greater precautions. Chapter Four also indicates that Board review of applications for permits to drill could be strengthened by establishing

criteria or a review process to determine when hydrogen sulfide emergency plans should be prepared for individual wells.

Typical drilling operations cause noise levels in excess of the 55 decibels-A weighted-scale (dBA) that EPA has established as a guideline for continuous exposure. The noise from drilling operations typically exceeds this threshold approximately 1/2 mile from the drill site. A drilling rig may cause noise levels in excess of the EPA sleep interference guideline (35 dBA) at greater distances from the site. Gas pipeline compressor stations that are operated for the life of a producing field produce similar noise levels. Workers exposed to on-site noise levels, which normally exceed 90 dBA, can be expected to experience hearing damage if exposed over the long term without use of special protective equipment.

Off-site noise levels during drilling can be reduced by use of mufflers, sound screens, auxiliary brakes when stopping the draw works, by using diesel-electric drilling rigs, and by orienting the rig to reduce sound levels in the direction of residences. Mufflers, barriers, and screens can reduce noise levels by as much as 25 dBA. Noise levels during the production phase also can be reduced. Gas compressor stations can be located away from residences and sensitive wildlife habitat. For oil fields, an option for reducing noise is to use electric pump jacks, which are at least 30 dBA quieter than gas-powered engines. Alternatively, gas-powered engines can be equipped with mufflers.

WILDLIFE AND FISHERIES

The adverse impacts on wildlife from oil and gas development are those associated with increased road construction; displacement of animals from winter range in mountainous areas; stress during the winter, spring, and young-rearing period; and increases in legal and illegal shooting. Based on criteria such as acres of winter range, susceptibility of winter range to impact, species diversity, and probability of impact on resident species, the regions of the state most susceptible to adverse impact, in decreasing order of importance, are: Overthrust, Northern, Big Horn, Central, Powder River and Williston Basin. Operations located in mountainous terrain can be expected to create more serious impacts on wildlife because of the greater importance of critical habitat and presence of more sensitive species in these areas. The likelihood of an adverse impact occurring in any particular location depends on the intensity of oil and gas activity, including length of time that operations occur, sensitivity of the environment, cumulative disturbance that a wildlife species has been subjected to previously, and implementation of mitigation measures. Areas that include habitat used by threatened or endangered species are especially sensitive to disturbance and may require special evaluation to determine how development can proceed in the least intrusive manner.

In most cases, an individual well drilling operation will not create significant long-term adverse effects on wildlife if the well turns out to be a dry hole and the access road is reclaimed. Potential for significant adverse impacts will be greatest where an initial wildcat well leads to discovery of a commercial oil and gas reservoir and full field development, or where an access road into a previously inaccessible area is not reclaimed.

Streams most likely to be adversely affected are Class I and II streams (as classified by the Department of Fish, Wildlife and Parks). These streams tend to support the highest populations of recreationally valued fish and fish species especially sensitive to water quality degradation. Development of roads and other facilities along or near these streams could significantly increase suspended and deposited sediments, thereby reducing habitat and fish populations. Oil, chemical, and drilling fluid spills, even of relatively low volume, could result in adverse impacts on fish populations.

The most effective means of mitigating wildlife impacts is first by avoidance of critical habitat, and second by restricting activities in the seasonally important habitats to times of year when these areas are not critically important to the life cycles of sensitive species. Seasonal and daily management of traffic on access roads, including road closure and siting roads so that they are screened from view, also are effective ways to reduce impacts. Road obliteration is effective in reducing impacts where continued use poses an adverse impact on wildlife. Riparian areas, woody draws and wetlands should be avoided wherever possible. Sedimentation of rivers and streams can be avoided by constructing roads on non-erodible soils and on gentle slopes as far from water as possible, or by prompt revegetation of disturbed areas.

WATER QUALITY

The primary sources of water pollutants from oil and gas drilling are reserve pit fluids and muds. The main pollutant associated with oil and gas production is produced water, especially when it contains high concentrations of sodium chlorides and total dissolved solids. Adverse impacts are most likely to occur when reserve pits and produced water evaporation pits are located close to potable sources of either surface or groundwater, when subsurface soils are porous and therefore do not inhibit leaching and downward migration of fluids, and when the fluids, drilling muds, and produced waters contain elevated levels of salts, trace metals and total dissolved solids. The potential for contamination of both surface and groundwater can be greatly reduced by proper siting, construction, maintenance and reclamation of reserve pits and produced water pits, and by appropriate disposal of wastes.

The analysis in Chapter Four indicates that existing Board regulations could be strengthened by adding guidance

concerning what is required to adequately construct or reclaim reserve pits and produced water pits. More specific directives and incorporation of sensitive area concepts based on distances from susceptible hydrologic settings also could be used to improve the drill permitting and inspection procedures.

RECREATION AND AESTHETICS

The adverse impacts associated with drilling often are short term and localized, with the severity of impacts depending mainly on the degree to which visibility of drilling equipment, construction activities and increased traffic disrupt recreation settings, and whether the activities encroach upon visually sensitive areas. Aesthetic impacts will be more severe in areas of high scenic quality, high viewer sensitivity to intrusions, and high potential for landscape alteration.

Exploratory drilling that results in development of a new oil or gas field has the greatest potential to result in long-term, significant impacts on recreation and aesthetics. Some recreation activities may be permanently displaced and changes in recreational use patterns may occur due to the cumulative effect of new and upgraded access roads and a change in the character of an area from less to more developed. These impacts would be incremental where development occurs within or near existing oil and gas fields. In general, the scale of potential impacts associated with field development will be greater with oil production than with gas production because the former generally involves use of more surface facilities with wells closer together.

Examples of potentially sensitive recreation areas and sites include national, state and local parks and recreation areas; wild, scenic and recreational rivers; established trail systems; private campgrounds, resorts and dude ranches; fishing access sites; rivers and streams with high quality fishing; natural areas; and areas with unique habitats. Other examples of sensitive viewing areas are residential areas and highways and roads. Examples of options that may mitigate adverse effects on recreational use of these areas include avoidance of the areas by oil and gas equipment and vehicles, establishment of buffer areas around developed recreation sites, restricting oil and gas activity to times of day or season to minimize conflicts, use of natural vegetation and topography to screen oil and gas facilities, siting and construction of roads and other facilities to minimize disturbance of land forms and vegetation, and reclamation of disturbed areas to return them to natural conditions to the extent feasible.

VEGETATION

Impacts on vegetation tend to be most serious in areas with high erosion potential or areas where local conditions make reclamation difficult. Specialized techniques and additional cost, time, and labor may be necessary to restore some areas to their previous productive capability. Disturbance of the surface can often encourage the spread of noxious weeds. Prompt reclamation of disturbed areas, weed control efforts during the time that sites and roads are in use, and cleaning of vehicles to remove weed seeds may be necessary to mitigate this potentially serious problem. Avoidance of special status plants, some of which are rare in Montana, is another mitigating measure that may be applicable in some locations.

LAND USE AND COMMUNITY CONFLICTS

Potential land use impacts primarily consist of conflicts between oil and gas activities and other uses of property such as agriculture and residences. Direct impacts, that is, those effects directly associated with disturbance of the land surface, may be easier to mitigate through modifications of the oil and gas operations around irrigation equipment and through eventual reclamation. These impacts are often reduced through negotiations between the landowner and the company. Indirect effects, such as visual effects and traffic impacts on property near to or adjoining an oil and gas lease, are more difficult to mitigate. For example, residential impacts often involve issues such as residents' expectations for maintaining the character of their neighborhood, health and safety concerns, and waste disposal.

CULTURAL RESOURCES

Impacts on cultural, historical and archaeologic properties or sites have many characteristics in common with recreation and visual impacts (e.g., changes in the quality of visitor experience and changes in integrity of the setting of a historic or cultural property). Further, some cultural sites or objects could be physically destroyed or impaired. As with recreational and visually sensitive areas, avoidance or creation of buffer zones around known cultural resources is the most effective way to reduce impacts.

ECONOMIC AND PUBLIC SERVICE EFFECTS

Oil and gas activity has produced significant benefits for the Montana economy, contributing revenues to state and local governments and the educational systems and income to private mineral owners and businesses. The industry also is subject to boom/bust cycles which contribute to problems for local and regional economies and to problems for local governments in providing public services. Natural gas exploration and development has had less dramatic social and economic effects than the effects attributed to oil exploration and development. Several factors contribute to the effects, both positive and negative, associated with development and production.

Intensity of development is greatly influenced by the price of oil and the economics of exploration activity.

Successes in making new discoveries also can notably increase interest in leasing and drilling in an area.

Deep wells require larger workforces for longer periods and have greater employment and income effects than do shallow wells. Most of the direct employment in the industry occurs during well development, with a much reduced workforce during production. Employment levels and the effect that oil and gas-related activity have on an area are influenced by the length of time required to drill a well, the number of wells drilled, and the characteristics of the economy in the area affected. Montana's large cities are better able to handle moderate-to-large temporary changes in economic activity and population with the attendant demands for services. Impacts to smaller cities and towns can be overwhelming, even at moderate levels of oil and gas activity. The seriousness of these effects depends on the extent of the activity and how well the local community can adjust to changes in the economic situation and in the demand for services. Often the collection of revenues needed to fund public services lags behind the demand for these services, or revenues are collected by jurisdictions other than those receiving the increased demand for services. During boom periods, this has required local governments to incur long-term debts to fund capital improvements such as sewer and water to serve a temporary workforce.

In smaller communities, the bust effect also can result in business failures, significant reductions in local employment and incomes, and financial difficulties for local governments and education systems.

Actions by local governments, schools, and businesses can lesssen the disruptive effects and rapid changes that can accompany oil and gas development. When planning, actions should be based on best possible information about industry activities and an understanding of the cyclical nature of oil and gas developments. Problems for local governments and schools can remain when capital improvements are required as a result of the demand for services.

ENVIRONMENTAL REVIEW ALTERNATIVES

As described in Chapter One, Senate Bill 184 requires that the programmatic impact statement discuss methods for incorporating environmental review into the Board's rules and drill permit process. The remainder of this chapter describes in detail a number of program and administrative alternatives that include (1) methods for the Board to expediently evaluate environmental impacts associated with individual drilling proposals, and (2) methods and measures for the Board to use to help ensure that oil and gas drilling and production occurs in an environmentally sound and reasonable manner. The latter category of options is intended to provide the basis for the Board to be able to conclude, for a majority of drilling and production operations, that significant impacts on the quality of the human environment will not be likely to occur if the operations comply with Board rules, guidelines, and permit conditions.

Much of the discussion that follows concerns how the Board could determine the appropriate level of evaluation required for various types of drilling projects and how some of the options or steps in the environmental review process could be eliminated or rendered unnecessary for some drilling proposals. In a few cases, primarily those involving wells proposed in extremely sensitive areas or the development of new well fields, detailed site-specific environmental review may be necessary to determine the extent of impacts and identify appropriate mitigation. A listing of program and administrative alternatives that would assist the Board in fulfilling its environmental review objectives includes the following, at a minimum: 1) collection of data describing proposed drilling operations and locations 2) development of levels of review and companion procedures to provide for technical review of applications for permits to drill; 3) pre-drill site inspections where special conditions warrant; 4) attachment of general and/or site-specific conditions to drilling permits to mitigateadverse impacts; 5) where conditions warrant, consultation among the Board and landowners, land-managing agencies, and other agencies with jurisdiction or expertise concerning environmental resources that might be affected by drilling and production; 6) development of guidelines specifying minimum appropriate practices for variousaspects of oil and gas drilling and production in Montana; 7) revision and additions to Board rules to ensure availability of sufficient information to conduct environmental review and to assist in implementing appro-priate mitigation; 8) development of Memorandums of Understanding defining how the Board and other agencies would coordinate their respective responsibilities for oil and gas drilling and production, and for resources affected by these activities; 9) field inspections and enforcement of Board imposed requirements for drilling and production activities; and 10) training and education for existing Board staff and potential addition of new staff.

The alternatives discussed in this chapter are presented to fulfill both the overall purposes of the programmatic environmental statement (see Chapter One) and to address specific types of environmental problems that can be associated with oil and gas drilling and production (see analysis in Chapter Four). To meet the requirements of Senate Bill 184, the Board may choose to implement some or all of the alternatives discussed herein.

A primary requirement of the Montana Environmental Policy Act is that state agency decision makers must consider the environmental consequences of their actions to the fullest extent possible. This includes the environmental consequences of projects that must receive agency approval. Agencies also are directed to integrate use of the natural and social sciences and principles of environmental design in planning and decision making. These provisions and guidance provided by various court decisions at both the state and federal levels have resulted in efforts by state agencies to identify ways for programs and projects to minimize adverse environmental consequences.

Virtually all agency actions occur in compliance with specific laws that establish the agencies' general areas of responsibility and, in some cases, the specific limits of their authority over particular types of activities. The Board's authority over oil and gas drilling and production is conferred by the Montana Oil and Gas Conservation Act. This Act primarily focuses on the conservation and prevention of waste of oil and gas, but it also specifically authorizes the Board to prevent drilling and production operations from contaminating or damaging surrounding land and underground strata.

This document cannot resolve existing legal ambiguities concerning either the limits of the Board's authority or the limits of its discretion to address environmental issues. Alternatives for clarifying legal issues include legislative action, court decisions, and attorney general's opinions. These alternatives are available to affected parties but they are not the focus of this programmatic statement. Rather, emphasis has been placed on clearly and accurately identifying the range of potential environmental impacts that could occur as a result of drilling and production. Equally important to the analysis is the identification of mitigation strategies that could be expected to be reasonably effective in reducing adverse effects if appropriately applied. The following discussion places additional emphasis on tailoring the environmental review process and any resulting mitigation measures to the impacts that can reasonably be expected from any individual drilling or production operation and location. As discussed further below, options are available for addressing most potential environmental problems. Regardless of how or whether the legal ambiguities are eventually clarified, the key element to successfully incorporating environmental review into the Board's permitting process is to devise reasonable solutions to site-specific problems on the basis of cooperation, timely sharing of information, and, where necessary, detailed interaction and discussion among the Board, oil and gas operators, landowners, and other affected parties.

TOPICS FOR POTENTIAL BOARD RULE REVISIONS AND GUIDELINES

The analysis in Chapter Four identifies several topic areas where the Board's existing rules and field inspection practices could be strengthened by the addition of minimum acceptable methods of siting, constructing, maintaining, and reclaiming a drill site and associated access road; requirements ensuring the safety of workers and the public; and specifications regarding the reserve pit and produced water evaporation pit siting, design, maintenance and reclamation. The following discussion separates the aspects of oil and gas drilling from those of production to summarize where more detailed guidance may be warranted. Later sections discuss administrative alternatives available to help the Board decide which requirements are specifically appropriate to individual drilling sites, and to ensure that only those practices that are reasonable and justified by site-specific conditions are required.

If the Board develops new guidelines or revises its rules following the adoption of this programmatic statement, the Board could request other agencies with jurisdiction or special expertise in topic areas covered by the rules to review and comment on draft rules. Opportunities for review by industry and other interested groups also could be provided prior to public hearings on the proposed rules.

Table 40 summarizes most of the rule-related alternatives that are discussed in the text and identifies options that currently are being implemented by the Board, neighboring states, the Bureau of Land Management, and the Province of Alberta. In some states, an agency other than the oil and gas agency may be responsible for implementing certain items.

DRILLING PHASE OF DEVELOPMENT

Siting and Construction of Drill Locations and Access Roads. As discussed in chapters Three and Four and related appendices, oil and gas operators generally tend to rely on existing roads wherever possible and to construct the minimum length and quality of new roads necessary to enable the required equipment and vehicles to reach a drilling location. For example, operators will usually drive over open rangeland or rely on bladed trails except where rugged terrain require cut-and-fill construction and higher grade road surfaces. In many cases these practices help avoid or reduce some of the more serious impacts attributable to road construction.

It is not possible or practical to specify general road construction guidelines that would be applicable or appropriate to all types of locations in Montana where drilling or production operations might occur. However, there are a number of design principles that oil and gas operators could be required to observe, particularly when it is necessary to construct a new access road across a stream or when cut-and-fill construction is necessary. The Board, in cooperation with state and federal agencies, could prepare guidelines reflecting these principles that would constitute a set of minimum standards for access road construction. While the Board could refer to similar standards published by the Bureau of

Land Management and U.S. Forest Service to create the guidelines, road use and management on private lands may require a different prespective. The Board could request the cooperation of landowners, landowner groups, and oil and gas companies in developing draft guidelines.

Except where a drilling operator is able to rely exclusively on existing roads and tracks, the location of the access road is one of the single most important factors influencing a wide range of potentially significant impacts that may be caused by oil and gas drilling and production. These impacts include the following: (1) impacts on streams, wetlands, and riparian vegetation through increased sedimentation, destruction of forage for both wildlife and domestic animals, degradation of water quality, erosion; (2) impacts on critical wildlife habitat; (3) land use conflicts, such as interference with irrigation equipment and cultivation patterns, impacts on residences; and (4) impacts on recreational and visually sensitive areas.

The judicious siting of new access roads is likely, in many instances, to be a major factor influencing the Board's determination of whether an individual drilling proposal would be likely to have a significant impact on the quality of the human environment. Therefore, it is important for oil and gas operators, landowners, the Board, and any other potentially affected parties to cooperate at an early stage of drill site planning to identify options for siting access roads in a location and manner that will best balance cost considerations, the landowner's preferences, and mitigation of adverse environmental impacts. A later section on Board review of drilling permit applications includes a discussion of the types of sensitive environmental features whose presence indicates a heightened probability that significant environmental impacts may occur. Another option the Board could consider is the adoption of a rule requiring avoidance to the greatest extent feasible or practicable of sensitive areas such as slopes greater than 30 percent, wetlands, and riparian areas. If this option is favored, proposals that involve new roads crossing sensitive areas could be reviewed on a site-specific basis to determine the most appropriate way to proceed with construction.

Reserve Pit Construction, Liner Specifications, and Reclamation. The Board's current rule concerning reserve pits requires the pits to be constructed in a "manner adequate to prevent undue harm to the soil or natural water in the area" and that "when a salt-base mud system is used as the drilling medium, the reserve pit shall be sealed when necessary to prevent seepage." The rules also stipulate that solid wastes accumulated during drilling must either be removed from the site or buried to a minimum depth of 3 feet. Based on the analysis in Chapter Four, it appears that the potential for contamination of both surface- and groundwater and soils would be substantially reduced if the Board's rules were strengthened to specify how pits should be constructed, how liners should be installed and what quality of liner is necessary. The likelihood of contamination would be further reduced if pit reclamation methods and procedures were specified according to site conditions, particularly for sites where plastic liners are deemed necessary.

Another option the Board could consider modifying is the existing rule that requires an oil and gas operator to exercise judgment in determining what is necessary to avoid undue harm to the soil or natural water of an area. For purposes of environmental protection and providing clear guidance to operators, the Board could consider providing criteria for making these judgments, or it could decide what is required on a site-by-site basis. This would enable operators to avoid making incorrect judgments that could result in penalties and extra expense.

Examples of criteria for determining pit design and reclamation requirements include depth to groundwater, soil porosity, and chemical content of the drilling mud and fluids. Decisions on whether it is more appropriate to leave drilling wastes in the pit or to haul the wastes to another location for ultimate disposal could be based on these same criteria.

Examples of specific rules the Board could consider include the following: (1) requiring minimum standards for liner material and installation in all reserve pits that would contain salt-based drilling fluids; (2) requiring liners in any reserve pit located within a certain distance of water wells or potable groundwater supplies; (3) prohibiting construction of reserve pits in fill or other porous material, in wetlands, or in areas that block drainages; (4) prohibiting use of reserve pits for disposal of toxic materials; and (5) requiring that pits be reclaimed without breaching the liner unless site conditions minimize the potential for contamination, and requiring that a bentonite cap be placed over buried drilling wastes to minimize potential for leachate movement into groundwater.

An important aspect of pit reclamation is the length of time a pit is allowed to dry out before it is filled in, particularly in situations where the muds will be buried in the pit at the time the site is reclaimed. The Board could consider developing criteria or guidelines for these decisions because no single set of requirements or time limitations would be appropriate for all drilling locations.

Health and Safety Considerations. Major accidents such as well blowouts and pipeline ruptures are rare. According to the analysis in Chapter Four, comprehensive procedures and equipment are available to ensure proper control of wells during both the drilling and production phases, and to protect the health of workers and the general public. The American Petroleum Institute, Bureau of Land Management, and Alberta have published information regarding measures and equipment to guard against major accidents.

The Board's current rules addressing well control equipment require that in proven (producing) areas the use of blowout prevention equipment must be in accordance with established practice, and that in unproven areas the equipment

Table 40. Summary of Administrative Options for Revising Board Rules.

Topic Area	Administrative Option	Used By:	Comments
1. RESERVE PIT CONSTRUCTION AND DESIGN REQUIREMENTS	a) Rely on general "no pollution" provision.	Colorado	No specific rules or state involvement. Rely on landowner/ company agreement. Agency does enforce "no pollution" requirement (rule 317(c)).
	b) Require that pits be sealed or lined when drilling with certain muds such as salt-based muds.	Montana	ARM 36.22.1005(2) requires that a pit be sealed when necessary to prevent seepage; operator to construct pit to prevent undue harm to soil or natural water.
	c) Require special permit or approval for any earthen pits used during drilling.	Wyoming	Rule 326 requires pit approval (Form 14-B). Supervisor determines if lining is necessary to protect surface- or groundwater. Separation distances from surface waters and water supplies specified.
		New Mexico	Liners required in specific water basins. Pit design and notice of liner required as part of drill permit approval. (Guidelines vary between districts within the state.)
	d) Determine pit lining requirements on a case-by-case basis using pre-drill or other site inspection.	North Dakota	Rule 43-02-03-19 requires supplemental information as part of permit application. Permit may be approved before site inspection but inspection usually once prior to drilling and weekly during drilling.
		Utah	Rule 615-3-16. Site inspection occurs within 15 days of permit application and requirements tailored to the site. Inspections include state geologist, company, and landowner to determine conditions to be placed on drill permit. Unlined pits are inspected again during drilling.
		Alberta	ERCB guidelines contain detailed site design factors and specify separation distances from surface waters or water supplies. Actual requirements tailored to site conditions following a pre-drill site inspection.

		B L M / U . S . Forest Service	43 CFR 3160 (Onshore Oil and Gas Order 1). Both agencies use guidance in this order for authority to determine requirements on a site-by-site basis using information supplied in permit application and obtained from a site visit. F.S. is proposing new regulations which would provide additional guidance on Forest Service lands (draft 36 CFR 228E).
2. DRILLING WASTE DISPOSAL PRACTICES	a) Allow burial on-site in virtually all cases, including breaching of liners and trenching.	Montana	ARM 36.22.1005(1) allows operator discretion to remove waste or to bury on site 3 feet below restored land surface.
		New Mexico	No specific disposal requirements, although agency enforces general non-degradation rules.
		Colorado	Relies completely on agreements between landowner and company.
	b) Based on individual site characteristics, may allow on-site disposal of wastes with appropriate methods to ensure wastes are contained.	North Dakota	Under Rule 43-02-03-19, agency allows on-site burial of muds if site is on impermeable soils; water protection concerns including high water table, nearby stream, or permeable soils may require removal or other treatment such as solidification.
		Wyoming	Under Rule 326, agency requires on-site inspections while pits are in use. Disposal on site generally acceptable; some muds (oil-based mud and muds containing heavy metals) may require treatment prior to pit closure.
		Utah	Evaporation and burial used where pit properly operated and no evidence of leakage found during inspections. Disposal requirements not detailed in rules since this decision relies on the pre-drill site inspections to determine construction and disposal options (Rule R615-3-16).
		Alberta	Provincial consent required for on-site disposal. Muds are screened using lab toxicity test. Appropriate disposal methods may require no treatment, treatment on site, or reinjection.

Table 40. Continued

Topic Area	Administrative Option	Used By:	Comments
2. Continued	b) Continued	B L M / U . S . Forest Service	Based on case-by-case evaluation of site and mud characteristics, agencies evaluate disposal options including solidification, chemical treatment, or reinjection (NTL-2B).
	c) Under appropriate circumstances, require off-site disposal at acceptable disposal site.	Alberta	Following screening, removal of high toxicity muds could be required if on-site treatment and/or reinjection options are not workable.
		B L M / U . S . Forest Service	Off-site disposal can be required under NTL-2B. Decisions regarding off-site disposal depend on factors present at drill site, chemical characteristics of the mud and the practicality of removing the muds and solids from the site.
		North Dakota	Specific site conditions (for example, high water table, nearby stream, or permeable soils) may require that muds be hauled to state-approved disposal site. Small percent (4-5) of sites require this method (Rule 43-02-03-19).
3. PIT RECLAMATION REQUIREMENTS AND METHODS	a) No special requirements for pit reclamation other than return to near original contour or productive capability.	Montana	ARM 36.22.1307: when weather or ground conditions permit, the site shall be restored to its previous grade and productive capability and that necessary measures be taken to prevent adverse hydrological effects. Landowners may agree to other reclamation measures.
		Colorado	No special measures beyond general requirements for "no pollution." Reclamation measures negotiated by landowner and company (Rule 317(e)).
	b) Specify certain requirements for pit reclamation, including time limits for completion, or other measures on a case-by-case basis.	New Mexico	Uses regional guidelines specifying time limits (usually 3 months), depth of burial (2 feet of covering), and near original contours.

		Wyoming	Specify (Rule 326) certain reclamation requirements, including time limits (no later than 1 year), topsoil stockpile and salvage, species mix on public lands (private lands proposed for inclusion), and fencing during pit drying. Landowner can recommend alternative or more specific measures.
		North Dakota	Rule 43-02-03-19 requires time limits (not more than 1 year), cover depth (4 feet), topsoil stockpiling and salvage, fencing, and restoration to near-original contour.
		Utah	Specific determination of reclamation requirements depend on results of predrill site inspection (Rule 615-3-16). Measures for reclamation attached as permit conditions (Rule 615-3-18).
	c) Require approval of specific reclamation plan or oversee development of comprehensive pit reclamation procedures or measures.	North Dakota	Require reclamation plan approval by inspector prior to start of reclamation (Rule 43-02-03-19).
		Alberta	Surface Conservation and Reclamation Law provides ERCB authority to issue Reclamation Certificate to require operator to bring site back to original condition. Bond not released for 5 years following drilling.
		B L M / U . S . Forest Service	43 CFR 3160 (Onshore Order 1) provides agencies with general authority to oversee all aspects of reclamation. Agencies coordinate with surface owner where federal minerals are under private surface. Approved site reclamation plan required for all wells.
4. GENERAL SITE RECLAMATION	a) Generally require all sites be restored to an acceptable standard.	Montana	ARM 36.22.1307 requires that site be restored to previous grade and productive capability.
		New Mexico	Regional guidelines described general acceptable conditions. Rely to large extent on negotiations between company and landowner.
		Colorado	General abandonment requirements for returning well to approximate original condition (Rule 319).

Table 40. Continued

Topic Area	Administrative Option	Used By:	Comments
4. Continued	b) Require certain individual aspects of reclamation for sites, including stockpiling of soil and specifying acceptable seed mixtures or site-specific conditions.	North Dakota	Well site restoration (43-02-03-15) requirements less specific than those for reclamation of pits (43-02-03-19), but in practice similar.
		Wyoming	Well site restoration requirements less specific than those on pit restoration (Rule 326), but in practice similar.
		Utah	Up to end of 1988, general site reclamation requirement applied as permit conditions based on site inspection. Beginning in 1989, specific well site reclamation requirements to be adopted, including landowner consultation provisions.
	c) Specify comprehensive reclamation requirements or require operator to submit a reclamation plan.	Alberta	Under provisions of the Surface Conservation and Reclamation Law, ERCB requires a detailed surface reclamation plan covered under the Reclamation Certificate. ERCB acts as mediator in disputes over reclamation requirements where private surface and mineral estates are separated.
		B L M / U . S . Forest Service	Detailed surface reclamation plan required. Where surface is privately held, agencies consult with landowner to determine reclamation requirements (43 CFR 3160, Onshore Order 1).
5. ROAD SITING, CONSTRUCTION, AND RECLAMATION	a) Rely on negotiations between landowner and company to resolve issues.	Montana Colorado New Mexico	
	b) Require road reclamation bond or minimum road reclamation requirements.	North Dakota	Road reclamation included under general site reclamation bond.
		Wyoming	Road reclamation included under general site reclamation bond. Landowner can waive reclamation of road. On one occasion, agency has conditioned well approval based on the use of an alternative road location.

	c) Address issues about road siting or design based on landowner requests.	Utah	Road to be formally included under site reclamation bond beginning January 1989. Prior to this date, road issues were addressed at predrill site inspection; without agreement between landowner and company, inspector determined minimum acceptable reclamation requirements (R615-3-18).
		North Dakota	On a voluntary basis, when requested by the landowner, the agency has recommended road siting and reclamation measures (Rule 38-08-04).
	d) Detailed agency review of road siting and design based upon information supplied by operator or developed by the agency.	Alberta	Separate permit required from Forestry, Lands, and Wildlife Agency for roads crossing Provincial (Crown) lands; where negotiation on private lands does not resolve road issues, ERCB may use an "induced negotiation" process to resolve issues. ERCB staff also assists in fulfilling negotiated road agreements.
		B L M / U . S . Forest Service	General authority over roads given by Onshore Order 1 and various federal laws granting agencies responsibility for land management. Detailed policies and procedures for road siting and design are found in Forest Service and BLM operation and procedure manuals. In March 1989, agencies expect to publish the "Gold Book" (3rd edition) which summarizes the various direction given in each agency manual. Where private surface overlies federal minerals, agencies cooperate with the landowner in locating, constructing, and reclaiming roads.
6. PRODUCED WATER DISPOSAL METHODS AND PRACTICES	a) Established general requirements for impounding salt or brackish water in earthen pits.	Montana	ARM 36.22.1227 allows disposal of salt or brackish water when pit is underlain by tight soil such as heavy clay or hardpan.
	b) Require individual pit licensing, registration, or lining requirements based on case-by-case evaluation.	Colorado	Rule 325 requires application for permit (Form 15), including analysis of produced water, description of quality of water in receiving area, and a soil analysis. Board determines when liners are used based on site conditions.

Table 40. Continued

Topic Area	Administrative Option	Used By:	Comments
6. Continued	b) Continued	Wyoming	Requires pit registration (Form 14a) and permit. Certain requirements pertaining to acceptable locations have been established (Rule 326). Separate regulations (NPDES) for water quality may apply through Department of Environmental Quality.
		Utah	Rules 615.9-1 through 9. Permits required for all disposal sites. Liners generally required, although unlined pits may be approved. Certain requirements for pit construction and design have been established (Rule 615.9-4). New rules (January 1989) would require synthetic liners rather than compacted bentonite.
	c) Prohibit use of surface pits completely or under certain conditions.	Montana	ARM 36.22.1227(2) prohibits use of pits where soil is porous or closely underlain with gravel or sand.
		North Dakota	Prohibits virtually any use of surface pits (Rule 43-02-03-53(2) and (5)). A few grandfathered pits do exist but require a monitoring system to ascertain impermeability of the pit. Above ground, produced water tanks widely used.
	d) Require comprehensive pit construction methods or procedures.	New Mexico	Requires registration for produced water pits. Clay or equivalent liners generally required. Regional guidelines for design and construction of pits have been developed. Leak detection systems required in sensitive water areas.
		Alberta	Has established pit design and construction specifications. Requires pit registration and permit. Pit specifications may vary between districts. Site monitoring not required. Policy is to begin to phase out surface pits.
		B L M / U . S . Forest Service	NTL-2B provides general guidance and authority for produced water disposal. Disposal based on case-by-case evaluation. Produced water of poor quality and/or large volumes may require special treatment.

7. PRODUCTION FLARING AND VENTING AS RELATED TO AIR QUALITY REQUIREMENTS	a) No routine evaluation requirements for air quality impacts; limited review for any flaring approval.	Montana	Venting limited to 20 MCF per day. Average flaring limit of 100 MCF per day without a permit. All gas containing 20 ppm of hydrogen sulfide must be burned (ARM 36.22.1220 and 1221). Oil and Gas Agency approves all flaring. Air Quality Bureau involved when air quality complaints are received, but not routinely involved in flaring decisions. Air quality permit required by Air Quality Bureau when emissions exceed 25 tons per year.
	b) Share information with air quality agency or require specific information for sour wells.	Utah	Maximum flaring limit of 25 MCF per day without a permit. Flaring above limit requires approval for flaring under restricted rate (R615-3-22). Complaints about flaring referred to Oil and Gas Agency. Air Quality Agency does not review well flaring issues.
		Wyoming	Interagency "Policy Memorandum" (Guidelines under Section 19 of Wyoming Air Quality Act dated May 5, 1986) between Oil and Gas Agency and Air Quality Agency contains provisions for joint notice when flaring more than 50 MCF per day or for any well containing hydrogen sulfide. Air Quality Agency review normally triggered for any well containing hydrogen sulfide. An air quality permit required when emissions are likely to exceed 50 tons per year. New rule (Rule 346) effective January 1989 would formalize existing process and procedures for flaring review.
		New Mexico	Flaring requests authorized under Rule 306 (Fornm C129) by Oil and Gas Agency. Any flaring, except for completion and well tests, requires approval of district supervisor. Agreement with Air Quality Agency requires that air quality consideration be given prior to flaring approvals. Rule 118 requires analysis of gas and other safety measures for hydrogen sulfide wells. Little flaring occurs.
		Colorado	Any well flaring more than 150 MCF per day requires application for flaring permit. Oil and Gas Agency may authorize flaring emissions up to 5 tons per year without air quality permit review. Any well emitting more than 5 tons of pollutants per year may require both a permit to flare from Oil and Gas Agency and air quality permit from Department of Health. All sour wells require gas analysis be submitted to Department of Health. Any planned release of sour gas requires an air quality permit.

Table 40. Continued

Topic Area	Administrative Option	Used By:	Comments
7. Continued	c) Require registration and/ or conduct routine evaluation of air quality impacts related to flaring requests.	North Dakota	A flaring permit not required, although several review requirements for wells may apply. After July 1, 1987, the Department of Health requires that all new or recompleted wells that flare gas be registered. Registration includes a review of flare stack specifications and possible ambient air impacts. Recommendations from the Department of Health are forwarded to Oil and Gas Division (Chapter 33-15-20). Wells that flare sour gas may require a hearing if flaring equipment does not meet minimum requirements. The Oil and Gas Division conducts any necessary hearings to determine flaring equipment requirements. The Department of Health may request that a hearing be held and usually participates regarding ambient air quality and public health issues.
		Alberta	The ERCB "Guide to Production Facilities Construction" requires detailed information necessary for approval of production facilities. ERCB reviews and approves all flaring emissions for air quality concerns. Wells containing more than 1 percent H2S or which would emit 10 tons or more per day of sulfur compounds usually require detailed review.
		B L M / U . S . Forest Service	An environmental analysis of flaring impacts is usually conducted to meet requirements of the National Environmental Policy Act (NEPA). NTL-4A provides authority to regulate flaring. Threshold levels have been established that when exceeded, require modification of flaring requests, interagency consultation, or other more detailed air quality review.
8. ON-SITE SAFETY EQUIPMENT AND PROCEDURE	a) Specify general blowout prevention equipment (BOP) requirements.	Montana	ARM 36.22.1001(3) and (4). In proven areas (producing), equipment shall be in accordance with established practice. Unproven areas: mastergate or equivalent, an adequate BOP, and choke-and-kill line(s) of proper size and working pressure. All equipment shall be in good working conditions at all times.

b) Specific detailed well control equipment and procedural requirements; or require operator to submit a well control plan.	North Dakota	Rule 43-02-03-23. BOP equipment not fully specified. Requirements for periodic equipment testing.
	Colorado	Rule 317 as amended (Cause 1, Order 1-34, December 1985), establishes detailed requirement on most aspects of BOP equipment and testing and worker safety and training. Relies on American Petroleum Institute Report #53.
	Wyoming	Rule 320-A. Specifies detailed BOP equipment and procedures and delineates over pressure zones. Drilling in these zones requires minimum acceptable BOP equipment. For a major drilling program near a city, agency stationed a resident well inspector to monitor daily testing of BOP equipment. Worker safety or training not specifically addressed.
	Utah	Requirements for well control (R615-3-7). When operating in hydrogen sulfide zones, well control plan required. Formations containing hydrogen sulfide identified through maps.
	New Mexico	Establishes range of requirements depending on pressure and location distances from cities and residences. BOP diagram required as part of application to drill.
	B L M / U . S . Forest Service	Onshore Order 2 describes newly adopted safety and BOP requirements for federal wells. These rules rely on recommended practices established by the American Petroleum Institute. BLM is also preparing rules addressing special requirement for wells likely to contain hydrogen sulfide.
	Alberta	ERCB determines if a well in a mapped hydrogen sulfide area is a "critical" sour gas well. For critical sour gas wells, detailed well control, notification, evacuation, and BOP equipment requirements apply (Interim Directive 87-2).

Table 40. Continued

Topic Area	Administrative Option	Used By:	Comments
9. OFF-SITE EMERGENCY PLANNING	a) Require emergency contingency plans in hydrogen sulfide areas.	New Mexico	Requires certain safety devices and notification of surrounding residents within 1/4 mile (Rule 118E3)
		Alberta	Detailed requirements for emergency planning contained in ERCB Interim Directive 87-2 and Guidelines for Preparation of Emergency Response Plans for Sour Gas Wells.
		Wyoming	In identified hydrogen sulfide areas, Rules 202 and 206 are used to require preparation of a contingency plan.
		Utah	Rule R615-3-12 specifies drilling practices and requires written contingency plan when drilling hydrogen sulfide formations.
		B L M / U . S . Forest Service	A draft order detailing emergency response planning for wells containing hydrogen sulfide is being proposed. The material relies on recommended practices and procedures established by the American Petroleum Institute.

Source: Compiled by Mark Kelley and Kevin Hart, DNRC, based upon the phone interviews with officials in each listed state agency, federal agency, and Canadian Province.

must include a master gate or its equivalent, an adequate blowout preventor, and choke and kill line(s) of proper size and working pressures. The Board's current rules do not mention other items that are also part of the overall assembly of equipment that may be needed to ensure well control. Similarly, employee safety training and eduction, safety equipment, and development of hydrogen sulfide contingency plans are not mentioned. Producing oil wells must be equipped with chokes or other adequate control equipment to ensure safe operations. The rules specify that this equipment must be in good working order at all times. Also, at any well where gas containing 20 ppm or more of hydrogen sulfide is vented, a workable ignitor system must be installed and other steps taken as necessary to ensure that all of the gas is burned. It is relevant to note that the latter rule contains the only reference to special procedures or equipment required for safe operations where hydrogen sulfide is present.

The aforementioned rules could be enhanced by adding criteria to assist oil and gas operators in selecting adequate equipment and indicating how the Board would determine whether the selected equipment is appropriate for the working pressures and other site specific conditions that may be encountered. Similarly, criteria could be developed to define what constitutes "established practice" in an area, or, alternatively, what should be done if the operator's inquiries turn up potentially conflicting answers. Additional guidance could be provided by the use of API standards and guidelines which identify minimum requirements for the appropriate level of site planning, employee training, special equipment, special operational procedures, and emergency response planning to protect the public.

The Health and Safety section of Chapter Four provides a detailed description of the procedures and criteria established by the Bureau of Land Management, the Alberta Energy Resources Conservation Board and the states of Utah and Wyoming to help ensure that drilling and production operations are conducted in a safe and proper manner. For example, criteria have been developed to determine which proposed wells should have hydrogen sulfide emergency plans, based on estimated gas flow rate, estimated hydrogen sulfide content, and proximity of residences, urban centers, roads, and other areas frequented by the public.

This material could be used by the Board to develop draft rules and guidelines addressing the minimum procedures, blowout prevention equipment, testing, employee training, and planning, including emergency planning necessary to ensure the safe drilling for and production of oil and gas in the various producing regions of Montana. The Board also could establish criteria to be used to determine which proposed wells should have emergency contingency plans. The Board could take the further step of developing a model contingency plan that would suffice for most locations but that could be modified as necessary to accommodate special concerns or circumstances at individual drilling sites.

Site and Access Road Reclamation. The Board's rules currently require that drilling sites must be returned to their previous grade and productive capability, and that measures must be taken at the time of abandonment to prevent adverse hydrological effects from plugged wells unless the surface owner agrees in writing, with the approval of the Board or its representative, to a different plan of restoration. According to the Board's field inspection staff, oil and gas operators usually confer with landowners or determine on their own how best to comply with this rule. While a Board inspector may be asked to give advice concerning appropriate reclamation procedures or seed mixtures used to revegetate disturbed areas, the inspectors usually are involved primarily in site inspections after reclamation efforts have been undertaken. If problems are discovered the inspector notifies the operator or dirt contractor that further work is needed.

Some of the major steps or activities necessary to increase the likelihood of successful reclamation of drill sites and access roads include stockpiling and replacement of topsoil; ripping compacted soil to a depth sufficient to promote new root growth; appropriate choice of seed mixtures; the addition of mulch, fertilizers, or implementation of other measures as necessary to encourage revegetation; stabilization of slopes, stream banks, and other areas that may be particularly susceptible to erosion or failure; installation of water barring as needed in roadways that will not be revegetated; and removal of culverts and other measures necessary to restore stream crossings.

There are defined principles and minimum acceptable methods for accomplishing satisfactory reclamation of most soil types and landforms in Montana. Many of these methods have been tested and established over the years by land management agencies, other units of government with regulatory responsibility for various types of projects and activities that disturb the land surface, and industry practice. Information about these methods is available through DSL, DNRC, and federal agencies.

The Board could develop guidelines or a model plan for reclamation of oil and gas drilling locations and access roads, or it could specify preferred practices by policy or rule. Rather than attempting to incorporate specific measures that would be required for individual soil types and landforms of Montana, guidelines could concentrate on establishing minimum acceptable practices or procedures. For sensitive sites that might pose special problems for successful reclamation, site-specific measures could be identified at the time that individual drilling permits are issued or at the time that the first site inspection is made. Landowners or companies who wish to deviate from the guidelines on a site-specific basis could do so with the approval of the Board or its representative in a manner similar to that contemplated by the Board's existing rule. Conversely, the guidelines could be written to apply primarily where a landowner does not have a preference for any particular measures.

Alternatively, the Board could require oil and gas operators to include a proposed reclamation plan with each individual drilling permit application. Either of these alternatives would help ensure reclamation success and might reduce costs by minimizing the likelihood of inappropriate choices when site abandonment efforts are undertaken.

Air Quality Considerations. During drilling operations, nitrogen dioxide and carbon monoxide could be emitted at levels that trigger the need for an air quality permit, primarily in situations where rigs with 1500-2000 horsepower engines are used for periods of three months or longer. When the Board reviews the drilling permit application for these types of operations, it could request the Air Quality Bureau to review the project or could advise the oil or gas operator to contact the AQB.

PRODUCTION PHASE

Produced Water Evaporation Pit Design and Reclamation. The Board's rule concerning produced water evaporation pits requires that such pits may only be used when the site is "underlaid by tight soil such as heavy clay or hardpan." The rule also contains a prohibition against impoundment of "salt or brackish water" where the soil under the pit is "porous and closely underlaid by a gravel or sand stratum." This rule could be enhanced by provision of further guidance for oil and gas operators to follow in judging when natural soil conditions are sufficiently impermeable to prevent seepage or when gravel or sand stratum are close enough to the pit bottom to potentially contribute to a contamination problem. Also, requirements for reclamation or ultimate disposal of unevaporated fluids remaining in the pit could be addressed.

Another portion of the Board's rule stipulates that operators must prohibit produced water from escaping over adjacent land or into streams. This rule might be enhanced by guidance concerning the size of the pit relative to production volumes and length of time the water would be stored, with further guidance concerning the need for and capacity of dikes or other measures to keep fluids from escaping and to divert surface runoff from the overall well site.

If the terms "salt or brackish water," "clay," and "hardpan" are retained, the Board could define them in order to provide precise guidance concerning the chemical composition of the water that causes it to be classified as either saltwater or brackish, and to establish an impermeability standard that could be used to judge the acceptability of clay or hardpan for siting an evaporation pit. Alternatively, the Board could consider requiring a special permit for construction of evaporation pits or banning the use of these pits if the produced water has concentrations of sodium chloride or TDS above a certain level. The Board also could consider selectively banning surface pits in areas of the state where surface or groundwater is of relatively high quality. In North Dakota where most produced water is salty, the oil and gas agency has taken the step of banning produced water pits.

Another alternative would be to allow operators to install plastic liners in pits that would contain salt or brackish water in areas where naturally occurring subsoils do not meet impermeability criteria. Technical Appendix 3 contains an example of guidelines developed by the New Mexico Oil Conservation Commission for the installation of pit liners. Oil and gas operators are expected to apply these guidelines unless they can demonstrate that a different method or procedure would accomplish essentially the same objectives.

Based on the analysis in Chapter Four, the environmentally preferred method of disposal of produced water is by underground injection, unless the quality of the water is equal to or better than the water on the surface or in shallow aquifers naturally occurring in an area. The water quality impact analysis and information provided by Board field staff indicate that in some producing areas of Montana the produced water is of lesser quality than surface- or groundwater, but there are not enough disposal wells to accommodate the volume of water produced, particularly in the older producing fields. While there are secondary recovery/waterflood operations in these areas, these operations do not normally accept produced water because it may contain bacteria that could interfere with the water flood operations. The Board could consider establishing a review and permitting process for commercial surface water disposal facilities, either on its own or in conjunction with the Department of Health and Environmental Sciences. This option also could include disposal of drilling muds and mud solids as an alternative solution for areas of the state where other acceptable waste disposal options are limited. However, this option would likely require involvement of the Solid and Hazardous Waste Bureau and the development of specific procedures and requirements for timely siting and licensing of such facilities.

Air Quality Considerations. The primary air pollutants emitted during production operations in quantities that could violate air quality standards are hydrogen sulfide and sulfur dioxide. The Board's rules allow flaring of an average of 100,000 cubic feet of gas per day which is primarily done to convert hydrogen sulfide for safety reasons or when it is not economical to market the gas. The analysis in Chapter Four indicates that wells that flare gas containing 1 percent hydrogen sulfide require an air quality permit (for sulfur dioxide emissions) if they are flaring up to the limit of the Board's rule. Wells flaring smaller quantities of gas with higher concentrations of hydrogen sulfide also could require a permit in some cases. Hydrogen sulfide may be emitted to the atmosphere through accidental or temporary venting, through incomplete combustion during flaring, and through fugitive or breathing losses from storage tanks, pipelines, pumps, seals, and other equipment. Besides the flaring, gas

also may be burned on site to fuel heater treater units, separators, compressors and ancillary equipment. All of these activities contribute to the total load of sulfur dioxide emissions produced at a site.

The Board could consider establishing a joint process with the Air Quality Bureau to determine which oil or gas wells may produce enough of these pollutants to trigger the need for an air quality permit or to violate ambient air quality standards. The analysis in Chapter Four discusses several options for a screening process that would allow the Board to identify the wells. The main information needed is the concentration of hydrogen sulfide in the gas, the flow volume of the well, and the volume of gas being vented, flared, or used on site. The Board could consider adopting a rule to require operators to submit gas analysis data at the time that production begins for each well that produces any quantity of hydrogen sulfide gas. The North Dakota State Department of Health recently adopted a rule requiring all oil and gas wells emitting 10 tons or more per year of "total sulfur" to register the well and provide a gas analysis and other information as needed to determine compliance with ambient air standards.

The Board also could consider establishing criteria or a system for analyzing the gas analysis data and other factors to determine which new production wells are likely to require an air quality permit or which wells should be analyzed in more detail to determine the potential for air quality problems. The Bureau of Land Management considers the gas emission rate, the distance downwind from a well site to Class I or II air quality areas, and whether the well (individually or in combination with other wells in an area) would exceed PSD (prevention of significant deterioration) increments or qualify as a PSD source.

When a drilling permit application is reviewed, the Board could consider the proximity of other wells and whether they are venting or flaring hydrogen sulfide, and also consider the proximity of residences or any designated areas where a reduction in air quality would either be prohibited or would have the potential to create special problems. Data of the production and gas analysis from other wells in the vicinity or producing from the same target formation(s) could also be evaluated to determine whether a proposed well would have the potential to produce either volumes or concentrations of hydrogen sulfide that would cause problems. If the Board were to begin collecting gas analysis data, this information could be incorporated in a data base for use by either the Board, the Air Quality Bureau, or both agencies in analyzing the potential for air quality problems when new wells are proposed. With this information the Board and the Air Quality Bureau would have an enhanced ability to identify wells where venting or flaring should be limited, where air quality monitoring should be done, where special equipment or operating procedures may be necessary to reduce hydrogen sulfide emissions to acceptable levels, and, in rare cases, where it may be impossible to operate a well without violating ambient air quality standards. In these situations, it would be desirable to discover the problem as early as possible. The Air Quality Bureau and the Board could cooperatively evaluate individual wells that could cause air quality problems, particularly in complex situations where the potential need for monitoring or special operating constraints to reduce hydrogen sulfide is unclear.

Another option the Board could consider is a prohibition on flaring at wells that produce gas containing any quantity of hydrogen sulfide until analyses are performed to determine the specific amount that can be flared without violating air quality standards. The amount of flaring that is ultimately allowed could vary depending on mitigating measures implemented to limit emissions. Consultation between the Board and the Air Quality Bureau may be especially warranted when an operator applies to the Board for a variance to allow flaring in quantities greater than the 100,000 cubic feet per day average. Where several production wells are jointly contributing to a problem situation, the Board could consider working jointly with the Air Quality Bureau to develop an emission abatement plan.

BOARD REVIEW OF DRILL PERMIT APPLICATIONS

In order for the Board to expediently evaluate the potential environmental impacts associated with individual drilling proposals, certain information concerning the nature of the individual projects and their proposed locations would be required. As discussed in Chapter Four, the amount of information, level of analysis, and amount of time required to perform an environmental review for any given drilling proposal may vary within regions, primarily depending on the characteristics of the location where drilling is proposed, the location's proximity to existing wells or fields, and other factors as discussed below.

As a result of the Board's evaluation of an individual drilling proposal, special stipulations or conditions might be attached to the drilling permit in order to mitigate specific adverse environmental impacts associated with a particular location. In all cases, the Board would assume that drilling and any subsequent production operations would proceed in compliance with Board rules. As discussed previously in the preceding subsections, certain revisions or additions to the Board's rules would be effective in addressing many potential impacts to air and water quality, safety, and site reclamation, thereby reducing the need to examine these issues in detail on a site-specific basis.

Figure 47 identifies in chronological order the steps that may be necessary to accomplish environmental review of drilling proposals with varying levels of complexity and potential environmental problems. Table 41 outlines possible levels of analysis that might be required to adequately identify

FIGURE 47

ENVIRONMENTAL REVIEW PROCESS FOR OIL AND GAS WELLS

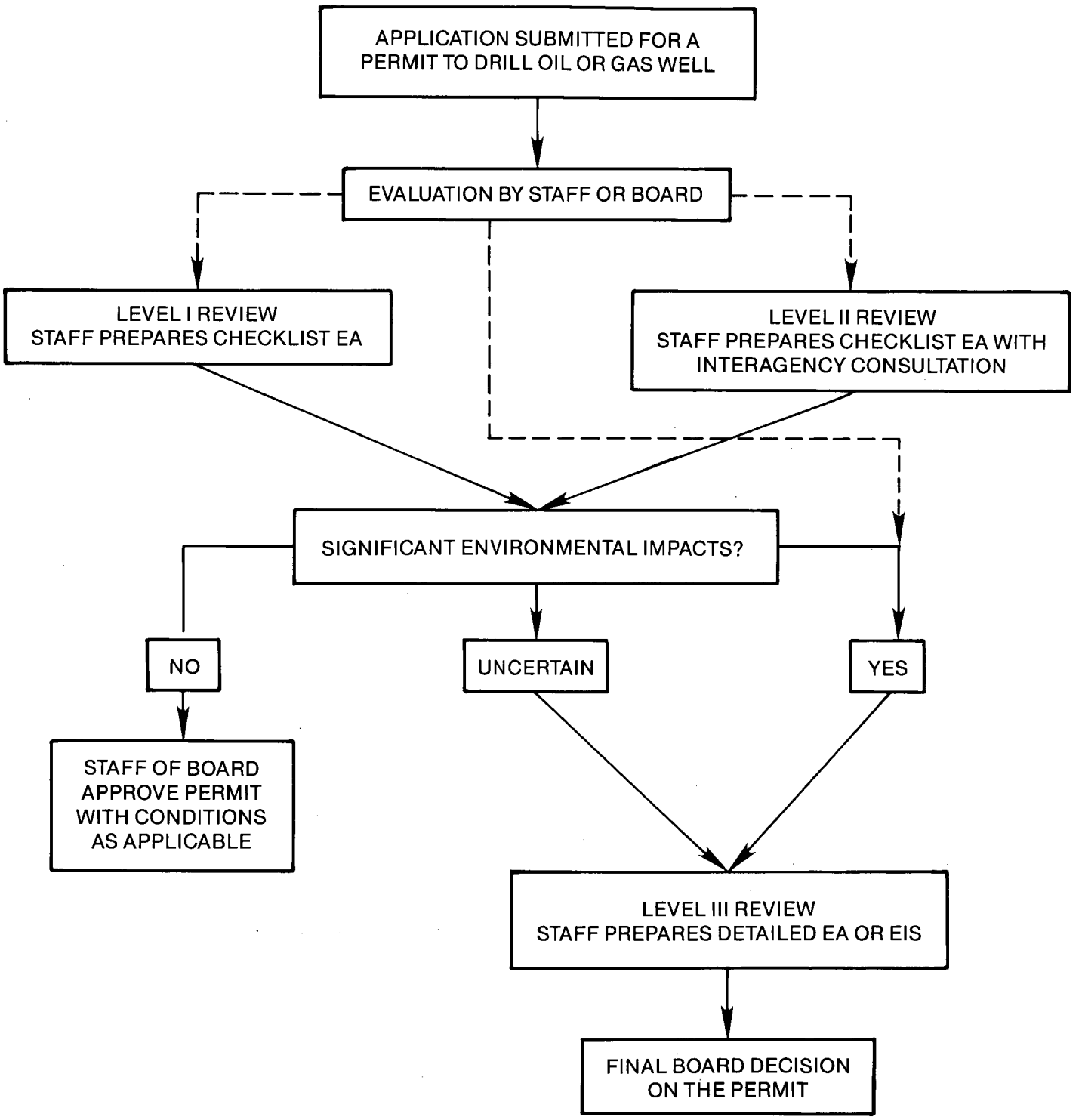


TABLE 41
LEVELS OF ENVIRONMENTAL REVIEW FOR OIL AND GAS WELLS

Possible Levels of Board Review	Administrative Components	Examples of Possible Well and Site Characteristics that Define this Level of of Review[1]	Estimated Annual Percent of Wells Likely to Qualify for this Level of Review[2]	Estimated Time Required Requird by Board to Complete Permit Process[3]
LEVEL I Standard Drilling Operation	a) Operator submits drill permit application form and supplemental information. b) Board prepares checklist; c) Board may attach permit conditions.[1]	a) drilling and waste disposal plans are clearly in compliance with Board rules. b) Adequate date is available to allow the Board to identify any environmental problems and effective mitigating measures based on a brief desk review.	85% - 90%	1 - 2 days
LEVEL II[4]	a) and b) same as Level I c) Board consultation with other agencies d) Board may determine that documentation in addition to the checklist is necessary to explain its decision and any mitigating measures that are deemed necessary. e) Board will likely attach site-specific permit conditions, which could include a special stipulation that discovery of a commercially producible reservoir will necessitate further environmental review before further development may proceed	a) Specific characteristics of target formation(s) may be uncertain or unknown; b) Sensitive environmental features or constraints present; interagency consultation is necessary to identify environmental impacts and appropriate mitigation.	9% - 14%	10 - 30 days[5]
LEVEL III[4]	Board determines that a detailed environmental assessment or environmental impact statement is necessary, involving extensive interagency consultation, site-specific field study, and interaction with the applicant.	Sensitive environmental features are present; serious environmental problems could occur; more detailed information and analysis needed.	1%	6 months - 1 year

1 Compliance with applicable, revised Board rules is assumed for all drilling operations.

2 If the Board defers to environmental review conducted by other agencies when drilling occurs on federal or state-owned land or minerals, these wells would be excluded from the estimates.

3 The estimated time requirements are based on the following assumptions: (a) that the Board has developed rules/guidelines specifying minimum acceptable practice for drilling and production operations; (b) that the information described in Figure Application Form is readily available; (c) for Levels II and III that the Board has established consultative relationships with other agencies; and (d) that the Board has adequately trained staff and that the workload level allows staff to begin review the same day an application for a permit to drill is received.

4 The primary difference between Levels I and II is the amount and quality of information available and the level of uncertainty about whether adverse environmental impacts would occur. The likelihood that Level II or Level III review would be necessary is primarily based on the types and number of sensitive environmental features in an area and the seriousness of environmental impacts that are considered likely to occur.

5 If interagency consultation can be accomplished by telephone, the time required for reveiw could potentially be reduced to 2 or 3 days. The estimates assume that procedures would be established to ensure timely response to Board requests for consultation. If there are interagency disagreements about the nature of environmental impacts, mitigation, and strategies to address problems, additional time would likely be required to complete the permitting process.

potential environmental impacts associated with different types of drilling proposals and locations. Estimates of the average percentage of wells likely to qualify for a particular level of review also are presented, based on the characteristics of well proposals received by the Board. Estimates of the time required for the Board to complete each level of review also are included in the table. Figure 47 includes the levels of review that are described in Table 41. As indicated on Figure 47 and as discussed further below, more detailed review (e.g. levels II and III) would be applied to progressively more complex drilling proposals and locations. However, as shown by the dotted lines between the levels on the chart, any given drilling project could potentially qualify for a lesser level of review or a higher level, depending on site-specific characteristics.

LEVEL I REVIEW OF DRILLING PROPOSALS

Board decisions concerning the types of information needed to expediently evaluate individual drilling proposals involve important tradeoffs among the following considerations: (1) ensuring that environmental resources are adequately identified and that sufficient information exists to evaluate potential impacts; (2) ensuring that any extra expense and time required of oil and gas operators to mitigate environmental impacts are imposed only at locations where problems would otherwise be likely to develop; and (3) ensuring that the extra expense and time required for operators to supply information to the Board is fairly and reasonably allocated, and focused to the greatest extent feasible on operations and locations where environmental problems are most likely to occur.

The term "categorical exclusion" is included in new revisions to the MEPA rules. As used in these rules, categorical exclusion refers to a type of agency action that the agency has determined would almost never individually, collectively, or cumulatively result in significant impact on the quality of the human environment. The action is therefore categorically excluded from additional environmental review. Categorical exclusions are usually established through rulemaking and may be based on supporting studies that establish the reasons a particular action would not create significant impacts. Under the rules, a categorical exclusion does not exempt the action from complying with MEPA, but removes, except for extraordinary circumstances, the requirement that an environmental assessment or environmental impact statement be prepared.

While the Board could consider the use of categorical exclusions in its drill permitting process, this option would not eliminate the need for sufficient information from operators to document that a particular drilling project qualifies for the exclusion. As discussed below, the administrative steps included in a "Level I" review may represent the minimum level of documentation likely to be necessary for evaluation of standard drilling operations. As noted previously in Chapter Four, it is not possible for the Board to predetermine that drilling operations have no significant impacts without some type of case-by-case evaluation.

A relatively large percentage of proposed drilling operations are likely to qualify for Level I review (see Table 41). Under Level I review, it is assumed that accurate information about both the surface and sub-surface is readily available for a proposed drilling operation, and that no unusual circumstances would raise questions about its ability to comply with applicable Board rules. The steps the Board would take to complete a Level I review would include a desk review of data submitted by the operator or collected by the Board, preparation of a brief environmental checklist (see later discussion), and, if necessary, attachment of special permit conditions to address any environmental problems. The time necessary to complete these administrative tasks normally would not exceed two days.

The types of information and level of site-specific detail needed to evaluate the environmental impacts of a drilling proposal depend at least partially on decisions the Board makes concerning adoption of new rules and development of guidelines delineating minimum acceptable practices for activities such as drill location, siting, construction, and reclamation of access roads, and the construction and reclamation of reserve pits and evaporation pits. For example, if the Board defines minimum acceptable practices and attaches a general condition to each drilling permit requiring compliance with these practices, it probably would not be necessary for operators to submit site-specific construction and reclamation plans unless sensitive resources would require special measures in addition to the minimum practices. It should be noted that the technical mitigation measures discussed in Chapter Four are examples of strategies that may be effective in addressing special problem situations.

Another Board decision that will affect the amount and types of information that must be reviewed concurrently with drill permit applications is whether the Board will determine the necessity of pit liners for each individual drilling operation, or whether pit liners would be automatically required by rule for some drilling operations, such as those that use saltwater-based drilling muds. The Board also could rely on a combination of these options. For example, if a freshwater drilling operation is proposed at a site with relatively impermeable soils and a deep water table, a pit liner might be unnecessary. However, if the same operation were proposed at a site overlain by glacial till and located near the headwaters of a stream, a pit liner might be needed. Either some level of site-specific data would be needed for the Board to make this determination, or the Board's rules would need to clearly identify the circumstances where liners are necessary. A key issue is how the Board can most efficiently

FIGURE 48
REVISED DRILL PERMIT APPLICATION

Board of Oil and Gas Conservation
of the
State of Montana

Application for Permit to:			Oil well	Gas well	Other
Drill: ☐	Deepen: ☐	Recomplete: ☐	☐	☐	☐

_____Montana_____ Date:_____19_____
(county) (field or wildcat)
Lease Name:_____Well Number:_____

¼¼ Sec._____ Section_____ Township_____ Range_____ MPM

Footage Location:
surface: _____Feet from___(N/S) line and _____Feet from___(E/W) line of Section____
Directional Holes: (give location at top of proposed producing zone and bottom hole)
_____

Drilling/Spacing Unit:_____ Elevation_____(Ground or KB)

Exception Location? _____(Y/N) API number of another well on this lease (if applicable) 25-_____-_____

Total Depth:	Formation at TD	Principle Objective Formation(s)

Est. date work will begin:_____

Est. time to drill: _____

Possible H2S formations to be penetrated by this well:	Formation at the Surface:

Casing - Cementing

Hole size	Casing size	Weight /foot	Grade API	Depth (MD)	Sacks of cement	Type of cement

Description of Proposed Operations
Include: proposed mud program or indicate if well will be air drilled; probable source(s) of drilling water. Describe BOP stack including type, pressure rating etc. of each major component, or attach an appropriately labeled diagram.

Approved by_____
Date_____

Operator_____
Agent _____
Address _____
City/State_____
Telephone (____)_____

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Supplementary Information *

1) Attach a topographic map or suitable equivalent of the location:
Please show the location, access route from county roads or other established roads, nearest fresh water streams, lakes, ponds, etc.
Name and distance to closest surface water if not shown on map:
_____

2) Are there any water wells within 1/2 mile of the location?
Yes ☐ No ☐ If yes, Location_____
Depth_____Formation_____

3) Attach a plan view of the location showing dimensions and orientation of location, size and location of pit(s), location of topsoil stockpile, and approximate cut/fill at the corners and centerstake of the location.

4) Will the reserve pit be lined?
Yes ☐ No ☐ If no, what is the soil type and approximate depth to the water table.
If Yes, what type of lining/sealing material will be used?_____

5) Are there occupied dwellings, schools, recreation areas, parks etc. within one mile of the location?
Yes ☐ No ☐ If Yes, please show on topographic map, or attach a list showing distances, directions and names of the residents, facilities, etc. If too numerous to list give an estimate of the number of residences or the name of the town, subdivision, or residential area.

6) Is this location near a designated Historical or Cultural resource area listed by the Montana Historic Preservation Office.
Yes ☐ No ☐ If yes please give name (if named) and type of resource (eg. historic site, archaeological site, etc.)
Name/type_____
Location _____

7) Does the location or access road lie in or near a designated wildlife refuge, or game management area? (Areas managed by Dept. of Fish, Wildlife, and Parks or federal agencies)
Yes ☐ No ☐ If yes please indicate the name of the refuge, park or area. (or approximate location if not named)
Name_____

8) Does the construction of the access road or location, or some aspect of the drilling operation require additional State or Federal permits? Please indicate below:

☐ Stream Crossing Permit (apply through county Conservation District)

☐ Air Quality Permit (may be required if drilling time exceeds 90 days and total engine horsepower exceeds 1500 hp)

☐ Water use permit (must be filed for groundwater withdrawals exceeding 100 gpm within 60 days of water well completion)

☐ Federal Drilling permit

☐ Other Federal or State Permit: (specify)_____

* This information will be required to complete the checklist. An attempt has been made to balance who could provide the required information so that the permit processing time could be shortened. If this information was collected after submitting a drill permit the processing time could be longer.

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obtain the information needed to ensure that the rules are appropriately applied.

Persons desiring to construct an earthen reserve pit in Wyoming must obtain a special permit from the Wyoming Oil and Gas Conservation Commission. The permit usually is issued along with or at approximately the same time as the drilling permit. The form (see Technical Appendix 3) requires applicants to describe the proposed mud program, the design of the pit and type of sealing material to be used, the subsoil type, the drainage distance to the closest fresh surface water, the period the pit would be in use, and the plan for final disposal of the pit contents. An analysis of the water/fluid that would be placed in the pit also must be submitted. Wyoming and New Mexico have similar forms that must be filed by persons proposing to construct produced water pits.

Alternatively, the Board could decide to require pit liners for all drilling operations unless the operator submits site-specific data showing why the Board should grant a variance. If pit liners were automatically required, site-specific information concerning soil type and depth to groundwater might not be needed.

Figure 48 is a sample form that outlines the information the Board is likely to need from oil and gas operators to evaluate the potential environmental impacts of a drilling proposal. The requested information includes a description of the drilling operation, and certain characteristics of the location and surrounding area.

Figure 48 and other figures described in this chapter are draft examples of an application form or checklist that could be used to fulfill the objectives of Senate Bill 184. These examples are provided to help illustrate how to integrate MEPA into the Board's drill permit process. The Board may adopt or modify the application forms and checklist for its use, but such formal action would only occur following notice at a later date.

Some of the environmental impacts that may be associated with oil and gas drilling and production may be most appropriately addressed by the Board through revision of its rules as discussed earlier in this chapter. Examples include most of the water quality-related impacts, health and safety considerations, some of the air quality impacts, and most concerns relating to site construction and reclamation. The other categories of impacts, including wildlife, recreation, aesthetics, land use, cultural resources, and socioeconomic considerations, may not lend themselves as readily to a rule-oriented approach for either analysis purposes or for impact mitigation. However, the Board could consider addressing these topics through rules directing operators to avoid sensitive environmental features wherever possible and requiring site-specific evaluation if avoidance is not possible.

The Board probably would find it necessary to supplement the location-related information provided by operators in drilling applications in order to evaluate potential environmental impacts. Options for obtaining this information include: (1) establishing and maintaining an in-house data base system and maps at the Board's office; (2) obtaining data and other information through consultation with other agencies of state, federal, and local governments having jurisdiction or expertise concerning a particular geographic area or type of environmental resource; (3) reliance on the Montana State Library, Natural Resource Information System data base; (4) personal knowledge of Board staff; (5) consultation with affected landowners; and (6) pre-drill site inspections when warranted. The Board's selection of the best option or combination of options for obtaining necessary information should be based on considerations of efficiency and effectiveness, and the three primary trade-offs identified at the beginning of this subsection.

Much of the information necessary for the Board's evaluation of drilling proposals is readily available in both published and unpublished reports and maps produced by various state and federal agencies. However, the quality and level of specificity of published data varies considerably. For example, the geologic and soils maps of Montana produced by the Soil Conservation Service and the Montana Bureau of Mines and Geology generally indicate the dominant soil type and surficial geologic characteristics for a given area, but do not note smaller locations where deposits of a different soil type or geologic unit may exist within the mapped area. These different deposits could have a major influence on the time and expense required to properly site and construct a reserve pit if, for example, an operator had a choice between placing the pit either over relatively deep but porous soil or in porous but shallow soils over an impermeable clay subsoil. The difference in soil types and surficial geologic materials might not be discovered unless the operator submits appropriate descriptive data or unless the Board's staff, the landowner, or other persons familiar with the characteristics of a proposed drilling location are able to supplement and clarify the written or mapped data. Consultation and personal contact with knowledgeable individuals may be the most efficient and effective option for verifying data and gaining an accurate understanding of the environmental resources of an area. Site inspections also may be necessary in some cases. These steps are especially integral to the more detailed levels of review (Levels II and III) where the presence of sensitive environmental features and uncertainties in available data require more effort to identify potential environmental problems.

Table 42 provides a summary of the sensitive areas and characteristics identified in Chapter Four whose presence at or near a proposed drilling site indicates that adverse environmental impacts could occur. Most of the location-

TABLE 42
SENSITIVE ENVIRONMENTAL FEATURES AND CONSTRAINTS FOR OIL AND GAS WELLS*

GEOLOGY/SOILS

Steep slopes (30% or greater)
Unstable slopes
Produced waters—high TDS sodium chlorides
Erodible soils
Porous soils
Floodplains

WATER QUALITY

Municipal watersheds
Portable surface and ground water
High water table

AIR QUALITY

Hydrogen sulfide
Sulfur dioxide
Class I areas
Non-attainment areas
Narrow mountain valleys

WILDLIFE/FISHERIES

Critical game habitat
- winter range
- migration routes
- birthing grounds
- breeding grounds

Class I and II streams
Waterfowl Production areas
Riparian habitat
Threatened/endangered species habitat
Designated game refuges and ranges

LAND USE

Residences
Public roads
Public buildings
Cities/towns
Irrigated cropland
Designated natural areas
Roadless areas

RECREATION/AESTHETICS

Developed recreation sites
Dude ranches/resorts
Parks/monuments
Fishing access sites
Wild/scenic rivers
Wilderness/primitive areas
Established trails
Scenic overlooks/roadways

CULTURAL/HISTORIC

Native American religious sites
National register sites/landmarks
Paleontological sites
Historic sites

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* Definition of sensitive environmental features and constraints may need to be developed. Use of sources from published information or available from other agencies may ease the task of determining presence or absence of these factors.

related data the Board is likely to need would be used to establish whether any of these sensitive features or constraints are in the vicinity of an individual drilling operation. If the Board favors the use of the "sensitive area" concept and establishment of its own data base or a system for quickly referencing data collected and managed by other agencies, the Board could eventually consider working with other agencies to create maps of the various oil and gas producing regions in the state, identifying the locations of all known natural and cultural resources that should be considered for purposes of impact evaluation. Maps of this type would substantially increase the efficiency of the environmental review process.

LEVELS OF REVIEW II AND III

The principal difference that distinguishes Level II and III review from Level I review is the amount and quality of readily available information describing the surface and sub-surface characteristics of a drilling location, and the level of uncertainty concerning whether adverse environmental impacts would be likely to occur. Also, there may be uncertainty about what mitigating measures would be most effective. The uncertainties associated with drilling in "new" areas some distance away from established producing wells are more likely to require interagency consultation to identify potential environmental impacts. Proposals requiring more extensive review (Level II) may also require more detailed documentation of the Board's analysis and resulting permit conditions than would normally be included in an environmental checklist. This subject is discussed further in the following section on evaluation of environmental impact. The success and timeliness of interagency consultation depends to a large degree on whether the Board and the other involved agencies agree on both the procedures to be followed when the Board requests assistance and on the level of detail needed to respond to a request.

Level III is the most detailed level of review. It is reserved for proposals deemed likely to cause significant environmental impacts. This level of review would include extensive interaction between the applicants, the Board, and other affected parties. It would culminate in the preparation of either a detailed environmental assessment or environmental impact statement.

Except for situations where the nature of a drilling proposal and the presence of sensitive environmental features clearly and immediately indicate a need for detailed analysis (i.e. Level III review), all drilling proposals would receive the same initial evaluation, with the preparation of an environmental checklist (see discussion in following subsection). Some examples of drilling proposals the Board could be called upon to evaluate may be useful in illustrating when a particular level of environmental review might be applied and how the presence of sensitive environmental features may affect both the timing and complexity of the Board's permitting process.

Table 43 presents some examples of hypothetical drilling proposals that the Board is likely to receive. The examples draw upon the impact analysis in Chapter Four for the combinations of environmental features and constraints that could be present at proposed drilling locations. The estimated time required to conduct the environmental review for each example is highly dependent upon data availability, Board staff workload and training, and the status of the Board rules/guidelines as explained in the footnotes.

BOARD EVALUATION OF IMPACTS

With the information concerning the drilling operation and the proposed location as described in the previous subsection, the Board would be prepared to determine whether an individual drilling proposal would be likely to have a significant impact on the quality of the human environment, and could identify mitigating measures that could be taken to reduce or avoid the impacts. The Board also could use the information to fulfill MEPA's requirement for interdisciplinary review of proposed actions. The analysis in Chapter Four indicates that most drilling operations, particularly those that are ultimately unsuccessful, are not likely to cause significant impacts if they are conducted in accordance with Board rules and guidelines described earlier in this chapter, and with any special permit conditions that the Board imposes. Therefore, for most drilling operations, a major purpose of the Board's impact evaluation is to document reasons behind the conclusion that no significant impacts would be likely.

It is important to distinguish between the information the Board would collect to evaluate impacts and the evaluation itself. For example, maps, consultation with various agency personnel, and other data may indicate the presence of a number of sensitive environmental features in the vicinity of a drilling site (as listed in Table 42). The purpose of the evaluation is to determine whether conditions warrant further investigation or analysis and whether the proposed drilling and production would be likely to have a significant impact. The presence of a sensitive environmental feature signals the possibility of adverse impacts, but the evaluation may reveal that problems either would not be likely to occur or that the problems can be mitigated by modifications in the way the drilling or production operation is conducted.

The Montana Environmental Policy Act is the basis for the Board's obligation to integrate use of the natural and social sciences and environmental design principles in planning and decision making and to consider the environmental consequences of actions and proposed projects under its jurisdiction, including determining the significance of impacts of drilling proposals. Over the years that MEPA has existed, state agencies have developed both formal and informal procedures for making the significance

TABLE 43

EXAMPLES OF ENVIRONMENTAL REVIEW SCENARIOS

Hypothetical Drilling Proposal[1]	Environmental Features/Constraints	Likely Level of Environmental Review	Likely Time Required
Wildcat Well to Known Producing Formation — Location is near a producing well — H2S present — saltwater drilling — 1/2 mile new access trail—bladed — lined reserve pit	— rangeland, flat to gently rolling — 1/2 mile to nearest surface water — no sensitive features at or near the drill site	Level I	1 or 2 days[2]
Rank Wildcat Well — formation characteristics uncertain — saltwater drilling anticipated — H2S may be present — 1/2 mile new access road—partly cut and fill construction — lined reserve pit	— irrigated cropland — riparian vegetation — 1/4 mile to river — shallow water table — no nearby residences — 1/2 mile to developed recreation sites (campground & fishing access)	Level II	1 or 2 days[2,3]
Rank Wildcat Well — deep target formation, characteristics uncertain — 1/2 mile new access road—partly cut and fill construction — H2S likely present — fresh water drilling — lined reserve pit — road use only by the operator and contractors — road reclamation planned if well is unsuccessful	— foothills — big game winter range — municipal watershed — 1/2 mile to public land and recreation area — rural residences down-drainage — porous soils — Class I stream less than 1/4 mile away	Level II or III[4]	10 - 30 days[2,5]
Rank Wildcat Well — H2S present — extensive new access roads — fresh water drilling	— mountainous terrain — Class I stream drainage — critical wildlife habitat — grizzly bear habitat — roadless area — adjacent primitive recreation area — visually sensitive — adjacent private recreation facilities or business — glacial till soils	Level III	6 months - 1 year[6]

Footnotes

1 "Wildcat" and "Rank Wildcat" wells may require formal definitions.

2 Assumes (a) that the Board has developed rules/guidelines specifying minimum acceptable practies for drilling and production operations; (b) that the information described in Figure 48 is readily available; (c) that the Board has established consultative relationships with other agencies; and (d) that the Board has adequately trained staff and that the workload level allows staff to begin review the same day an application for a permit to drill is received; (e) that no exceptions to the statewide spacing rule are involved.

3 This example assumes only telephone contact for interagency consultation.

4 Level II review could be adequate for this example if sufficient data is readily available to assess impacts, if all involved agencies are essentially in agreement about any mitigating measures that would be applied, and if sufficient data and analysis has been done to allow Board to determine that convern over impacts raised by other agencies or the public have been adequately addressed.

5 This time estimate assumes interagency agreements can be readily reached. If documentation is required or if further effort to work out disagreements is necessary, additional time will be needed to complete the review process.

6 The assumptions included in Footnote 3 would also apply to Level III review except that the data necessary to conduct the environmental evaluation will likely require more extensive effort to compile than the other levels of review.

determination and recording the results. State agencies use the "preliminary environmental review" (PER)--in new MEPA rules this document would be a type of "environmental assessment" known as an EA--to document their predictions of impact significance and to fulfill their other MEPA responsibilities. For projects or types of actions that normally are not expected to have significant environmental impacts, the PER or EA is a brief checklist.

Figure 49 is an example of a checklist that the Board could consider adopting for use in evaluating the impacts associated with drilling. This type of checklist could be prepared for projects that receive Levels I and II review. As noted in Table 41, Level II could involve additional analysis and documentation for more complex projects that do not warrant Level III review. The sample checklist is specifically tailored to identify the impacts of drilling and production operations in the context of the type of well being drilled and the various natural and cultural resources that may be present. The checklist requires the evaluator to decide whether a particular impact would be likely to occur, whether it would be major, moderate, or minor, and whether options are available and necessary to reduce the adverse effects.

Because MEPA does not define the term "significant," state agencies, over the years, have developed their own internal processes and considerations for making this judgment. The administration has recently adopted new rules implementing MEPA which, for the first time, describe the criteria most state agencies have been using to evaluate the significance of impacts on the quality of the human environment. These criteria are as follows: 1) the severity, duration, geographic extent, and frequency of occurrence of the impact; 2) the probability that the impact will occur if the proposed action occurs; or conversely, reasonable assurance, considering the severity of an impact, that the impact will not occur; 3) growth-inducing or growth-inhibiting aspects of the impact, including the relationship or contribution of the impact to cumulative impacts; 4) the quantity and quality of each environmental resource or value that would be affected, including the uniqueness and fragility of those resources or values; 5) the importance to the state and to society of each environmental resource or value that would be affected; 6) any precedent that a proposed action might set that would tend to commit the agency to future actions with significant impacts, or a decision in principle about such future actions; and 7) potential conflict with local, state, or federal laws, requirements, or formal plans.

The impact analysis in Chapter Four, and the general conclusion that most drilling operations are not likely to result in significant impacts on the quality of the human environment when reasonable mitigation is applied, are based on these criteria. This conclusion assumes the short-term, localized nature of the impacts when drilling does not discover commercially producible oil or gas and when all aspects of the operation conform to Board rules and guidelines, and use of available mitigating measures that are effective in reducing drilling impacts in sensitive locations that contain fragile or unique resources. If adequate information is available concerning a proposed drilling operation and its location, preparation of the checklist would not be a time-consuming element of the Board's environmental review process. Table 41 shows that inadequate data, the likelihood of potentially serious environmental problems, and the complexity of mitigating measures are the most likely to increase the amount of time required to complete review for a drilling proposal.

Once the Board determines the approach it will take to establish its environmental review process, some period of time likely will be needed to establish a data base, collect maps, develop new rules/guidelines, establish consulting relationships with other agencies, train staff, and to explain the process to oil and gas operators and landowners.

If the Board decides to use a checklist to document its environmental evaluations, it may wish to advise the staff on the assumptions and approach to be used in filling out the checklist. Some of the considerations include: (1) determining what type of study, if any, is warranted by a lack of site-specific information or the potential for environmental problems; (2) determining whether to omit some categories of impacts from the checklist because individual drilling projects seldom or never cause those impacts; (3) determining whether impacts associated with production rather than drilling should be included in the checklist evaluation, and if so, deciding how they should be treated; and (4) determining how mitigation and assumptions about compliance with the Board's rules should be reflected in the checklist. The following discussion explores these issues further.

When a checklist is prepared, the Board would have to decide whether the information available is adequate to immediately complete the checklist, or whether circumstances warrant further study. The staff's personal familiarity with various geographic areas of the state is likely to be important in judging whether the available information is sufficient for evaluation of possible impacts. Also, if the Board favors collection of relevant published data and establishment of an in-house data base, the staff's ability to conduct desk reviews of drilling applications would be enhanced.

Consultation with staff of other agencies having expertise in resource areas such as water, wildlife, and soils would probably be the most effective method of resolving questions about sensitive environmental features and whether any serious problems are likely to occur as a result of drilling or production. Only when these inquiries fail to generate satisfactory answers would further site-specific investigation become necessary.

The analysis in Chapter Four indicates that individual drilling projects will seldom or never cause certain types of impacts. Some examples include economic and

FIGURE 49
ENVIRONMENTAL CHECKLIST FOR OIL AND GAS WELLS

PART A

Development well/short step-out
(one mile or less from existing field:)

SAMPLE

Is this well within one mile of an existing field or producing well?

Yes ☐ No ☐ Field Name _____
(if No use part B)

Is there any aspect of the proposed operation which differs significantly from the existing operations?

Yes ☐ No ☐

If Yes, what is the difference? _____

Will this difference result in impacts (or levels of impact) that would not usually be associated with the type of wells commonly drilled in the field or producing area?

Yes ☐ - use part B

No ☐ - explain: _____

Will successful completion of this well result in expansion of the field into areas with substantially different resources or values, or result in substantially increased impacts or impacts not associated with the existing wells?

Yes ☐ - use part B

No ☐

Complete the Summary Evaluation of Impacts Section (Part C).

PART B

EXPLORATORY OR LONG STEP-OUT WELLS
(greater than one mile from existing production)

When completing the following section consider potential impacts that could occur as a result of drilling and possible production from the individual well.

AIR QUALITY:

OVERALL RATING:

(POSSIBLE CONCERNS)
- Long drilling time
- Unusually deep drilling (high horsepower rig)
- Possible H_2S Gas production
- In/Near Class I air quality area
- Air quality permit for flaring/venting (if productive)

MAJOR	
MODERATE	
MINOR	
NONE	

MITIGATION:
- Air quality permit (AWB Review)
- Gas plants/pipelines available for sour gas
- Special equipment/procedures requirements
- Other: _____

_____

WATER QUALITY:

OVERALL RATING:

(POSSIBLE CONCERNS)
- Salt/oil based mud
- High water table
- Surface drainage leads to live water
- Water wells nearby
- Porous/permeable soils
- Class I stream drainage

MAJOR	
MODERATE	
MINOR	
NONE	

MITIGATION:
- Lined reserve pit
- Adequate surface casing
- Berms/dykes, re-routed drainage
- Closed mud system
- Other: _____

_____

SOILS/VEGETATION/LAND USE:

OVERALL RATING:

(POSSIBLE CONCERNS)
STREAM CROSSINGS
- High erosion potential
- Loss of soil productivity
- Unusually large wellsite
- Loss of native vegetation/timber/crops/special status plants
- Damage to improvements
- Conflict with existing land use/values

MAJOR	
MODERATE	
MINOR	
NONE	

MITIGATION:
- Avoid improvements (topographic tolerance)
- Exception location requested
- Stockpile topsoil
- Stream crossing permit (other agency review)
- Reclaim unused part of wellsite if productive
- Special construction methods to enhance reclamation
- Other: _____

_____

SAMPLE

HEALTH HAZARDS/NOISE:

OVERALL RATING:

(POSSIBLE CONCERNS)
- Proximity to public facilities/residences
- Possibility of H_2S
- Size of rig/length of drilling time

MAJOR	
MODERATE	
MINOR	
NONE	

MITIGATION:
- Proper BOP equipment
- Topographic sound barriers
- H_2S contingency and/or evacuation plan
- Special equipment/procedure requirements
- Other: _____

WILDLIFE/RECREATION:

OVERALL RATING:

(POSSIBLE CONCERNS)
- Proximity to sensitive wildlife areas (FWP identified)
- Proximity to recreation sites
- Creation of new access to wildlife habitat
- Conflict with game range/refuge management

MAJOR	
MODERATE	
MINOR	
NONE	

MITIGATION:
- Avoidance (topographic tolerance/exception)
- Other agency review (FWP, federal agencies, DSL)
- Screening/fencing of pits, drillsite
- Other: _____

HISTORICAL/CULTURAL/PALEONTOLOGICAL:

OVERALL RATING:

(POSSIBLE CONCERNS)
- Proximity to known sites

MAJOR	
MODERATE	
MINOR	
NONE	

MITIGATION:
- Avoidance (topographi tolerance, location exception)
- Other agency review (SHPO, DSL, federal agencies)
- Other: _____

SOCIAL/ECONOMIC:

OVERALL RATING:

(POSSIBLE CONCERNS)
- Substantial effect on tax base
- Create demand for new governmental services
- Population increase or relocation

MAJOR	
MODERATE	
MINOR	
NONE	

SAMPLE

PART B (Continued)

EVALUATION OF CUMMULATIVE IMPACTS

If additional wells were drilled within 2 miles of the proposed well what would be the cummulative impacts on the following:

	MAJOR	MODERATE	MINOR	UNKNOWN
AIR QUALITY				
WATER QUALITY				
SOILS/VEGETATION/LAND USE				
HEALTH HAZARDS/NOISE				
WILDLIFE/RECREATION				
CULTURAL/PALEONTOLOGICAL				
SOCIAL/ECONOMIC				

SAMPLE

Complete Part C

PART C
SUMMARY EVALUATION OF IMPACTS

Does the proposed drilling project considered as a whole:

Have impacts that are individually limited, but cumulatively considerable? (A project may result in impacts on two or more separate resources which create a significant effect when considered together or in total.)

Contribute substantially to adverse effects on an environmental resource that are occurring or anticipated due to other development, including oil and gas drilling, in the same geographic area as the proposed drilling project?

Establish a precedent or likelihood that future actions with significant environmental impacts will occur?

OVERALL SUMMARY RATING OF IMPACTS:

MAJOR	MODERATE	MINOR	NONE

The proposed project will have:

☐ No significant impacts; no further evaluation necessary.

☐ Impacts are potentially significant. Additional environmental analysis, documentation or consultation needed, as follows: _____

_____

_____

_____

Prepared by: _____ (Title) _____

Date: _____

SAMPLE

public service impacts. Activities extensive enough to trigger these impacts generally are associated with cumulative aspects of development. Therefore, if these categories of impact are included on a checklist, the evaluator would, in most instances, probably check the columns marked "none" or "minor." The argument that favors leaving these categories on the checklist is that they would then be formally considered and documented along with the rest of the impact evaluation.

A related issue concerns categories of impact that rarely would be considered issues for drilling operations but which would be matters of concern if the drilling is successful and production follows, particularly in locations not adjacent to wells or fields. Some examples are recreational areas and facilities or cultural/historic properties which might be subjected to minor impacts during drilling but would suffer long-term impacts if drilling were successful and production were to result. The question in this context is how the possible production impacts should be evaluated in the checklist and what measures should be taken or committed to, if any, to address the production-related issues when the drilling permit is approved.

The sample checklist attempts to address these concerns in two ways. The issues related to production from the individual well, if drilling is successful, would be considered when completing the checklist. Reasonably foreseeable cumulative impact issues would be disclosed by indicating potential impacts if additional wells were drilled in the area. This approach would allow disclosure of possible cumulative impact issues associated with a new field but recognize that field development occurs on a well-by-well basis.

The Board could consider several options for determining how the checklist evaluation should reflect mitigation and assumptions about compliance with Board rules. The most basic issue is whether staff should be instructed to determine the level of impact assuming no special precautions were taken to prevent a particular type of environmental problem or to determine the impact level considering that a certain mitigating measure is taken, and then cite the applicable Board rule, or otherwise record on the checklist what mitigation would be necessary. The latter approach appears more consistent with discussion elsewhere in this chapter concerning the need for all drilling projects to comply with the Board's rules, especially if they are revised as discussed in the earlier section. The alternative assumption that there would be no mitigation or compliance with Board rules may be unnecessarily confusing and could produce misleading results.

BOARD RELATIONSHIPS WITH OTHER AGENCIES

This chapter refers repeatedly to Board consultation with various other agencies of state, federal and local government. The efficiency and effectiveness of the Board's environmental review process can be substantially enhanced by developing cooperative working relationships with other agencies that have jurisdiction or expertise concerning various environmental resources or geographic areas of Montana. The state agencies the Board is most likely to work with include but are not limited to the Water Quality Bureau, Air Quality Bureau, Solid and Hazardous Waste Bureau (all three bureaus are part of the Department of Health and Environmental Sciences), Department of Fish, Wildlife and Parks, the Water Rights Bureau (Department of Natural Resources and Conservation), Department of State Lands, the State Historic Preservation Office, the Natural Resource Information System in the State Library, and the Bureau of Mines and Geology.

Local and other units of government that may be able to assist the Board include county planners and sanitarians, Conservation Districts, and county weed control personnel. Numerous federal agencies are likely to have information that the Board may need, including the U.S. Forest Service, Bureau of Land Management, U.S. Environmental Protection Agency, Soil Conservation Service, and U.S. Fish and Wildlife Service.

The Board's current working relationships with many of these agencies are described in Chapter Two. For the most part, these relationships do not include the type of consultation discussed in this chapter except in problem situations where some type of complaint has been filed or an accident has occurred. The relationships that the Board could establish in the future include sharing of data and expertise, joint field inspections, and sharing or division of responsibilities.

A formal mechanism that agencies often rely on to define their relationship is a Memorandum of Understanding (MOU). The Board has an existing MOU with the Bureau of Land Management outlining how the Board's responsibility for issuing permits to drill is integrated with the BLM's responsibility for development of federal minerals. The Board could consider expanding this MOU to address how the Board would either integrate its environmental review process with the federal process conducted under the National Environmental Policy Act, or defer to the federal process by adopting environmental documents prepared by federal agencies. A similar MOU could be established with the U.S. Forest Service, and possibly also with the departments of State Lands, and Fish, Wildlife and Parks, for drilling operations on state-owned lands. Some of the topics that could be addressed by an MOU or other type of interagency

agreement include procedures for ensuring timely response to Board requests for assistance, format of information requests made by the Board to ensure adequate response, and procedures for resolving differences of opinion among agencies.

The Board appears to have several options to consider concerning the relationship it might establish with the Air Quality Bureau, Water Quality Bureau and possibly the Solid and Hazardous Waste Bureau. When a drilling or production operation requires an air, water or solid waste disposal permit, the oil and gas operator clearly needs to deal directly with the appropriate bureau. In situations where it is unclear whether a permit is needed, whether a problem exists, or whether the characteristics of a drilling location indicate a potential need for special drilling permit conditions to protect air and water quality, the Board's staff and DHES staff would need to work together. An unrealistic option that could be considered is assigning complete responsibility for air quality, water quality, and solid waste-related issues to one agency.

Since neither the Board nor DHES currently allocate staff time to analyze potential air, water or solid waste problems before a drilling permit is issued, it appears that both agencies may find it necessary to reassign or share staff. The latter option has been successfully pursued by the Department of State Lands and Water Quality Bureau for review of mining permit applications. Where both a mining permit and water discharge permit are needed the agencies retain their separate authorities, but the analysis of information is handled jointly. If this option is favored for oil and gas permitting, both the Board and DHES agency workload and budgets may increase.

For other agencies of state government, local government, and most federal agencies except BLM and USFS, the nature of their relationship with the Board is likely to be primarily consulting (sharing information, occasional joint site visits, development of suitable mitigation measures). Until the Board begins implementing its environmental review process, the level and volume of interaction is difficult to estimate. It also is important to note that the number of drilling permits the Board reviews can vary dramatically from year to year and that agency managers would need to adjust accordingly.

BOARD STAFFING AND BUDGET CONSIDERATIONS

The Board probably would have to add some staff to implement the environmental review process and to work with the oil and gas industry to achieve participation and compliance. As discussed in the previous subsection, the Board could consider sharing one or more staff positions with DHES. Also, existing staff may need training in conducting environmental reviews and field investigations. Another possible resource available to the Board for general environmental staff support could be found in DNRC, which assists other state agencies in the preparation of environmental documents. A combination of technical and managerial skills may be desirable if the Board favors the option of adding new staff. Special attention would need to be given to defining how any new positions will relate to the field inspection staff.

Staffing implications accompany all the options the Board may consider for revision of its rules, for collecting information to evaluate drilling proposals, and for potentially adopting a classification system to assign certain types of drilling proposals to certain levels of environmental review. For example, if the Board favors the adoption of rules and guidelines that effectively predetermine the need for pit liners at certain drilling operations and minimum acceptable practices for construction, reclamation, and waste disposal, less staff time may be needed. Conversely, however, new rules and guidelines are likely to increase the workload for the field inspection and enforcement staff. If the Board adopts an environmental review classification system that places a high percentage of drilling proposals in review levels I and II, the process will clearly require far less staff time than if all or most drilling proposals were to receive detailed, site-specific review. If such a system is applied to the present rate of drilling permit applications, staff requirements could range from one or two new positions to a dozen or more, primarily depending on how drilling proposals are assigned among the various possible levels of review.

Training and education of existing Board staff is a related consideration that is likely to require attention. Training could be accomplished by sending staff to workshops and seminars on preparation of environmental review documents. This type of training is periodically offered by private consultants or sponsored by groups of state or federal agencies. Board discussions establishing cooperative and consulting relationships with other agencies also could include plans for bringing their staffs together both in the office and in the field to educate one another about their respective responsibilities and resource areas. State agency staff with experience in conducting environmental reviews under MEPA also could be requested to meet with the Board's staff on both a formal and informal basis, and to be available to answer periodic questions. Another option the Board could consider is contracting with other state agencies for staff assistance in performing environmental review for the relatively few drilling proposals likely to require such extensive study and documentation.

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GLOSSARY

Abandon

To cease producing oil or gas from a well when it becomes unprofitable. A wildcat (exploration) well may be abandoned after it has been proven nonproductive. Usually, some of the casing is removed and salvaged, and one or more cement plugs placed in the borehole to prevent migration of fluids between formations.

Abnormal pressure

Pressure exerted by a formation and exceeding or falling below the normal pressure to be expected at a given depth. Normal pressure increases approximately 0.465 psi per foot of depth. Formations with abnormally high pressure must be controlled to prevent a blowout.

Acidize

To use acid to increase production of oil-bearing limestone or other formations. The acid etches the rock, enlarging the pore spaces and passages through which the reservoir fluids flow.

Alluvial material

Material, transported and deposited by running water in riverbeds, lakes, alluvial fans and valleys. It includes clay, silt, sand, gravel and mud.

Anhydrite

The common name for calcium sulfate, $CASO_4$, sometimes call gypsum or gyp. Anhydrite formations are sometimes encountered during drilling.

Anion

A hydrogen atom or a molecule of other compounds that carries a negative charge (opposite of cation).

Annular blowout preventer

A large valve, usually installed above the ram preventers, which forms a seal in the space between the pipe and wellbore, or, if no pipe is present, on the wellbore itself. The annular preventer fills the space by hydraulically extruding a resilient packing element.

Annulus or annular space

The space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing.

Application for Permit to Drill, Deepen or Plug Back (APD)

The Department of Interior application permit form to authorize oil and gas drilling activities on federal land.

Aquifer

1. A layer of material that contains water.
2. The part of a water-drive reservoir that contains the aquifer.

Artificial lift

Any method used to raise oil to the surface through a well, after reservoir pressure has declined to the point where the well no longer produces by means of natural energy. Sucker-rod pumps, hydraulic pumps, submersible pumps, and gas lift are the most common methods of artificial lift.

Best Available Control Technolog (BACT)

The best available air pollution control technology for a given purpose as stipulated by the U.S. Environmental Protection Agency.

Blooey pit

The pit that receives cuttings and other discharges from a well drilled with air.

Blowout

An uncontrolled expulsion of gas, oil, or other fluids from a drilling well. A blowout or "gusher," occurs when formation pressure exceeds the pressure applied to it by the column of drilling fluid and when blowout prevention equipment is absent or fails.

Blowout Preventer (BOP)

Equipment installed at the well head to prevent the escape of pressure either from the annular space between the casing and drill pipe or from an open hole during drilling and completion operations (see annular BOP or ram BOP).

Brackish water

Water that contains relatively moderate concentrations of any soluble salts. Brackish water is saltier than fresh water but not as salty as salt water or brine water.

Brine

Water containing relatively large concentrations of dissolved salts, particularly sodium chloride. Brine has higher salt concentrations than ordinary ocean water.

Brine pit

An excavated pit used to hold brine produced from a well.

Buffer zone

1. An area between two different land uses that is intended to resist, absorb or otherwise preclude developments or intrusions between the two use areas.
2. A strip of undisturbed vegetation that retards the flow of runoff water, causing deposition of transported sediment and reducing sedimentation in the receiving stream.

Bureau of Land Management (BLM)

The Department of Interior agency responsible for managing most federal government subsurface minerals. It has surface management responsibility for federal lands designated under the Federal Land Policy and Management Act of 1976. BLM is a major Montana land holder with surface holdings of approximately 8 million acres (9 percent of Montana).

Casing

Steel pipe placed in an oil or gas well to prevent the hole from caving.

Cation

A positively charged hydrogen atom or a molecule of other compounds (opposite of anion).

Christmas tree

The control valves, pressure gauges, and chokes assembled at the top of a well to control the flow of oil and gas after the well has been completed.

Class II injection well

A well, as defined by the U.S. Environmental Protection Agency, that injects fluids:

a. that have been brought to the surface in connection with oil or natural gas production (produced waters);
b. for enhancing recovery of oil or natural gas, or
c. for storing liquid hydrocarbons.

Close in

1. To temporarily shut in a well that is capable of producing oil or gas.
2. To close the blowout preventers on a well to control a kick.

Closed mud system

A drill mud system that reuses or reclaims all the drilling fluid used. Oil-base mud systems are often closed mud systems.

Completion

The activities and methods to prepare a well for production. Includes installation of equipment for production from an oil or gas well.

Colluvial

Loose, incoherent geological deposits at the bottom of a slope or cliff, having fallen from above.

Decibel or dB

A unit for measuring sound intensity, usually measured on the decibel A weighted scale (dBA) which approximates the sound levels heard by the human ear at moderate sound levels.

Deepen

To increase the depth of a well. Deepening is generally a workover operation carried out to produce from a deeper formation or to control excessive gas found in the upper levels of a reservoir.

Developed recreation

Recreation activities that occur where improvements enhance the recreation opportunity and accommodate concentrated recreation activities in a defined area.

Development well

A well drilled in proven territory (usually within 1 mile of an existing well).

Derrick

The large load-bearing structure used to raise and lower the drill pipe. In the past, the derrick was assembled and bolted together piece by piece. The derrick has largely been replaced by the mast, which is raised and lowered as a unit (see Figure 16).

Desander

A centrifugal device used to remove fine particles of sand from the drilling fluid or mud.

Desilter

A centrifugal device, simular to a desander, used to remove very fine particles, or silt, from the drilling fluid.

Directional drilling

The intentional deviation of a wellbore from vertical to reach subsurface areas off to one side from the drilling site.

Dispersed recreation

Recreation activities using wide areas that require few, if any, improvements. These activities include hunting, fishing, viewing nature, picnicing, berrypicking, off-road vehicle use, hiking, horseback riding, and camping.

Displacement

As applied to wildlife, forced shifts in the patterns of wildlife use, either in location or timing of use.

Disposal well

A well into which produced water from other wells is injected into an underground formation for disposal.

Doghouse

1. A small enclosure on the drill rig floor used as an office for the driller or as a small storehouse.
2. Any small building used as an office or for storage.

Drill pipe

The heavy seamless tubing used to rotate the drill bit and circulate the drilling fluid. The standard drill pipe section is 30 feet long (a joint).

Drill rig

The mast, drawworks, and attendant surface equipment of a drilling or workover unit.

Drill stem test

The use of a drill-stem testing tool to test a formations potential productivity. The tool is lowered to the formation and is packed off from the above formations. The tool is then operated to sample the formation and the results recorded. Also, called a formation test.

Dry hole

Any well incapable of producing oil or gas in commercial quantities. A dry hole may produce water, gas or even oil, but not enough to justify production.

Elevated flares

The use of piping and a burn stack to elevate the flare that burns unusable petroleum vapors. Elevated flares may include an ignitor to ensure continuous burning or an incinerator where gas is added to ensure complete combustion of petroleum products.

Endangered plants

Any plant species in danger of extinction throughout all or a significant portion of its range in Montana.

Endangered species

Any species in danger of extinction throughout all or a significant portion of its range. These species are protected by The Endangered Species Act of 1973.

Enhanced recovery

The use of artificial means to increase the amount of hydrocarbons that can be recovered from a reservoir. A reservoir depleted by normal extraction practices usually can be restored to production by secondary or tertiary methods of enhanced recovery.

Environmental Assessment (EA)

A written analysis of a proposed action to determine whether an Environmental Impact Statement is required and to ensure compliance with the Montana Environmental Policy Act.

Environmental Impact Statement (EIS)

The detailed document required by Section 75-1-201, Montana Code Annotated, and prepared to assess the environmental consequences of state government actions having significant impacts on the human environment.

Environmental review

A process established by the Montana Environmental Policy Act to assess the impacts of state agency actions on the human environment. This process may involve an environmental assessment, an environmental impact statement or a programmatic review.

Evaporite

A sedimentary rock (such as gypsum or salt) that originates from the evaporation of seawater in enclosed basins.

Exploration well

A well drilled in an area where there is no oil or gas production. Same as a "wildcat" well.

Extinct plant

A species that, based on recent field searches, is thought to no longer occur in Montana.

Flare

The piping and burners used to dispose (by burning) of unuseable vapors from a well or collection plant. The flaring of oil field gas is regulated by the Montana Board of Oil and Gas Conservation, and may require an air quality permit from the Montana Department of Health and Environmental Sciences.

Flow line

The surface pipe through which oil travels from a well to processing equipment or storage.

Forage
All browse and nonwoody plants available to livestock or wildlife for feed.

Foreground view
The landscape area visible to an observer within 1/2 mile.

Forest Service (FS)
The agency of the United States Department of Agriculture responsible for managing National Forests and Grasslands under the Multiple Use and Sustained Yield Act of 1960. The Forest Service manages approximately 16.7 million surface acres in Montana (18 percent of Montana).

Fracture treatment
A method of stimulating well production by increasing the permeability of the producing formation. Under extremely high hydraulic pressure, the fracturing fluid (water, oil, dilute hydrochloric acid, or other fluid) is pumped into the formation and parts or fractures it. Proppants or propping agents such as sand or glass beads are pumped into the formation as part of the fracturing job. The proppants become wedged in the opened fractures, leaving channels for oil to flow into the well after the hydraulic fracture pressure is released. This process is often called a "frac job." When high concentrations of acid are used, it may be called an "acid-frac job."

Geophysicist
A scientist who applys physics and mathmatics to discover mineral resources in the earth's crust.

Habituation
The process of getting accustomed to conditions which formerly were disturbing.

Heater-treater
A container that heats the oil, gas or water/oil emulsion to remove the water and gas and make the oil acceptable for pipeline transmission (see Figure 22).

Hiding cover
Vegetation, primarily trees, capable of hiding animals from predators. Hiding cover is capable of normally concealing animals from view.

Hoist
At an oil or gas well, the arrangment of pulleys and cables used for lifting heavy objects; the drawworks.

Human environment
The factors that include, but are not limited to biological, physical, social, economic, cultural and aesthetic factors that interrelate to form the environment.

Impact
The result of an action in comparison to the present condition or a baseline condition. It can be either beneficial or detrimental.

Indicator species
A species of animal or plant whose presence is a fairly certain indication of a particular set of environmental conditions. Indicator species serve to show the effects of development actions on the environment.

Injection well
A well used to inject fluids into an underground formation to increase reservoir pressure.

Kelly
The heavy steel bushing, four or six sided, suspended from the swivel through the rotary table and connected to the topmost joint of drill pipe. It is used to transfer twisting motion from the rotary table to the drill pipe.

Kick

A pressure rise in well caused by the entry of water, gas, oil, or other formation fluid into the wellbore. If a kick is not controlled, it may lead to a blowout.

Leachate

The soluble minerals or metals dissolved out of soil or other material by percolation of water.

Lease

1. A legal document that conveys to an operator the right to drill for oil and gas.
2. The tract of land, on which a lease has been obtained, where producing wells and production equipment are located.

Lost circulation

A condition resulting from the loss of drill mud into a formation, usually in fissured or coarsely permeable beds, evidenced by the complete or partial failure of the circulated mud to return to the surface. Usually solved by adjusting the drill mud viscoity and gel strength using additives to prevent mud flow into the porous formations. Also called lost returns.

Marketable timber

Trees that can be sold with an acceptable profit level.

Mast

A portable derrick capable of being erected as a unit. For transportation, the mast can be divided into two or more sections.

M.C.A.

Montana Codes Annotated, a compilation of Montana Laws by subject area, prepared biennially by the Montana Legislative Council.

Mitigation

1. Avoiding an impact by not taking a certain action or parts of an action.
2. Minimizing impacts by limiting the degree or magnitude of an action and its implementation.
3. Rectifying an impact by repairing, rehabilitating, or restoring the affected environment.
4. Reducing or eliminating an impact over time by preservation and maintenance operations during the life of an action or the time period thereafter during which an impact continues.

Montana Board of Oil and Gas Conservation (Board)

The quasi-judicial board established in Montana Code Annotated 2-15-3303. The Board consists of seven members, three of whom are from the oil and gas industry and two of whom are landowners in oil and gas producing counties. The Board is allocated to the Department of Natural Resources and Conservation for administrative purposes only and may hire and supervise its own staff.

Montana Department of Fish, Wildlife, and Parks (DFWP)

The state department responsible for conserving and managing wildlife, and for providing park and recreation opportunities. The department issues hunting and fishing licenses, enforces wildlife laws, manages wildlife areas, parks and recreation areas, and seeks to enhance state wildlife populations.

Montana Department of Health and Environmental Sciences (DHES)

The state department responsible for protecting the health of the states citizens. It provides air and water quality control, environmental sanitation, child health and nutrition, medical facility oversight, and local health services.

Montana Department of Natural Resources and Conservation (DNRC)

The state department responsible for the conservation and use of Montana's water, soil and rangelands, for the efficient use of energy resources and for minimizing the impacts of energy and water developments. The Oil and Gas Division, which is the staff of the Montana Board of Oil and Gas Conservation, is attached to the Department for administrative purposes.

Montana Department of State Lands (DSL)

The state department responsible for managing Montana statehood lands to achieve maximum returns for the school trust. The Department of State Lands manages approximately 5.1 million surface acres (5.5 percent of Montana). It also administers Montana mining reclamation laws and provides fire protection services on state and private lands.

Montana Environmental Policy Act (MEPA)

The Montana law concerning environmental assessment of state actions (Montana Code Annotated, Chapter 75, Parts 1-3).

Mud

The liquid circulated through the wellbore during rotary drilling and workover operations. Although the mud originally used for drilling was a suspension of earth solids (particularly clays) in a water base, modern drilling muds are a three-phase mixture of liquids, reactive solid and inert solids. The liquid may be fresh water, salt water or oil.

Mud additives

Any material added to drilling fluid (mud) to change some of its characteristics or properties.

Mud pump

A large, reciprocating pump used to circulate the mud on a drilling rig. The mud pump typically is driven by a crankshaft actuated by an engine. Also called a slush pump.

Mud pit

A reservoir or tank, through which the drilling mud is cycled to allow sand and fine sediments to settle out. Mud pits are also called shaker pits, settling pits and suction pits, depending on their main purpose (see slush pit).

Oil mud

A drilling mud in which oil is in the fluid base.

pH

A measure of acidity or alkalinity. A solution with a pH of 7 is neutral, pH of over 7 (to 14) is alkaline and a pH less than 7 (to 0) is acidic.

Pit flaring

The burning of unuseable petroleum vapors in an excavated pit.

Preliminary Environmental Review (PER). (obsolete) See Environmental Assessment.

A brief written statement on a proposed action to determine whether the action will significantly affect the quality of the human environment and therefore require an environmental impact statement.

Pressure gradient

The variation in pressure between points in a system such as the top and bottom of an oil well.

Prevention of Significant Deterioration (PSD)

The criteria established under the Clean Air Act Amendments of 1977 for new emission sources in an air quality area. Increments of air quality degradation are established depending on an area's air quality classification.

Produced water

Water produced from oil and gas wells.

Programmatic review

An analysis (EIS or EA) of the impacts on the quality of the human environment caused by or resulting from agency-initiated actions, programs, or policies. This may include the continuancy of a broad policy or program which may involve a series of future actions.

Ram preventer, or ram blowout preventer

A blowout preventer that uses horizontal sliding gates or rams to seal off pressure on a hole with or without pipe or casing in place. "Blind" rams are used to close the hole when no tools or pipe are in the hole. "Pipe" rams have a notch which fits around the drill pipe when the rams are closed.

Rare plants

A plant species, or subspecies, that is limited to a restricted geographic range, or one that occurs sparsely over a wider area in Montana. Rare plant status has been given to species whose distribution within the state appears restricted to a small area (usually one or two counties) or to those that are more widespread but are limited to a very restricted habitat. A rare species must be native to Montana and rare in Montana; but it need not be restricted to Montana.

Reclamation

Rehabilitation of a disturbed area to make it acceptable for designated uses. This normally involves regrading, replacement of topsoil, revegetation and other work necessary to restore it for use.

Recreation experience

The social and psychological outcomes and benefits of voluntarily engaging in intrinsically rewarding recreation activities.

Recreation opportunities

The combination of recreation settings, activities and experiences provided by an area.

Reserve pit

1. Usually an excavated pit that may be lined with plastic, that holds drill cuttings and waste mud.
2. Term for the pit which holds the drilling mud.

Revegetation

The reestablishment and development of self-sustaining plant cover. On disturbed sites, this normally requires human assistance such as seed bed preparation, reseeding and mulching.

Rig (short for drill rig)

The mast, drawworks, and attendant surface equipment of a drilling or workover unit.

Riparian areas

Zones along streams, ponds, or other water bodies characterized by plants and animals requiring substantial amounts of water. This includes floodplains, wetlands and all areas within approximately 100 feet of the normal high water line.

Rod pump or sucker-rod pump

The downhole assembly that uses reciprocating action to lift fluid to the surface.

Saline water

Water containing high concentrations of salt (see also brine water and brackish water).

Security habitat

Hiding cover modified by open roads. The greater the density of open roads within an area, the less effective the area is in providing security for large animals.

Sediment

Solid mineral or organic material that is transported by air, water, gravity, or ice.

Seismic operations

Use of explosive or mechanical thumpers to generate shock waves that can be read by special equipment to give clues to subsurface conditions.

Shut-in
To close the valves on a well so it stops producing.

Slush pit
The pit in which the drill cuttings are separated from the mud stream or in which the mud is treated or temporarily stored before being pumped into the well (see mud pit).

Sour well
In an oil or gas well, a condition caused by the presence of hydrogen sulfide or another sulfur compound.

Spawning areas
Areas used by fish and other aquatic animals for laying eggs.

Spud or spud in
To begin drilling the hole.

Stands
The connected joints of pipe racked in the derrick or mast when making a trip. A common stand is 90 feet long (three lengths of pipe screwed together).

State agency
An office, commission, committee, board, department, council, division, bureau or section of the executive branch of Montana state government.

Step out well
A well drilled some distance from a proven well to determine the limits of the oil or gas reservoir.

Stipulations
Requirements and conditions that are part of a mineral lease or permit. Some stipulations may be standard on any lease, while special stipulations are used where needed to protect natural resources or land uses.

Strutting grounds
Areas used by sage grouse for displays during the mating season.

Surface casing
The first string of casing set in a well after the conductor pipe; varying in length from a few hundred feet to several thousand feet. Surface casing is used to protect surface aquifers.

Sweet well
An oil or gas well lacking sulfur and any significant amount of hydrogen sulfide or mercaptans.

Tank battery
A group of production tanks that store crude oil in the field.

Thermal cover
During the winter, plant or topographic cover used by wildlife for shelter. For elk, a stand of coniferous trees 40 feet or taller with an average crown closure of 70 percent or more provides thermal cover.

Threatened plant
Any species that is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range in Montana.

Trip (make a trip)
To hoist the drill stem out of the wellbore to perform one of a number of operations (change bits, take a core, etc.) and return the drill stem into the wellbore.

Tubing

Small-diameter pipe that is run into a production well to serve as a conduit for the passage of oil and gas to the surface.

Vapor recovery

A system or method by which petroleum vapors are retained and conserved.

Visual management system

A management system that establishes the "visual landscape" as a basic resource, treated as an essential part of the land. The visual management system provides a framework to inventory the visual resource and provides measurable standards for its management.

Visual resource

The composite of basic terrain, geologic features, water features, vegetative patterns, and land use effects that typify a land unit and influence the visual appeal the unit may have for visitors.

Waiting On Cement (WOC)

Pertaining to the time when drilling or completion operations are suspended so the cement in a well can harden sufficiently.

Weeds

1. Plants growing where they are not wanted or that are more harmful than beneficial.
2. Any exotic plant species established or that may be introduced in the state of Montana which may render land unfit for agriculture, forestry, livestock, or other beneficial use.

Well bore

The hole in the earth drilled by the bit.

Well completion

See Completion

Well logging

The recording of information on conditions in the well bore. Information used includes drilling records, mud and cutting analyses, core analysis, drill-stem tests, and electric and radioactivity procedures.

Well stimulation

Any of several operations used to increase production of a well by enlarging old channels or creating new ones. These include acidizing, fracturing, and nitro-shooting.

Wildcat well

An exploratory well drilled in an area where there is no oil or gas production (see exploration well).

Wildfire

A fire, other than a controlled burn or prescribed burn, occurring on wildlands.

Winter range

Areas used by wildlife during the winter, usually including forage, security, and thermal cover areas.

Workover

To perform one or more remedial operation on a producing well to increase production. Deepening, plugging back, pulling, and resetting the liner are examples of workover operations.

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