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Unconventional Gas Recovery: State of Knowledge Document

C. A. Geffen

DOE Project Manager
Dr. George J. Rotariu

January 1982

Prepared for the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

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Richland, Washington 99352

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FOREWORD

This state-of-knowledge document is one of several reports prepared to summarize the types and degree of work completed in the last several years relating to environmental, health, and safety considerations of Unconventional Gas Recovery (UGR) technologies. This report is a synthesis of environmental data and information relevant to the four areas of UGR resource recovery: methane from coal, tight western sands, Devonian shales and geopressurized aquifers. Where appropriate, it provides details of work reviewed; while in other cases, it refers the reader to relevant sources of information.

This report, by Pacific Northwest Laboratory, consists of three main sections, 2, 3, and 4. Section 2 describes the energy resource base involved and characteristics of the technology and introduces the environmental concerns of implementing the technology. Section 3 reviews the concerns related to unconventional gas recovery systems which are of significance to the environment. The potential health and safety concerns of the recovery of natural gas from these resources are outlined in Section 4.

Responsibility for the contents and development of a state-of-knowledge document is assigned to individual technology specialists in the Technology Assessment Division. Technical comments regarding this document would be appreciated and should be addressed to the following.

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INTRODUCTION

Unconventional gas recovery (UGR) is defined as the commercial production of natural gas from reservoirs that do not yield gas economically by conventional techniques. The resources that are the target of this development include methane in coal beds, natural gas in tight western sand basins and Devonian shale, and methane from geopressured aquifers.

This state-of-knowledge document identifies the potential environmental, health and safety impacts of Unconventional Gas Recovery technologies and addresses the uncertainties in these areas that remain to be resolved through research and development activities. The resolution of these uncertainties may require adjustments in ongoing technology programs to allow commercialization of the various resource recovery techniques. The impacts and concerns presented in this document are considered generically without reference to specific predetermined sites. Hence, site-specific implications are not generally included in the report.

The information presented in this document was obtained primarily from a series of four technology assessments of the potential environmental, health and safety impacts of unconventional gas resource recovery operations (Ethridge, et. al. 1980; Riedel, et. al. 1980; Riedel, 1981; Usibelli, et. al. 1980). These assessments were developed using extensive literature searches, and describe in detail each of the specific technologies summarized in this report. The purpose of these assessments was to provide a detailed description of the potential public health and safety issues and the potential environmental impacts of UGR operations. Thus, the information contained in this state-of-knowledge document is a distillation of the detailed analysis available in the above-mentioned reference documents. Readers desiring further information on particular topics mentioned here should consult the relevant technology assessment document listed in Section 5, References.

In addition to the summary in Section 1, this report consists of three main sections. Section 2 describes the energy resource base for unconventional gas and the characteristics of the various recovery technologies. Section 3 discusses the concerns related to UGR systems that are of significance to the environment. The potential health and safety concerns associated with the recovery of these resources are outlined in Section 4. A list of acronyms and a glossary of petroleum industry-related terms is included in Appendix A.

1.0 SUMMARY OF ENVIRONMENTAL ASPECTS OF UNCONVENTIONAL GAS RECOVERY TECHNOLOGIES

Unconventional gas recovery (UGR) is defined as the commercial production of natural gas from natural underground reservoirs that do not yield gas economically by conventional techniques. The natural resources that are the target of this development include methane in coal beds, natural gas in tight western sands and Devonian shale, and methane from geopressured aquifers.

It appears that these resources can be recovered and utilized in an environmentally acceptable manner. Although there are some environmental impacts associated with UGR operations, these impacts do not differ significantly from those found in conventional petroleum and gas recovery activities, whose effects are being researched and mitigated by ongoing programs. Most of the potential environmental, as well as health and safety, impacts identified for UGR activities are of minor consequence and may be easily controlled by currently available technology.

Existing environmental, health and safety regulations also serve to mitigate most of the potential impacts of UGR technologies. Many similar problems, such as air emissions from diesel engines, noise, and disposal of drilling and waste water, are regularly encountered in conventional oil and gas recovery operations. The environmental impacts of UGR are primarily local, temporary concerns and are anticipated to have no severe consequences.

The following paragraphs summarize the potential environmental impacts that may be experienced in UGR operations. Potential impacts or concerns that are unique to a specific resource base or recovery technology are identified separately.

The activities associated with development of a gas field that could potentially result in minor environmental impacts include site preparation and drilling and stimulation of production wells. Most of the impacts resulting from these activities are insignificant and can be readily controlled with available technology. Environmental consequences during site preparation center on air emissions from the diesel engines used in construction and effects on the local ecology from general construction operations. These emissions are anticipated to be below the limits set by the Environmental Protection Agency and affect local areas only for limited, temporary periods of time.

After production begins, the noise levels, human activity, and air pollution decrease. The only noise that may then occur from the site is when the gas needs to be compressed before entering the pipeline. There may also be intermittent high noise levels during routine maintenance checks. This should be minimal compared to drilling or fracturing.

Fracturing jobs usually last three to eight hours; therefore, the potential noise and air pollution impacts from machinery will probably not be measurable over the long term. The constituents of fracturing fluid are non-toxic, so provided spills are cleaned up, no impact from chemical spills will result. These impacts are not unique to UGR operations. Similar impacts are experienced in conventional petroleum recovery operations on a larger scale.

The only significant environmental concerns experienced in unconventional gas recovery are those associated with recovery of methane from geopressured aquifers. Surface subsidence resulting from geofluid withdrawal and the reinjection of spent brines into subsurface formations will be the two most difficult environmental aspects of this resource development. In each case the uncertainty is high. The severe adverse impacts of subsidence or the inability to successfully reinject huge volumes of brine may slow or halt commercial development of the resource. Specific environmental, health and safety concerns are discussed below for each UGR resource base and technology.

- Methane from Coal

The major environmental constraint to the development of coal bed methane relates to the disposal of produced water. The composition of coal bed water varies from slightly acidic to slightly alkaline and only minimal knowledge of the mineral makeup is available. Other important impacts identified were from health and safety impacts during fracturing and from potential health and safety impacts to miners if the coal seams containing the gas are subsequently mined. The impacts during fracturing result from the emissions released by the diesel engines and from high levels of noise. The potential impacts to miners result from the potential for cave-ins due to fracturing of overlying strata during stimulation and from the potential for explosions due to in-mine pipeline leaks and intersection with gas pockets caused by boreholes used in degasification.

- Tight Western Sands

There were no significant environmental concerns identified for development of this resource. All potential impacts were determined to be of minor consequence, being of a local and temporary nature.

- Devonian Shale

There were no significant environmental concerns identified for development of this resource. All potential impacts were determined to be of minor consequence, being of a local and temporary nature.

- Geopressured Aquifers

Surface subsidence resulting from geofluid withdrawal and the reinjection of spent brines into subsurface formations are the two most difficult environmental aspects of resource development. The probability of subsidence resulting from geopressured development--both its magnitude and rate--is largely unknown. Experts disagree on the adequacy of current levels of theoretical knowledge for analyzing and predicting subsidence in the necessary site-specific manner. The potential severity of geopressured subsidence in the low-lying Gulf Coast indicates that research is needed in this area.

The produced water from a geopressured well also presents some handling and disposal problems because of the amounts involved. Vast quantities of brackish water extracted from the deep geopressured aquifers will have to be disposed of in a manner that both minimizes disposal cost and does the least damage to the surrounding environment. The problem of disposal technology is not new, but the volume of fluid to be disposed of presents a challenge. Also, spent brine is a hot and chemically complex fluid that varies greatly in composition. Concentrations of heavy metals, organics, and trace elements frequently occur at levels far in excess of seawater concentrations and Environmental Protection Agency (EPA) toxicity standards.

In an untreated form, discharge of this brine into terrestrial or aquatic ecosystems may cause substantial adverse biological impacts.

The status of the technologies for recovery of unconventional gas resources and the status of available environmental, health, and safety information is briefly reviewed in the following sections of this report.

2.0 UNCONVENTIONAL GAS RECOVERY RESOURCE BASE AND TECHNOLOGY

This section describes the unconventional gas resource bases and the different technologies involved in unconventional recovery of these resources. This information will provide the basis for the discussion of environmental effects in Section 3.

2.1 RESOURCE BASE

Natural gas is currently the nation's largest domestic energy source and its second most utilized fuel. It has declined in production from a peak of 22.6 Tcf in 1973 to 19.3 Tcf in 1978 (Rotariu and Powderly 1979). Recovery from conventional gas reserves is expected to continue to decline, but despite stringent conservation and fuel-conversion efforts, demand for this clean, versatile fuel remains high for the foreseeable future. The resulting supply gap for conventional gas has focused increasing attention on unconventional sources of natural gas.

Unconventional gas recovery (UGR) is defined as the commercial production of natural gas from natural underground reservoirs that do not yield gas economically by conventional techniques. The natural resources that are the target of this development include methane in coal beds, natural gas in tight western sands and Devonian shale, and methane from geopressured aquifers.

In this report, the term "methane" is used primarily in connection with coal beds and geopressured aquifers and "natural gas" is used with western sands and Devonian shale resources. Methane is the principal component of natural gas. The resource bases for each of these sources of unconventional gas are described in the following sections of this report.

2.1.1 Methane from Coal

Coal bed gas is a natural by-product of coal formation and can be found in varying quantities in many coal seams. Although a large portion of this gas has escaped to the atmosphere, some remains trapped in place within the rock formation. Methane is the primary component of this gas, generally constituting 85 to 99 percent of the volume (National Petroleum Council 1980). Commercial quantities of methane have been produced in the Appalachian coal region since 1949 (Rotariu and Powderly 1979).

Gas occluded in coal is located in relatively shallow (500-6000 ft) formations (Rotariu and Powderly 1979). Coal mines in the United States emit more than 200 thousand standard cubic feet per day of methane into the atmosphere from ventilation shafts. If the average gas content is estimated at 220 ft^3/ton, the minable coal in the coterminous U.S. may contain more than 300 trillion cubic feet (Tcf) of gas. This is a conservative estimate that may be extended as additional information becomes available on the thickness and continuity of other deeper formations. Coal beds considered too thin to be minable can still contain significant volumes of methane gas that may be recoverable (Ethridge, et. al. 1980). The location of the coal reserves in the United States is shown in Figure 2.1. These reserves represent potential sources of methane gas.

2.1.2 Tight Western Sands

Large quantities of natural gas exist in a number of sedimentary basins containing sands of low permeability (so-called "tight" formations). The flow rate of the natural gas in these formations is normally low enough to preclude commercial development of these basins. Recently there has been a surge of new activity in some of these basins, spurred perhaps by the higher prices of natural gas that resulted from the National Gas Pricing Act (Riedel et. al. 1980). The new development has also been encouraged by the introduction of massive hydraulic fracturing techniques which create a large area in the low permeability formations from which gas can flow into a single well. A fractured well, by exposing considerably more of a formation's rock face, can produce at many times the rate than an unfractured well can. A fractured well in a tight gas formation typically produces at a lower rate but over a longer period of time than a well in a conventional formation (National Petroleum Council 1980).

The commercialization goal set by the Department of Energy for gas production yield from the Tight Western Sands is from three to six trillion cubic feet (Tcf) of natural gas per year. For comparison, the U.S. currently consumes approximately 20 Tcf of natural gas every year (Riedel, et. al. 1980).

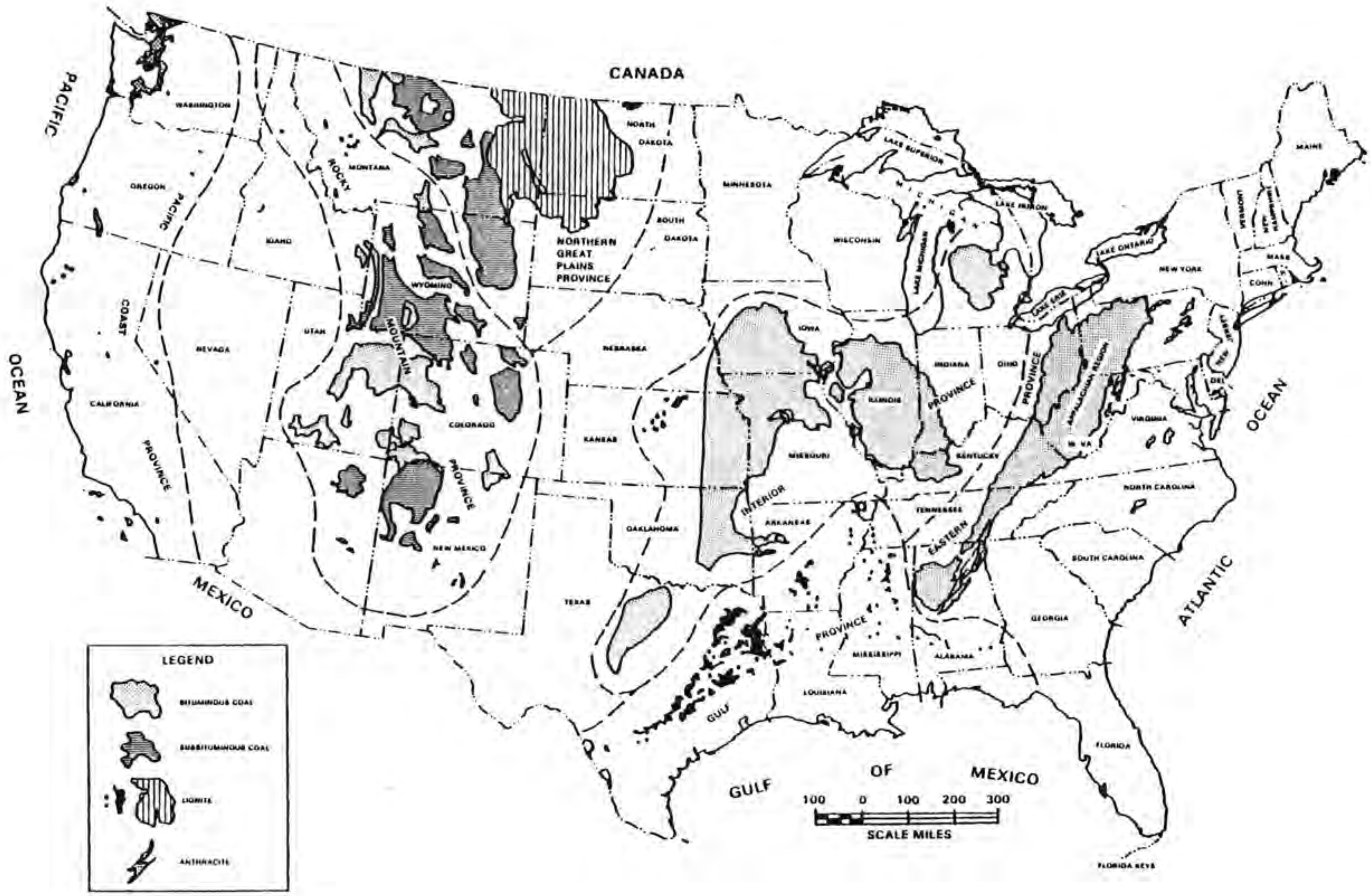


FIGURE 2.1. Distribution of Coals in the Contiguous U.S.

The geographical location of the Tight Western Sands resource is shown in Figure 2.2. Table 2.1. summarizes the reservoir characteristics of these formations. A 1973 Feferal Power Commission (FPC) Report identified three basins, the Uinta Basin, The Piceance Basin and the Greater Green River Basin, as having good potential for additional natural gas production. These basins contain an estimated 600 Tcf of gas. The FPC study estimates that up to 231.9 Tcf of gas might be recoverable from these basins. This would provide approximately an 11.5-year supply of gas for the United States at the current rate of usage (Riedel, et. al. 1980).

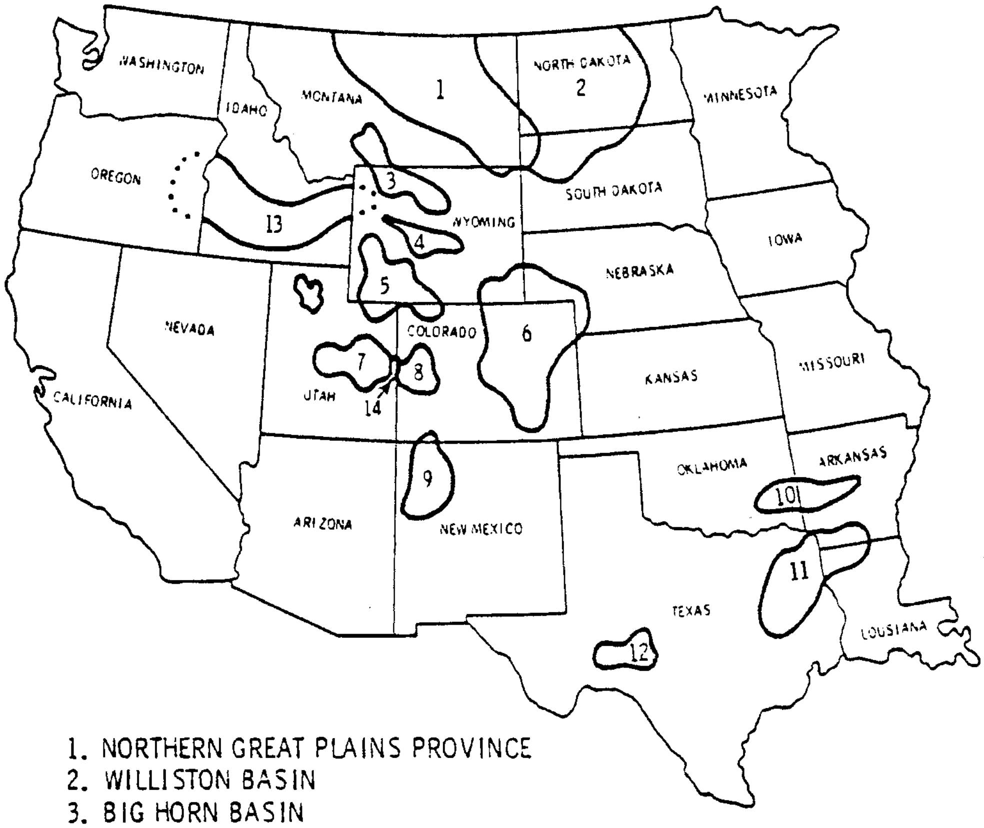
The uses for gas produced from Tight Western Sand basins are the same as for any produced natural gas. However, because of the large distances from well fields to commercial pipelines and the low production rates of the gas wells, the economics of Tight Western Sand basins are marginal. As demand and price for domestic natural gas increase, the profits from these gas fields will increase, thereby stimulating production (Riedel, et. al. 1980).

2.1.3 Devonian Shale

Vast quantities of high quality natural gas [up to 1500 British thermal units per cubic feet (Btu/ft^3)] are contained in shale deposited during the late Devonian and Early Mississippian geologic eras. This gas can be recovered and added to the existing reserves to supplement our more conventional natural gas supplies.

Gas has been produced from Devonian age shale for a long time. Commercial wells in Kentucky, Ohio and West Virginia have been in production since 1921 (Rotariu and Powderly 1979). However, this production has never been a major contributor to our overall natural gas reserves. Its proximity to the large industrial gas users in the East suggest that increased production from this resource would be beneficial.

Devonian shale represents one of the most important resources of unconventional gas, potentially containing over 900 Tcf of gas, which is about a 45-year supply of natural gas at today's use patterns. The total gas produced from this resource is estimated to have been 2.5 Tcf (Riedel 1981). The shale



1. NORTHERN GREAT PLAINS PROVINCE
2. WILLISTON BASIN
3. BIG HORN BASIN
4. WIND RIVER BASIN
5. GREATER GREEN RIVER BASIN
6. DENVER BASIN
7. UINTA BASIN
8. PICEANCE BASIN
9. SAN JUAN BASIN
10. ARKOMA BASIN
11. COTTON VALLEY TREND
12. SANDRA BASIN
13. SNAKE RIVER DOWNWARP
14. DOUGLAS CREEK ARCH.

FIGURE 2.2. Tight Gas Sand Basins (Western Gas Sands Project 1978)

TABLE 2.1. Reservoir Characteristics of the Tight Gas Formation

Target/basin	Formation	Depth, ft	Gross interval, ft	Net pay, ft	Nature of pay	In-situ gas perm. µd	Gas-filled porosity, %	Reservoir pressure psi	Reservoir temperature, °F
WESTERN TIGHT GAS SANDS									
Greater Green River	Fort Union	5,700-9,000	500-2,680	21-625	Lenticular	1-50	3.4-5.0	3,150-5,334	135-194
	Almond A	8,000-10,700	400-500	9-20	Blanket	9-50	4.1-4.5	4,200-6,200	180-215
	Almond B	8,000-10,700	400-500	18-45	Lenticular	9-50	4.5-5.4	4,200-6,200	180-215
	Erickson	8,400-11,400	350-400	35-68	Lenticular	7-20	4.1-5.4	4,400-6,500	186-231
	Rock Springs/Blair	9,700-12,500	1,500-2,500	19-80	Lenticular	7-8	4.1-5.4	5,000-7,200	206-248
	Other Mesaverde	9,000-12,700	2,150-5,000	28-164	Lenticular	1-9	3.4-4.5	5,850-8,250	194-220
Piceance	Fort Union	5,000	600	18-44	Lenticular	3-27	4.0-5.2	2,100	135
	Corcoran-Cozette	6,000	50	10-38	Blanket	8-75	4.2-6.1	2,600	145
	Other Mesaverde	6,900-9,100	800-2,200	40-275	Lenticular	3-60	3.6-5.4	3,000-3,400	160-170
Uinta	Wasatch	6,500	500	43-156	Lenticular	66-600	4.4-5.8	2,795	175
	Barren	7,500	500	43-156	Lenticular	30-270	3.8-5.0	3,225	195
	Coaly	8,500	500	43-156	Lenticular	10-90	3.2-4.2	3,655	214
	Castlegate	9,500	250	25-75	Blanket	3-30	2.6-3.4	4,275	233
SHALLOW GAS BASINS									
Northern Great Plains and Williston	Judith River	600-1,600	30-50	8-20	Blanket	17-1,000	5.2-13.7	270-680	80-85
	Eagle	1,800-2,000	30-60	3-25	Blanket	17-10,000	7.4-12.2	800-900	90-100
	Carlisle	1,500	30-50	4-10	Blanket	10-900	5.4-7.1	670	85
	Greenhorn/Frontier	2,000-2,600	30-50	3-29	Blanket	17-2,700	5.4-7.8	900-1,130	100
OTHER TIGHT LENTICULAR GAS SANDS									
Big Horn	Mesaverde	2,285	645	110-275	Lenticular	13-120	6.6-8.7	1,100	95
Douglas Creek Arch	Mancos	2,845-4,045	2,400	120-300	Lenticular	7-60	4.8-7.5	437	120
	Dakota	7,545	72	4-9	Lenticular	10-90	3.6-4.7	1,100	240
Sonora	Canyon	6,000-7,000	600	30-103	Lenticular	8-84	4.4-6.3	2,100-2,700	145
TIGHT BLANKET GAS FORMATIONS									
Cotton Valley "Sweet"	Cotton Valley sand	9,000	1,100	35-88	Blanket	3-30	4.0-5.3	6,000	250
	Gilmer lime	11,000	350	20-50	Blanket	3-30	5.6-7.4	5,400	280
Denver	Niobrara	2,300	67	11-28	Blanket	3-30	2.6-3.5	950	110
	Sussex	4,460'	50	11-26	Blanket	3-30	3.6-4.7	1,500	185
	Dakota	8,000	50	14-34	Blanket	5-50	4.0-5.3	2,900	260
Quachita	Stanley	4,600-9,000	6,000-7,200	186-465	Blanket	1-5	3.7-5.1	1,700-2,200	148-160
San Juan	Dakota	7,180	173	35-88	Blanket	10-90	5.8-7.5	3,090	222
Wind River	Frontier	1,441	153	20-50	Blanket	33-300	6.5-8.5	550	99
	Muddy	2,529	100	10-25	Blanket	1-9	8.8-11.6	1,000	109
OTHER LOW PERMEABILITY GAS FORMATIONS									
Cotton Valley "Sour"	Bruckner-Smackover	12,000	900	18-44	Blanket	44-400	8.0-10.5	5,600	290

ranges in thickness from 20 feet in Kentucky to more than 7000 feet in the West Virginia - Virginia border region. It is exposed at the surface in parts of Kentucky, Ohio and Tennessee, but it is also found at depths of from 1500 feet in New York to 5000 feet in Virginia. Gas shale formations underlie much of the Appalachian, Illinois and Michigan Basins (Figure 2.3).

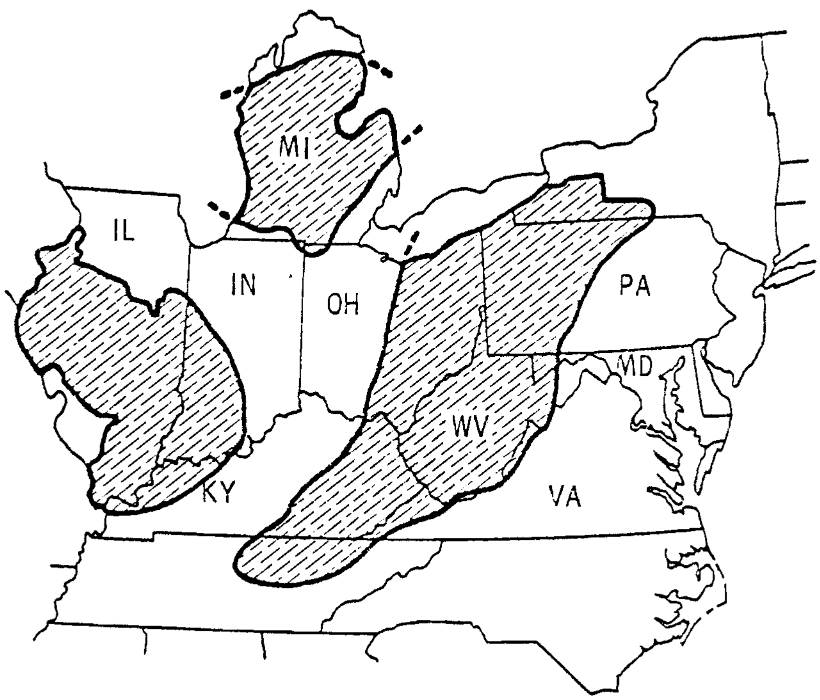


FIGURE 2.3. Appalachian, Illinois and Michigan Basins

2.1.4 Geopressured Aquifers

Geopressured geothermal aquifers are overpressured water-bearing formations containing methane in solution. Vast areas containing geopressured (i.e., in excess of hydrostatic pressure) formations underlie coastal portions of Texas and Louisiana at varying conditions of depth, temperature and extreme pressure. The geopressured resource represents another potential source of methane to supplement diminishing conventional natural gas reserves. The extracted brine is postulated to contain dissolved methane in quantities of from 20 to 50 or more standard cubic feet (scf) per barrel.

The size of the geopressured resource base is unknown. Estimates of the total amount of methane entrained in Gulf Coast brines range from a few hundred to about 50,000 trillion cubic feet.

The geology of the Gulf Coast of Texas and Louisiana has an important influence on the development of the resource. The resource is located in sandstone/shale deposits. Successive cycles of deposition and compaction have led to extensive networks of growth faults that roughly parallel the Gulf Coast and the line of deposition. Growth faults are one mechanism for the formation and maintenance of the abnormally high pressures found in this resource base.

2.2 RECOVERY TECHNOLOGIES

The technology used for unconventional gas recovery basically incorporates improvements in conventional petroleum recovery techniques. The general technology currently used in petroleum resource recovery is described in Appendix B. Technology development for UGR can be loosely classified into improvements in fracturing technology for tight formations and development of new production techniques for resources such as gas from coal beds. Some specific recovery techniques for each of the identified unconventional resources are discussed in the following sections of this document. A comparison of the overall development sequences used to recover these deposits and conventional petroleum resources is shown in Table 2.2.

Drilling and completion activities for an unconventional gas well development program range from design of the drilling program to the final well completion tasks. Most of these tasks are identical to, or vary only in degree from, those for a conventional petroleum drilling program. These process requirements include exploration, site preparation and site restoration activities. These steps will not be discussed in detail here. Other documents (Ethridge, et. al. 1980; Riedel, et. al. 1980; Riedel 1981; Usibelli, Deibler, and Sathaye 1980) describe the technologies of the complete recovery

TABLE 2.2. Petroleum Recovery Operations for Major Onshore Petroleum Resources

Comparison Factors	Typical Onshore Oil Field	Typical Onshore Gas Field	Devonian Shale	Tight Western Sands	Coal Bed Methane	Geopressured Aquifers
Well Pad Area: Somewhat dependent on well depth - Larger area needed for deeper well	1 to 2 acres/10,000 ft	2 to 5 acres/10,000 ft	1 acre/5,000 ft	3 to 6 acres/10,000 ft	1/2-1 acre/1,000 ft	1 to 2 acre/10,000 ft
Common Well Spacing	40 acres/10,000 ft	640 acres/10,000 ft 160 acres/5,000 ft	40 acres	640 acres/10,000 ft	Unknown	Unknown
Well Completion Activities	1. Isolate zone(s) of interest by setting a packer. 2. Cement casing across zone. 3. Perforate ~1 to 2 shots/foot. 4. Run small acid job.	1. Isolate zone(s) of interest by setting a packer. 2. Cement casing across zone. 3. Perforate 1 shot/ft to 1 shot/25 ft. 4. Run small acid job. 5. Run frac job.	1. Isolate zone(s) of interest by setting a packer. 2. Cement casing across zone. 3. Perforate 1 shot/ft to 1 shot/25 ft. 4. Run acid/frac jobs. 5. Run foam frac jobs.	1. Isolate zone(s) of interest by setting a packer. 2. Cement casing across zone. 3. Perforate 1 shot/ft to 1 shot/25 ft. 4. Run acid jobs.	1. Several procedures only one of which resembles the preceding ones. More common is to drill large vertical hole and drill horizontal holes outward from this. Holes are not cased and perforated.	1. Isolate zone(s) of interest by setting a packer. 2. Cement casing across zone. 3. Perforate 1 shot/ft. 4. Special equipment for high pressures.
Production Operations	1. Electrical pump in operation. 2. Three phase separator. 3. May have large amounts of brine to be disposed of. 4. Oil is pipelined or trucked. 5. Gas[a] is pipelined (may need compressor station). 6. Work area is 400 sq. ft. 7. Central processing area is ~5 acres.	1. No pump. 2. Three phase separator. 3. Very limited brine production. 4. Condensate is trucked. 5. Gas[a] is pipelined. 6. Work area is about 1 acre. 7. Gas compressor station (if needed) may occupy 2-5 acres.	1. No pump. 2. Two phase separator. 3. Almost zero brine production. 4. No condensate 5. Gas[a] is pipelined. 6. Work area is less than 1 acre. 7. Gas compressor station may occupy 1 to 3 acres.	1. No pump. 2. Three-phase separator. 3. Very limited brine production 4. Condensate is trucked. 5. Gas[a] is piplined. 6. Work area is about 4 to 5 acres. 7. Gas compressor station (if needed) may occupy 2 to 5 acres.	1. Small pump to produce brine. 2. Two phase separator. 3. Moderate brine production. 4. No condensate. 5. Gas[a] is compressed and pipelined. 6. Surface facilities occupy 1 acre. 7. May need central gas compressor which occupies 1 to 3 acres.	1. No pump. 2. Two phase separator. 3. Brine production ~50,000 BPD/well. 4. No condensate. 5. Gas: either pipeline or used to generate electricity. 6. Surface facilities occupy 1 to 2 acres. 7. Electric lines carry total energy output.
Production Life	1. Primary 0 to 5 years. 2. Waterflood 10 to 15 years. 3. Tertiary 10 to 40 years.	1. Primary ~5 to 20 years.	1. Primary ~50 years.	1. Primary ~5 to 20 years.	1. Primary 1 to ? years.	1. Unknown.
Minimum Road Mileage Needed for 100 sq. mile field	380 miles	175 miles	DOES NOT EXIST AS DISCRETE FIELDS. However, road length per well ranges from 0 to 1/2 mile.	175 miles	Not developed as discrete fields. Road length averages about 1/2 mile per well.	No data
Ownership of lands	1. Federal and private.	1. Federal and private.	1. Mainly private.	1. Mostly federal.	1. Mainly private.	1. Mainly private.

(a) Gas at this stage still contains the natural gas liquids (NGL) mainly ethane and propane. The NGL may be extracted and trucked to market or the NGL may be left in.

processes in detail. The specific technologies for recovery of unconventional gas resources are discussed in this section.

2.2.1 Methane from Coal

Current methods of coal bed methane recovery fall into two main categories: recovery from coal before mining (virgin coal) and recovery from active mines. The major techniques for gas recovery include vertical drilling, recovery from horizontal boreholes, and directional drilling techniques.

2.2.1.1 Vertical Boreholes

Vertical holes may be used to recover methane from coal in either virgin seams or active mines. Vertical boreholes from the surface provide a means of draining methane from coal beds before they are opened for mining. In this technique, small-diameter, vertical boreholes are drilled from the surface to the coal bed. After drilling is completed, the well is cased and cemented to the surface. As the water that accumulates in the well is pumped off, methane flows from the coal bed. Since coal has a low permeability, flow rates from coal into small vertical boreholes are quire low, usually between 0.5 and 10 thousand standard cubic feet per day (Mscfd). Stimulations increases gas production substantially, from 5 to 20 times the original flow rate. A description of stimulation techniques can be found in Section 2.2.1.3.

Vertical boreholes are also used to drain methane from strata above the coal bed. A hole is drilled to the strata just above the coal bed and ahead of mining operations. When it is intersected by mining, the overburden fractures and the methane that would normally be released into the waste material is drawn to the surface. Such holes can remove as much as one million scfd of methane from a mine and reduce underground emissions of methane by more than 50% (Ethridge, et. al. 1980).

2.2.1.2 Horizontal Boreholes

Horizontal holes in coal beds produce gas at rates substantially higher than those from vertical boreholes. In this technique, a shaft or group of shafts is sunk to the coal bed a minimum of three years before mining is to be started. In the coal bed, the base of the shaft is enlarged to provide space for men and equipment to drill a series of horizontal holes 500 to 2000 feet long into the coal bed. These holes intersect the fracture system of the coal bed. It is this fracture system that comprises the effective permeability of the coal bed. Figure 2.4 shows a cross-sectional view of a

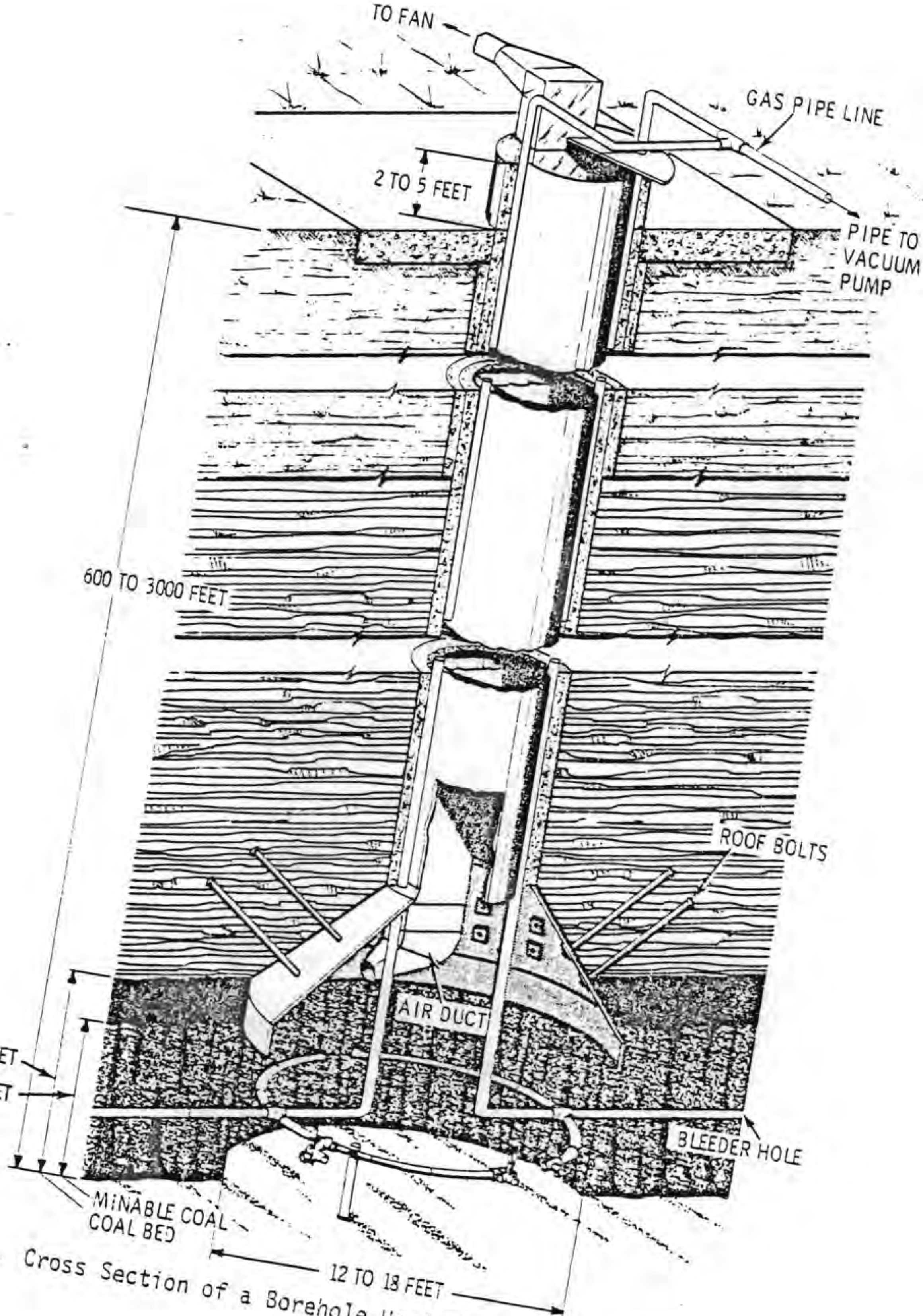


FIGURE 2.4. Cross Section of a Borehole Used for Degasification

borehole used for degasification. Each of the horizontal holes is connected through a mechanical packer and water trap to a common receiver tank, as shown in Figure 2.5. The gas is then piped to the surface.

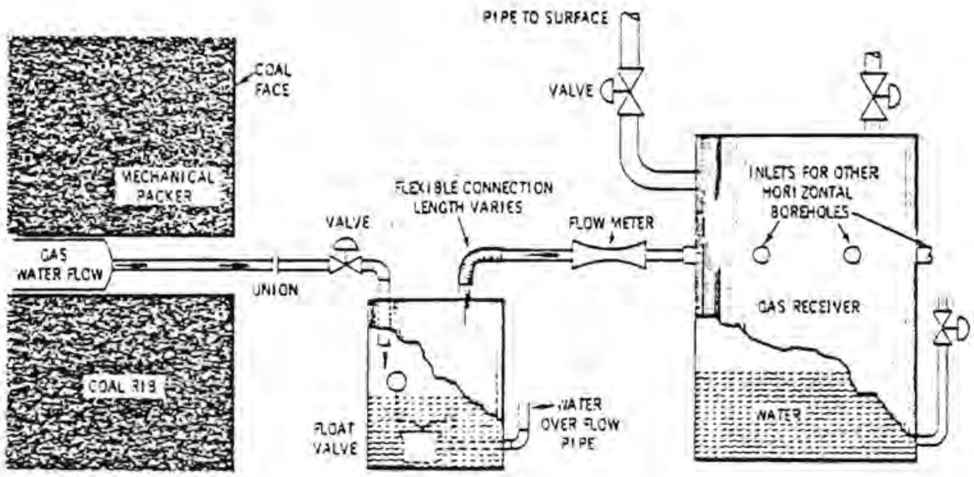


FIGURE 2.5. Flow of Processes in Degasification

Gas can also be produced from the active working sections of a developing mine that has not been advanced to the property boundaries. This technique consists of drilling small diameter horizontal boreholes into the virgin coal as the working face is advanced. The methane drained from these boreholes is conducted by pipeline to the surface (Ethridge, et. al. 1980).

2.2.1.3 Directional Drilling

Directional drilling techniques for removing gas from coal beds combine the efficient drainage of horizontal boreholes with the lower cost of small-diameter vertical boreholes. In directional drilling, a small diameter borehole is drilled from the surface and intentionally deviated in order to intercept the coal bed horizontally. The major difficulty with this technique is the narrow target zone. The coal bed must be penetrated at a very acute angle since the average coal bed thickness is between 3.9 and 5.9 feet (Ethridge, et. al. 1980).

Stimulation Techniques

If vertical drilling is used, stimulation techniques may be employed to increase gas flow rates. Coal beds have very low flow rates due to low permeability and porosity. Hydraulic stimulation can be used to increase flow by inducing and extending vertical fractures in a selected section of a formation or coal bed. For coal beds, the large surface area that is produced also promotes gas desorption.

The fracturing is accomplished by applying hydraulic pressure with controlled injection of a fluid. Water-based and foam-based fluids are the types of fluids currently in use. The continued pumping of a large volume of treatment fluid extends the induced fractures several hundred feet into the coal bed. After fracturing a well, it is shut-in to allow the fluids to break down. The well is then cleaned to remove the water and any other waste materials.

2.2.2 Tight Western Sands

The Tight Western Sands are considered non-commercial at this time because of their limited flow capacity. One way to increase flow capacity in a reservoir is to increase the effective wellbore drainage volume using some type of fracturing technique. Techniques under development to produce commercial quantities of gas from Tight Western Sands include a number of advanced fracturing processes. Among the many methods which have been tried at least once in Tight Western Sands are:

- Advanced hydraulic fracturing and
- Chemical explosive fracturing.

Each of these methods is discussed below.

2.2.2.1 Hydraulic Fracturing

Hydraulic fracturing is a method of well stimulation which has been in use since 1947. It is a process of creating a fracture or a system of fractures in a reservoir via the injection of a fluid under pressure. The fracture is then kept open (propped) by a propping agent (sand) which has been added to the fracturing fluid. Hydraulic fracturing is normally used to accomplish five basic jobs:

- overcome wellbore damage
- create deep-penetrating reservoir fractures
- aid in secondary recovery operations
- assist in the disposal of oilfield brines
- provide standard completion method for gas well.

There are two types of advanced hydraulic fracturing methods: 1) massive hydraulic fracturing and 2) foam fracturing. Massive hydraulic fracturing (MHF) is any fracture treatment in excess of 300,000 gallons of liquid. Some operators consider any treatment requiring over 50,000 gallons to be massive. A typical hydraulic fracturing treatment consists of injecting a fracturing fluid and a proppant. The fracturing fluid used may be water-based, oil-based, or mixed-based. Different types and sizes of propping agents are often used in the same treatment. A schematic of a hydraulic fracturing process is shown in Figure 2.6.

In the foam fracturing (FF) procedure, which is conceptually similar to an MHF, compressed gas and water containing a number of additives, one of which must be a surfactant (a foaming agent), are pumped down the well under sufficiently high pressure to cause formation breakdown and fracturing. Foam fracturing has the advantage over the conventional MHF jobs in that very little water is used and thus the well cleans up much faster.

2.2.2.2 Chemical Explosive Fracturing

Chemical explosive fracturing is a method in which an explosive fluid is injected under sufficient pressure to cause hydraulic fracturing to occur. After the explosive fluid has been injected into the formation, it is detonated. This detonation causes further fractures to grow and at the same time generates a proppant material in situ.

This technique is still in a developmental stage. Results of a recent demonstration test in the Fort Worth Basin in Texas showed only marginal increases in well production. This method needs further improvement and testing before it can be considered viable for use in MGR projects.

2.2.3 Devonian Shale

A typical Devonian shale well after being drilled and completed will have little or no open flow of gas (although an occasional well can have flows of as much as 100 Mscfpd). Thus, some method of stimulation must be used to increase flow rates from these wells to commercial levels. Methods that have been tried with some success include the following: borehole shooting; chemical explosive fracturing; and hydraulic fracturing. These methods of stimulation are discussed in further detail below, as well as an additional procedure, directional drilling.

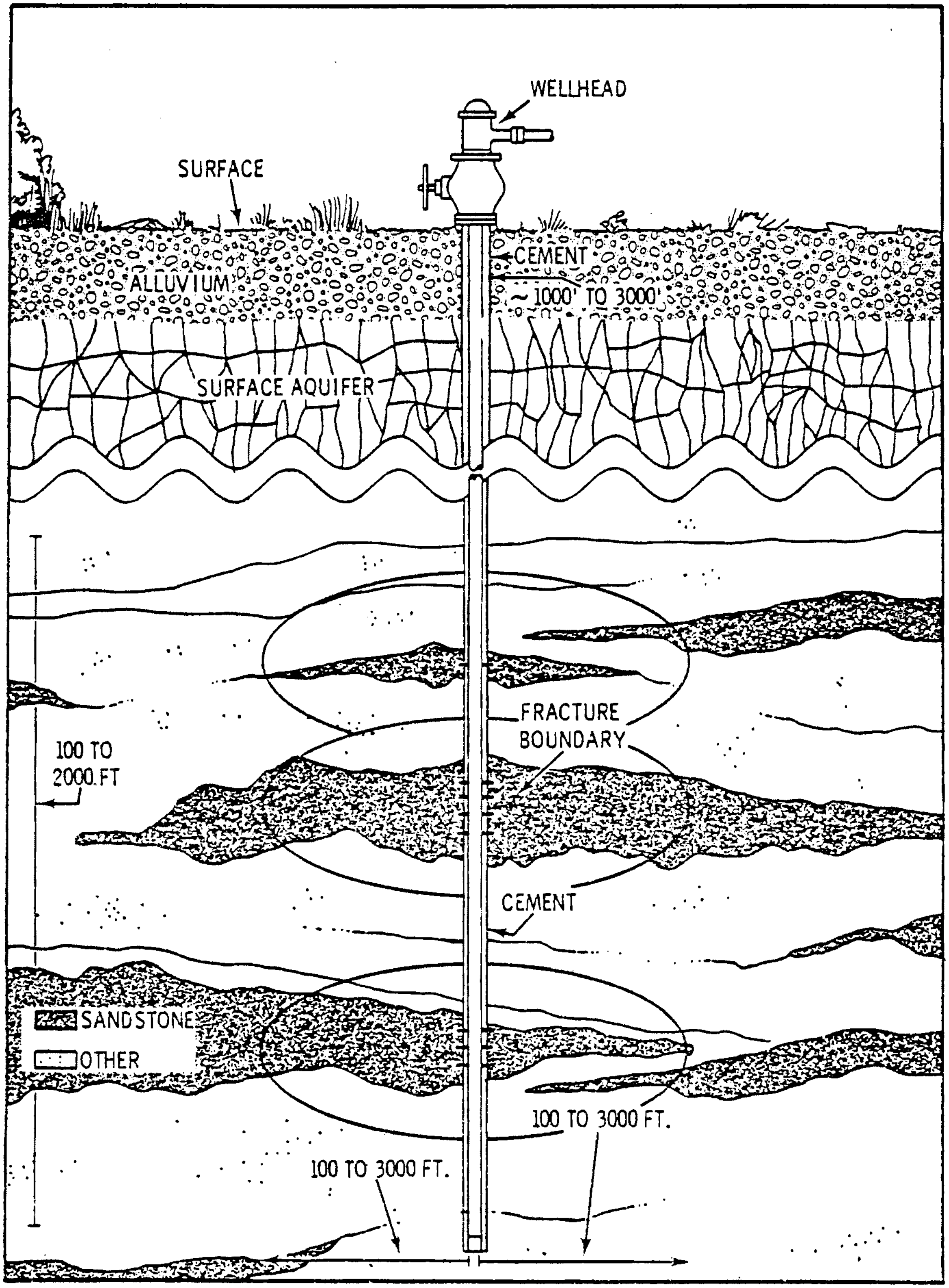


FIGURE 2.6. Multistage Massive Hydraulic Fracturing Job

2.2.3.1 Borehole Shooting

The traditional stimulation method used for Devonian shale well is borehole shooting. This method involves the detonation of gelled nitroglycerine in the wellbore over the producing interval. The formation face is physically shattered by the explosion. When the rubble is removed from the hole, the enlarged wellbore radius provides better gas movement between the formation and the wellbore.

2.2.3.2 Chemical Explosive Fracturing

Chemical Explosive Fracturing (CEF) is a procedure in which chemicals are injected into a well under high pressure and forced into the producing formation. When sufficient quantities have been injected they are detonated. Upon detonation, the explosion creates secondary fractures which are propped open by the rubble. The explosive mixture which was in the wellbore enlarges the wellbore radius upon detonation. This procedure is intended to increase flow capacity and drainage radius.

2.2.3.3 Hydraulic Stimulation

Hydraulic stimulation has been in use since 1947. It is a process of creating a fracture or a system of fractures in a reservoir via the injection of a fluid under pressure. The fracture is then kept open (propped) by a propping agent which has been added to the fracturing fluid.

Hydraulic stimulation methods which have been used in the Eastern shales are:

- Massive hydraulic fracturing -- MHF
- Foam fracturing
- Cryogenic fracturing (or CO_2 fracturing)
- Dendritic fracturing.

Massive hydraulic fracturing and foam fracturing were discussed earlier in this report in Section 2.2.2. Each of the other fracturing techniques will be briefly discussed below.

Cryogenic Fracturing. Cryogenic fracturing is very similar to foam fracturing. In this method the injection fluid consists of 25% liquid CO_2 with the remainder being water. The CO_2 is transported to the fracturing site at low temperature and at the high pressure of 300 psi to keep it liquid. Water is gelled and sand is added. This fluid is then mixed with the CO_2 at approximately 3,000 psi and injected into the wellbore. Once the fracturing job is completed, the wellhead pressure is released and the CO_2 is vaporized. The majority of the injected fluid is then produced back into a surface storage vessel.

Dendritic Fracturing. The preceding methods all produce fractures in a single plane whose orientation is dependent on the overburden pressure. The dendritic method is designed to propagate fractures in several directions, allowing improved penetration of the reservoir. The concept of dentritic fracturing involves sequential cycles of fluid injection followed by shutting in the well and then allowing the well to backflow. These cycles are designed to fracture the formation and redirect fracture growth. Figure 2.7 illustrates the dendritic fracturing pattern of this process.

2.2.3.4 Directional Drilling

Directional drilling was originally developed by the petroleum industry to solve some specific problems such as drilling from an offshore platform, reaching locations away from the drill rig, straightening crooked holes and bypassing salt domes. Directional drilling is the process of intentionally drilling a bent hole (see Figure 2.8). Directional drilling is expected to work well in the Devonian shale since the intersection with the natural fracture system is enhanced. Directional drilling has been performed successfully in both Devonian shale and coal beds.

2.2.4 Geopressured Aquifers

Commercial development of the geopressured brine resource as a source of methane gas involves two operations: production of the methane by surface separation or the rapid drawdown process (RDP) and dewatering and cleaning of the produced gas for introduction into natural gas pipeline systems. The latter operations use processes and facilities common to much of the

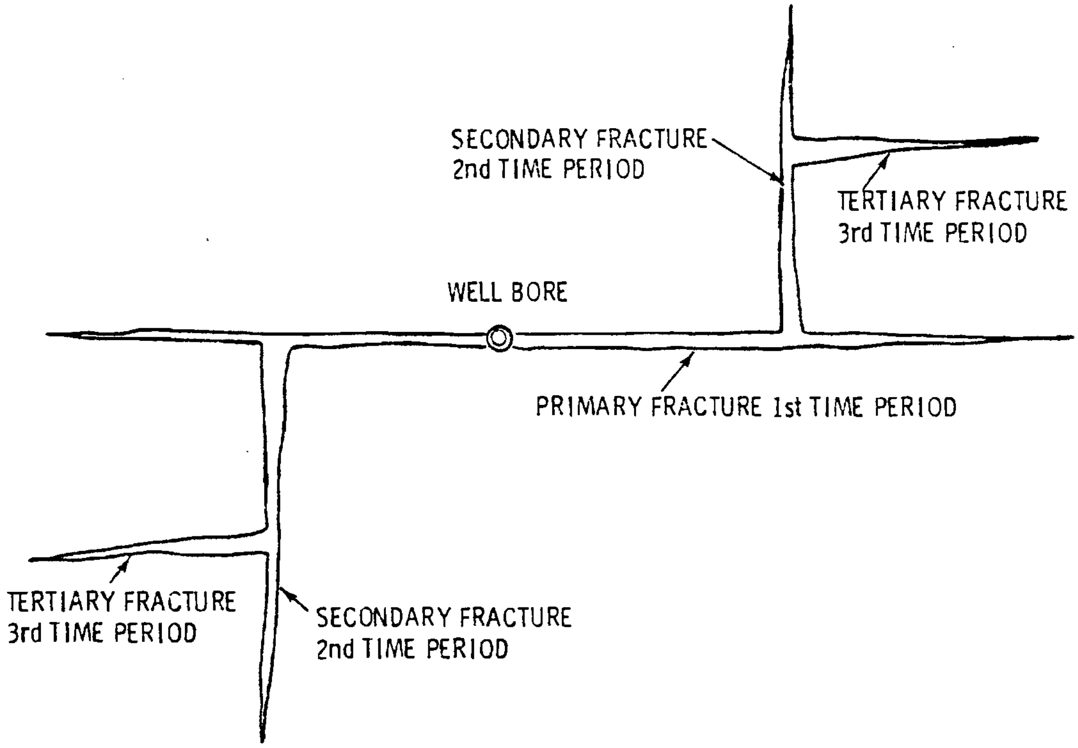


FIGURE 2.7. Dendritic Fracturing Pattern

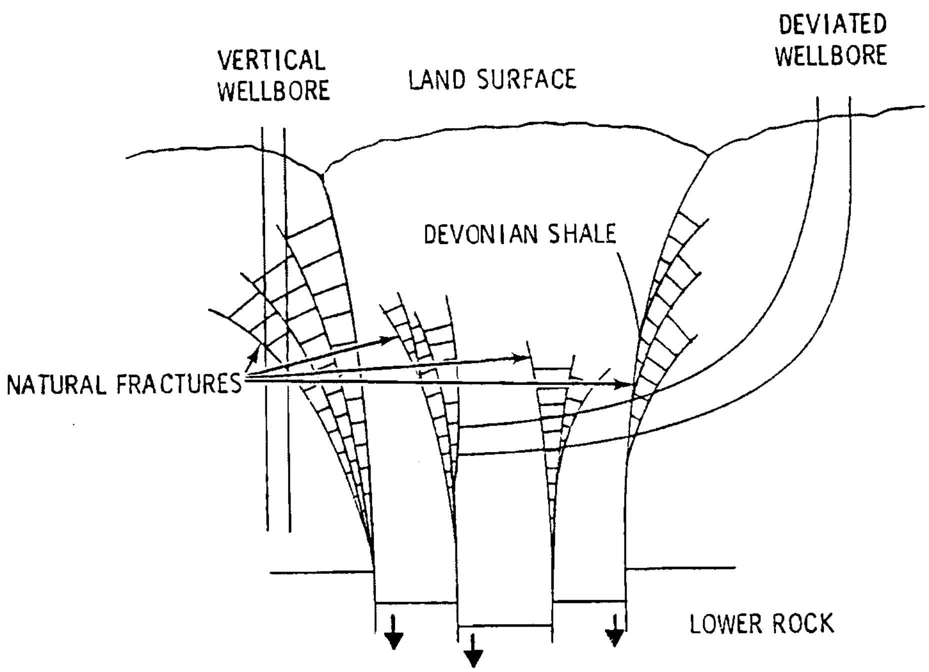


FIGURE 2.8. Deviated Wells and Earth Fracture System
(not to scale)

conventional natural gas industry, while the former require techniques unique to geopressured brines. There are three methods that can be used to separate methane from geopressured brines. These are:

- Pressure drop and evolution of the gas out of the brine stream
- Gas stripping
- Liquid solvent extraction.

Each of these methods is discussed briefly below.

2.2.4.1 Pressure Drop

Pressure drop separation of methane gas from aqueous solutions is a relatively common practice of the oil and gas industry. Pressure drop production takes advantage of a basic property of methane gas in solution. As pressure decreases, the equilibrium solubility of methane decreases and some of the gas moves out of solution and into a gaseous phase. The surface pressure drop method is based upon the solubility of methane gas at various pressures. At 1,000 psia about 80% of the methane that is in solution at 10,000 psia or greater is liberated from the brine, and at 150 psia essentially all of the methane comes out of solution.

Surface separation of methane from geopressured brines is significantly different in scale from standard gas production processes. Both the high rates of flow and the high wellhead pressures expected in geopressured wells affect the technology and processes to be utilized. Flow rates of 40,000 or more barrels of brine per day and wellhead pressures of 3,000 to 6,000 psia can be expected at a wellsite. By contrast, oil well flow rates of a few hundred to several thousand barrels per day are typical and wellhead pressures are often orders of magnitude less than geopressured values. Consequently, the ratio of brine produced to methane gas is much greater than in a typical oil and gas well and the corrosion, scaling, erosion, and pressure effects, etc. on the separation equipment are correspondingly increased.

A second pressure drop procedure is the Rapid Drawdown Process (RDP). There are two RDP procedures that have been considered: 1) rapid depressuring of a well in order to form an "artificial" gas cap as methane moves out of solution in the reservoir, and 2) production of interstitial gas that may exist in conjunction with brine waters. The RDP procedures have not been extensively tested. There still exists some disagreement as to whether these processes will be effective in recovering methane from geopressured reservoirs. The theories being applied to develop this technology are described in more detail in relevant literature (Usibelli, et. al. 1980).

2.2.4.2 Gas Stripping

Gas stripping involves the desorption of a dissolved gas, in this case methane, by means of a stripping agent gas. This process is currently widely used in the petroleum industry. Studies investigating the feasibility of gas stripping for recovering methane from geopressured brine streams identify N_2 and the halogenated hydrocarbon, dichlorotetrafluoroethane, as candidate stripping agents. Though technically feasible, gas stripping is too costly to be utilized at this time.

2.2.4.3 Liquid Solvent Extraction

The liquid solvent process is similar in principle to gas stripping except that a liquid rather than a gaseous stripping agent is used. A high-boiling point paraffinic hydrocarbon is contacted with the brine in an extraction tower. Methane, being more soluble in the hydrocarbon, is extracted and subsequently recovered in essentially pure form by depressurization of the extract. The most promising agent identified to date for use in this process is hexadecane. Unlike gas stripping, this process appears to be economically viable.

2.3 SUMMARY

This section has included a description of the resource base available for unconventional gas recovery and a brief outline of the processes and technology required to recover and utilize gas from a variety of unconventional resources. The environmental concerns arising from each technology will be discussed in detail in Section 3. Potential health and safety impacts that may be encountered during UGR activities are discussed in Section 4.

3.0 ANALYSIS OF EXISTING ENVIRONMENTAL INFORMATION

The basic technology involved in conventional gas recovery is fairly well established. For the most part, the recovery techniques used in UGR are modifications of the technology currently being used in the recovery of conventional petroleum and gas resources. Because this basic technology has been in use for some time, most of the environmental impacts resulting from its use are known and have been studied in some detail. The use of unconventional gas recovery methods is not anticipated to present any significant new environmental concerns.

The unconventional gas recovery technologies discussed in Section 2 of this report have many operations in common. Thus, to simplify the presentation of material in this section, the potential environmental impacts of the technologies will be discussed simultaneously under each area of potential impact. For instance, the environmental impacts of road construction are basically the same for all technologies. Instead of presenting this information separately for each UGR resource, it will be discussed for all technologies in only one section of this report.

The potential environmental impacts that may be experienced with the use of each UGR technology are identified in the following series of tables, Table 3.1 to Table 3.4. In these tables, environmental impacts are identified for each phase of the UGR operation, from initial site exploration through production and site restoration. The environmental concerns for the technologies are discussed collectively under each area of potential impact in the following sections of this report.

3.1 ENVIRONMENTAL CONCERNS

The purpose of this section is to present an assessment of the potential environmental impacts of unconventional gas resource development. The impacts of various UGR technologies on air, water, geology, and the surrounding ecology are examined in the following sections of this report.

TABLE 3.1 Overview of Environmental Impacts from Coal Bed Methane Production

Environmental Impacts	Site Preparation	Drill Pad Siting	Roads	Pipelines	Drilling	Stimulation	Production	Restoration Activities
Air Pollution	Minor	Minor	Minor	Minor	Minor	Moderate	Minor	Minor
Surface Water	Minor	Moderate	Minor	Minor	Minor	None	Moderate	None
Ground Water	None	None	None	None	Minor	Minor	None	None
Land Use	1/2 acre	1/2 acre	1-2 acres/well	1-2 acres/ well	None	None	None	None
Ecology								
Flora	Moderate	Major	Major	Moderate	Minor	None	None	None
Fauna	Moderate	Minor	Minor	Minor	Minor	Minor	Minor	Minor
Noise	Minor	Minor	Minor	Minor	Moderate	Moderate	Minor	Minor
Geological	Moderate	Moderate	None	None	None	Major	None	None

None = No noticeable impact

Minor = Short term, local, within permissible standards

Moderate = Temporary, local, some noticeable impact

Major = Long term, local, large impact

TABLE 3.2 Overview of Environmental Impacts from Tight Western Sand Gas Field Development

Environmental Impacts	Site Preparation	Drill Pad Siting	Roads	Pipelines	Drilling	Stimulation	Production	Restoration Activities
Air Pollution	Minor	Minor	Minor	Minor	Minor	Moderate	Minor	Minor
Surface Water	None	Moderate	Minor	Minor	Minor	Minor	Minor	None
Ground Water	None	None	None	None	Minor	Minor	None	None
Land Use	4-5 acres/well	4-5 acres/well	2-4 acres/well	2 acres/well	None	None	None	None
Ecology								
Flora	Minor	Major	Major	Moderate	Minor	None	None	None
Fauna	Minor	Minor	Minor	Minor	Minor	Minor	Minor	Minor
Noise	Minor	Minor	Minor	Minor	Moderate	Moderate	Moderate	Minor
Geological	None	Moderate	None	None	None	Minor	None	None

None = No noticeable impact

Minor = Short term, local, within permissible standards

Moderate = Temporary, local, some noticeable impact

Major = Long term, local, large impact

TABLE 3.3 Overview of Environmental Impacts from Devonian Shale Gas Field Development

Environmental Impacts	Site Preparation	Drill Pad Siting	Roads	Pipelines	Drilling	Stimulation	Production	Restoration Activities
Air Pollution	Minor	Minor	Minor	Minor	Minor	Moderate	Minor	Minor
Surface Water	None	Moderate	Minor	Minor	Moderate	Minor	None	None
Ground Water	None	None	None	None	Minor	Minor	None	None
Land Use	1/2-2 acres/well	1/2-2 acres/well	Minor	Moderate	None	None	None	None
Ecology								
Flora	Minor	Major	Major	Moderate	Minor	None	None	None
Fauna	Minor	Minor	Minor	Minor	Minor	Minor	Minor	Minor
Noise	Minor	Minor	Minor	Minor	Moderate	Moderate	Moderate	Minor
Geological	None	Moderate	None	None	None	Minor	None	None

None = No noticeable impact

Minor = Short term, local, within permissible standards

Moderate = Temporary, local, some noticeable impact

Major = Long term, local, large impact

TABLE 3.4 Overview of Environmental Impacts from Geopressured Aquifer Methane Production

Environmental Impacts	Site Preparation	Drill Pad Siting	Pipelines	Drilling	Stimulation	Production	Restoration Activities
Air Pollution	Minor	Minor	Minor	Minor	Minor	Minor	Minor
Surface Water	None	Moderate	Minor	Major	Major	Major*	None
Ground Water	None	Minor	None	Minor	Minor	Minor	None
Land Use	Minor	Minor	Minor	Minor	Minor	Minor	Minor
Ecology							
Flora	Minor	Minor	Minor	Minor	None	None	None
Fauna	Minor	Minor	Minor	Minor	Minor	Minor	Minor
Noise	Minor	Minor	Minor	Moderate	Moderate	Moderate	Minor
Geological	None	Moderate	None	Moderate	Major	Major*	None

None = No noticeable impact

Minor = Short term, local, within permissible standards

Moderate = Temporary, local, some noticeable impact

Major = Long term, local, large impact

* = Significant concern

3.1.1 Air Pollution

Each of the unconventional gas recovery technologies has operations that generate some air pollutants during various stages of recovery. The information presented below outlines the potential impacts on regional air quality from UGR during site preparation, the actual drilling and/or stimulation operations, and site restoration. None of the UGR technologies are anticipated to create noticeable impacts on regional air quality.

3.1.1.1 Site Preparation

One of the activities required to prepare a site for gas recovery, in conventional or unconventional operations, is the construction of temporary and/or permanent roads and other support facilities.

During construction of the roads, the principal pollutant will be air emissions of diesel engine exhaust and dust. The impact of diesel emissions on air quality is anticipated to be minimal except in the immediate vicinity of the road equipment because of the atmospheric dispersion characteristics existing in areas of resource development and the lack of sensitive environments in the immediate vicinity of most UGR sites. Dust may be a severe local problem at the construction site during dry weather and high wind conditions, although this quantity of dust would be similar for any equivalent-sized road construction site. The regions in which most UGR sites are located are in areas that already have very high total suspended particulate (TSP) levels. The small amount of road construction that may be required by UGR activities is anticipated to add very little to these TSP levels.

3.1.1.2 Drilling and Stimulation

The major activity associated with the development of any gas field is drilling the wells. Stimulation of these wells using some form of advanced hydraulic fracturing is also often necessary to obtain reasonable flow rates of production. All UGR resource development techniques require drilling and stimulation operations. The potential impacts from these operations will thus be discussed here as relevant for all UGR technologies.

A small amount of air pollution resulting from construction of the drill pad will result from diesel engines and windblown dust. The diesel engines emit carbon monoxide (CO), sulfur oxides (SO_X), nitrogen oxides (NO_X), hydrocarbons (HC) and particulates. Dust may also be a problem during construction and for the life of the pad site. These pollutants should have an impact only in the immediate vicinity of the construction site and will be well below air quality standards a short distance from the site. During high wind conditions, dust from the construction area may add minimally to the local TSP levels. Any such impact would be short-term and temporary.

During drilling, the major potential sources of air pollution are the emissions from the 1000 to 1500 hp diesel engines. The diesel engines will run continuously for between 2 and 54 days, depending on the size of the well. Primary emissions will be CO, SO_X, NO_X, hydrocarbons and particulates, as discussed above. The quantities emitted by a diesel engine are given in Table 3.5. These values are very small and will be below air quality standards a few hundred feet from the source. Normally, only one or two drilling rigs will be operational at a given time in a field. These emissions, averaged over the entire gas field, will be quite small and well within ambient air quality standards. They should thus present no significant environmental impact.

TABLE 3.5 Emissions from One 1100 hp Diesel Engine

Pollutant	Quantity (g/sec)
SO_X	2.08
HC	1.63
NO_X	2.84
CO	2.50
Particulate	0.80
Aldehydes	0.13

The principal potential sources of air pollution during well stimulation are the air emissions from the diesel engines used during the fracturing treatment. During fracturing, several large diesel engines will be used to pump the fluid under high pressure into the well. For example, for a hydraulic fracturing treatment of 20,000 to 50,000 gallons, there will be one pump truck and one blender or mixer truck, each with two large diesel engines. If a foam fracturing method is used, there will be one additional nitrogen pump truck. These large diesel engines may create local high concentrations of air pollutants and high levels of noise. The air pollution levels that may be expected during the 1/2- to 2-hour operation are given in Table 3.6.

TABLE 3.6 Emissions from a Typical Well Stimulation Using Three 1100-hp Diesel Engines

Pollutant	Release Rate (g/sec)	Release During Typical Treatment (kg/hr)	Total Release for a Two-Hour Treatment (kg)
SO_x	21.23	23	46
HC	16.6	18	36
NO_x	28.93	31	62
CO	25.46	28	56
Particulate	8.2	9	18
Aldehyde	1.32	1.2	2.4

Local air quality standards may be exceeded at specific points within a short distance of the well site. When averaged over the entire field, the standards should not be exceeded at any time.

Additional sources of air emissions may be encountered at a geopressured site. These potential pollutants include emissions of gases associated with the brine stream. Gases produced from the brine, in addition to methane, include carbon dioxide (CO_2), nitrogen (N_2), hydrogen sulfide (H_2S) and sulfur dioxide (SO_2). Gas composition tests from the Pleasant Bayou No. 2 Well, as an example of the amount of these pollutants that may be encountered at a geopressured site, are given in Table 3.7.

TABLE 3.7 Composition of Gas Produced from Pleasant Bayou No. 2 Well (Mole Percent)

	Sample Number	
	79GG201G	79GG204G
Gas Ratio (scf/bbl)	27	21
Methane (CH_4)	88.93	84.51
Ethane (C_2H_6)	4.65	2.97
Carbon Dioxide (CO_2)	5.24	10.54
Nitrogen (N_2)	0.67	0.57
Hydrogen Sulfide (H_2S)	<0.01	-----
Sulphur Dioxide (SO_2)	<0.05	-----
Oxygen (O_2)	<0.02	-----
Argon (Ar)	<0.02	-----

Of all the pollutants listed above, only hydrogen sulfide and sulfur dioxide present any potential air pollutant hazard, and the concentrations listed are at levels that should be of little concern. It is unlikely that H_2S emissions will cause significant ecological or health effects, other than the unpleasant odor emitted by this source.

3.1.1.3 Site Restoration

From an environmental standpoint, site restoration is an important step in the overall recovery process. In this operation, the original topography of the land is restored to reduce erosion and return the land to its original use. To make any great changes in the topography, large construction equipment will be needed. This may result in a short-term increase in noise levels, human activity, air pollution from diesel powered equipment and air pollution from blowing chemicals, if fertilizer is used. However, these effects would be of short duration (a matter of days) and temporary, presenting no significant environmental impact.

3.1.2 Water Pollution

All unconventional gas recovery operations generate some potential for water pollution, primarily from erosion as a result of construction operations or the required disposal of waste waters produced at the well. However, these impacts are not anticipated to be significantly different from similar impacts currently experienced in related industries, such as construction, petroleum recovery, and mining industries. The one exception here is the disposal of waste water produced from geopressured aquifers. The amount of brine produced is much greater than that encountered in conventional operations. Adequate control technologies will need to be developed to handle and dispose of this waste in an environmentally acceptable manner. The potential impacts on water resources of the UGR technologies are discussed below. Impacts not otherwise referenced apply to all the UGR techniques.

During site preparation, erosion and runoff from the road beds may result in some increase in solids to local bodies of surface water. The impacts on surface water should be relatively insignificant, however, particularly for recovery of gas from western sand basins, since in these arid regions permanent roads are required by law to be constructed with culverts. Also, the amount of runoff involved is not anticipated to be significantly greater than that currently being experienced at most sites.

During well drilling, groundwater pollution from the drilling mud pit may be a potential source of pollution. However, the amount of fluid involved is less than 400 m^3. Constituents of the drill mud water are normally non-toxic and have been deemed so by the EPA in conjunction with the Resource Conservation and Recovery Act of 1976 (RCRA) (PL 94-580). The only "toxic" element that might be present in mud or naturally contaminated waste water is barium. The concentration of the element is expected to be less than the 10 mg/ℓ level set by EPA as the concentration which is potentially toxic to public health (National Interim Drinking Water Regulations 1976, Development of Environmental Monitoring Guidelines for EOR and EGR Processes 1978, Vol. II). Also, drilling mud fluid will be isolated from public exposure pathways by high dikes. The high evaporation index from the pit and the fact that groundwater levels are usually far below the level of the pit will also prevent the contamination of ground- or surface water resources.

A potential source of environmental impact during well stimulation is contamination of freshwater aquifers with fracturing fluid components. Standard oilfield practices to prevent this seem to be effective. It is anticipated that groundwater contamination will only occur if the cementing of the casing has not been properly done. The possibility of stimulating a well with an inadequate cement job is believed to be low because a cement bond log is run previously to insure a good bond.

During the production stages of all UGR technologies, any brine produced by the well will be separated from the gas and disposed of in the mud pit. The amount of brine produced is usually small, especially in comparison to the evaporation index, and should not result in any environmental impact or groundwater contamination. This may not be true for recovery of methane from coal seams or geopressured aquifers, however.

A potential problem during production of methane from coal seams is disposal of the water that is produced from the coal seam. Table 3.8 lists the composition of water from three coal beds. The composition varies widely, from slightly acidic to slightly alkaline, and from potable to saline. The waste water is temporarily stored in a lined waste water pit until treated for release to nearby surface water. The water must meet state or federal standards before being released into the natural water system. The planning of pollution control and water disposal systems must be determined on the basis of the water at each site. Water from some coal beds, especially in the western part of the United States, may be of higher quality than the alkaline surface waters. However, coal mine operators are also faced with the problems of proper waste water treatment and disposal, and have developed appropriate control measures that serve to mitigate any potential impacts from this source.

TABLE 3.8 Composition of Water from Three Coal Beds

Coal Bed Identification		Pittsburgh				Mary Lee	Pocahontas No. 3
pH		7.45	7.65	8.15	8.05	8.35	6.75
Acidity		0	0	0	0	0	110
Alkalinity	ppm	1,825	790	2,043	876	355	0
Dissolved solids	ppm	4,478	9,774	17,246	3,108	1,428	156,440
SO_4	ppm	63	133	ND	ND	ND	2
Ca	ppm	159	477	127	162	12.5	*2.95%
Mg	ppm	132	193	482	29	8	*0.67%
Fe	ppm	0.5	ND	ND	0.13	ND	1
Chlorides	PPM	2,356	7,700	13,600	2,200	700	*13.97%

ND - Not detected.
* - Reported as percent.

Control and disposal of spent brine from geopressured aquifers may also present some environmental concern. Unlike the oil and natural gas production industries, where quantities of fluid wastes are small compared to the amount of energy resources produced, a single geopressured well can yield from 10,000 to 50,000 barrels of liquid per day throughout its producing lifetime. In addition, the brine produced is hot and chemically complex. Taken together, these factors underscore the potential for serious environmental impacts. Under well blowout conditions, the maximum potential flow rate (based on a well with a 7-inch casing) could reach more than one-half million barrels within the span of a few days.

The temperatures of the brine vary according to site location, but generally are expected to range between 250° and 300+°F. Release of this fluid to the surrounding water body could result in extensive thermal pollution. Large quantities of fluid, even fluid at an elevated temperature, however, may not present major environmental concern if the chemical composition is compatible with affected terrestrial and marine ecosystems. Geopressured brines generally do not possess this compatibility, and are chemically complex and potentially hazardous wastes.

The chemical composition of geopressured brines ranges in total dissolved solids (TDS) from 10,000 to 275,000 ppm. Concentrations of a variety of chemicals including boron, ammonia, and heavy metals, make these brines significantly different from Gulf Coast seawater. Table 3.9 shows the chemical composition of several samples of geopressured brine as compared to seawater composition.

Direct discharge into surrounding terrestrial or aquatic environments of the geopressured aqueous effluent will generate a number of serious negative impacts. The type and severity of these impacts depends on both the characteristics of the effluent and the sensitivity of the impacted ecosystem. The potential ecological impacts are described in more detail in Section 3.1.4.

The type and magnitude of these impacts vary according to the specific properties of a given brine and the methods of disposal employed. At present, reinjection of the waste brine into subsurface aquifers located above the producing formation is the only disposal method under serious consideration. Undesirable communication of the brine with adjacent freshwater formations

TABLE 3.9 Chemical Composition of Seawater, Oil Field, Geothermal, and Geopressured Geothermal Brines

Location	Seawater(a)	Oilfield Brine(b)	Cerro Prieto Mexico(b)	Wairakei New Zealand(c)	Lafayette,LA Weeks Island(a)	Brazoria,TX Brazoria #2(d)	Corpus Christi,TX Portland(a)	McAllen-Pharr,TX Pharr(a)
Sample #	---	---	---	---	77-GG-19	79-GG-204	76-GG-63	77-GG-107
Depth (m)	---	---	---	---	4,275	4,462	3,514	3,018
Temp.(^{o}C)	---	---	---	---	117	138	123	127
Pressure (psia)	---	---	---	---	6246	11406	8406	7594
Fluid Production								
Oil (m^3/day)	---	---	---	---	21.9	---	4.8	---
Water(m^3/day)	---	---	---	---	56.0	230	7.5	7.1
Gas (1000 m^3/day)	---	---	---	---	6.1	---	25.1	3.2
TDS	34,600	N.D.	25,426	4,400	235,700	132,000	17,800	36,600
pH	8.03	N.D.	7.89		6.2	6.5	6.8	6.8
Na	10,500	12,000-150,000	8,016		78,000	38,000	6,500	9,420
Cl	19,000	20,000-250,000	14 828		143,000	80,600	9,270	22,000
Li	0.17	----	22.9	----	16	39	3.6	7.5
K	380	30-4,000	1,899	----	1,065	840	68	
Rb	0.12	----	11.2		3.4	6.3	0.3	0.1
Cs	0.0005	----	39.5		11.8	50	----	2.9
Mg	1,350	500-25,000	0.5		1,140	660	15	18
Sr	8	----	15.4		920	1,020	7.0	256
Ba	0.03	----	9.4		185	760	1.4	27
Fe	0.01	----	0.51		84	62	2.3	4.1
Mn	0.01	----	0.88		N.D.	25	N.D.	N.D.
Pb	----	----	----		300	1.1	1.2	N.D.
Zn	----	----	<0.5		45 000	1.5	3.7	N.D.
B	4.6	----	17.7		44	32	62	105
NH_3	0-0.7	---	N.D.		100	78	5.8	21.5
HCO_3	0-1,200	0-1,200	59.0		450	365	1,600	114
F	1.3	----	2.0		0.8	1.4	1.5	3.9
Br	65	50-5,000	23.7		419	82	19	78
I	0.06	1-300	0.74		18	30	25	22
SO_4	2,700	0-3,600	13.0		6.4	5.4	110	7.4
SiO_2	----	----	1,318		48	120	93	90

(a) Kharaka,Y.K.; E. Chemerya, J.C. Callender,and M.S. Lico, "Potential Problems Arising from the Disposal of Spent Geopressured-Geothermal Waters from Coastal Texas and Louisiana," in Forefronts in Ocean Technology-Part II, Marine Technology Society, Washington D.C., 1979. Table 1.

(b) Phillips, Sidney L.; Mathur Ashwani K., and Raymond E. Doebler, A Study of Brine Treatment, Lawrence Berkeley Laboratory, Berkeley, CA., EPRI ER-476, LBL 6371, November 1977. Table 1-3.

(c) Axtmann, Robert C., " Environmental Impact of a Geothermal Power Plant," Science March 1975, Volume 187, Number 4179, p 795-803.

(d) Kharaka, Yousif K; Lico Michael S.; Wright, Victoria A., and William Carothers, "Geochemistry of Formation Waters from Pleasant Bayou No.2 well and Adjacent Areas in Coastal Texas," presented at the Fourth United States Conference on Geopressured/Geothermal Energy:Research and Development, Austin Texas, October 29-31, 1979, Table 1.

or with the ground surface is a risk that can be minimized with proper operating procedures. Control of reinjection pressures can reduce the threat of environmental disruption resulting from fluid disposal. Surface disposal of brine to the Gulf of Mexico is more problematic. Disposal of hypersaline brines into the Gulf from the Federal Strategic Petroleum Reserve (SPR) Program may provide useful data on dispersion patterns and possible impacts. Unfortunately, any disposal comparison is only partially realistic because of the different chemical and temperature characteristics of the two fluids. Brines probably cannot be dumped into the Gulf except with intensive treatment. Thus, disposal of waste brines should present no significant environmental concerns unless surface disposal is used.

3.1.3 Geology and Land Use

The only real impacts of unconventional gas recovery technologies on the surrounding geology and land use at a site will be the required construction of roads, pipelines, and other production and support facilities necessary to recover unconventional gas resources. These impacts are anticipated to be no different from those encountered in other conventional operations, and affect only a fraction of the land areas impacted by similar construction in other energy-recovery industries.

To transport drilling equipment into the site, temporary roads or off-road vehicular travel may be necessary. The amount of temporary roads constructed or land impacted by off-road vehicular travel will be minimal because of the large number of roads anticipated to be already available in most areas. The minimum required cleared land areas for road development may range from 100 to 300 acres, or between 1 and 3% of the total well field area, depending on the type of gas recovery technology and the area of the country involved.

In addition to construction of roads for transporting well field equipment, development of a gas field may require construction of pipelines between wells and to the nearest commercial transmission pipeline if the gas is to be sold to a pipeline company. Distance to the nearest commercial transmission pipeline is highly variable and may only be determined on a field-by-field case. It is anticipated that the length of pipeline required will be approximately equal to the minimum road distance required. However, pipeline construction disturbs less land by width of area. The total amount of land disturbed by pipelines is anticipated to be less than 1% of the total gas field area. If the pipelines are buried, a backhoe is used to dig a trench about 10 inches wide. After burial of the pipe, this area is recontoured and reseeded.

The major activity associated with the actual development of the gas field is drilling the wells. The primary impact from drilling is the clearing of the drill pads, which may cover between 1/2 and 4 acres, depending on the resource in question. Included in this acreage is a mud pit for disposal of drilling mud and waste production water, as well as a smaller flare pit where the produced gas is burned when testing the well. The mud pit is about 1250 ft^2 in area and the smaller flare pit occupies about 400-600 ft^2. If it is necessary to site the well on a slope or hilltop, the topography of the area will be altered and part of the hillside may be leveled. However, these original land contours are usually required to be restored when the site is abandoned.

There has been some concern expressed that hydraulic fracturing operations might lead to increased seismic activity. Fracturing operations should not result in seismic events in most instances because:

- The volume used in a fracturing job is from one-hundredth to one-ten-thousandth of the amount which has triggered seismic events.
- None of the recovery areas is seismically active.
- Past fracturing jobs have not resulted in seismic or other subsurface activity.

However, there is some evidence that production and disposal of large volumes of fluid from geopressured reservoirs can lead to pressure changes that may induce seismic activity. These pressure changes can affect the faulting systems present in an area and, in turn, can induce seismic events. However, the only evidence that directly ties geopressured activities with increased local seismicity comes from the Pleasant Bayou No. 1 environmental baseline tests. Following operation of the well, several seismic events were observed. Table 3.10 lists several of the larger events out of a family of 70 documented seismic occurrences.

TABLE 3.10 Pleasant Bayou No. 1 Microseismic Events

Date	Magnitude (R)
Nov. 3, 1978	1.00
Nov. 3, 1978	1.03
Nov. 7, 1978	1.33
Nov. 13, 1978	0.90
Nov. 15, 1978	1.31

The correlation between the geopressured well tests and increased seismic activity is clearly present. The small magnitude of the events, however, indicates that the possibility of serious damage is slight. Thus, induced seismicity as a result of recovery from geopressured aquifers is of little environmental concern.

The final procedure in UGR is to either recontour and reseed all disturbed land (roads and drill pads) back to their original conditions or to leave the land as specified in the lease. If the landowner desires, the site, including roads and drill pad, may be left for his use after being cleaned and decontaminated. Seeding should reduce erosion possibilities.

3.1.3.1 Disposal of Waste

Solid waste is generated by drilling operations (cores) and from normal site waste disposal with use of all UGR technologies. These wastes are common to all large drilling operations and should present no major environmental problems if existing standard disposal practices are followed and if existing laws and regulations are observed.

If mud is used during drilling, a small mud pit will be dug to hold the mud. In most cases air or gas is used in drilling because it speeds up the drill rate. This would eliminate any environmental impacts associated with the mud pit. If drilling mud is used, constituents of the drill mud water are normally non-toxic. The only "toxic" element which could be present in mud or naturally contaminated waste water is barium. The concentration of the element is expected to be less than the 10 mg/ℓ level set by EPA as the concentration which is potentially toxic to public health.

3.1.3.2 Erosion

There may be some erosion and runoff experienced from the roads constructed during preparation of the site. The disturbed vegetation and surface topography may also encourage erosion. The excess siltation in the streams from erosion may have adverse effects on the aquatic life. Some local soils may have poor subsoil embankment stability with a high slip hazard, which could further exacerbate any erosion encountered.

Because of the remote locations of some of the gas fields, particularly in the western sand basins, some off-road travel may be required to transport exploration equipment. Desert soils and the alpine tundra areas of Appalachia are particularly vulnerable to off-road traffic. Once the soil is broken down and the vegetative cover stripped away, such soils become susceptible to wind, water and mechanical erosion. However, the amount of land impacted by off-road vehicular traffic compared to the total land area of the gas resource basins is small; therefore, the impact is anticipated to be minimal.

3.1.3.3 Subsidence

The potential subsidence of land in most UGR operations is of little concern. However, the probability of subsidence resulting from geopressured aquifer development--both its magnitude and rate--is largely unknown. Experts disagree on the adequacy of current levels of theoretical knowledge for analyzing and predicting subsidence in this resource area in the necessary site-specific manner. Some factors indicate high potential for subsidence; others point to low potential. For instance, the extensive growth faulting of the Gulf Coast may help limit the areal extent of subsidence. At the same time, the undercompacted sediments of geopressured reservoirs may enhance the probability of significant subsidence. Any analogy of geopressured subsidence with subsidence resulting from the extraction of geofluids (such as oil and gas, geothermal fluids, or groundwater) is far from precise. Its depth as well as its highly faulted sediments are unique features thought to be determinants of subsidence. The potential severity of geopressured subsidence in the low-lying Gulf Coast indicates that more research in this area is necessary.

3.1.4 Ecology

The impact of unconventional gas recovery operations on the local ecology is related to the amount of land disturbed, the noise levels experienced and potential effects of air or water pollutants.

The construction of permanent roads has probably the largest areal impact. For example, a 20-ft roadbed would result in a minimum of 2.42 acres cleared for every mile of road. Removal of flora and fauna will occur along all roadbeds. The amount of flora and fauna removed will have minimal impact on the total ecosystem because of the small amount of land involved.

Since there will be increased road traffic in the area, the probability for road kills of animals will increase. The net road usage is still low (a few trips per week), however, and the net probability for road kills will be slight.

Because of the remote location of many gas resources, some off-road vehicular traffic may be needed for the transportation of exploration equipment. Off-road traffic temporarily may damage ecosystems by damaging soil, crushing vegetation and killing or disturbing wildlife. However, the total amount of land impacted is small compared to the total area of the resource basin, and the duration of such disturbances should be temporary and very short.

During production operations, the noise generated by the diesel engines will by 76 db (40 CFR 204.52). However, the engine will be located near the center of the drill pad and the calculated decibel level at the edge of the bed about 400 feet from the engine will be reduced to about 50 db. This is approximately the level of noise in an average home and is therefore not anticipated to adversely impact the fauna. The noise level that may be experienced is not excessive and should last for a maximum of about one month at each drilling site. Wild animals that are sensitive to high noise levels may flee from this zone; however, most of the fauna anticipated to exist near UGR sites consists of domesticated or semi-domesticated animals which should be able to tolerate these low noise levels.

After site restoration, the plant life would slowly recover the damaged area and the local fauna population would return to normal. Seeding with native flora would decrease the time required to achieve original ecological conditions.

The air pollutants generated by UGR operations are minimal and should not adversely impact local ecologies. The mud pits in which wastes are stored are fenced to prevent ground animals from drinking the fluids. Where migratory bird flyways may overlap the drilling areas, state and federal regulations require that the mud pits be covered to prevent exposure to the waste fluids.

The most severe impact conceivable on the local ecology would be that of a brine spill from geopressured aquifer operations. The impacts of a brine spill (or of direct surface disposal) may include an initial kill of local aquatic life because of osmotic, thermal or other toxic stress, followed by long-term, possibly chronic effects of gradual dissipation of elevated levels of salinity, heavy metals and other geothermal compounds. Natural ecosystems which receive such brines are modified in a number of ways that affect water circulation systems, osmotic regulations of aquatic organisms, water stratification, specific heat, hydrogen ion balance, buffer systems, solubility of oxygen, turbidity and ion balance. Such changes result in destruction of bottom communities and soil structure and low species diversity.

Elevated salinity levels are of particular concern because of the low salt tolerance of most plant species relative to typical geopressured brine concentrations. Maximum salt levels for these plants are only 50,000 ppm, substantially below the 275,000 ppm of some Louisiana aquifers. Additionally, even with high salt tolerance, many plants (and animals) are adapted to a specific range of concentration variations, and may not be able to tolerate exposure to concentrations outside of that range.

Table 3.11 briefly lists some of the toxic constituents in brine, their concentrations relative to recommended limits, and their chief effects.

TABLE 3.11 Toxic Effects of Geopressured Brines

Constituent	Maximum Concentration	Effects
SiO_2	900x steam turbine limit	Algae blooms
Sr	12x drinking water standard	Limited concern
Cu	100x aquatic plant tolerance	LC_{50} from 0.0018 mg/l to 7.5 mg/l
Fe	70x freshwater limit	Destruction of benthic species
NH_3	1300x freshwater limit	Toxic 0.2 to 2.0 mg/l

3.2 REGIONAL IMPACTS

The regional impacts that might be generated from recovery of unconventional gas resources are minimal. Most of the environmental, health and safety impacts of gas recovery will be centered at the site location. However, it is expected that homes will be scattered around the area near the drill site. Some may be close enough to the drilling site to be disturbed by the noise of construction and well drilling. This disturbance is based on the EPA prescribed maximum safe levels of 45 dB during the night from 10 p.m. to 7 a.m. This maximum noise level could be exceeded within a 2-mile radius if hills or other topographical features do not block or otherwise attenuate the noise levels. However, since drilling lasts one month or less, this should not be a major obstacle.

Also, the blasting associated with clearing a drill pad on a hillside would have considerably more impact on the surrounding communities than merely locating the well on level ground at the bottom of one of the area's natural hollows.

3.3 LEGISLATIVE STATUS

The environmental, safety and health impacts of unconventional gas recovery processes are controlled by a number of existing federal and state regulations. Federal regulations applicable to these activities are summarized in Appendix C. State regulations are specific to each drill site and will not be discussed in this document. Information on particular state regulations may be obtained from the appropriate state agency.

3.4 STATUS OF CONTROL TECHNOLOGY AND COSTS

Most of the environmental problems or concerns discussed in this section have been of minor consequence and may be easily controlled by currently available technology. Many similar problems, such as air emissions from diesel engines, noise, and disposal of drilling and waste water, are regularly encountered in conventional oil and gas recovery operations. The environmental impacts of UGR are primarily local, temporary concerns and are anticipated to have no severe consequences.

The primary uncertainties are the control of rock stability in coal mines after degasification, the monitoring and effects of subsidence in geopressured aquifers, and the monitoring and control of brine disposal from geopressured aquifers. The necessary technology to control these areas has not yet been clearly identified.

3.5 SUMMARY OF ENVIRONMENTAL CONCERNS

The activities associated with development of a gas field that could potentially result in minor environmental impacts include site preparation and drilling and stimulation of production wells. Most of the impacts resulting from these activities are insignificant and can be readily controlled with available technology. Environmental consequences during site preparation center on air emissions from the diesel engines used in construction and effects on the local ecology from general construction operations.

After production begins, the noise levels, human activity, and air pollution decrease. The only noise that may then occur from the site is when the gas needs to be compressed before entering the pipeline. Compressors can be extremely noisy pieces of equipment but may be housed in a building to bring the noise down to acceptable levels. There may also be intermittent high noise levels during routine maintenance checks. This should be minimal compared to drilling or fracturing.

Fracturing jobs usually last three to eight hours; therefore, the impacts over the long term will probably not be measurable. The constituents of fracturing fluid are non-toxic, so provided spills are cleaned up, no impact from chemical spills will result.

These impacts are not unique to UGR operations. They are also experienced, in greater magnitude, in conventional petroleum and gas recovery operations as well as the related energy-recovery and construction industries. These temporary, minor impacts thus do not constitute environmental concerns for UGR operations.

The only significant environmental concerns experienced in unconventional gas recovery are those associated with recovery of methane from geopressured aquifers. Surface subsidence resulting from geofluid withdrawal and the reinjection of spent brines into subsurface formations will be the two most difficult environmental aspects of this resource development. In each case the uncertainty is high. The potentially severe adverse impacts of subsidence or the inability to successfully reinject huge volumes of brine may slow or halt commercial development of the resource.

4.0 HEALTH AND SAFETY

There are a variety of potential human health and safety impacts that may be experienced during the development of an unconventional gas field. These impacts include noise and air pollution effects as well as other hazards that apply more specifically to each type of unconventional gas resource. The potential health and safety impacts discussed below are not necessarily unique to UGR operations, however. Most of these impacts are also experienced in conventional petroleum and gas recovery operations. Also, these impacts primarily affect the workers at each UGR site. Few health and safety effects are anticipated to be sufficiently large to affect the general public. The distance of most UGR sites from population areas also serves to mitigate any potential consequences to the public from UGR operations. Specific health and safety impacts that may be experienced in recovering gas from unconventional sources are discussed below.

4.1 NOISE

Health effects of noise will be experienced at all four types of UGR sites, just as they are experienced in any petroleum recovery operation or construction site. Ambient noise levels will be increased in the vicinity of the well site during the development period, especially during the drilling and fracturing phases of the operation. Sources of particularly large increases in noise levels include: operation of service vehicles and construction equipment, the operation of generators and diesel motors during drilling and stimulation and pumping operations, and the noise resulting from the general increase in the level of activity at the site. Typical noise levels at 50 feet are:

scraper	88-95 decibels (dBa)
grader	77-87 dBa
truck	66-91 dBa
drilling rig	∿90 dBa
fracturing	90-100 dBa.

Figure 4.1 shows the decibel levels and verbal loudness description of various sounds. In general, continuous exposure to noise levels of about 80 decibels or higher can produce permanent hearing loss; however, the effect is faster for louder noises. For example, continuous occupational exposure to a 95-decibel noise can depress a person's hearing ability by 15 decibels in 10 years. To prevent this hearing loss, the onsite workers will need hearing protection according to OSHA (Occupational Safety and Health Administration) requirements. Table 4.1 shows the OSHA standards for noise exposure in the work place. Table 4.2 summarizes the Environmental Protection Agency (EPA) standards for protection of the public from non-ambient noise levels (PL 92-574). Because most UGR sites are located at some distance (minimum of several miles) from public dwellings and meeting areas, it is anticipated that any noise generated from UGR operations will be well below the non-ambient noise level limits set for these areas.

TABLE 4.1 Permissible Noise Exposures in the Workplace[a]

Duration (hours/day)	Sound Level dB(A)[b]
8	90
6	92
4	95
3	97
2	100
1-1/2	102
1	105
1/2	110
1/4	115

(a) OSHA Standards for Noise Exposure in the Workplace, Bureau of National Affairs, Washington, DC.
(b) dB(A) = decibels over ambient.

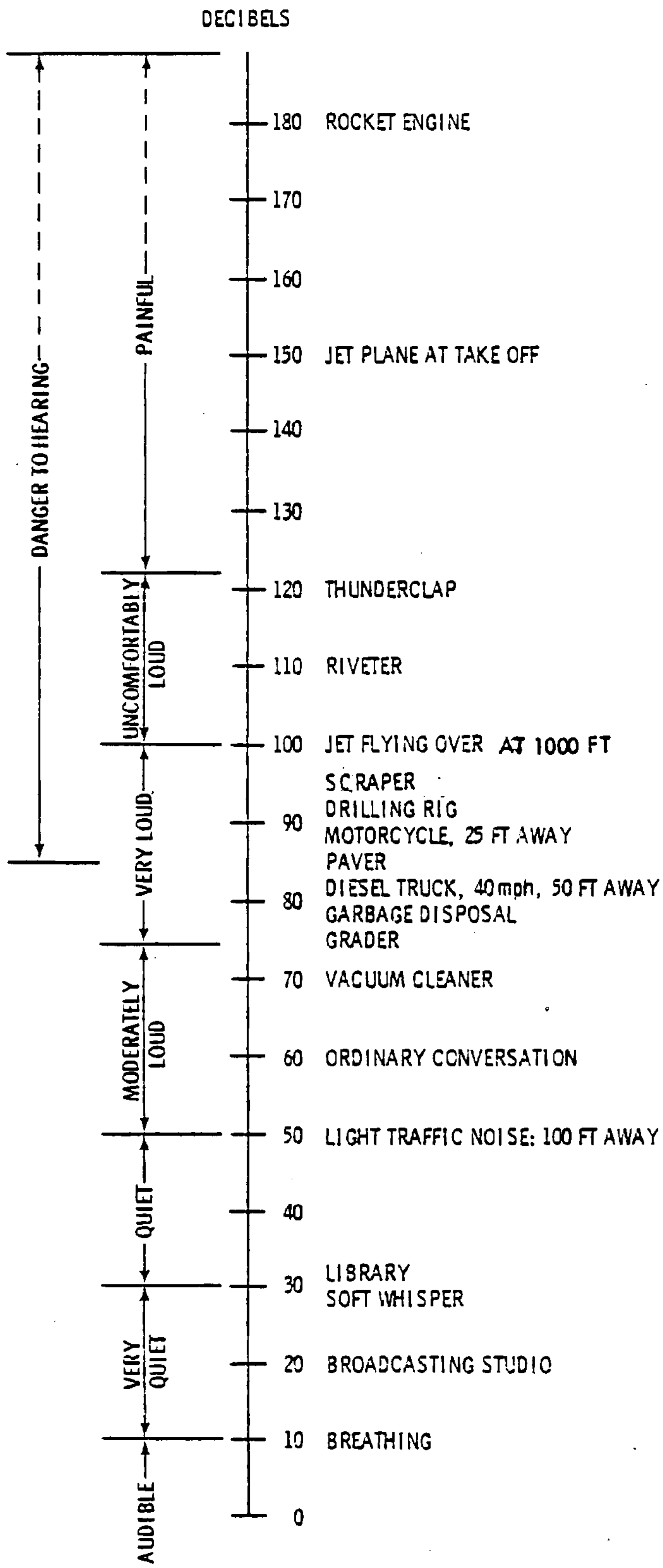


FIGURE 4.1. Decibel Levels and Verbal Loudness Descriptions of Various Sounds

TABLE 4.2 Summary of Noise Levels Identified as Requisity to Protect Public Health and Welfare with an Adequate Margin of Safety[a]

Effect	Maximum Allowable Noise Level[b]	Area
Hearing loss	55 dB	All areas.
Outdoor activity interference and annoyance	55 dB	Outdoors in residential areas and farms and other outdoor areas where people spend widely varying amounts of time and other places where quiet is a basis for use.
		Outdoor areas where people spend limited amounts of time, such as schoolyards, playgrounds, etc.
Indoor activity interference and annoyance	45 dB	Indoor residential
		Other indoor areas with human activities such as schools, etc.

(a) EPA, Environmental Protection Agency Standards for Non-Ambient Levels, PL 92-574.

(b) Sound energy averaged over 24-hour period.

4.2 AIR POLLUTION

As discussed in Section 3 of this document, the recovery of gas from unconventional resources will result in some additional, temporary air pollution to the local region generated by the equipment used during various phases of the recovery operations. Again, similar impacts would be experienced in any petroleum recovery operation or heavy construction activity. These impacts are not unique to UGR operations, and are included here only for completeness.

The equipment used during recovery of unconventional gas resources includes diesel engines, which release a variety of pollutants into the air during operation. The concentrations of these constitutents in the local air stream will vary with the number of engines operating, as well as with atmospheric conditions. The maximum amount of pollutants produced at a site, when the diesel engines are all operating at full capacity, is shown in Table 4.3. Potential health effects from air pollution primarily center on effects of carbon monoxide on the workers at the site. Other diesel exhaust constituents are not expected to reach even the "alert levels" specified in the Clean Air Act (PL 91-604).

TABLE 4.3 Emissions from a Typical Stimulation Job Using Ten 1100 hp Diesel Engines

Pollutant	Release Rate (g/sec)	Release During Typical Sized Job (kg/hr)
SO_x	21.23	76
HC	16.6	60
NO_x	28.93	104
CO	25.46	92
Particulate	8.2	30
Aldehyde	1.32	4

Carbon monoxide (CO) produced from these operations is expected to reach concentrations of 15-50 ppm near the source under calm wind conditions. These levels do not exceed the threshold limit value for workroom environments but could cause some somatic effects in workers. Myers et al. (1970) estimates that 50 ppm would be the level at which one might expect some reduced mental acuity and headaches over a 10-hour period (see Figure 4.2). No other potential effects of slightly elevated carbon monoxide concentrations include cardiac function effects (∿30 ppm) and work performance impairment (∿120 ppm). However, repeated exposure to low concentrations of the gas, up to 100 ppm, is generally believed to cause no signs of poison or permanent damage (Sax 1979). The dispersion of gases by the amount of mixing of air allowed in an outdoor environment should also reduce this potential impact by preventing a buildup of CO in the atmosphere.

Particulates due to traffic, construction of roads and drill pads, and wind scouring of exposed surfaces may present, visually, an air pollution problem. Each new mile of road and acre of cleared drill pad will add to the particulate grain loading of the local area. Such effects, however, will be extremely localized, especially for dusts greater than 5 microns (μ) in diameter. Based on this size particle, only unstable atmospheric/high wind conditions will permit the carrying of dust particles more than one kilometer.

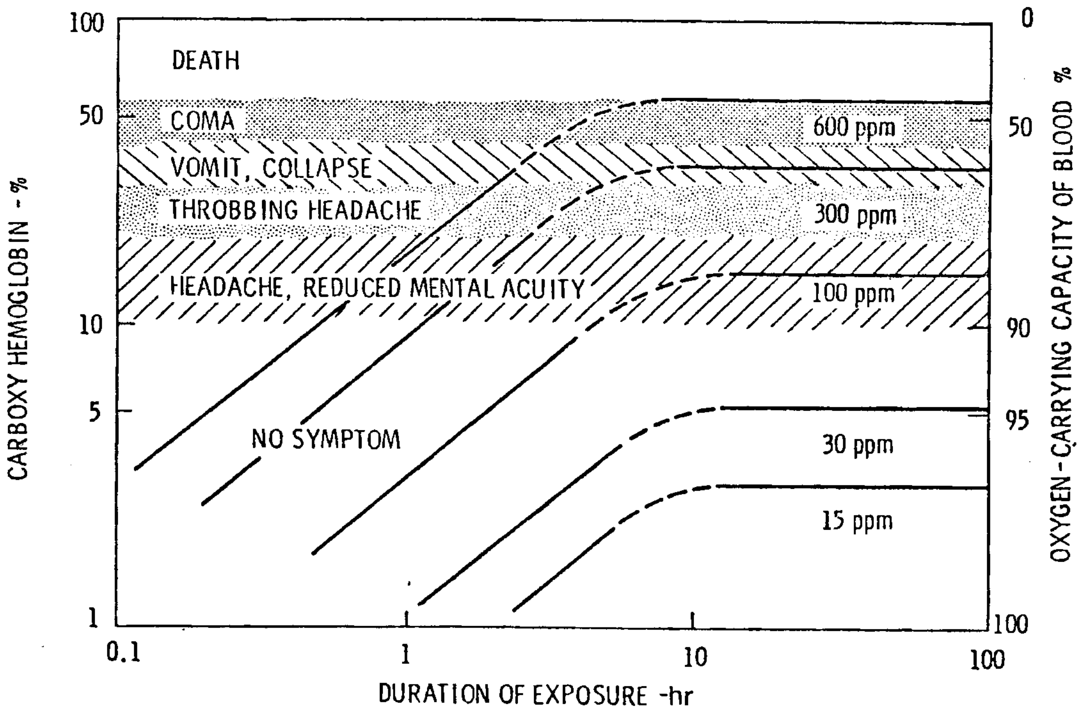


FIGURE 4.2 Relationship Between CO Exposure (Hours and Concentration) and Health Effects .

4.3 OCCUPATIONAL INJURIES AND ACCIDENTS

Accidents that can result in injury to workers happen in any industry. Occupational injuries and fatalities in UGR operations are expected to be less than or comparable to those commonly experienced in the petroleum industry as a whole. The nature of UGR activities do not present any special hazards to working personnel that have not been encountered in conventional petroleum and gas recovery operations. General petroleum industry accident data can therefore be used to estimate the magnitude of occupational safety impacts potentially associated with UGR operations.

Data on occupational injuries and fatalities for the petroleum industry are summarized by job category in Tables 4.4 and 4.5. Using this data gives average injury rates of .04/worker for exploration and production operations, .27/worker for drilling and .05/worker for pipeline construction and operation. The average industry fatality rate obtained from this data is 1.3×10^{-4}/worker. Use of these fatality and injury rates should provide a conservative estimate of fatalities and injuries in UGR operations because the data includes offshore and deep drilling operations that are inherently more hazardous than the activities encountered in recovering gas from unconventional resources.

TABLE 4.4 Summary of Fatal Injuries in the Petroleum Industry, 1974 to 1979

Job Category	Number of Fatal Injuries per Year					
	1974	1975	1976	1977	1978	1979
Exploration and Production	19	7	7	23	19	10
Gas Processing	0	0	0	1	0	1
Gas Pipeline	3	3	0	0	1	1
Drilling	1	2	0	0	0	0
Total Employees	--	424,904	417,713	425,629	435,524	447,040
Number of Workers per 1 Fatality	5,806	8,498	10,188	5,995	5,807	8,597
Total Industrial Fatalities	--	50	41	71	75	52

TABLE 4.5 Summary of Occupational Injuries in the Petroleum Industry, 1975 to 1979

Job Category	Number of Occupational Injuries/Year					
	1975	1976	1977	1978	1979	Avg.
Exploration and Production						
Total Number of Employees	54,598	60,866	68,537	72,729	79,543	67,240
Total Number of Injuries	2,466	2,591	2,642	2,758	2,777	2,650
Gas Processing						
Total Number of Employees	5,927	7,084	6,083	7,220	8,082	6,880
Total Number of Injuries	299	288	306	318	347	310
Drilling						
Total Number of Employees	1,918	2,486	2,794	2,947	2,534	2,535
Total Number of Injuries	515	608	904	809	541	675
Gas Pipeline						
Total Number of Employees	16,736	16,365	16,697	18,551	18,198	17,300
Total Number of Injuries	921	835	921	859	965	900

4.4 OTHER HEALTH AND SAFETY IMPACTS

Techniques associated with degasification of coal seams may result in increased hazards to miners. For example, although fracturing of coal has proved effective in increasing the gas flow rates, most mine operators are concerned that fracturing may damage the overlying rock which makes up the roof of the mine, creating unsafe mine conditions. However, a number of stimulated boreholes have been mined through and show that the fracturing was contained within the coal seam. Thus, this potential concern appears to be insignificant, although more research may be needed to ensure that different rock types do not respond differently to the fracturing methods currently in use.

There may also be a potential safety hazard associated with a pipeline in the mine. Concentrations for explosive mixtures of methane in air range from 5% to 15% by volume. In the case of an accident or a methane detector malfunction, a leak in the pipeline could fill the mine area with an explosive mixture very quickly. Mining safety regulations require that the pipeline be intrinsically safe and incorporate fail-safe leak detectors and shut-off valves. However, there has been limited operational experience with these fail-safe systems and their overall effectiveness is not known.

Another problem is presented by the danger of mining through a degasification borehole. This empty space is essentially a "gas pocket" which encourages concentrations of methane to gather, potentially creating an explosive mixture. Extreme care must be taken with horizontal boreholes so that their exact location is known when mining operations approach the area. Extra precautions may be taken by totally plugging the borehole before the mining operation comes close. This would decrease the chances of explosive mixtures collecting in the mine. More research is needed to quantify the level of potential hazard and determine methods for reducing the chances of explosive mixtures entering and collecting in the mine.

Tight Western Sands

The handling of radioactive tracers could present some safety impact in the recovery of gas from the Tight Western Sands resource base. The fracture sand used has Ir-192 added as a tracer. Each can of tracer contains 5 mCi of activity and 5 cans are used per fracture treatment. In a single treatment, a worker is calculated to receive a dose of from 12 to 20 mrem (millirem) from direct exposure over a 2 to 3 hour working time. If that same worker handled the radioactive tracer for 3 fracture jobs per week for 50 weeks, based on the dose for one job he may receive a dose of as much as 2 to 3 rem per year. Calculations were also performed to estimate the potential dose to a worker from inhalation of Ir-192. The highest organ dose rate calculated was 3×10^{-2} rem per year based on a relatively insoluble Ir-192 and 150 jobs/year. This level of radiological inhalation is not anticipated to represent a significant safety hazard to workers, particularly when compared to the potential dose from direct exposure.

However, the petroleum industry has used radioactive tracers in its operations for many years. Safe handling procedures have been developed to help protect the workers who administer these tracers. Thus, use of radioactive tracers should present no special safety hazards for recovery of gas from Tight Western Sands.

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APPENDIX A

GLOSSARY OF TERMS AND ACRONYMS

List of Acronyms

UGR	unconventional gas recovery
EPA	Environmental Protection Agency
Tcf	trillion cubic feet
ft	feet
ft^3/ton	cubic feet per ton
FPC	Federal Power Commission
Btu/ft^3	British thermal units per cubic feet
scf	standard cubic feet
Mscfd	thousand standard cubic feet per day
MHF	massive hydraulic fracturing
FF	foam fracturing
CEF	chemical explosive fracturing
RDP	rapid drawdown process
psia	pounds per square inch (absolute)
TSP	total suspended particulates
CO	carbon monoxide
SO_x	sulfur oxides
NO_x	nitrogen oxides
HC	hydrocarbons
CO_2	carbon dioxide
N_2	nitrogen
H_2S	hydrogen sulfide
SO_2	sulfur dioxide
m^3	cubic meters
mg/l	milligrams per liter
°F	degrees Fahrenheit
ft^2	square feet
db (a)	decibels (above ambient)
ppm	parts per million
OSHA	Occupational Safety and Health Administration

List of Acronyms (cont)

hp	horsepower
g/sec	grams per second
kg/hr	kilograms per hour
mCi	millicuries

List of Terms

Air Drilling	Rotary drilling system using compressed air instead of mud as the circulation medium.
Barrel	A unit of measure for crude oil and oil products equal to 42 U.S. gallons.
Blowout	When excessive well pressure runs wild and blows the string and tools out of the hole.
Borehole	The hole in the earth made by the drill; the uncased drill hole from the surface to the bottom of the well.
Casing	Steel pipe used in well to seal the borehole to prevent fluid escape and to keep the walls from collapsing.
Cement	Mixture used to set the casing firmly in the borehole. A slurry that is allowed to set until it hardens.
Cementation	The natural filling in of the pore spaces in a reservoir by limestone.
Cementing	Pumping the cement slurry down the well and back up between the casing and the borehole. Once hardened, the cement is then drilled out of the casing.
Circulating System	The portion of the rotary drilling system that circulates the drilling fluids or mud.
Completion	Finishing a well. Getting a newly-drilled well ready for production.
Compressor	Mechanical device used in the handling of gases much as a pump is used to increase the pressure of fluids. Also used to increase air pressure.
Compressor Station	Placed at selected intervals along a gas pipeline, these units maintain the pressure necessary to keep the gas flowing through the lines.

Conductor	Outer pipe near the top of the well used to seal off unstable formations or to protect ground water near the surface.
Confirmation Well	A well drilled to prove the formation or producing zone encountered by an exploratory or wildcat well.
Connate Water	The water, usually saline, present in a petroleum reservoir in the same zone occupied by oil and gas.
Core	Literally a "plug" lifted or cut out of the earth at a predetermined depth.
Core Drilling	Using a special bit for the purpose of cutting a core.
Core Sampling	Taking out a core for geological examination of the composition of the strata at a particular depth.
Coring Bit	A hollow bit designed to make a circular cut for a core sample.
Deviated Hole	Directional change from the absolute vertical in drilling either by design or accident.
Devonian	Geologic period from about 405,000,000 B.C. to 345,000,000 B.C.
Directional Drilling	The technique of drilling at an angle from the vertical by deflecting the drill bit.
Drilling Mud	A fluid consisting of water or oil, clays, chemicals and weighting materials used to lubricate the bit and flush cuttings out of the hole.
Dry Hole	A well that fails to hit oil or gas, a "Duster."
Fault	A fracture in the earth's crust accompanied by a shifting of one side of the fracture with respect to the other side.
Flares	To burn off excess of unwanted natural gas at a well or production site.
Flow	Movement of petroleum through the reservoir.
Formation	A sedimentary bed or series of beds sufficiently alike or distinctive to form an identifiable geological unit.

Fracturing	Artificially opening up a formation to increase permeability and the flow of oil to the bottom of a well.
Acidizing	The pumping in of an acid solution to dissolve limestone or other deposits.
Explosive Fracturing	Use of explosive charges to shatter a formation. May be fired through the sidewalls of the well.
Hydraulic Fracturing	Forcing formation open by pumping in liquid under pressure.
Gas	Any fluid, combustible or non-combustible, which is produced in a natural state from the earth and which maintains a gaseous or rarified state under ordinary temperature and pressure conditions.
Gas Drilling	Drilling process using gas as the circulating system, similar to air drilling but using natural gas.
Interstitial	Water found in the interstices or pore openings.
Logging	The lowering of various types of measuring instruments into a well and gathering and recording data on porosity, permeability, types of fluids, fluid content and lithography.
Magnetometer	Device which detects minute fluctuations in the earth's magnetic field and show the presence of sedimentary rock.
Mud Logger	Person who analyzes the cuttings brought up with the drilling mud from the hole.
Mud Program	Planning for the supply of and use of drilling fluids in the drilling process.
"Natural Gas"	Gases and all other liquid hydrocarbons not defined as oil.
Offset Well	A well drilled on the next location to the original well. The distance between the two wells depends upon spacing regulations.
Oil	Liquid hydrocarbons including petroleum oil and any other hydrocarbons, regardless of gravities, which are produced at the well in liquid form by ordinary oilfield production methods, and which are not the result of condensation of gas before or after it leaves the reservoir.

Packer	A device lowered into a borehole that automatically swells or can be made to expand by manipulation from the surface to produce a water tight joint against the sides of the borehole or casing.
Pay Sands	The zone of production - where oil and/or gas is found in commercially feasible amounts.
Perforating	Literally punching holes in the casing so the oil and gas can flow into the well from the formation.
Permeability	A measure of the resistence offered by a porous rock to the movement of fluids through it.
Plugged Back	To plug off a well drilled to a lower level in order to produce from a formation nearer the surface.
Pores	The void spaces between the rocks in a reservoir.
Porosity	The capacity of rock to hold liquids in the pores.
Proppant	Material used in hydraulic fracturing for holding open the cracks made in the formation.
Proven Reserves	Oil and gas which have been discovered and determined to be recoverable but are still in the ground.
Reservoir	A porous, permeable, sedimentary rock formation or trap holding an accumulation of petroleum enclosed or surrounded by layers of less permeable rock; a structural trap; a stratigraphic trap.
Reservoir Fluid	Crude oil, natural gas, and salt water.
Rocks-Igneous Rock	The "first" rock, formed as the molten magma cooled.
Rocks-Magma	Rock in its molten state.
Rocks-Metamorphic Rock	Created from sedimentary rock subjected to great heat and pressure.
Rocks-Sedimentary Rock	Created under extreme pressure from particles of sediment.
Salt Domes	Salt plug forced upward by the accumulation of petroleum beneath it.
Sandstone	Sedimentary rock composed of grains of sand cemented together by other materials.

Sediment	Particulate matter carried along with water which settles to the bottom.
Sedimentary Rock	Rocks composed of sediments forced together under great pressure. See rocks.
Separator	Device placed between well head and lease tank battery to separate crude oil from natural gas and water.
Seismograph	Extremely sensitive recording device capable of detecting earth tremors as used in oil exploration to record man-made shock waves.
Shale	Rock composed of clay and fine-grain sediments.
Shut-Down - Shut-In Well	There is a great difference between a shut-down well and a shut-in well. A well is shut down when drilling ceases which can happen for many reasons: equipment failure, waiting for equipment, waiting for cement, etc. A well is shut in when its wellhead valves are closed, shutting off production. A shut-in well is often waiting for pipeline construction.
Sour Gas	Natural gas containing hydrogen sulfide (H_2S). H_2S is very poisonous and in small concentration smells similar to rotten eggs.
TD	Total depth.
Tectonic Map	A geological map; a structural map showing the folding and faulting of subsurface formations.
Traps	A geologic structure which halts the movement of a petroleum accumulation.
TVD	Total vertical depth. TVD is always less than a well's TD because of the inevitable deviations from the vertical of the well bore.
Unconformity	A cap of rock laid down across the cut off surfaces of lower beds.
Vibroseis	Mechanical means of producing shock waves for seismographic exploration without the use of explosives.
Viscosity	The ability of a fluid to flow. The more viscous a fluid is the less readily it will flow.
Wildcat Well	A well drilled in an unproved area far from a producing well; an exploratory well.

Wireline	A "rope" or cable made of steel wire.
Workover	Cleaning, repairing, servicing, reopening, or perhaps drilling deeper, or plugging back, a well to secure continued or additional production.
Zone	An interval of subsurface formation containing one or more reservoirs.

APPENDIX B

PETROLEUM FIELD TECHNOLOGY[a]

During its first half century, the American Oil Industry found petroleum resources by using the skills of experienced oilmen who spent their lives in the oil field. It was not until the second decade of the 20th century that the petroleum sciences, including geophysics, geology, and petroleum engineering, became important in finding and developing petroleum fields. The technologies for the location and exploitation of petroleum resources have continued to evolve since then.

Petroleum exploration, discovery, development, and production are scientifically and technically based functions which utilize information from the physical sciences, the earth sciences, and petroleum engineering. The exploration and initial drilling efforts combine the expertise of the geophysicist, geologist, and engineer. The development work is principally the job of the engineer, with assistance from the geologist and a very slight contribution from the geophysicist. Production and resource processing are tasks directed by the engineer. Thus, full cooperation among these three disciplines is required to effectively develop petroleum resources.

Presented in this section, in a generic sense, are the numerous stages in the exploration and exploitation of a petroleum (gas) field. The general steps in the finding and development of a petroleum resource are listed in Table B.1. Not all the steps may be required for each well within a given field.

B.1 EXPLORATION

Petroleum exploration covers all of the techniques, including the drilling of wildcat wells, which may be used in locating geologic traps that could contain petroleum accumulations. It utilizes the tools of geology and geophysics. Geologists examine the rocks themselves or work with rock properties that are measured by devices in close proximity to the rocks. Geophysicists obtain additional information by measuring physical characteristics of the earth from a distance which is only indirectly related to geology.

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[a] Petroleum is used here as a generic term for any oil or gas field. Until a wildcat well is drilled and tested, it is not known whether it contains oil, gas, or both. Most "gas" wells produce some condensate (oil).

TABLE B. 1. Stages in the Recovery of Petroleum for Reservoirs

1. EXPLORATION
   - Regional Surveys
   - Detailed Surveys
   - Wildcat Drilling
2. FIELD DEVELOPMENT
   - Reservoir Definition
   - Planning Well Space and Location
   - Installation of Treating Facilities
   - Collection and Distribution Facilities
3. PRODUCTION
   - Surface Facilities Maintenance
   - Well Maintenance
   - Stimulation
4. ABANDONMENT
   - Plug Wells (cement to surface) and Mark
   - Remove Surface Facilities
   - Recontour and Reseed Well Sites and Lease Roads.

B.1.1 Regional Surveys

Regional exploration surveys employ environmentally passive techniques. The geologist creates maps of the earth's gross surface features using aerial photos and various earth satellite imagery which may show important underground structures. The geophysicist uses airborne instruments to measure and map abnormalities in both the earth's magnetic and gravitational fields. Both of these kinds of maps are used to delineate features that may require further examination.

A chemical survey technique, gas chromatography, can also be used to locate petroleum reservoirs by locating and identifying hydrocarbons which seep into the atmosphere. Both gas and oil deposits have been successfully located via hydrocarbon seeps.

B.1.2 Detailed Surveys

When regional surveys indicate that promising subsurface features are present, more detailed surveys are conducted. The most important technique is three-dimensional seismic mapping. Another technique is detailed geological surface mapping, which includes precisely locating rock outcrops, describing the many characteristics of the different strata, and mapping their geometry and areal distribution.

The seismic technique is by far the most sophisticated, complex, and useful technique in petroleum exploration. Seismic data are collected by sending sound waves into the ground. These sound waves are, in turn, reflected and refracted by the subsurface geologic strata and are recorded on the surface by sensitive receivers (geophones).

The most common technique used to generate sound waves has been with the use of dynamite or some other type of explosive. However, newer and less environmentally destructive methods are available that have the advantages over dynamite of eliminating the shot hole and generating a purer frequency.

The principal non-dynamite energy sources are Vibroseis® and Dinoseis®. The Vibroseis® system utilizes a heavy weight which is coupled to the ground and then vibrated through a controlled frequency range. The Dinoseis® system also employs a heavy weight held in contact with the ground. However, with Dinoseis, energy comes from the explosion of gases in a chamber attached to the weight.

Seismic data are interpreted through the use of very sophisticated computer programs. Following sophisticated corrections and filtering operations on the raw data a seismic map is generated. These seismic maps show the depth and geologic nature of each type of subsurface bed. In fact, they can even distinguish gas sands from those not containing gas. More important, they can locate stratigraphic and paleogeomorphic traps or unconformities that may contain petroleum.

B.1.3 Wildcat Drilling

The previous exploration techniques can only indicate structures which could be potential petroleum traps. The actual location of a petroleum deposit and determination as to whether it contains commercial quantities of oil or gas require that a well be drilled and tested. Any well which is drilled into a locally new zone is considered to be a wildcat well.

Once a site for the wildcat well has been selected, permits to build a temporary road and approval of the complete drilling plan must be obtained. Since wildcats enter new zones, the danger of blowouts is greater than the drilling of a developmental well. The actual drilling operation is similar to drilling any well and will be discussed in the following section. Figure B.1 shows the main features of a drilling rig. Figure B.2 illustrates the main features of a typical casing string.

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B.2 FIELD DEVELOPMENT

The initial wells drilled into a zone previously identified by geological and/or geophysical exploration are termed wildcats. These wells are used to define the areal extent of the reservoir, the number of productive zones, their continuity, and the production capabilities. Once these factors have been determined, the field will be developed on a regular surface spacing which is normally dictated by state and/or federal regulations. Common well spacings for gas wells are 40 acres/well, 80 acres/well, 160 acres/well, 320 acres/well, and 640 acres/well. The number of wells drilled into a field during development is usually dependent on the depth of the producing zone, i.e., the deeper the zone, the fewer the wells that will be drilled. It is assumed that a lease to the mineral rights has been previously obtained. In addition, a lease must be negotiated with the surface-rights owner.

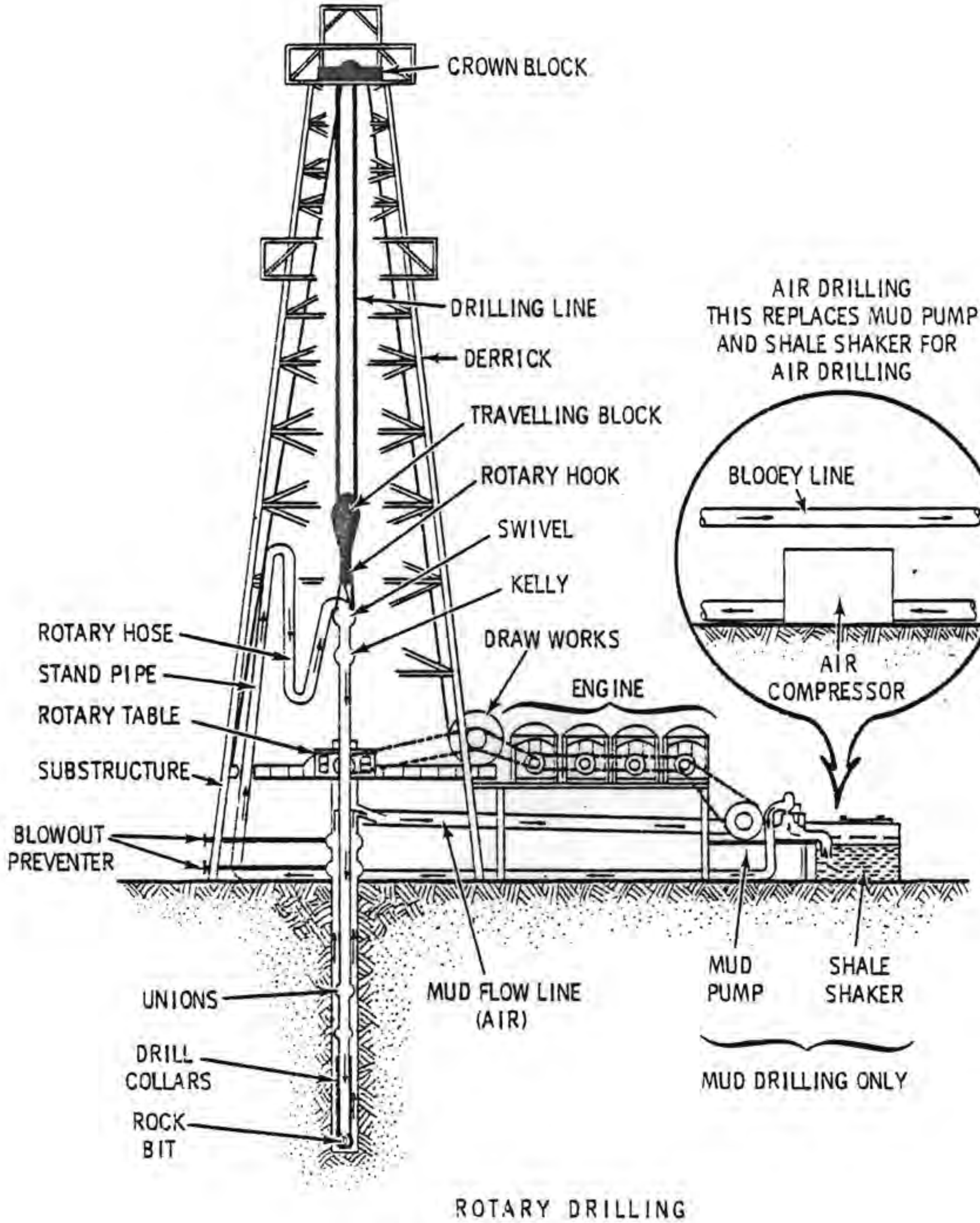
Once the development for the field is selected, the locations of the drilling sites are known. A permit[a] for all permanent roads to be constructed and for each well to be drilled must be obtained from the appropriate state and/or federal agency [USGS, BLM, BOIA (Bureau of Indian Affairs)]. This usually involves an actual inspection of the site. In addition, for a number of possible sites, a disclaimer stating that there are no important archeological sites present must be obtained.

B.2.1 Site Preparation

Once all the required permits and approvals have been obtained, work commences on clearing and leveling of the site. The leveled area may be from 1/2 to 5 acres, depending on the sizes of the drilling rig and stimulation job planned. A drill pit of approximately a few hundred square feet up to 1/2 acre (included in the 1/2 to 5-acre total) is also constructed.

Some of these sites are on virtually level ground, while others may require extensive excavation, due to hilly locations. Some sites may be located on hills with more than a 30% slope, which may result in serious erosion problems. It is, however, important to remember that each and every site has been approved by the appropriate licensing agency and the surface rights owner.

(a) Permits: Virtually every state in the acquisition, exploration, and development of petroleum is licensed by some agency. On federal land, the BLM is in charge of leasing rights. Each drill site is inspected by the USGS. Each drilling program for each well is approved by the USGS. If the possibility of endangered species exists, the Wildlife Commission may be called in to help. State regulations are all handled through state oil and gas commissions or some equivalent agency.



ROTARY DRILLING

<u>FIGURE B.1.</u> Rotary Drilling Rigs

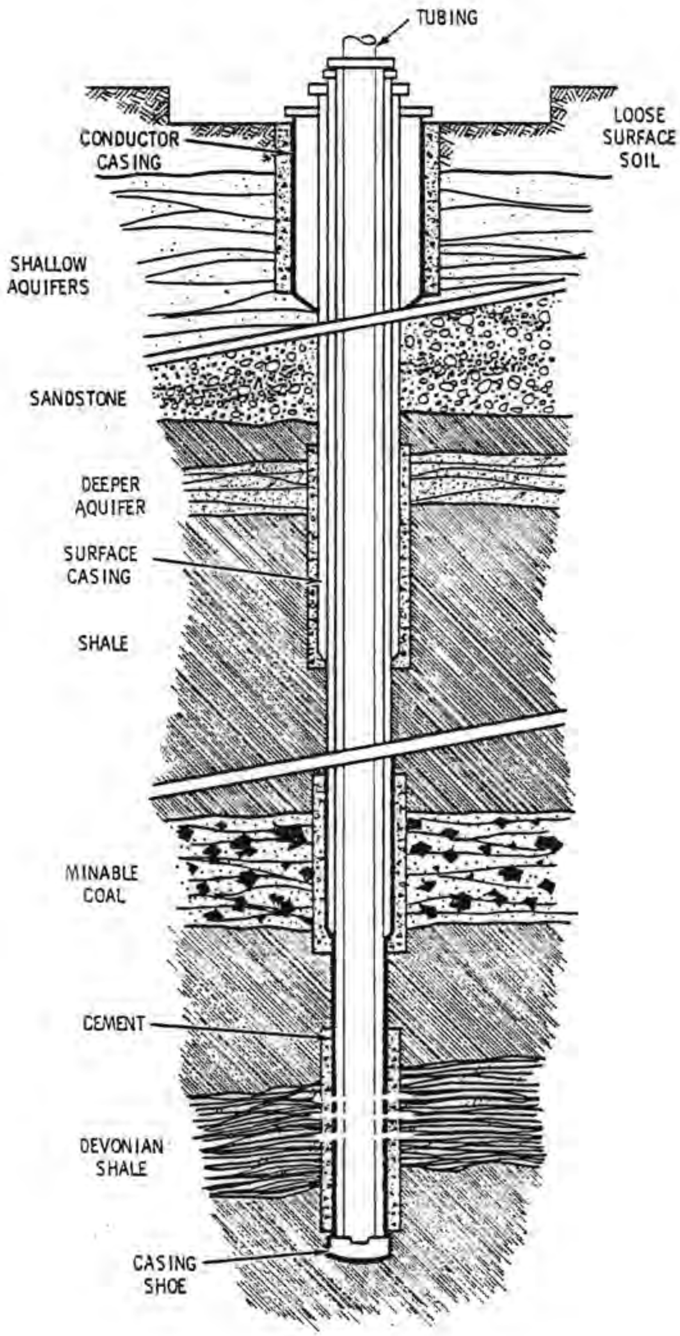


FIGURE B.2. Casing Strings and Pipe Used in an Oil Well

B.2.2 Drilling

When a well is drilled, a certain zone is the target, whether it is a wildcat or developed well. The mud program is selected before drilling is started. Air or gas drilling is frequently used in place of mud drilling for low pressurized regions. An appropriate government (state) agency will have preset the depth for conductor and surface casing to be set. The well may be cored through all different zones of interest. Casing will usually be cemented across the producing interval. If problem zones are encountered, these will be isolated by the cementing of casing also.

B.2.3 Completion

Most gas wells are completed through casing which has been cemented in place. Once the cement is set, the well is completed by shooting shaped charges through the casing into the zones of interest. Upon completing the perforations, a small acid job may be run to clean up the well. Frequently, a larger hydraulic fracturing job will be run as well.

B.2.4 Well Testing

Once the well has been completed, it is normally tested. Each zone within the range is tested separately (isolating the zone by setting a packer between the zones). These tests will show the flow capacity and permeability of each zone of interest and may also be used to estimate the overall reserves present in each zone.

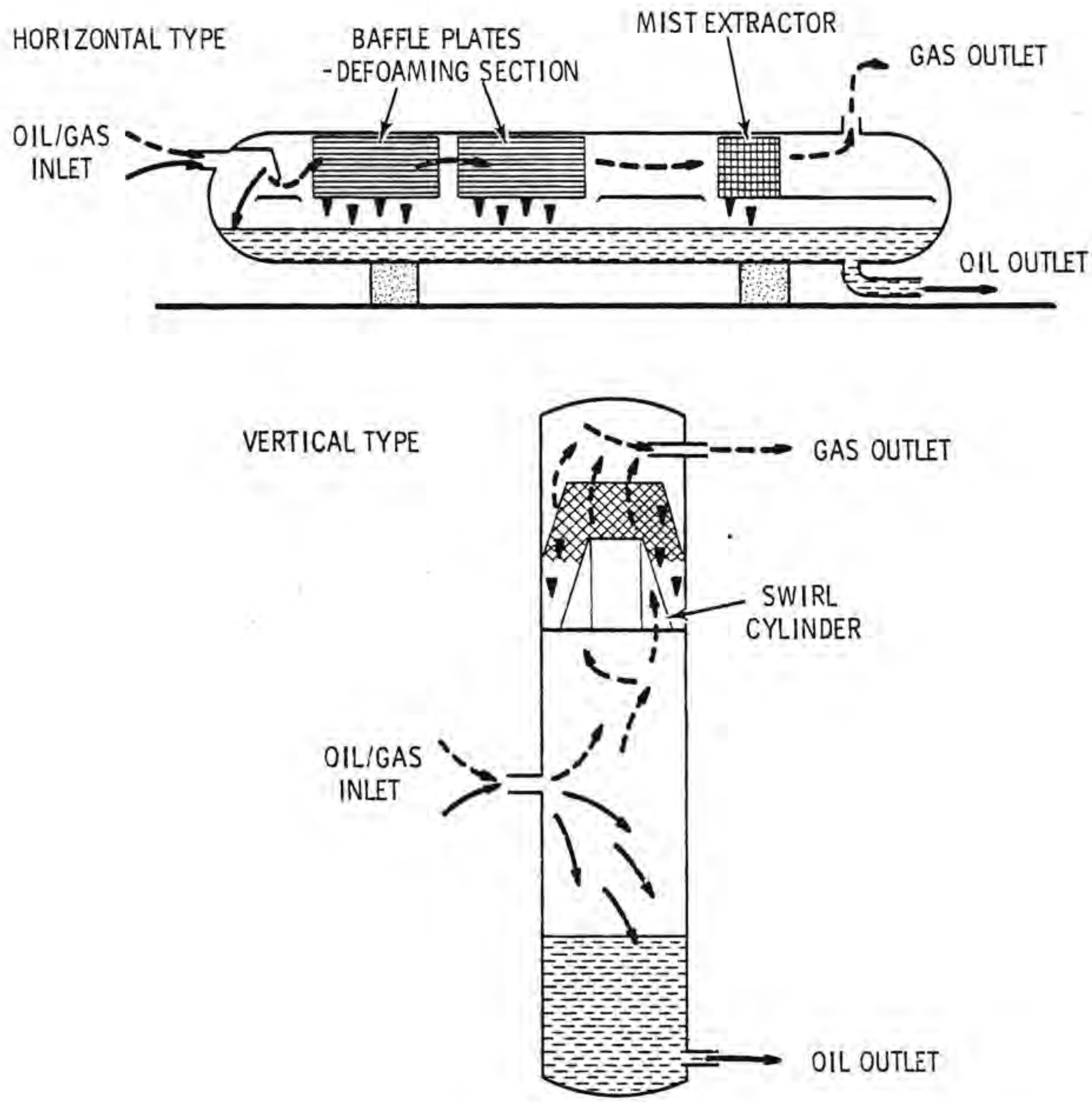
B.3 PRODUCTION

The main surface facilities used during production include the well-head valves, a two- or three-phase separator (see Figure B.3) and surface storage facilities. On a regular schedule, a tanker will come to remove the condensate (assuming there is some). There may be a need to dispose of produced water, although this is very uncommon for wells completed in the Devonian shale. In addition, most companies have a routine well-logging program where temperature surveys, radioactive logs and other electronic logs are routinely run.

In the flow rate of the well drops off, a new hydraulic fracturing job may be instigated. Again, fracturing may occur on an almost routine time interval.

B.4 ABANDONMENT

Once a well has reached the end of its productive life, it is abandoned. In a gas well, this occurs when the pressure has become too low to cause any gas to flow. Proper well abandonment procedures are very important and are regulated by either federal and/or state agencies.



SEPARATORS

FIGURE B.3. Two-Phase Separator

The steps used in abandonment are:

- Remove useable downhole tubing
- Plug and mark well
- Remove all surface facilities
- Site restoration.

If usable downhole tubing is present, it will be cut and removed from the well. The well will then be cemented to the surface and marked. The type and grade of cement as well as the marker are normally regulated by the oil and gas commissions of each state. All of the surface facilities such as tanks, separators, tubing and well-head valves are removed. Once the above steps have been completed, site restoration occurs.

Since most Devonian shale wells are located on private land, the nature of the site restoration is normally a negotiated part of the land-use lease. Typical steps may be the recontouring and reseeding of the well site and any road constructed.

APPENDIX C

RELEVANT ENVIRONMENTAL, HEALTH AND SAFETY REGULATIONS

Existing legislation and resultant regulations applicable to the development of unconventional gas resources are summarized in Table C.1. This body of legislation provides the legal authority to control environmental, health and safety impacts from gas exploration and production operations in unconventional gas recovery (as well as from most other industries) to acceptable levels.

TABLE C-1 Applicable Federal Environmental, Health, and Safety Regulations

Legislation	Pollutant/Concern	Current/Proposed Standards	Possible New Standards
Clean Air Act NSPS PSD Nonattainment Visibility	Fugitive emissions Particulates SO_x NO_x Hydrocarbons Polycyclic aromatics Hydrogen sulfide Ammonia Accidental releases of noxious gases (CO, H_2S)	Environmental Assessment and Environmental Impact Statement needed. Ambient standards have been set for: SO_2, NO_x, particulates, CO, hydrocarbons, and oxydants. NSPS have not yet been set.	NSPS will be developed for criteria pollutants. States may classify areas as nonattainment.
Federal Water Pollution Control Act	Disposal of drilling wastes and produced waters Subsidence	A NPDES permit is required unless waste water is reinjected. Subject to the Act of discharging into a navigable water. If toxics are released or treated in effluent stream they will be regulated under Sec. 307.	
Toxic Substances Control Act	Injection fluids and products of production		
Resource Conservation and Recovery Act	Sludges from drilling mud cleanup and recovered brine.	Waste streams will require testing for hazardous waste. If waste is classified as hazardous, the facilities will have to meet RCRA requirements. Hazardous waste disposal must comply with air and water standards. Potential impacts on siting.	Facilities engaged in treatment, storage, or handling of hazardous waste will require permits.
Safe Water and Drinking Act	Injection fluids surface wastewaters	Underground injection permit will be required--although the stringency is uncertain. Public hearings on each permit application.	State regulations could restrict siting and injection practices.
Occupational Safety and Health Act	Explosives Fires Exposure to toxics	Maintain employee health and exposure records. New benzene standards.	Revised toluene standard.

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