# 6. UNCONVENTIONAL GAS RECOVERY

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## 6.1 RESOURCE DESCRIPTION

Unconventional natural gas is the term applied to gas that exists in reservoirs that are marginal to unfavorable for production of gas at current market prices, using conventional recovery methods. Natural gas provides about 30% of the nation's total energy requirement, but proven domestic gas reserves and annual gas production have declined over the past decade (Kuuskraa et al. 1978). Currently, unconventional gas sources contribute about 28 x $10^9$ $m^3$ [1 Tcf (trillion cubic feet)] of natural gas annually, which is about 5 % of the domestic gas production (NPC 1980). Gas from unconventional sources could add significantly more to U.S. reserves within the century.

Figure 10 shows the location of major U.S. unconventional gas resources, of which there are four categories: (1) gas present in tight, or low permeability, sandstone formations in the West, (2) free gas present within Devonian-age shale formations in the East, (3) methane associated with coal seams, and (4) methane dissolved in geopressured aquifers located along the Texas-Louisiana Gulf Coast. Two recent studies explored the potential of unconventional gas (Kuuskraa et al. 1978, NPC 1980). Table 14 presents estimates from these studies of gas-in-place and recoverable resources from each of the four categories of unconventional sources of natural gas.

### 6.1.1 Western Tight Gas Sands

The most promising source of unconventional gas is sand reservoirs of low permeability, termed tight gas sands, located in several western sedimentary basins (Fig. 10). The gas-bearing sands in the basins are interbedded with unproductive clays and shales over intervals as thick

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Table 14. Estimates of gas-in-place and economically recoverable gas resources from unconventional sources of natural gas [in $10^9$ $m^3$ and trillion cubic feet (Tcf); estimates of economically recoverable resources are for base case technology and lowest economic return and advanced technology and highest economic return]

| | Unconventional gas in $10^9$ $m^3$ (Tcf) | | |
|---|---|---|---|
| | Gas in place | Economically recoverable resources | |
| | | Base case technology return Lowest | Advanced technology return Highest |
| Western tight gas sands | | | |
| (Kuuskraa et al. 1978) | 11,600 (409) | 2,000 (70) | 5,300 (188) |
| (NPC 1980) | 12,600-26,200 (444-924) | 5,400 (192) | 16,200 (574) |
| Devonian gas shales | | | |
| (Kuuskraa et al. 1978) | 2,260 (80)[a] | 57 (2) | 708 (25) |
| (NPC 1980) | 11,000-57,300 (387-2023)[b] | 85 (3) | 1,104 (39) |
| Methane from coal seams | | | |
| (Kuuskraa et al. 1978) | 13,600 (480)[c] | 0 [d] | 57-708 (2-25)[d] |
| (NPC 1980) | 11,300 (398) | 142 (5) | 1,275 (45) |
| Methane from geopressured aquifers | | | |
| (Kuuskraa et al. 1978) | 39,600 (1400) | 0 [f] | 28-142 (1-5) |
| (NPC 1980) | ---[e] | 0 | 9-18 (0.3-0.6) |

[a]Free gas only, does not include gas "locked" into kerogen structure.

[b]Includes all gas -- free and that present in kerogen.

[c]Minable coal seams - 8775 x $10^9$ $m^3$ (310 Tcf), unminable 4810 x $10^9$ $m^3$ (170 Tcf), from Kuuskraa (1981).

[d]No base case technology assumed with present technology. No methane is recovered from coal; range of resources recoverable under advanced technology indicates least to most favorable economics.

[e]No independent estimate given of gas-in-place.

[f]No methane will be recovered with base case technology; the estimates for recoverable resources with advanced technology are for a range of economic returns.

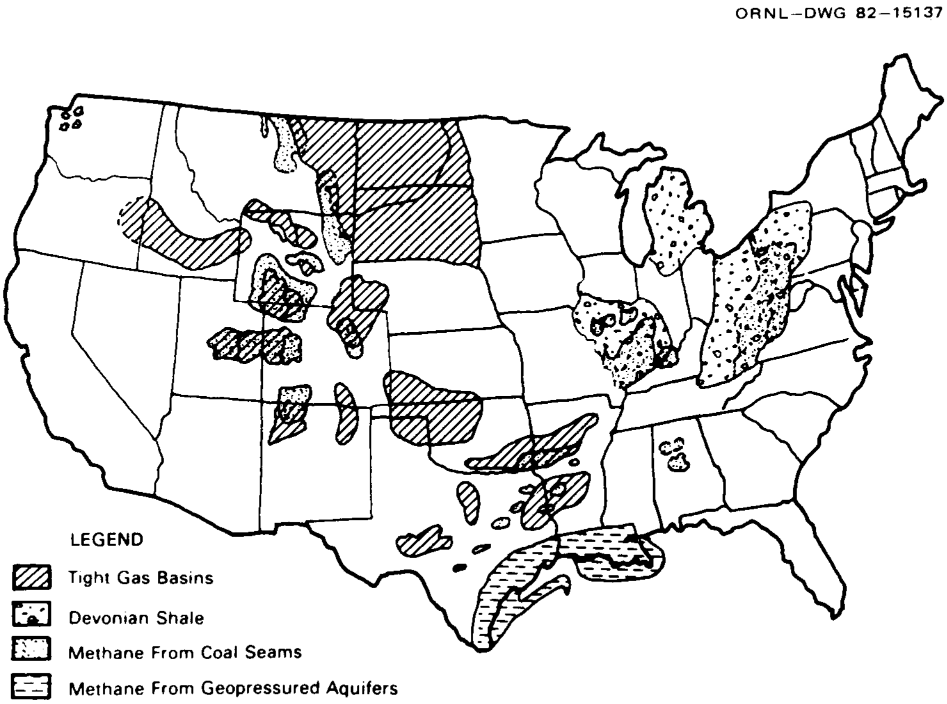


Fig. 10. Unconventional gas resources of the United States (U.S. DOE 1980).

as 5000 m. The thicknesses of the sand reservoirs range from a few meters to over 30 m (100 ft). The thicker blanket-type sand reservoirs, which exhibit continuity over a relatively large area, are the most promising for gas production. In many basins, however, the gas-producing sands are thin and unpredictably discontinuous, due to their lenticularity (lens-like nature). A single well may penetrate up to 100 of these production layers (Riedel et al. 1980).

Current domestic annual production of unconventional gas from tight gas sands is about $22.5 \times 10^9$ $m^3$ (0.8 Tcf) (NPC 1980). The main limitation on gas production from tight sands is their low permeability (by definition less than 1 millidarcy), resulting in uneconomically low rates of gas flow into the well. Favorable production rates are achievable by fracturing the formations to create a large area around the well bore into which the gas will flow. A major thrust of R&D in unconventional gas recovery is in developing advanced methods of formation fracturing (Sect. 6.2.2).

### 6.1.2 Eastern Devonian Gas Shales

Devonian-age shales of primary interest for unconventional gas recovery underlie the Appalachian, Michigan, and Illinois structural basins in the eastern United States (Fig. 10). These are black and brown shales of marine origin containing an organic substance, kerogen, that is the source of natural gas (Kuuskraa et al. 1978). The gas is present both as free gas, recoverable by drilling, and as gas "locked" into the kerogen, recoverable by retorting of the shale to convert the hydrocarbons to synthetic gas and oil (Kuuskraa et al. 1978). Only the mobile (or free) gas is being considered here for unconventional gas recovery. Between 2 and $6 \times 10^{12}$ $m^3$ (80 to 225 Tcf) of gas may be present as free gas-in-place in Devonian shales (NPC 1980, Kuuskraa et al. 1978).

Throughout this century, gas has been produced from Devonian shales in northern Ohio and in the Big Sandy Field of Kentucky (Kuuskraa et al. 1978). Present production is about $6 \times 10^9$ $m^3$ (0.2 Tcf) annually (NPC 1980). Gas production from most of the shales is marginal due to low formation permeability and a low incidence of naturally occurring fractures. Current recovery methods include directional drilling to intersect natural fracture systems and stimulation of wells with small-scale explosive fracturing, termed "shooting."

### 6.1.3 Methane from Coal Seams

Methane gas, a natural product of coal formation, may be found in varying quantities in most coal seams. Interest in coal-bed methane as a gas resource grew out of research to reduce the safety hazard of methane in underground coal mines, particularly in the "gassy" bituminous coals of the eastern United States (Ethridge et al. 1980). About $2 \times 10^6$ $m^3$ [73 MMcf (million cubic ft)] of methane is currently vented each year from operating coal mines (Ethridge et al. 1980); none is recovered. Minable coal seams in the United States contain an estimated $8.5 \times 10^{12}$ $m^3$ (310 Tcf) of methane (Kuuskraa et al. 1978, NPC 1980). Coal seams that are too deep or too thin to mine contain an additional $5 \times 10^{12}$ $m^3$ (170 Tcf) of methane (Table 14).

Methane from coal seams may involve some unique institutional and legal considerations. The ownership of the gas may be disputed in cases where the oil and gas rights and coal rights to an area are held separately (Ethridge et al. 1980). Also, the classification of coal seam gas is an issue that could affect regulations concerning production and sale of the gas (Ethridge et al. 1980). The regulations that apply to natural gas may be appropriately applied to methane from unminable coal seams, but special regulations for the production of methane from minable coal seams may be necessary to take into account the safety of future mines in the coal seam (Ethridge et al. 1980).

### 6.1.4 Methane from Geopressured Aquifers

Geopressured aquifers, underground reservoirs of hot salt water existing under great pressures, are known to contain dissolved methane. Geopressured aquifers that present the best possibility for resource production are located in a band approximately 80 to 100 km (50 to 70 miles) wide, straddling the Gulf Coast of Texas and Louisiana (NPC 1980). Early estimates of gas-in-place in geopressured aquifers (Papadopulos et al. 1975, Jones 1976) indicated a vast resource of up to 1.5 x $10^{15}$ $m^3$ (50,000 Tcf), but later information reduced these estimates by about two orders of magnitude (Samuels 1980). Recent geopressure well tests indicate that the brines are saltier and not as hot as earlier expected. Both these factors adversely affect methane solubility. Indications are that the brines may contain about 3.5 to 4.5 $m^3$ methane/$m^3$ brine (20 to 25 scf/bbl) at saturation (Samuels 1980). Recovery of the methane may be coupled with production of electricity from the hot brines. Recovery costs for methane from geopressured aquifers are estimated to be \$0.18 to \$0.35/$m^3$ of gas [\$5.00 to \$10.00 Mcf (thousand cubic feet)] (Samuels 1980), which may be compared with the current market price for natural gas of about \$0.07/$m^3$ (\$1.75/Mcf) (EIA 1981).

## 6.2 TECHNOLOGY OVERVIEW

Recovery of gas from unconventional sources will involve several methods common to all four types of resources, including drilling, well testing, and gas production. All sources, except perhaps geopressured aquifers, may require well stimulation by fracturing of the formation. Those techniques common to all unconventional gas projects are described below, followed by brief descriptions of resource-specific recovery methods.

### 6.2.1 Drilling

Drilling techniques are essentially the same for all four types of unconventional sources of gas. The major differences will be in the number, type, and depth of the wells (see following resource-specific sections). Drilling is by conventional rotary methods using a platform-mounted drill rig (Fig. 11). Rotary drilling is accomplished by rotating a cutting drill bit at the end of a length of drill pipe, through which is circulated a lubricating and cooling fluid, termed

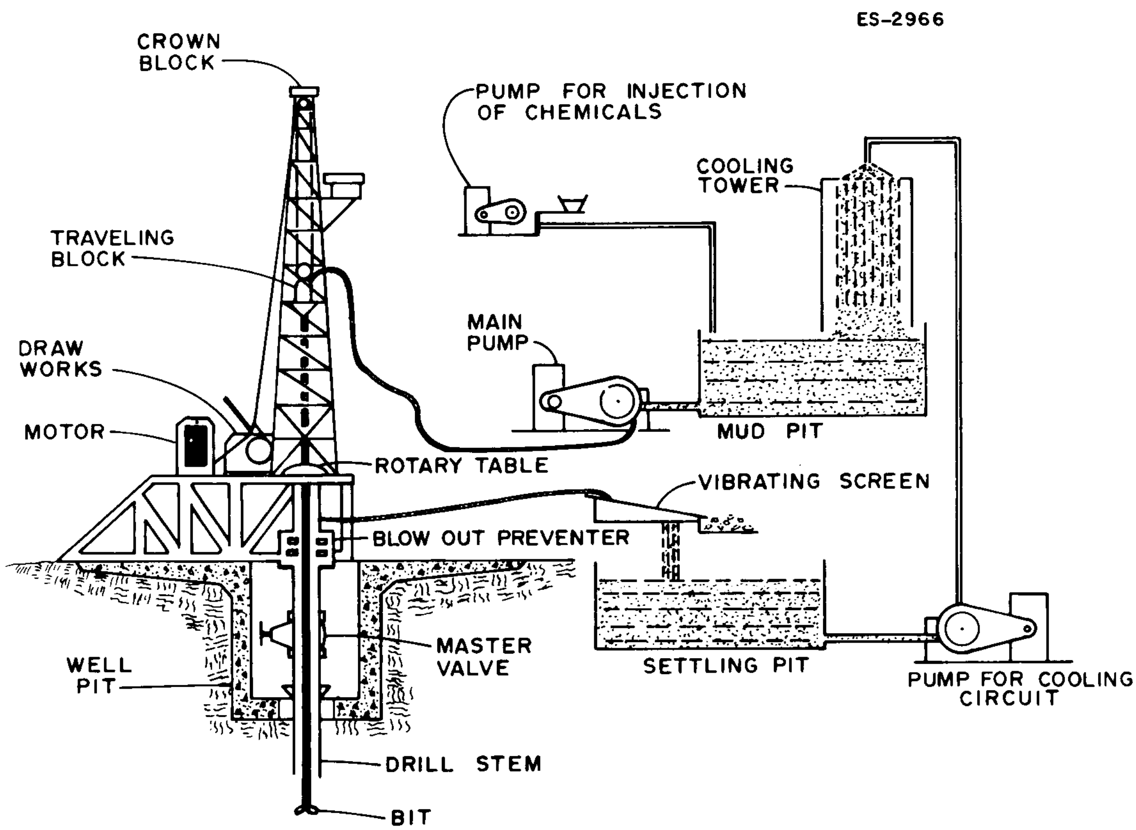


Fig. 11. Typical platform-mounted rotary drilling rig (U.S. ERDA 1977a).

drilling mud. The mud is a water-based slurry containing clays, chemical additives to maintain viscosity and density, detergents for lubrication, and caustic soda. The mud is recirculated and cooled in mud tanks, and the formation cuttings are removed and stored in a reserve pit excavated adjacent to the rig. Blowout preventers are installed on many wells during drilling and maintained throughout the life of the well. After drilling is completed, casing is set and cemented to appropriate depths to isolate different production zones, keep the integrity of the well bore, and protect any freshwater zones.

Site preparation for drilling involves clearing and leveling a pad for the drill platform and excavating a reserve pit. The drill pad and pit may occupy between 0.5 and 2 ha (1 to 5 acres). Additional land may be occupied by fuel and water storage tanks, holding ponds for produced fluids, and equipment storage. Access roads may be constructed for the rig and other equipment.

### 6.2.2 Advanced Fracturing Methods

Most unconventional gas resources are uneconomic because of their limited flow capacity. Fracturing the gas-bearing formation increases the well bore drainage area, thus increasing flow capacity. Advanced fracturing methods include massive hydraulic fracturing, foam fracturing, and chemical explosive fracturing.

Hydraulic fracturing, in use since the late 1940's, involves injecting a fluid under pressure into the formation, thus inducing fracturing (Riedel et al. 1980). The fluid must be pumped out prior to gas production. A proppant, such as sand or glass beads, is entrained in the fracture fluid and remains in the formation to prop open the fractures when the fluid is withdrawn. Fracture fluids are usually water-based, but several chemicals may be added to amend the fluid (Riedel et al. 1980). Massive hydraulic fracturing is the term generally used to refer to hydraulic fracturing operations that use large volumes of fracture fluid. A typical massive hydraulic fracturing operation may inject over 1000 $m^3$ (300,000 gal) of water and 500 Mg($1 \times 10^6$ lb) of sand or other proppant (Riedel et al. 1980, U.S. DOE 1979a). The resulting fractures may be over 30 m (100ft) high and extend 300 m (100ft) horizontally from the well bore. Massive hydraulic fracturing requires facilities for sand and water storage, blending tanks, and pumping units.

Foam fracturing is essentially the same technique as hydraulic fracturing. Compressed gas and a surfactant, or foaming agent, are added to the fracture fluid and injected under pressure. The foam creates additional pressure for fracturing. Foam fracturing has the advantage of using less water and taking a shorter time for well cleanout than hydraulic fracturing (Riedel et al. 1980).

Chemical explosive fracturing may involve one of two approaches. Borehole "shooting," which is currently used in Devonian gas shale wells, involves detonation of nitroglycerin within the well bore to increase well bore size and induce small fractures (Kuuskraa et al. 1978, Pulle et al. 1981). More advanced chemical explosive fracturing involves pumping a chemical slurry into existing natural fractures (or previously created hydraulic fractures) and subsequently detonating it (U.S. DOE 1979a). No proppant is injected, as the detonation generates its own proppant from formation rubble (Riedel et al. 1980).

### 6.2.3 Well Testing

All wells are generally tested for varying periods after completion of reservoir stimulation to evaluate the production capacity and success of fracturing. Usually gas produced during testing is flared on the site. Gas volumes will vary depending on the resource and well success. Testing may last a few days to a few weeks. Geopressure wells are tested for fluid flow as well as methane content. Large volumes of geopressured brines are produced during flow testing and their disposal will probably be by injection. Methane separated from the brines during testing will probably be flared. On completion of testing, any wells not used for commercial gas production are plugged and abandoned according to state-mandated procedures.

### 6.2.4 Gas Production

Commercial production activities related to the development of unconventional gas sources will be essentially the same as those for normal commercial gas production. The produced gas may contain some fluids (probably water) and require field separation into the gas and liquid phases. The produced fluid requires disposal. Compressors may be needed to transmit the gas from the wellhead to the separators and pipeline system. The size and number of compressors required will depend on specific reservoir characteristics. If the produced gas contains large concentrations of hydrogen sulfide, desulfurization may be needed. Gas pipelines will link the production and market areas. Existing pipeline systems will be used whenever possible; however, several unconventional gas resource areas are far removed from current gas-producing regions and are not served by pipelines. Large-scale commercial production in these areas may require construction of new pipeline rights-of-way.

An alternative method for getting gas to market in areas not served by pipelines is to liquify the gas for transportation to markets. Liquefaction may be achieved by adiabatic expansion or multistage mechanical refrigeration (Bastress 1978, University of Oklahoma 1975). A portion of the produced gas is used to fuel the liquefaction plant. The energy required for liquefaction may represent up to 20% of the energy in the produced gas (University of Oklahoma 1975).

### 6.2.5 Tight Gas Sands

The depths of tight gas wells vary from basin to basin but are usually less than 3000 m (10,000 ft), except for those in the Green River Basin of Wyoming and Colorado and the Cotton Valley Trend in east Texas, which may be as deep as 3800 m (12,000 ft) (Riedel et al. 1980). Production well spacing is at approximately 1.5-km (1-mile) intervals (Riedel et al. 1980). Massive hydraulic and foam fracturing are the usual fracturing techniques used. In many tight gas basins, the permeable sand strata contain large volumes of connate water, which may inhibit gas production until removed. In some cases it may take from 3 to 6 months to sweep the water from the well (Kuuskraa et al. 1978). Disposal of the produced water is generally by surface evaporation. The stages in recovery of gas from tight western gas sands are as follows: (1) drill production well; (2) fracture formation; (3) clean fracture fluids from well and test gas production; (4) install water separators, gas clean-up equipment, and compressors as necessary; and (5) transfer product gas to collection pipelines.

### 6.2.6 Devonian Gas Shales

Well depths for shale wells are mostly less than 2200 m (7000 ft)(Pulle et al. 1981). Current drilling practices make frequent use of directional drilling to intercept natural fracture systems. The most commonly used method of well stimulation is "shooting" with nitroglycerin charges (Kuuskraa et al. 1978). Several shale development projects recently used hydraulic and foam fracturing for reservoir stimulation. The stages in gas recovery from Devonian shales are the same as those for western tight sands.

### 6.2.7 Coal Seam Methane

Methane recovery from coal seams is in the developmental stage; there are currently no commercial projects. Methane may be recovered from minable or unminable coal deposits. Recovery from unminable deposits will be essentially similar to recovery from Devonian shales or western tight gas sands. Methane recovery from minable coal seams may occur by several methods before or during mining.

Recovery techniques used before mining include small-diameter vertical or directional boreholes drilled into the coal seams from the surface and horizontal boreholes drilled into the coal seams from the bottom of vertical shafts (Ethridge et al. 1980). To drain all the methane effectively, these techniques must be applied 3 to 5 years prior to mining (Ethridge et al. 1980). Gas flows from vertical wells are low. These wells may be stimulated by hydraulic or foam fracturing, but there are some concerns related to mine roof stability where fracturing is employed (Ethridge et al. 1980). Directionally drilled wells that follow the coal seam produce much better gas flow rates than do vertical wells, but the thin coal seams (average thickness of 1 to 2 m) present a difficult drilling target (Ethridge et al. 1980). Horizontal holes drilled into the coal seam from shafts which are drilled from the surface to the coal seam provide favorable gas flow rates. The shafts may later be used during mining for ventilation (Ethridge et al. 1980).

Gas can be produced from working mines by drilling a series of small horizontal boreholes into the active working face of the mine. Vertical boreholes may also be drilled into the "gob" area, the strata above the coal, ahead of mining. As the area is mined, methane is released into this waste strata and drawn off by the wells.

Methane produced from the coal seams is of pipeline quality, but "gob" gas may have high concentrations of inert gases and require upgrading. Product gas may be used to produce heat or generate power for mining equipment, injected into pipelines, liquified, or used to produce ammonia or methanol (Ethridge et al. 1980, Bastress 1978). In many cases, wells drilled into coal seams produce varying quantities of water which must be treated before disposal.

### 6.2.8 Methane from Geopressured Aquifers

Production of energy and methane from geopressured aquifers remains in the early developmental stage. Techniques for drilling and brine production are described in U.S. ERDA (1977a) and by Usibelli et al. (1980). Briefly, a production well is drilled to the geopressured zone, and hot pressurized brine is produced. The brine is "flashed" to atmospheric pressure to produce steam for electrical generation and to separate the methane gas. Recent test results indicate brine temperatures of 120 to 150°C (250 to 300°F), salinities between 10,000 and 275,000 mg/L and methane contents below 4.5 $m^3/m^3$ of brine (25 scf/bbl) (Samuels 1980, McCoy et al. 1980, Dobson et al. 1980, Geoenergy Corp 1980). The brine flow from a single production well may be on the order of 2000 $m^3/d$ (13,000 bbl/d). The most likely method for disposal of the brine is injection into saline aquifers above the geopressured zone. From one to four injection wells may be required to dispose of the brine from a single production well (U.S. ERDA 1977a).

## 6.3 POTENTIALLY SIGNIFICANT ISSUES

With the possible exception of recovery of methane from geopressured aquifers, unconventional gas recovery projects should not have the potential to cause major or long-term environmental impacts. The primary impacts associated with most unconventional gas recovery projects are related to land disturbance, water consumption, and short-term air quality degradation caused by site preparation, drilling, and reservoir stimulation activities. There is a potential for contamination of surface and groundwaters during drilling and formation fracturing and, where applicable, from disposal of produced formation waters. The majority of impacts associated with unconventional gas projects will occur during the initial project phases of drilling, reservoir stimulation and well testing. The time interval over which these activities will take place is generally 3 to 6 months, and is short relative to the 20- or 30-year life of a production well. Geopressure projects have a greater potential for environmental impacts than other unconventional gas projects because they will involve disposal of large quantities of low quality brines and, in many cases, may be located in wetlands. Aside from impacts directly related to unconventional gas recovery, extensive new major gas supply pipelines may be constructed to serve new resource regions and could, therefore, affect large areas of land distant from the actual project sites. The following sections discuss significant issues which are most likely to be associated with unconventional gas projects.

### 6.3.1 Land Use

Land disturbance at an unconventional gas project site is minimal compared to many other energy technologies and is limited to site preparation of drill pads, equipment lay-down areas, and access roads. The degree of disturbance connected with site preparation will depend on the terrain of the site; minimum disturbance may be expected in the relatively flat western tight gas basins and maximum disturbance in steep Appalachian Devonian shale and coal resource regions (Aerospace 1981). Much of the land disturbed in the early phases of the project will be restored and revegetated after drilling and fracturing are completed. The greatest potential for land-use conflicts will be associated with geopressure projects, many of which will be located in coastal wetlands, where extensive diking and dredging may be required for access, site preparation, and construction of spill containment areas. Also, several geopressure resource areas contain valuable agricultural land.

Many unconventional gas resource regions are not close to major gas supply pipelines. Development of these areas may require construction of hundreds of kilometers of large-diameter gas pipelines and many more kilometers of smaller product-gathering lines. The land-use impacts of construction of the new pipelines will far exceed the impacts related to the unconventional gas projects themselves. A recent estimate reported by Aerospace (1981) indicated that over 5000 km (3100 miles) of major gas pipelines may be required for extensive commercial development of unconventional gas resources. The impacts of construction of these pipelines will be common to all major pipelines. Up to 1.5 ha of land is disturbed by construction of each kilometer of major pipeline (6 acres/mile), and the 15-m (50-ft) right-of-way is kept clear of trees and shrubs after pipeline burial (Aerospace 1981). All but low intensity land uses may be prohibited within the right-of-way.

For the project site and the surrounding area, baseline information should describe:

- present and planned land use;
- present and projected land ownership;
- national parks, national monuments, recreation areas, existing or proposed wilderness areas, and scenic, historic, or archaeologic sites or landmarks;

- Indian-owned lands and areas sacred to local Indian tribes;
- the existence of wetlands and 100-year floodplains in relation to the project; and
- location of prime or unique agricultural lands.

This baseline information should be reviewed to determine if the project may create any land-use conflicts which should be analyzed as potentially significant issues. Particularly for geopressured projects, the analysis should indicate whether any floodplains or wetlands will be affected by the project. Where appropriate, coordination with the planning agency responsible for coastal resource management should be provided. An analysis of effects on any prime or unique farmland should be provided. Visibility of the project site from any public use areas or Indian sacred areas should be analyzed. A map should be included to show surrounding land uses and potential routes for heavy equipment and other traffic associated with the project. The possibility of adverse effects from increased traffic on roads through sensitive land-use areas (e.g., Indian lands or recreation areas) should be addressed. Additionally, if the project will require construction of new gas supply pipeline rights-of-way, the analysis should state approximately how many kilometers of pipeline will be constructed, indicate the probable location of the pipelines, and discuss impacts of the pipelines on land uses along the route.

### 6.3.2 Induced Seismicity and Subsidence

Two types of geologically related impacts, induced seismicity and subsidence, may be issues for some unconventional gas projects. They are most likely to be associated with geopressured methane projects, which involve long-term withdrawal and injection of large volumes of fluid. Although seismic events have been demonstrated to result from deep injection of large volumes of fluid under high pressure in Colorado (Evans 1976, Raleigh 1971), the volumes of fluids injected during massive hydraulic fracturing are one to three orders of magnitude less than those that triggered the seismic events. Because costs are high, injection of geopressured brines is unlikely to occur at high pressures (Usibelli et al. 1980). Seismicity may also be induced by withdrawal of large volumes of fluids, triggering a sudden release of stress along nearby faults (Aerospace 1981). Only geopressured methane projects will involve long-term withdrawal of large fluid volumes. The Gulf Coast area is aseismic (Algermissen 1968), but the possibility of induced seismicity along some of the existing growth faults in the area cannot be completely ruled out.

Subsidence has been demonstrated to be caused by withdrawal of fluids in several regions of the world, including withdrawal of geothermal fluid at Wairakei, New Zealand, groundwater in the Houston area, and hydrocarbons at Wilmington, California (Viets et al. 1979, Usibelli et al. 1980). Subsidence could occur at any unconventional gas project that withdraws large volumes of gas, but it is most likely to occur at geopressured projects where thousands of cubic meters of brine may be withdrawn each day. Both natural and man-caused subsidence is already occurring in the Gulf area and may be accelerated by project activities in areas surrounding geopressure projects.

Subsidence in the areas of low relief in the Gulf Coast region could cause significant environmental damage by altering drainage patterns, reversing flow regimes in estuaries, causing intrusion of saltwater into freshwater systems, and increasing the possibility and extent of flooding during severe storms and hurricanes (Usibelli et al. 1980). Subsidence can also cause damage to man-made structures (Viets et al. 1979). Many geopressure research projects that are currently planned or in operation include monitoring networks to detect subsidence resulting from project operations.

For all projects, but especially for geopressured projects, the analysis should include:

- an estimate of the volume of fluid expected to be withdrawn from the production well(s);
- an estimate of the volume of fluid to be injected at each injection well and the expected pressure of injection;

- the location of major faults in the project area and an analysis of the likelihood of project operations causing induced seismicity along these faults;

- an analysis of the probability and magnitude of subsidence that might be caused by project operations, and an estimate of the impact of such subsidence on local ecosystems or man-made structures; and

- a description of existing seismic and subsidence monitoring networks of any planned seismic or subsidence monitoring planned that is part of the proposed project.

### 6.3.3 Air Quality

Impacts on air quality from most unconventional gas projects should be localized and primarily confined to the initial 3- to 6-month time interval of site preparation, drilling, reservoir stimulation, and well testing. The major atmospheric pollutants will be fugitive dust from disturbed areas, exhaust emissions from diesel engines, and emissions from flaring of produced gas that may occur during well test activities. Of the three sources, emissions from the large [7500 to 11,000 W (1000 to 1500 hp)] diesel engines used to power the drill rig, the pumps, and the compressors necessary for fracturing operations will be the largest source of pollutants. The exhaust emissions will contain sulfur oxides, nitrogen oxides, particulates, hydrocarbons, carbon monoxide, and aldehydes. Operation of the several large diesel engines required for massive hydraulic fracturing may exceed ambient standards for some of these pollutants within a radius of a few kilometers of the project site for the few weeks duration of the fracturing operation (Riedel et al. 1980).

During project operations, possible sources of atmospheric pollutants would be limited to emissions from equipment such as compressors and pumps that may be required to process the gas. The characteristics and quantity of these emissions will depend on whether the equipment is powered by electricity, product gas, or diesel fuel. If $H_2S$ removal from the product gas is required, there may also be sulfur emissions from the treatment facility.

In addition to background information, the following information should be described and discussed:

- anticipated measures to be used for control of fugitive dust emissions;
- the number of diesel engines to be used during drilling and reservoir stimulation activities, an estimate of the emissions from the engines, and descriptions of the emission controls used on the engines;
- an analysis of the potential for the diesel emissions or fugitive dust from site preparation to cause ambient air quality standards to be exceeded, with particular reference to any Class I areas which may be affected; and
- a description of atmospheric emissions anticipated during project operations from any gas-handling and gas-cleaning equipment to be used and a description of the effect of these emissions on surrounding air quality.

### 6.3.4 Water Use

Drilling and reservoir fracturing at unconventional gas projects are water-intensive operations. Well drilling may require from 750 to 2250 $m^3$ (0.5 to 2 acre-ft) of water over a 30- to 45-d interval (U.S. ERDA 1977b, Aerospace 1981). Massive hydraulic fracturing can require up to 2000 $m^3$ (500,000 gal) of water over a 1-week period (Riedel et al. 1980). Availability of water for unconventional gas projects is expected to be a significant issue only in the case of western tight gas projects that will be located in arid regions of the West. A recent study reported in Riedel et al. (1980) indicated that extensive commercial development of western tight gas sands may require between $1 \times 10^6$ and $2 \times 10^6$ $m^3$ (800 and 1600 acre-ft) of water per year. The water used in drilling and fracturing must be relatively low in dissolved salts to prevent adverse reactions with clays that might result in swelling and lowered production rates (Riedel et al. 1980). Groundwater in many of the western basins is too saline for use and local surface waters may have insufficient flows to provide for all water requirements at a tight gas project (Riedel et al. 1980).

Abundant water of sufficient quality should be available in the eastern Devonian shale and coal resource areas and in the geopressured regions of the Gulf Coast.

The analysis should include the following, particularly for tight gas projects:

- best estimates of quantities of water required for various project operations, and sources of water available for project development;
- for projects using groundwater resources, evaluation of the effects on and interrelationships with surrounding groundwater uses; and
- for projects using surface water resources, documentation of the availability of adequate water rights or entitlements, quantification of available yields from surface water sources, and potential adverse impacts to downstream water users.

### 6.3.5 Water Quality

Unconventional gas projects can affect water quality by release of sediments from land disturbed by site preparation, by accidental release of drilling muds or fracturing fluids into surface or ground waters, or by accidental release or routine disposal of produced formation waters. For most unconventional gas projects, sedimentation from site preparation may be the largest routine source of water quality degradation. The potential for erosion and sedimentation will be the greatest for Devonian shale and coal-bed methane projects in the steep areas of Appalachia, and the least for tight gas projects in the arid West. Site preparation at some geopressure projects may require dredging in freshwater and coastal wetlands, which will cause localized increases in suspended sediments and could mobilize toxic pesticides, herbicides, and heavy metals that have accumulated in bottom sediment.

Accidental release of drilling muds and fracturing fluids could degrade surface and groundwater quality. Constituents present in drilling muds and fracturing fluids will vary according to the requirements of each project. Simple drilling muds usually contain only bentonite clays and possibly caustic soda, but some potentially toxic chemicals may be added to the muds (Aerospace 1981, MITRE 1981). Likewise, simple hydraulic fracturing fluids may contain primarily potassium chloride, but complex fluids may contain metal-based foaming agents, petroleum condensates, sulfonates, electrolytes, and acids (Aerospace 1981). Chemical explosive fracturing fluids may contain nitrate-based explosives and several other chemicals. Drilling muds could enter near-surface aquifers by seepage from unlined reserve pits. Fracturing fluids, which may be injected at pressures in excess of 80 MPa (12,000 psi), could potentially migrate to potable aquifers from improperly cased wells or unsuspected fractures connecting the target formation with the aquifer (Aerospace 1981). Spills of drilling muds and fracturing fluids on the order of several cubic meters could be possible from overflow of reserve pits or holding tanks or rupture of surface piping.

Many unconventional gas projects will involve production of varying amounts of water present in the gas-bearing formation. Water produced from tight gas formations may be high in dissolved salts and may possibly contain some hydrocarbon residuals. Water produced from eastern coal seams may be alkaline or acidic and may contain dissolved salts ranging in concentration from about 1,000 mg/L to 150,000 mg/L (Ethridge et al. 1980). Disposal alternatives for produced water range from surface evaporation in the western tight gas basins to treatment and disposal into surface waters in much of the eastern shale and coal resource areas.

Disposal and handling of geopressured brines will be the most significant issue associated with geopressured methane projects, not only because of the enormous quantity of brines involved, but because many of the projects are likely to be located near economically and ecologically important wetlands. One geopressure well may produce between 1600 and 6000 $m^3$ (10,000 and 50,000 bbl) of brine each day, or between 12 x $10^6$ and 60 x $10^6$ $m^3$ (10,000 and 50,000 acre-ft) of brine over a 20-year operating lifetime (Usibelli et al. 1980). Several production wells may be located at one project. Potential impacts to surface waters will depend on the volume of brine that may be released to surface systems and on the thermal and chemical characteristics of the brines. The temperature of geopressured brines may range between 120 and 150°C (250 and 300°F). The brines may exhibit salinities ranging from 10,000 to 275,000 mg/L and may contain environmentally damaging concentrations of boron, ammonia, fluorides, chlorides, iron, zinc, lead, and possibly other heavy metals (Usibelli et al. 1980, U.S. DOE 1981).

At most geopressure projects, the brines will not enter surface waters during normal operations. The most likely disposal method will be injection into saline aquifers above the geopressured zone (Usibelli et al. 1980). During emergency or upset conditions, such as those that might result from a well blowout or major pipe rupture, however, geopressured brines could enter surface waters. About 16,000 $m^3$ (100,000 bbl) of fluid might be released due to a pipe rupture, and over 80,000 $m^3$ (500,000 bbl) might be released within a few days during a well blowout (Usibelli et al. 1980). Because pressures are high and significant quantities of gas are present, well blowouts at geopressured wells are more likely to occur than at other types of wells (U.S. ERDA 1977a, Rehm and Goins 1978). Mitigation of accidental release of geopressured brines is best achieved with adequate blowout control and a spill control and counter-measure program.

The analysis should contain information about ambient water quality for all ground and surface water systems which may be affected by project activities. Applicable water quality standards should also be included. To address potential effects on water quality adequately, the following information should be provided for all unconventional gas projects:

- an estimate of the amount of erosion and sedimentation that may occur as a result of site preparation and pipeline construction and an analysis of effects on local water quality;
- a description of erosion and sedimentation control measures;

- a description of any dredging anticipated and an analysis of effects on local water quality;
- a description of constituents expected to be present in drilling muds and in formation fracturing fluids; and
- descriptions of the methods that will be used to ensure that these materials will not enter surface or groundwaters, including details about construction and lining of reserve pits and holding ponds, and any diking around well pads to contain spills and runoff.

For other than geopressured projects the following information should be provided:

- an estimate of the amount and chemical composition (if known) of any formation water that may be produced along with the product gas and, if possible, an estimate of the time interval over which these waters may be produced; and
- a description of the disposal alternatives being considered for the produced water, with an analysis of potential effects on surface and groundwater systems from this disposal.

For geopressured projects specifically, the following information should be provided:

- a description of the expected chemical constituents and their concentrations in the brines, and an estimate of the surface brine temperature;
- an estimate of the amount of brine that may be produced daily during normal operations and the anticipated disposal method;
- information about the water quality of the receiving aquifer and the anticipated depth, pressure, and rate of injection wells required for each production well, if disposal will be by injection,;
- worst-case estimates of the volume of brines which may be released to surface waters during upset conditions, including a major pipe rupture, failure of a holding pond, and a well blowout;

- an analysis of effects on water quality of the receiving system from the accidental releases described above; and

- a detailed spill control and countermeasure plan including clean-up methods in the event of an accidental release of brines.

For all projects, a list of all surface discharge or injection permits should also be provided, along with applicable water quality limitations. Information about anticipated surface and groundwater monitoring programs before and after project operations should be included.

### 6.3.6 Impacts on Biota

Unconventional gas projects will disturb some terrestrial wildlife habitat, but the amount of habitat that will be affected will be small compared to that disturbed by other energy technologies involving mining and construction of large permanent facilities. Tight gas and geopressured methane projects are those most likely to affect valuable wildlife habitat. The western tight gas basins contain several wildlife species that are sensitive to human presence and could be adversely affected by the noise levels and increased human activity associated with gas recovery. Geopressured methane projects could directly or indirectly affect important wildlife habitat in freshwater, brackish, and saltwater marshes of the Gulf Coast area.

Potential impacts on aquatic biota may result from point or non-point effluents from unconventional gas projects. Increased erosion and sedimentation may result in elevated suspended solids concentrations, thereby adversely affecting aquatic biota. Consumptive water withdrawals may alter instream habitat conditions. Dredging at geopressure projects may alter aquatic habitats, increase suspended solids, and mobilize toxic materials that have accumulated in the bottom sediments. Drilling muds, fracturing fluids, formation waters, or geopressured brines may be released into surface waters during normal operations or as a result of an accident. These materials could contain a variety of potentially toxic substances in currently unknown concentrations that could adversely affect aquatic biota downstream of the release.

Using general baseline information on the affected environment, onsite inventory data (the type and extent determined during early consultation), and the project description, the environmental analysis should:

- describe the terrestrial and aquatic habitats that will be disturbed by all project activities, with special attention to habitat for any endangered, threatened, rare, or otherwise protected plant and animal species;
- estimate the number of hectares of each type of habitat that will be disturbed by project activities;
- present a reclamation plan for all disturbed areas, along with an evaluation of the likely success of reclamation;
- provide information about the constituents and their concentrations in drilling muds, fracturing fluids, formation waters, and geopressured brines, and, where possible, evaluate the toxicity of these constituents to target species of aquatic biota; and
- include information from initial contacts with state and federal fish and wildlife agencies and conservation personnel (formal consultation with the U.S. Fish and Wildlife Service in relation to the status of federally listed threatened and endangered species is the responsibility of the federal action agency).

In addition to effects on biota from activities directly related to the unconventional gas project, construction of new major gas supply pipelines could affect hundreds of hectares of wildlife habitat far removed from the project site. If construction of significant new pipelines will be directly associated with the project, the following information should be provided:

- a description of the terrestrial and aquatic habitats that might be affected by pipeline construction, paying particular attention to habitat for rare, endangered, threatened, or otherwise protected plant and animal species;

- an estimate of the potential effect on these habitats from pipeline construction; and
- a reclamation and management plan for the pipeline corridor, including the method and frequency of removal of trees and shrubby vegetation from the pipeline right-of-way.

### 6.3.7 Noise

During the initial 3- to 6-month period of project activities, high noise levels will be associated with drilling and operation of large diesel engines during site preparation and formation fracturing. During this time noise levels from drilling may be about 85 to 90 dB(A) at 15 m (50 ft) from the well, attenuating to 50 to 55 dB(A) at 800 m, and noise levels from large diesel engines may be in excess of 100 dB(A) at 15 m (50 ft), attenuating to over 65 dB(A) at 800 m (0.5 mile) from the project site (U.S. DOE 1979b, Riedel et al. 1980). Noise could be a worker health and safety issue (Section 6.3.9) and would become an environmental issue in cases where the project may be located near residences, public use areas, wilderness areas, or habitat for sensitive wildlife species. Estimates of the level of noise produced by project activities should be supplied. Details about noise control measures should be supplied where appropriate. Information on the level of sensitivity and the distance to nearby sensitive receptors (e.g., recreational areas, backpacking trails, or residential areas) should also be provided.

### 6.3.8 Socioeconomics

Unconventional gas projects are not expected to create significant adverse socioeconomic impacts because they will not involve in-migration of a large work force. The largest work force will be present during drilling and fracturing operations and will consist of about 25 people for each well. These workers in most cases will not be from the local areas, as they are usually supplied by the contracting companies that specialize in drilling services. Most of these workers are likely to be housed in motels or rental housing. They may create some strain on the availability of such housing at projects located in areas remote from larger communities, but the work force should be not so large nor the duration of their stay so long as to create any adverse "boomtown" effects. The operational work force at most unconventional gas projects will be smaller than that present during drilling and will probably be drawn from the local population.

To address socioeconomic considerations for all types of unconventional gas projects, the following information should be provided:

- the number of workers expected to be involved in each phase of project activity, and an estimate of what percentage of them are expected to be nonlocal;
- plans for providing housing for the workers; and
- a determination of the adequacy of housing supply, municipal and community services, and transportation networks in these communities to support the in-migrating workers.

### 6.3.9 Health and Safety

The health and safety issues related to most aspects of unconventional gas technology are identical to those associated with conventional gas well drilling and production. Additionally, health and safety issues related to geopressure projects will be identical to those associated with geothermal drilling and operating technology. A summary of the issues follows:

- mechanical injury from setting casing, adding and removing drill string, rig assembly, and maintenance and equipment failure;
- exposure to significant noise levels during drilling, pumping operations, and venting of gas and fluids (MITRE 1981);
- exposure to high concentrations of exhaust emissions (particularly carbon monoxide) from diesel machinery used to power drill rig and compressors (U.S. DOE 1979a, Riedel et al. 1980, U.S. EPA 1979, NRC 1981);

- exposure to potentially harmful chemicals (including potential carcinogens) present in drilling muds and fracturing fluids (U.S. DOE 1979c, MITRE 1981);
- potential hazard associated with accidental mixing or improper handling aboveground of chemical explosive slurry used in chemical explosive fracturing operations (U.S. DOE 1979a);
- exposure to radiation from gamma emitter ($^{192}Ir$) added to fracturing sand (Riedel et al. 1980; ICRP 1959);
- occurrence of well blowouts, which could result in fire or uncontrolled release of large quantities of hot fluid in geopressure wells (the combination of dissolved gas and high pressures increase the potential for blowouts in geopressure projects); and
- for geopressure projects, the hazards of handling large quantities of hot and chemically complex brines that may contain high concentrations of ammonia, boron, and trace metals (the pressures involved with geopressure operation increase the potential for spills due to pipe rupture or other equipment failure).

The issues described above should be evaluated in detail appropriate to the type and scope of the unconventional gas project under consideration. Additionally, an environmental analysis should present plans for monitoring worker environments, accomplishing regular maintenance and inspections of all equipment and facilities, and use of protective clothing and equipment as necessary. Plans should be developed for compliance with existing National Institute for Occupational Health and Safety and Occupational Safety and Health Administration regulations, as appropriate.

There are some unique safety concerns related to projects involving methane from minable coal seams. Mine operators are concerned that fracturing operations to increase gas flow may damage the overlying rock strata that comprise the roof of the mine, thereby increasing the potential for cave-ins. Mining into a degasification borehole can suddenly release large quantities of methane that may have accumulated in the borehole following gas recovery operations. This methane released into the mine could create a potentially explosive atmosphere (Ethridge et al. 1980). Also, there is considerable resistance from mine operators and miners to methane recovery in an active mine because of the potential for accidental release of large quantities of gas into the mine from equipment or pipeline failure (Ethridge et al. 1980). These potential hazards should be addressed for projects recovering methane from minable coal, and the methods to be used to ensure mine safety should be described in detail.

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# 7. FUEL ETHANOL

R. Dickinson Roop[1]

## 7.1 RESOURCE DESCRIPTION

The resources available for production of fuel alcohol are quite varied and not easily quantified. Feedstocks suitable for fermentation (Table 15) include starch crops, sugar crops, cellulosic material, and some wastes. The feedstocks most readily converted to ethanol are starch crops (especially corn) and sugar crops (e.g., sugar beets). Although the quantities of such crop feedstocks which are produced are well documented (USDA 1978), the portion that might be economically available for ethanol production is dependent on many unknown factors such as the fluctuating demands for fuel and food. Table 16 gives estimates of potential ethanol production based on availability of various crops and wastes.

While processes for fermentation of cellulosic feedstocks exist, these have generally not been proven on a commercial scale. It is not known whether lignin-containing cellulosic material (e.g. forestry residues) will be suitable for fermentation. Thus, considerable speculation is involved in attempts to quantify the potential resource base of cellulosic material. The availablity of biomass feedstocks suitable for large-scale production of ethanol is considered in detail by Braunstein et al. (1981).

Land is the most basic resource affecting the availability of feedstock for ethanol production, and almost 90% of the United States' 936 x $10^6$ ha produces some sort of biomass that is commercially used. Approximately 20% of the U.S. area is devoted to growing crops (SCS 1977), with the greatest area devoted to corn, wheat, hay, soybeans, sorghum grain, and oats (in order of declining importance)

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Table 15. Feedstock advantages and disadvantages [modified from Table IV-1, SEIDB (1980)]

| Type of feedstock | Processing needed before fermentation | Principal advantage(s) | Principal disadvantage(s) |
|---|---|---|---|
| Starch crops:<br>Grains (e.g., corn, wheat, sorghum, barley<br>Tubers (e.g., potatoes, sweet potatoes) | Milling, liquefaction and saccharification | 1. Storage techniques are well developed<br>2. Cultivation practices are widespread except for sorghum<br>3. Livestock feed by-product is relatively high in protein | Preparation involves additional equipment, labor, and energy costs |
| Sugar crops (e.g., sugar beets, sweet sorghum, sugarcane, fodder beet, Jerusalum artichoke) | Milling to extract sugar | 1. Preparation is minimal<br>2. High yields of ethanol per hecatre<br>3. Crop coproducts have value as fuel, livestock feed or soil amendment | 1. Difficulty of storage may limit year-round use of single feedstock<br>2. Storage may result in loss of sugar<br>3. Cultivation practices are not widespread, especially with "nonconventional" crops |
| Cellulosic:<br>Crop residues (eg., corn stover, wheat straw<br>Forages (e.g., alfalfa, Sudan grass, forage sorghum | Milling and hydrolysis of the cellulose linkages | 1. Use involves no integration with the livestock feed market<br>2. Availability is widespread | 1. No commercially cost-effective process exists for hydrolysis of the linkages<br>2. Collection of diffuse materials<br>3. Erosion from removing residues |
| Wastes (e.g, distressed grains, cull fruits and vegetables, grain dust, and whey | Variable | 1. Low cost | 1. Limited availability<br>2. Distillers dried grain from aflatoxin-contaminated grain is not suitable as animal feed |

Table 16. Biomass availability for ethanol production
[million L/year (million gal/year)]

| Biomass feedstock | Currently available[a] | Potentially available[b] |
|---|---|---|
| Cheese whey | 341 (90) | 341 (90) |
| Citrus waste | 795 (210) | 795 (210) |
| Other food wastes | 568 (150) | 568 (150) |
| Corn | 681 (180) | 6,280 (1,660) |
| Grain sorghum | 114 (30) | 1,060 (280) |
| Sugar cane | - | 568 (150) |
| Wheat | - | 4,280 (1,130) |
| Municipal solid waste | - | 4,160 (1,100) |
| Total | 2,500 (660) | 18,050 (4,700) |

[a]Available biomass that can be converted to ethanol with present technologies, without changing set-aside and diversion policies.

[b]Available biomass if all set-aside and diverted lands (but no new or marginal lands) are brought into production and sugar surpluses and 50% municipal solid wastes are used with current technologies to make ethanol. No agricultural or wood residues or sweet sorghum potentials are included.

SOURCE: Muller Associates, Inc. 1981.

(USDA 1978). Crop production in the United States, although most concentrated in the Midwest, is widely distributed throughout the country. Because crop feedstocks suitable for fermentation vary and crop production is widely distributed, ethanol production facilities could be located in most parts of the United States, except possibly desert or mountain areas.

## 7.2 TECHNOLOGY OVERVIEW

The technology of alcohol production from grain and sugar crops has been well established by years of experience in the beverage industry. Production of fuel alcohol, however, allows the use of a wider variety of feedstocks, because taste and absolute purity of the product are of little importance. Cellulosic feedstocks (e.g., crop residues, forage grasses, and wood) also lend themselves to alcohol production, but a commercial process for hydrolysis to produce fermentable materials from cellulosics has not yet been proven. The discussion here will focus primarily on use of sugar or starch materials because they are the most likely to be used in the near term. A brief overview of fuel alcohol production is given below as general background for persons unfamiliar with the technology. More detailed descriptions of alcohol production terminology can be found in other documents (USDA 1980, SEIDB 1980, Elmore et al. 1982).

### 7.2.1 Alcohol Production Process

Production of fuel alcohol involves the following basic steps (Fig. 12):

- feedstock preparation (e.g., milling),
- pre-treatment (e.g., cooking and enzyme digestion),
- fermentation,
- distillation,
- dehydration, and
- by-product recovery.

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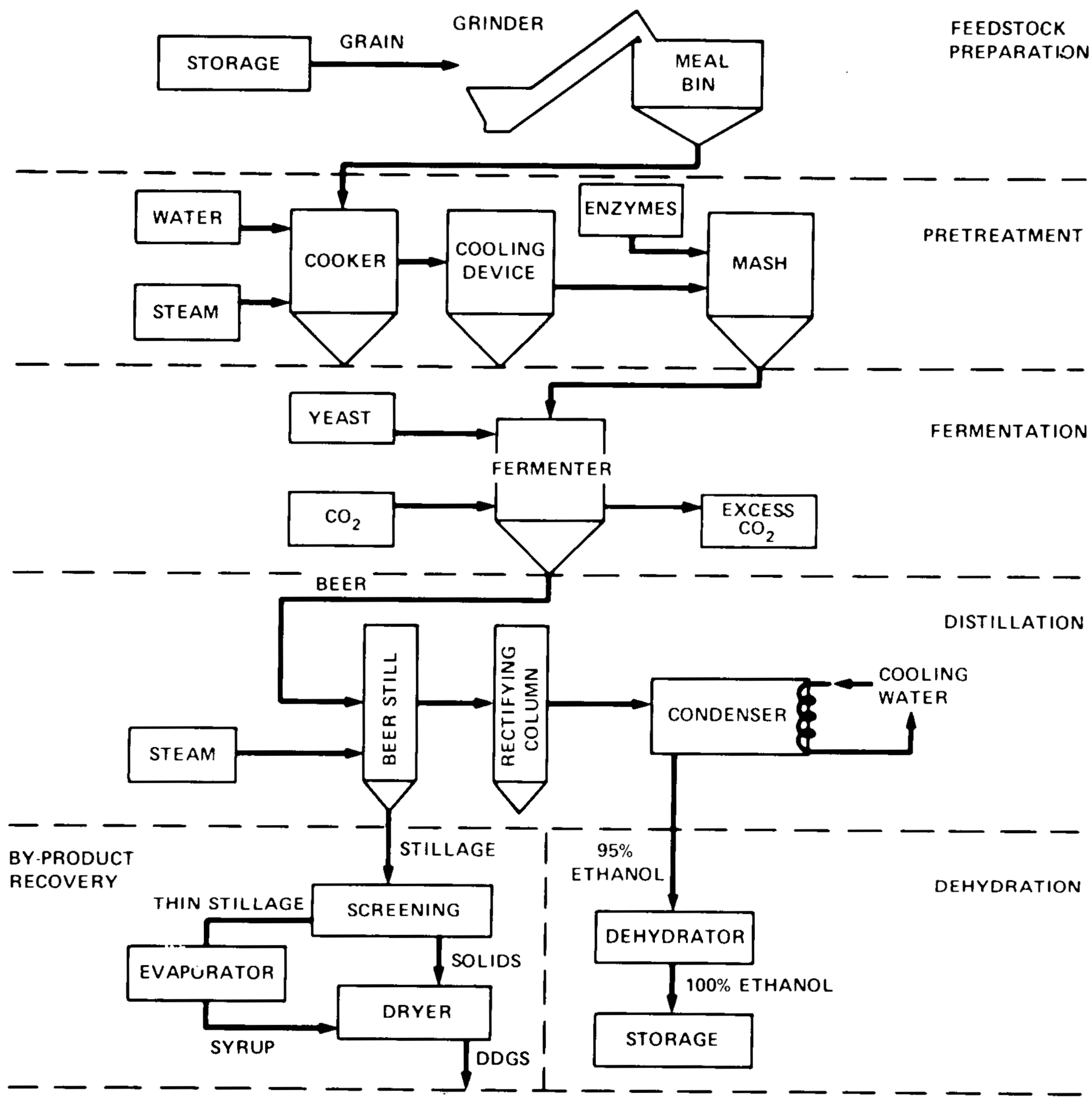


Fig. 12. Typical processing steps for conversion of grain to ethanol.

The basic process may be modified to some extent, depending on the feedstock involved. Corn or other grains are most commonly used, although sugar crops and a variety of food processing wastes can be readily employed in existing commercial processes.

Feedstock preparation and pre-treatment produce a solution of simple sugars for fermentation. The initial steps of this process, collectively known as liquefaction, involve milling the grain, adding water to form a slurry, cooking to release starch from plant cells and to provide an optimum temperature for hydrolysis, and adding enzymes or acids that convert starch to complex sugars (dextrins). Liquefaction is followed by saccharification, the conversion of complex sugars to simple sugars such as glucose, which is accomplished by lowering the temperature, adjusting the pH, and adding additional enzymes. The mash produced by this process is suitable for fermentation.

Fermentation, the conversion of sugars to ethanol and $CO_2$, is carried out by yeasts of the genus Saccharomyces. To produce a maximum quantity of alcohol, the strain of yeast is carefully selected and the mash or "beer" is adjusted to optimum conditions of sugar concentration (10 to 22%), pH (3.0 to 5.0), and temperature (27 to 32°C). The rate of fermentation varies with the sugar concentration and the initial concentration of yeast cells.

Distillation separates the ethanol from the "beer" by taking advantage of the ethanol's lower boiling temperature compared to that of water. Fermented mash is fed into a stripping column or beer still (Fig. 12) which is heated with steam. Ethanol and some water evaporate and leave the top of the column as vapor, while the remaining liquid (stillage) leaves the bottom of the column. The vapors enter a rectifying column in which counter-current flow further separates the alcohol from the water. The vapor from the rectifying column (Fig. 12) is condensed and part of the product is recycled to the top of the rectifying column. The product is an azeotropic mixture of about 95% ethanol and 5% water. This mixture has a constant boiling temperature and cannot be separated by simple distillation.

Dehydration of the azeotrope can be accomplished by either a tertiary distillation or use of a molecular sieve. In tertiary distillation, a third liquid (benzene, ether, gasoline, ethylene glycol, or some other solvent) is added to the azeotrope to change the boiling characteristics and allow separation of anhydrous ethanol. Molecular sieves remove the water from 190 proof alcohol by selectively adsorbing it to some material. This material then typically requires high-temperature regeneration to remove the water.

In some cases, the stillage from alcohol production can yield marketable by-products. If corn is used as the feedstock, the stillage will contain the protein originally present in the corn plus protein produced by the yeast. Unprocessed stillage (i.e., whole stillage) typically has only a 6 to 8% solids content (Anthony 1979). It can be fed directly to livestock, but it spoils very quickly and cannot be stored for more than a few days. Solids can be removed from stillage by passing it through separators or dewatering presses, yielding thin and thick stillage respectively. To recover a dried product, thin stillage is concentrated in evaporators to a syrup of 25% solids content that can then be added to the thick stillage and dried to form distillers dried grains with solubles (DDGS), having a 10 to 12% moisture content.

### 7.2.2 Raw Materials

The raw materials needed for ethanol production include feedstock, water, acids or enzymes, and yeast cultures. The feedstock for alcohol production is an important determinant of process design, facility siting, and economics. Potential conventional feedstocks include (1) sugar crops, (2) starch crops, (3) cellulosic materials, and (4) waste materials such as distressed grains, grain elevator dust, and whey from cheese manufacturing. Advantages and disadvantages of various feedstocks are summarized in Table 15.

The amount of water needed varies with the system design and may range from 50 to 240 L water/L ethanol (ASTM 1969). Water is used in several steps of the production process and for cooling, boiler feed and make-up, and washing. Relatively high quality water is required for certain steps in the production process (McKee and Wolf 1963), including liquefaction, saccharification, and fermentation. Water that meets the drinking water standard of 500 mg/L total dissolved solids is suitable for many boilers, but in some cases water softening to remove dissolved solids may be necessary.

The enzymes and yeast cultures needed for alcohol production are typically obtained from commercial suppliers, but large or experimental ethanol production plants may include facilities for enzyme production or for culturing necessary microorganisms.

### 7.2.3 Energy Sources

In the past, natural gas and oil have been the major fuels used to fire boilers that provide process heat for cooking, fermentation, distillation, and drying of by-products. Because the major reason for developing an alcohol fuels industry is to reduce dependence on scarce and imported fuels, current developers of alcohol facilities are considering a wide range of alternative energy sources. Fuels that may be used to fire boilers include coal, wood, bagasse (processed sugarcane), crop residues, and municipal solid wastes. Another possible fuel, biogas (methane), could be produced by anaerobic digestion of manure generated in feedlot operations. Close integration of distilleries and feedlots could result in high energy efficiency. Feeding whole stillage produced in alcohol production to livestock avoids the high energy costs of drying the stillage. Also, anaerobic digestion of feedlot manure solves a disposal problem and could reduce some of the nuisance caused by feedlot odor.

Low-temperature heat is adequate for many of the process steps in ethanol production. Cooking, fermentation, and by-product drying can all be accomplished at temperatures below 100°C. Ethanol production facilities could therefore utilize unconventional energy sources, such as geothermal energy, solar energy, or waste heat from electricity generation, petroleum refining, or other sources to meet all or part of their energy requirements.

### 7.2.4 Economic Factors

A full discussion of the economics of ethanol production is clearly beyond the scope of this document. However, several economic issues have a direct bearing on the environment and should therefore be considered.

Two economic factors will influence the size of alcohol production facilities. Economies of scale will promote selection of larger plants. Plant sizes of $39 \times 10^6$ to $113 \times 10^6$ L/year ($10 \times 10^6$ to $30 \times 10^6$ gal/year) are favored by many established engineering design firms in order to capture the benefits of process refinements such as continuous cooking and fermentation. In contrast, many developers will choose smaller plant sizes [e.g., $4 \times 10^6$ to $11 \times 10^6$ L/year ($1 \times 10^6$ to $3 \times 10^6$ gal/year) or smaller] to achieve integration with farm operations. Such an approach could produce cost-savings through use of locally produced feedstock and local distribution of whole stillage.

A third economic factor to be considered is the need to make the product accessible to markets. The output of smaller plants may be targeted to on-farm use, while the location of larger units will depend on location of end use, the sources of feedstock, and the availability of transportation.

The handling of stillage is vital to the economics of plant operation. For projects using corn as the feedstock, revenues from by-product sales are essential to profitable operation. Furthermore, unless stillage can be utilized in some manner, disposal costs will be incurred.

Other important economic considerations that will be of concern relate to the large volumes of water that are used and discharged and the availability of alternative energy sources for the plant (including cogeneration). Finally, market factors related to user demand and acceptance must be considered.

## 7.3 POTENTIALLY SIGNIFICANT ISSUES

Fuel ethanol production facilities are often small in scale compared to many energy installations, and environmental impacts associated with construction and operation of such facilities are normally of limited extent. Potentially significant issues that should commonly be considered are identified and discussed in the following sections. In cases where projects include large feedstock production operations, environmental impacts associated with such production should also be addressed.

### 7.3.1 Land Use

The potential for significant land-use conflicts at a fuel ethanol production facility will depend to a large extent on the current use of the site and its immediate vicinity and on the type of operation being proposed. If the proposed facility is an expansion of an existing operation (e.g., a feedlot or a municipal waste disposal plant), there may be minimal conflict, and existing problems, such as odor, may actually be alleviated. On the other hand, an entirely new ethanol production facility proposed for location in an urban area may create numerous land-use conflicts associated with zoning restrictions, traffic congestion, odor from feedstock storage areas, etc.

In rural areas, one of the most likely land-use conflicts to arise is the siting of a proposed facility on high-quality farmland or within a 100-yr floodplain. Federal land-use policy states the goals of preserving prime and unique farmlands (CEQ 1976, CEQ 1980), and Executive Orders 11988 and 11990 (1977a,b) instruct federal agencies whenever possible to avoid taking actions that would affect floodplains and wetlands. State and local land-use policies may invoke similar restrictions. Issues such as siting a facility on prime farmlands or on a floodplain may not appear to be significant for an individual project but may become highly significant when considered in the context of other developments within the region.

Background information on the site and the region should be carefully evaluated to identify possible land-use conflicts. For any land-use conflict identified, the following information should be provided:

- identification of the potential land-use conflict;
- a detailed description of current land-use and zoning or other land-use restrictions relevant to the issue under consideration;
- an evaluation of unique values associated with current land-use (e.g., prime farmland, extensive wetland areas, or historic sites);
- a detailed evaluation of the impacts on land use and mitigation measures to be applied for the proposed project; and
- cumulative impacts of development on the land use in question for the entire region.

### 7.3.2 Atmospheric Emissions

Atmospheric emissions from fuel ethanol production may originate either from the production process itself (including the storage, handling, and initial processing of the feedstock) or from the power plant used to generate process heat. The largest quantities of atmospheric emissions are likely to be released during the production of process heat.

The types of emissions that are released during the production process include particulates, sulfur dioxide, hydrocarbons, carbon monoxide, carbon dioxide, drying chemicals (e.g., ethyl ether), and nitrogen oxides. Of these emissions, particulates and carbon dioxide account for the bulk of the materials emitted. Particulate emissions arise mainly from dust that is generated during the handling of grain and usually are readily controlled by the use of cyclones or baghouses. Large volumes of carbon dioxide produced during fermentation are usually vented to the atmosphere but could be captured and sold as a by-product.

Power plant operations will most likely release the largest quantities of emissions from the facility and will probably be subject to best available control technology (BACT) or lowest achievable emission rate (LAER) restrictions in the permitting process. Control of sulfur dioxide and particulates using flue-gas desulfurization systems and electrostatic precipitators, respectively, will be required for coal plants and for some other fuels. Nitrogen oxide emissions may be high for coal plants and for biomass fuels and may present a problem because the technology for $NO_x$ control is not well advanced.

All the information gathered on atmospheric emissions for both the periods of construction and operations should be reviewed, and an evaluation of the types, levels, and impacts of these emissions should be presented. The following information should be presented or referenced:

- types and quantities of fuels to be used;
- anticipated types and levels of emissions (shown separately for the production process and the power plant);
- permit requirements that limit emission levels and the types of pollution control equipment that can be used;
- identification of uncertainties associated with emission levels such as sporadic episodes of high emission levels resulting from poorly controlled combustion;
- description and analysis of emissions associated with the use of novel energy sources (e.g., municipal solid wastes); and
- types of pollution control equipment (e.g., baghouses, electrostatic precipitators, or flue gas desulfurization equipment) that will be used to control specific types of emissions.

### 7.3.3 Stillage Use or Disposal

Stillage consists of unfermentable solids derived from several steps in the production process. A fuel ethanol plant will produce large quantities of stillage that must be either used as a by-product or handled as a waste disposal problem. Potential uses for stillage include (1) feeding it as is to livestock, (2) drying it to produce distillers' dried grains (DDG) or other by-products, which can then be used as a livestock feed, and (3) applying it as an amendment to agricultural soils. These potential uses of stillage are limited by (1) the nutritive value of the stillage (i.e., the nutritive value varies with the type of feedstock used); (2) the short storage life of unprocessed, whole stillage; (3) the requirements for and availability of energy for drying; and (4) the market demand for the by-product produced.

Wet-milling is an elaborate and sophisticated feedstock processing technique that produces a wide variety of by-products including corn sweetener, oil, fiber, and high protein animal feed. The wet-milling of corn may be adopted by large-scale facilities to allow them to shift from production of alcohol to production of corn syrup products as the market demands. Use of this process may confer greater economic stability on the industry, but also increases capital and processing costs. By producing a greater variety of by-products, the amount of stillage produced may be reduced.

If stillage marketing should not prove to be feasible for economic or other reasons, disposal of large amounts of stillage may be required (Sect. 7.3.4). Potential issues associated with waste disposal include odor problems, soil acidification from land spreading, pollution of surface and groundwaters, and overloading of municipal wastewater systems. Although adequate technology exists to control problems that may arise in stillage handling, economic factors may preclude universal application of this technology.

The environmental analysis should include the following information:

- data on the types and quantities of stillage that will be produced;
- plans for using the stillage as a by-product (including the types of by-products being produced, requirements for processing, handling, and storing the by-products, and the market available for the by-products);

- plans for disposing of stillage that cannot be marketed, including contingency plans for disposing of spoiled or excess stillage if normal avenues for marketing are unavailable; and
- impacts associated with the storage, handling, transport, and disposal of stillage.

### 7.3.4 Waste Water Discharges

Miscellaneous liquid wastes produced in alcohol production include domestic sewage, wash water from equipment cleaning, and occasional bad batches of mash. In addition, if it is necessary to dispose of large amounts of stillage (Sect. 7.3.3), this stillage will become a major waste stream.

While most wastewaters can be handled conventionally (i.e., discharged to sewers, septic tanks, or drain fields), a spoiled batch would contain even greater biochemical oxygen demand (BOD) loadings than an equal volume of stillage. Disposal methods such as lagooning or land spreading would then be required. Unused stillage and wastewaters may be mixed to form a single waste stream. Other sources of waste from a fuel ethanol operation that should be considered include runoff from storage and waste disposal areas (e.g., coal storage piles or ash disposal areas).

The wastewaters resulting from ethanol production will vary with the feedstock and the by-product recovery practices used. Raw waste streams may include whole stillage, thin stillage left after dewatering the wet distiller's grains, and condensate from evaporators. Partially treated stillage effluents will also be added to the waste stream.

Wastewaters from fermentation can have very high levels of BOD, acidity, and suspended solids (Chadwick and Schroeder 1973, Brown et al. 1976). Wastewater streams may be generated by stillage dewatering, by-product drying, or other processes. These streams may be recycled and used for mash preparation in some operations but otherwise would require disposal. High BOD levels from dissolved organic matter such as traces of ethanol and acetic acid would occur in these streams. The condensate from evaporators may contain volatile organic matter and have a BOD in excess of 5000 mg/L (Winston 1980). The principal methods available for treating such waste streams include anaerobic digestion, aerobic treatment, and land spreading (Sect. 7.3.3).

7.3.4.1 Anaerboic digestion

Anaerboic digestion is feasible for wastewaters that have very large (greater than 5000 mg/L) oxygen demands (Joyce et al. 1977). As with digestion of sewage sludge, methane can be economically generated from these wastewaters. About 25 volumes of gas are produced for every volume of wastewater treated, although large tanks are needed due to the long retention times (8-40 d) (Joyce et al. 1977). Anaerobic digestion can also be accomplished in lagoons, but this practice requires a sizable commitment of land and may involve odor problems. Although the effluent from digestion has a significantly reduced BOD, it is still too high for discharge to streams or municipal sewers, and land treatment or further aerobic treatment is required.

7.3.4.2 Aerobic treatment

Most wastewaters from beverage distilleries are treated aerobically using lagoons, activated sludge processes, trickling filters, and other standard procedures. Distillery wastewaters are readily degradable, although providing sufficient oxygen can be difficult for high strength wastewaters.

7.3.4.3 Land spreading

Stillage and distillery wastewaters can be disposed of by land spreading where land is available (Chadwick and Schroeder 1973). Stillage can be a valuable soil amendment since it adds high levels of organic matter and potassium. It contains little nitrogen, however, and its use may increase nitrogen fertilizer requirements. Severe odor problems can result from land spreading (Winston 1980). Use of a sludge plow that injects material 15-30 cm (6-12 in) below the surface has been suggested to minimize odor problems.

Stillage with a low pH can be successfully applied to soils when limestone is added to neutralize excess acidity (Winston 1980). Lack of neutralization of low pH liquid effluents may, however, inhibit the growth of crops and soil organisms. Neutralization to a pH of 6 to 8 minimizes adverse disposal effects as well as corrosiveness to process equipment (U.S. EPA 1980).

The following information should be provided:

- identification and characterization of wastewater streams;
- plans for treatment of wastewater streams, including contingency plans for disposal of spoiled batches;
- description of the existing condition of the receiving system based on an expansion of general baseline information; and
- an analysis of the impacts on the receiving system and any other affected land or water body.

### 7.3.5 Socioeconomics

The type and severity of immediate socioeconomic impacts will be related directly to the size of the work force required for construction and operation and the available pool of workers. The most significant impacts should be anticipated for large facilities located in rural areas where the available labor force is small and services to support in-moving workers and their families are limited. For large-scale facilities, where significant socioeconomic impacts may occur, the following points should be addressed:

- impacts on services, such as police and fire protection, education, housing, medical care, and especially water and sewage facilities;
- the community's ability, through aid from the project's proponents, taxation, grants, or other mechanisms, to mitigate any adverse impacts; and
- in cases where the intrusion creates "boomtown" conditions, changes in the economic and political base of the area, as well as effects on such factors as lifestyle, mental health and crime.

In addition, some note should be taken of the legal requirements for ethanol production, including the Bureau of Alcohol, Tobacco, and Firearms alcohol fuel producers (AFP) permit. Security measures to prevent illegal uses of ethanol produced should also be considered.

### 7.3.6 Health and Safety

As with any industrial or farm operation, ethanol production involves risks and hazards to health and safety. These are categorized somewhat arbitrarily as material hazards and process hazards. In general the hazards of ethanol production are relatively minor, especially when compared to large industrial operations such as producing synfuels from coals.

Materials and compounds that may be hazardous include ethanol, denaturants, dehydrating agents, chemicals for adjusting pH, and grain dust. Many of these substances carry the risk of fire or explosion, while some are toxic or detrimental to human health.

Table 17 provides hazard data on several organic compounds that may be used. Flash point, vapor pressure, and lower flammability limit indicate fire risk. Ether is the most available volatile material, but ether, benzene, and gasoline all have high explosive potential. Ethyl and methyl alcohols involve significant risks of fire, but they are somewhat less explosive than ether, benzene, and gasoline. Ethylene glycol, which is commonly used as antifreeze, is nonflammable and less toxic than the other materials. The "threshold limit values" refer to airborne concentrations and represent levels believed to be safe for occupational exposure. Although the compounds listed in Table 17 vary in their toxicity, all except ethylene glycol can cause poisoning and death through inhalation of the vapors at high concentrations. Symptoms resulting from high exposures include drowsiness, dizziness, stupor, and unconsciousness. Chronic exposure can also be detrimental, especially with benzene, a suspected human carcinogen.

The chemicals used to adjust pH include sodium hydroxide and sulfuric acid. In concentrated form these substances are caustic. Contact with skin can cause burns, while inhalation of vapors or mist

Table 17. Characteristics of chemical substances possibly handled in ethanol production

| Compound | Uses | Flash point[a] °C | Vapor pressure[a] (mm Hg at 25°C) | Lower flammability limit[a] (% volume in air) | Threshold limit value[b] (ppm) | Toxicity rating[c] |
|---|---|---|---|---|---|---|
| Ethyl alcohol | Motor fuel | 18 (95%)<br>14 (100%) | 50 | 3.28 | 1000 | Moderately toxic |
| Methyl alcohol | Denaturant, motor fuel | 12 | 125 | 6.72 | 200 | Moderately toxic |
| Ethylene glycol | Dehydrating agent | 116 | 0.06 at 20°C | - | 100 | Slightly toxic |
| Ethyl ether | Dehydrating agent | -40 | 439 at 20°C | 1.9 | 400 | Moderately toxic |
| Benzene | Dehydrating agent | -11 | 100 | 1.35 | 25 | Moderately toxic |
| Gasoline[d] (n-octane) | Dehydrating agent denaturant | 13 | 10.5 at 20°C | 0.96 | 500[d] | -[d] |

[a]Data from: Patty (1963).

[b]Data from: Fairchild (1977).

[c]Based on oral toxicity to rats ($LD_{50}$) (Fairchild 1977).

[d]Gasoline is a complex and variable mixture of aliphatic and aromatic hydrocarbons. Data for n-octane indicate flammability, while toxicological characteristics are dependent on content of aromatics, especially benzene.

can damage lungs. Proper equipment and handling procedures are required for safe use. Small fermentation operations can use more dilute reagents, such as a slurry of hydrated lime, to adjust pH.

Reports of particulate emissions from handling grain from elevator operations and from drying spent grain range from 1.5 to 2.5 kg/Mg grain handled, respectively (U.S. EPA 1977). Assuming that 2.7 kg of grain are needed to produce a liter of alcohol (2.5 gal/bu), total particulate emissions could equal 10.7 g/L of alcohol produced.

Fugitive emissions from production and handling of alcohol might equal as much as 0.25% of the volume produced. Such emissions would be greater if ethanol and gasoline are mixed at the production site.

Ethanol production will generate risks from the routine handling of potentially hazardous materials and use of steam for heat. Table 18 lists hazards and appropriate precautions. An additional hazard is the conception by workers that "it's only ethanol" because they drink ethanol. This familiarity with ethanol results in worker failure to realize that it is toxic and should be handled with care (Segnar 1981).

The environmental analysis should include the following information and analysis in the health and safety section:

- identification of material and process hazards associated with the proposed project;
- evaluation of the degree of risk; and
- plans for controlling and minimizing the risks of exposure and accidents.

Table 18. Ethanol plant hazards (SEIDB 1980)

| Hazards | Precautions |
|---|---|
| Overpressurization; explosion of boiler | Regularly maintain and check safety boiler "pop" valves that are set to relieve pressure when it exceeds the maximum safe pressure of the boiler or delivery lines. |
| | Strictly adher to boiler manufacturer's operating procedure. |
| | If boiler pressure exceeds $1.4 \times 10^5$ Pa (20 psi), require ASME boiler operator attendance during boiler operation. |
| Contact burns from steam lines | Insulate all steam delivery lines. |
| Ignition of ethanol leaks/fumes or grain dust | If electric pump motors are used, use fully enclosed explosion-proof motors. |
| | (Option) Use hydraulic pump drives; main hydraulic pump and reservoir should be physically isolated from ethanol tanks, dehydration section, distillation columns and condenser. |
| | Fully ground all equipment to prevent static electricity build-up. |
| | Never smoke or strike matches around ethanol tanks, dehydration section, distillation columns, or condenser. |
| | Never use metal grinders, cutting torches, welders, etc., around systems or equipment containing ethanol. Flush and vent all vessels prior to performing any of these operations. |

Table 18. (continued)

| Hazards | Precautions |
|---|---|
| Scalding from steam gasket leaks | Place baffles around flanges to direct steam jets away from operating areas. |
| | (Option) Use welded joints in all steam delivery lines. |
| Handling acids/bases | Never breathe the fumes of concentrated acids or bases. |
| | Never store concentrated acids in carbon steel containers. |
| | Mix or dilute acids and bases slowly, allow heat of mixing to dissipate. |
| | Immediately flush skin exposed to acid or base with copious quantities of water. |
| | Wear goggles whenever handling concentrated acids or bases; flush eyes with water and immediately call physician if any gets in eyes. |
| | Do not store acids or bases over work areas or equipment. |
| | Do not carry acids or bases in open buckets. |
| | Select proper materials of construction for all acid or base storage containers, delivery aids, valves, etc. |
| Suffocation | Never enter the grain bins, fermenters, beer well, or stillage tanks unless they are properly vented. |

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# APPENDIX A

## DESCRIPTION OF THE AFFECTED ENVIRONMENT

The assessment of project-related environmental impacts must be based in part on baseline data that describe site conditions before any project activities are initiated. Baseline information for the site and its immediate vicinity is often readily available from land owners and government agencies involved with resource management (e.g., U.S. Fish and Wildlife Service, Soil Conservation Service, and the Environmental Protection Agency). Often a general description of a site can be developed on the basis of such existing information plus a visit to the site to confirm that the available information is relevant to the site under consideration.

A major concern of government agencies in assembling a baseline description is to avoid the needless collection of detailed site data which will not affect the final decision on whether or not to approve the project. To determine what information is necessary, the general categories of environmental concerns summarized in Table A.1 should be reviewed for each project. The amount of detail needed for each category will vary with the type of project, the characteristics of the site, the anticipated environmental impacts, and the type of decision that is being considered. For example, if the agency decision is on final project approval and the information will be used as a basis for an environmental impact statement, more specific information may be needed than if the decision is to determine whether significant impacts are likely to occur and the information will be used as a basis for an environmental assessment.

At the minimum, the affected environment section should present a general description of the major environmental features of the site and a more detailed description of those features that are likely to be affected by project activities. A well-prepared section on the affected environment will provide the necessary background for the section on potentially significant issues and will assist in focusing the latter section on the evaluation of impacts.

Table A.1. Information needed for describing the existing environment of the site and its surroundings

| Category | Type of information | Possible sources of information |
|---|---|---|
| 1. Land use and zoning | Maps and tables showing present land use on the site and surrounding area; land ownership; regional, state, and local land-use plans and controls pertinent to the site and surrounding area. | State, regional, and local planning commissions; state agencies, such as Departments of Conservation, Fish and Game, and Parks; federal agencies, such as U.S. Geological Survey, Soil Conservation Service, Bureau of Land Management, Forest Service; onsite observations. |
| 2. Floodplains and wetlands | Maps showing the locations of the 100- and 500-year floodplains and onsite wetlands; table showing onsite area (hectares) for each floodplain or wetland; description of each onsite wetland, including dominant features and abundance of each wetland type. | FEMA Flood Insurance Rate Maps and Flood Hazard Boundary Maps; USGS topographic maps; county soil surveys; U.S. Fish and Wildlife Service National Wetlands Inventory; onsite observations. |
| 3. Prime and unique farmlands | Soils map of the site; description of onsite soil type; area (hectares) of soil on the site that is classified as prime or unique farmland. | U.S. Soil Conservation Service - contact state soil conservationist and local soil conservation office; state agricultural colleges. |
| 4. Cultural and aesthetic resources | Location and description of cultural and aesthetic resources on or in the vicinity of the site, including historic and archaeological sites, Indian tribal resources, scenic, and other aesthetic resources. | State historic preservation office; National Register of Historic Places; National Register of Natural Landmarks; U.S. Bureau of Indian Affairs; local tribal headquarters; onsite observations. |
| 5. Geology | Geological bedrock, and surface formations; topography; location and description of potential geologic hazards, including consideration of slope stability, mass movement, faults, subsidence, settlement, liquefaction, and volcanic activity; economically recoverable energy and mineral resources. | U.S. Geological Survey national distribution center, Reston, Virginia; USGS depositories of publications at state land grant universities; state geologist; USGS topographic and land-use maps; onsite observations. |
| 6. Terrestrial and aquatic ecology | Map and description of vegetation types on the site; wildlife species and habitats; presence of rare, unique, or important ecological communities or habitats; description of aquatic habitat types and aquatic species present in water bodies. | Ecologists and other biologists at local and state colleges and universities; private environmental and conservation organizations; state fish and game and conservation agencies; onsite observations, U.S. Fish and Wildlife Service habitat evaluation procedures. |
| 7. Endangered and threatened species | Lists and descriptions of federal and state endangered, threatened, rare, and protected species and their critical habitat present in the region of the site; observations and reports of such species and habitats on the site or on other areas to be affected by the project. Formal consultation with the U.S. Fish and Wildlife Service is the responsibility of the federal action agency; an applicant, however, should provide any information obtained from initial contacts, including copies of any correspondence concerning the project. | Federal list of endangered and threatened species, published annually and updated as needed in the Federal Register; state lists of endangered and threatened species, generally published by state departments of fish and game or conservation; local chapters of organizations concerned with environment and conservation (e.g., the National Audubon Society or the National Wildlife Federation). |

Table A.1. Continued

| Category | Type of information | Possible sources of information |
|---|---|---|
| 8. Groundwater | Description of groundwater resources that might be affected by the project, including aquifer characteristics, flow system characteristics, competing water use and availability, water quality, and designation of any sole-source aquifer. | U.S. Geological Survey; U.S. Environmental Protection Agency; delegated state agencies for administering EPA permit programs; state geological survey; geologists and hydrologists at local and state colleges and universities; National Waterwell Association. |
| 9. Surface water | Description of surface water features that will be affected by the project; a map showing the drainage pattern of the site and its surroundings and onsite water bodies; data on water availability and water quality of affected water bodies. | USGS topographic maps; aerial photographs; comprehensive data bases such as Water Resources Abstracts, WATSTORE, NAWDEX, and STORET; state and federal agencies responsible for permitting, including U.S. Environmental Protection Agency, U.S. Army Corps of Engineers, and delegated state agencies; onsite observations. |
| 10. Climate and air quality | Climatic parameters, such as, average temperatures, relative humidity, precipitation, wind direction and speed, wind stability classes, mixing heights, fog occurrence, and meteorological extremes (e.g., tornado or hurricane frequency); identification of air quality control regions in which the site is located and those affected by emissions from the facility; description of the attainment or nonattainment status for the criteria pollutants; description of present ambient air quality; State Implementation Plan (SIP) restrictions; location of any Class I area (nondegradation areas, e.g., wilderness areas or national parks) affected by project emissions; discussion of trends in pollutant levels over time where data on air quality is readily available. | National Weather Service or Federal Aviation Administration stations; National Climatic Center, Asheville, North Carolina; local airports; U.S. Environmental Protection Agency or state agency delegated to administer air quality permits; other industrial or research facilities that collect climatic or air quality data. |
| 11. Noise | Existing ambient background noise levels on the site and in the vicinity; major existing or planned noise sources and sensitive receptors. | Onsite measurements; contacts with local and state agencies; examination of area maps. |
| 12. Socioeconomics | Definition of socioeconomic impact region; current and projected population and relevant demographic characteristics; local government revenues, expenditures, and revenue-sharing arrangements; current and projected housing capacity; current and planned public service capacity (water, sewer, transportation, police, fire, health, education, and welfare); economic structure and labor force characteristics; local government characteristics; local organizations and interest groups; social structure and life styles; local support or opposition to the proposed project. | U.S. Bureau of Census publications; pertinent government and private reports; academic reports - especially by local institutions; local newspapers; interviews with government officials, researchers, and interested parties; inspection of the site and region. |

# APPENDIX B

## OUTLINE FOR AN ENVIRONMENTAL ANALYSIS

This appendix describes one way of organizing an environmental analysis being prepared for submission to a government agency. Many agencies have specific format and information requirements. The organization presented here is generally compatible with these types of requirements. The amount of information that should be included in each section described below will depend on the type and size of the project and the significance of the anticipated environmental impacts.

### B.1 SUMMARY

A summary of the information contained in the environmental analysis should include a brief description of:

- the type of project,
- the processes to be used,
- principal emissions and discharges,
- major features of the site and other affected areas,
- the impacts that have been identified, and
- plans for mitigation and monitoring.

### B.2 DESCRIPTION OF THE PROPOSED PROJECT

This section should provide sufficient information on the physical plant, the process, and the waste streams (atmospheric emissions, liquid effluents, and solid wastes) to evaluate the environmental, health, safety, and socioeconomic impacts of the proposed project. Both onsite and offsite facilities and activities should be described.

#### B.2.1 Purpose and Need

The environmental analysis should discuss the purpose of the project, the types of products and by-products produced, and the intended market for the product. The type of government involvement should be clearly stated, and, in cases where an applicant is seeking financial support or approval, alternatives available if no support were to be provided should be discussed.

### B.2.2 Site Description and Location

The location of the site and its geographic context should be described. A general map at the state and/or regional level showing the location of the site and other affected areas should be provided. Also, United States Geological Survey (USGS) topographic quadrangle maps (preferably 7.5 min. scale) should be included showing the boundaries of the site and other affected areas.

### B.2.3 Plant Description and Site Plan

The environmental analysis should describe the facilities that are planned for the proposed project. In addition to the proposed facilities, existing facilities on the site, offsite ancillary facilities that will be required by the proposed project, and facilities that are included in any plans for future expansion should be described. For example, the following types of facilities should be described for a project that includes surface mining, separation, and upgrading operations:

- well field or surface mine;
- separation facilities;
- fluid coker;
- nitrogen generator;
- amine plant;
- hydrogen plant;
- hydrotreaters;
- Claus plant;

- steam and power generation plant;
- relief and blowdown system;
- tankage and interconnecting piping;
- raw and cooling water distribution systems;
- cooling towers and recycle water facilities;
- transmission lines, pipelines, access roads, and rail spurs;
- ash handling and disposal facilities;
- settling ponds and other waste disposal facilities;
- sewage treatment facilities; and
- fire protection facilities.

A site plan should be provided showing the layout of proposed facilities associated with construction and operation.

### B.2.4 Construction

Resources needed for constructing the proposed project should be described, including requirements for land, materials, water, labor supply, and community services (e.g., water treatment facilities, sanitary landfills, and roads). A diagram of the site showing the location of all construction activities (e.g., lay-down areas or construction waste disposal sites) and a proposed schedule showing the major phases of construction should be provided.

### B.2.5 Operation

A description should be included of materials, energy, and manpower required by the proposed project; the process flow; and the products, by-products, and waste streams produced by facility operations.

B.2.5.1 Resources

Resources needed for plant operation should be described, including:

- sources, amounts, and transportation of feedstocks;
- energy sources, water, and other materials (e.g., catalysts or injection fluids);
- labor requirements disaggregated by craft;
- labor availability and use; and
- availability of community services.

B.2.5.2 Plant design and process flow

The basic plant design and process flow should be described, giving an overview of the entire operation and emphasizing those steps in the process where inputs are required and effluents generated. Options available for such process steps as pollution abatement or well injection should be described briefly. Process flow diagrams should be included.

B.2.5.3 Wastes and effluents

Solid, liquid, and gaseous effluents and wastes should be characterized in terms of their composition and the quantities produced. Special emphasis should be given to toxic and hazardous substances. Plans for treatment and/or disposal should be described.

B.2.5.4 Schedule of operations

A schedule of operations that includes both the initial shakedown period and normal operations should be provided. Any future plans for expanding or reducing operations should be discussed.

B.2.5.5 Planned mitigation and monitoring

Mitigation measures (including reclamation plans) and monitoring programs that are part of the proposed project should be described.

This section should collate and summarize specific mitigation measures and monitoring programs that have been developed for each potentially significant issue and should also include a list of standard good management practices that will be implemented. Planned mitigation measures that will be implemented to minimize or avoid adverse impacts during construction, operation, and decommissioning should be described. In addition, a monitoring program should be presented showing the location of monitoring stations and the types and frequencies of data to be collected for each phase of project activity (i.e., preconstruction, construction, operation, and decommissioning). The environmental analysis should indicate how the monitoring programs during construction and operation are related and how they differ. A discussion should also be included of how the monitoring data will be evaluated and used and how permit monitoring requirements will be integrated into the overall program.

### B.2.6 Permits and Approvals

An environmental analysis should list, describe, and discuss the status of permits, licenses, and approvals required by federal, state, regional, and local agencies and Indian tribes. A list of agencies and persons contacted should also be provided.

## B.3. ALTERNATIVES

Comparison of the environmental impacts associated with project alternatives, including the proposed project, is usually an important part of an environmental analysis. The range of alternatives to be considered and the extent of the analyses required depend to some extent on previously conducted studies that may include generic or programmatic alternatives such as the use of alternative energy resources. If such studies are available, they may be incorporated by reference into the environmental analysis.

The analysis of alternatives should discuss those alternatives considered during project planning (including the no-action alternative), the environmental impacts associated with each alternative, and the selection process used to choose the proposed site and process design.

B.4. THE AFFECTED ENVIRONMENT

This section of an environmental analysis should describe the environment of the site and the region in sufficient detail to provide an overview of the environment that will be affected by the proposed project and general background information for evaluating potentially significant environmental impacts (Appendix A). The information prepared for this section should also be used to ensure that all potential environmental impacts have been identified and adequately evaluated.

B.5. POTENTIALLY SIGNIFICANT ISSUES

Each potentially significant issue that has been determined to be relevant to a particular project should be discussed in detail in this section. Baseline information should be presented in sufficient detail to permit an independent evaluation of the significance of project-related impacts by the agency to which the environmental analysis is submitted. An analysis of impacts should be presented, including an evaluation of their significance and a discussion of mitigation measures planned for minimizing adverse effects. Methods used in collecting and analyzing the data should be described. Lengthy discussions of methodology should be relegated to an appendix. Data summaries are generally appropriate for this section, but the actual data should be either incorporated into an appendix or assembled in a separate document that can be made available on request for agency review.