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Preparation of Environmental Analyses for Synfuel and Unconventional Gas Technologies

Robert M. Reed

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Roger L. Kroodsma	Martin Schweitzer
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PREPARATION OF ENVIRONMENTAL ANALYSES FOR SYNFUEL AND UNCONVENTIONAL GAS TECHNOLOGIES

MASTER

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ABSTRACT

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Government agencies that offer financial incentives to stimulate the commercialization of synfuel and unconventional gas technologies usually require an analysis of environmental impacts resulting from proposed projects. This report reviews potentially significant environmental issues associated with a selection of these technologies and presents guidance for developing information and preparing analyses to address these issues. The technologies considered are western oil shale, tar sand, coal liquefaction and gasification, peat, unconventional gas (western tight gas sands, eastern Devonian gas shales, methane from coal seams, and methane from geopressured aquifers), and fuel ethanol. Potentially significant issues are discussed under the general categories of land use, air quality, water use, water quality, biota, solid waste disposal, socioeconomics, and health and safety. The guidance provided in this report can be applied to preparation and/or review of proposals, environmental reports, environmental assessments, environmental impact statements, and other types of environmental analyses The amount of detail required for any issue discussed must, by necessity, be determined on a case-by-case basis.

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1. INTRODUCTION

Interest in alternative energy technologies in the United States has increased considerably within the last five years in response to federal programs for providing industry with financial assistance to build demonstration and commercial facilities. Government initiatives were primarily the responsibility of the U.S. Department of Energy until 1981 when the Synthetic Fuels Corporation took the lead. Although the pace of development has been relatively slow, there is little question that these technologies will make an increasingly important long-term contribution to the nation's energy supply.

The present report reviews environmental issues associated with six energy technologies, namely, western oil shale, tar sand, coal gasification and liquefaction, peat, unconventional gas, and fuel ethanol. Although other technologies and resources could be included in this review, most of the effort in research, development, and commercialization is likely to be focused on these technologies because the resources are the most readily available and/or the technology is either the most promising or farthest along in development.

The purpose of this report is to provide guidance to government agencies, contractors, and industrial applicants for reviewing the environmental effects of proposed projects to comply with the National Environmental Policy Act of 1969. The report identifies potentially significant environmental issues that are likely to be encountered for the six technologies noted above and provides a generic discussion of the types of information and analyses needed to evaluate each issue. In addition, Appendix A discusses the acquisition of information for describing the affected environment and for providing baseline information needed to assess potentially significant impacts.

A major problem in conducting an environmental review of a proposed project is selecting those isssues that are potentially significant and that need to be carefully considered in decisions on project approval. If an environmental impact statement is being prepared, a scoping process will be conducted to determine which issues need to be considered in detail. If an environmental assessment or some other type of environmental review is being prepared, available information on the proposed project and on the site should be thoroughly reviewed to identify issues that deserve detailed analysis. The guidance contained in this report should assist project and agency staff in preparing and reviewing environmental analyses contained in proposals, environmental reports, and other types of environmental documents. Additional guidance for selecting the pertinent issues to be addressed should come from consultations with appropriate state and federal government offices and from discussions with other interested parties.

Although some of the issues discussed in this guidance document may not be applicable to a particular project, they should all be considered during the environmental review. If certain of these issues are not considered to be relevant to the project in question, the reasons for not providing a detailed analysis should be documented.

The format and content of environmental analyses required by different government agencies vary considerably. Some agencies such as the Nuclear Regulatory Commission have well-defined requirements for the development and submission of environmental information in a document known as an environmental report (10 CFR Part 51). Other agencies, however, have not defined specific requirements but define information and analysis needs on a case-by-case basis. Appendix B of this report presents an outline of an enviromental analysis that is generally consistent with most agency needs. Although this outline defines basic categories of information that are usually needed, each agency should be consulted about specific requirements early in the process. The outline contained in Appendix B will serve as a good basis for these initial discussions.

2. WESTERN OIL SHALE

Michael J. Sale,[1] Elizabeth L. Etnier,[2] Martin Schweitzer,[3]
and E. Douglas Waits[4]

2.1 RESOURCE DESCRIPTION

Oil shale is a fine-grained sedimentary rock containing a solid hydrocarbon called kerogen. By pulverizing the raw ore and heating it to temperatures greater than 450°C, the kerogen is decomposed to form hydrocarbon gases and liquids which, upon condensation, yield shale oil. The richest oil shales can contain a petroleum equivalent of 125 L/Mg (30 gal oil/ton shale) or more.

Four types of oil shale are found in the United States: (1) Tertiary period, lacustrine marlstones (not true shales) in the Green River Formation of Colorado, Utah, and Wyoming; (2) marine shales of the late Devonian and early Mississippian periods located across several mideastern and central states, from Michigan and Pennslyvania down to Oklahoma and Texas; (3) Mesozoic deposits of marine shale in Alaska; and (4) small deposits of Permian shales scattered through western Montana, Idaho, Nevada, and southern California.

Because the high-grade oil shale resources in Colorado, Utah, and Wyoming will most likely be the first developed in this country, the guidance is restricted to projects in the western United States. The largest concentration of high-grade oil shale is in the Green River Formation, a 44,000-km^2 (17,000-sq. mile) area in northwestern Colorado, northeastern Utah, and southwestern Wyoming. This western oil shale region contains over 90% of the total estimated U.S. resource, having yields greater than 42 L/Mg (10 gal/ton) (Bates and Thoem 1980).

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The oil shales of the Green River Formation are separated into four geologic basins (Fig. 1): the Piceance Basin in west-central Colorado, the Uinta Basin in Utah, the Green River Basin in Wyoming, and the Washaki/Sand Wash Basin in Wyoming and northwestern Colorado. The oil shale resource of the Piceance Basin is significantly greater than that of any of the other basins in terms of yield (Table 1) and thickness of the deposits [greater than 300 m (1000 ft) in places].

Colorado oil shale typically has an average organic content of 16.5% embedded within an inorganic, marlstone matrix of dolomite, calcite, and quartz. Because these deposits may be associated with

Table 1. Oil shale resource estimates in the Green River Formation

Grade	Oil shale yield	Piceance Basin (Colorado)	Uinta Basin (Utah)	Green River, Washakie, and Sand Wash basins (Wyoming and Colorado)
			$\times 10^9 m^3$ (10^9bbl)	
I	63 to 104 L/Mg (15 to 25 gal/ton)	191 (1200)	51 (321)	51 (321)
II	104 to 125 L/Mg (25 to 30 gal/ton)	97 (607)	10 (64)	10 (60)
III	more than 125 L/Mg (more than 30 gal/ton)	56 (355)	8 (50)	2 (13)
	Total resource	344 (2162)	69 (435)	63 (394)

Source: Bates and Thoem (1980).

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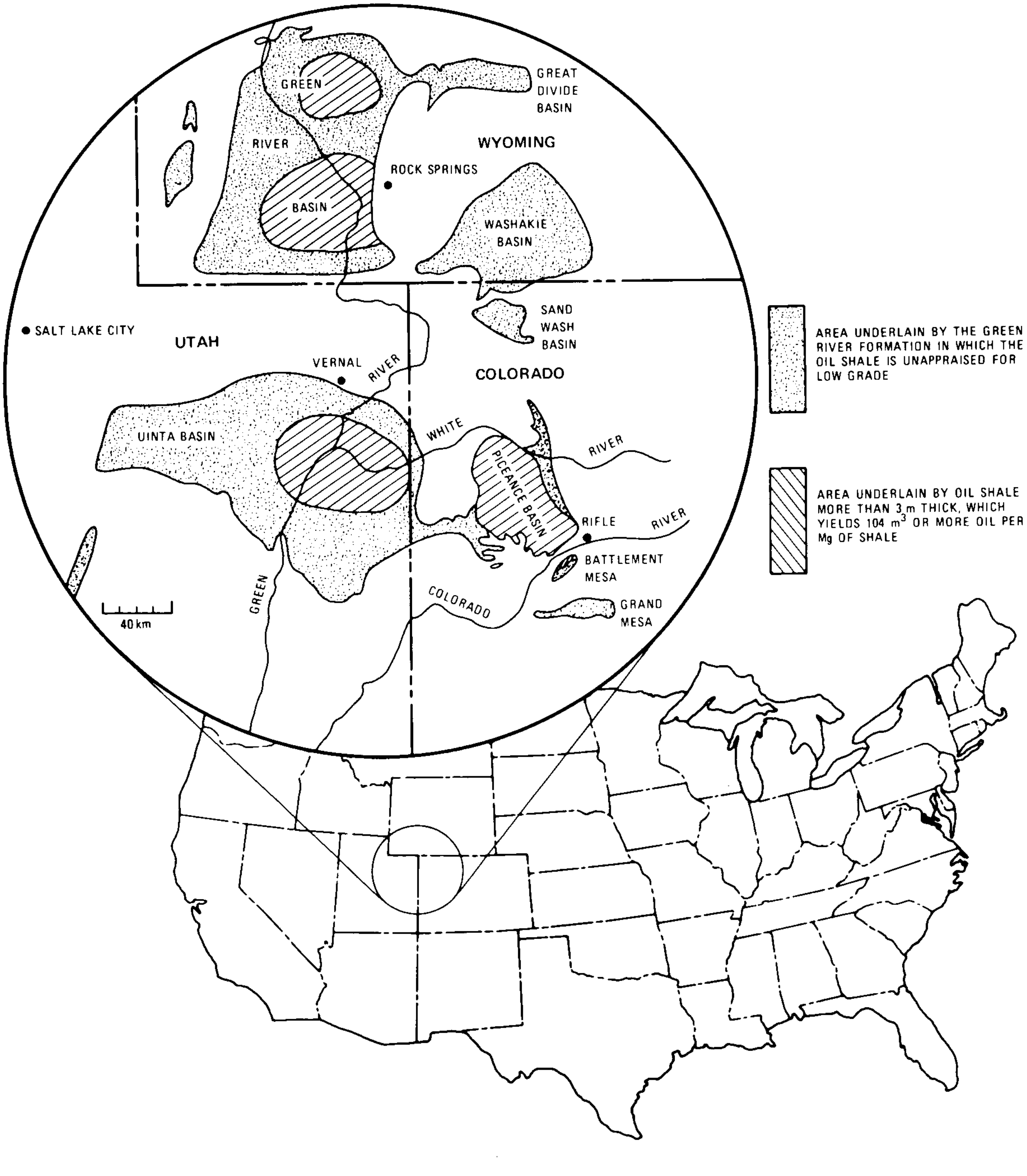

Fig. 1. Western oil shale deposits (modified from OTA 1980).

sodium-bearing minerals of commercial value, including nahcolite (sodium bicarbonate or baking soda), trona (a hydrated mixture of sodium bicarbonate and sodium carbonate) and dawsonite (dihydroxy sodium aluminum carbonate), oil shale development may include multimineral projects that simultaneously produce shale oil, soda, ash, and alumina (OTA 1980).

This hydrocarbon resource is becoming an increasingly attractive alternative to foreign oil imports and is expected to receive much pressure for development in the near future (Bates and Thoem 1980, NAS 1980, OTA 1980). Depending on economic conditions and world oil prices, the production of synthetic fuels from the western oil shale industry is expected to be in the range of 16,000 to 32,000 m^3/d (100,000 to 200,000 bbl/d) by 1990 and possibly as much as 95,000 m^3/d (600,000 bbl/d) by 1995 (Schramm 1980). Because the oil shale deposits in the Green River Formation are rich and accessible, this area is receiving the most attention from the emerging oil shale industry.

2.2 TECHNOLOGY OVERVIEW

The production of crude shale oil is based on a pyrolysis reaction in which the kerogen is decomposed into long-chain hydrocarbon molecules. This decomposition process is referred to as retorting and takes place at temperatures in excess of 450°C either in closed reactor vessels above ground or in specially prepared zones of underground deposits. The specific characteristics of shale oil can be quite variable, depending on the conditions under which pyrolysis takes place (Table 2). Raw shale oil, spent shale residue, and pyrolysis gases are the major products that result from the retorting process. Major processing stages common to all oil shale technologies are (Fig. 2): (1) mining and/or preparation of raw shale, (2) retorting, (3) upgrading and refining of the crude shale oil, and (4) transportation of the finished product. One of the principal differences among existing technologies is the type of retort process

Table 2. Properties of crude shale oil from various retorting processes (OTA 1980)

Retort	Aboveground processes												In situ processes				
	Fisher assay		NTU		Gas combustion		TOSCO II		Union Oil "A"	Union Oil "B"	Paraho direct		Occidental oil shale			U.S. Bureau of Mines	
Carbon, weight %	84.59	-	84.61	84.58	83.92	-	85.1	-	84.0	84.80	84.90	-	84.86	-	-	84.60	-
Hydrogen, weight %	11.53	-	11.40	11.76	11.36	-	11.6	-	12.0	11.61	11.50	-	11.80	-	-	12.08	-
Oxygen, weight %	-		1.10	-	1.67	-	0.8	-	0.9	0.90	1.40	-	1.13			1.18	-
Nitrogen, weight %	1.96	2.20	2.10	1.77	2.14	2.12	1.9	1.85	2.0	1.74	2.19	2.00	1.50	-	-	1.55	1.41
Sulfur, weight %	0.61	0.92	0.79	0.76	0.70	0.68	0.9	0.67	0.9	0.81	0.61	0.71	0.71	-		0.59	0.72
Carbon/hydrogen ratio	7.34	-	7.42	7.19	7.39	-	7.34	-	7.0	7.30	7.38	-	7.19	-	-	7.00	-
Gravity, °API	-	19.4	20.3	25.2	19.8	21.1	21.2	-	18.6	22.7	19.3	-	25	-	24.3	28.4	28.4
Specific gravity	0.92	-	-	-	-	-	0.93	0.93	-	0.81	0.94	0.94	0.90	-	-	0.89	-
Pour point, °C	27	27	32	21	29	29	27	-	27	16	29	-	4	-	18	4	4
Arsenic, ppm[a]	-	-	-	-	-	-	-	-	-	-	19.6	-	-	-	-	-	-
Nickel, ppm	-	-	-	-	6.4	-	6	-	6	-	2.5	-	-	-	-	-	-
Iron, ppm	-	-	-	-	108	-	100	-	55		71.2	-	-	-	-	-	-
Vanadium, ppm	-	-	-	-	6.	-	3	-	1.5	-	0.37		-	-	-	-	-
Distillation, volume %																	
5 @ °C	-	-	-	-	192	229	93	-	199	-	-	-	-	204	207	-	16
10 @ °C	163	256	-	-	226	258	135	182	241	204	271	277	227	238	-	194	327
20 @ °C	221	293	-	-	276	309	210	249	296	-	316	321	-	271	-	207	342
30 @ °C	270	-	-	-	319	353	260	316	338		360	360	316	299	316	-	352
40 @ °C	-	-	-	-	359	394	327	366	377	-	399	396	-	327	-	173[b]	361
50 @ °C	346	354	-	-	395	431	371	416	413	388	432	429	371	360		191[b]	371
60 @ °C	363	367	-	-	429	463	413	460	443		449	460	-	379	-	213[b]	389
70 @ °C	374	-	-	-	463	492	454	502	527	-	-	488	410	407	-	240[b]	409
80 @ °C	-	-	-	-	502	529	493	549	-	516	-	527	-	441	443	276[b]	432
90 @ °C	-	-	-	-	554	574	-	-	-		-	560	493	488	-	-	464
95 @ °C	-	-	-	-	593	-	-	-	-	-	-	-	-	566	538	-	490

[a] Parts per million.

[b] Vacuum distillation at 40 mm of mercury. All other results are from atmospheric distillation.

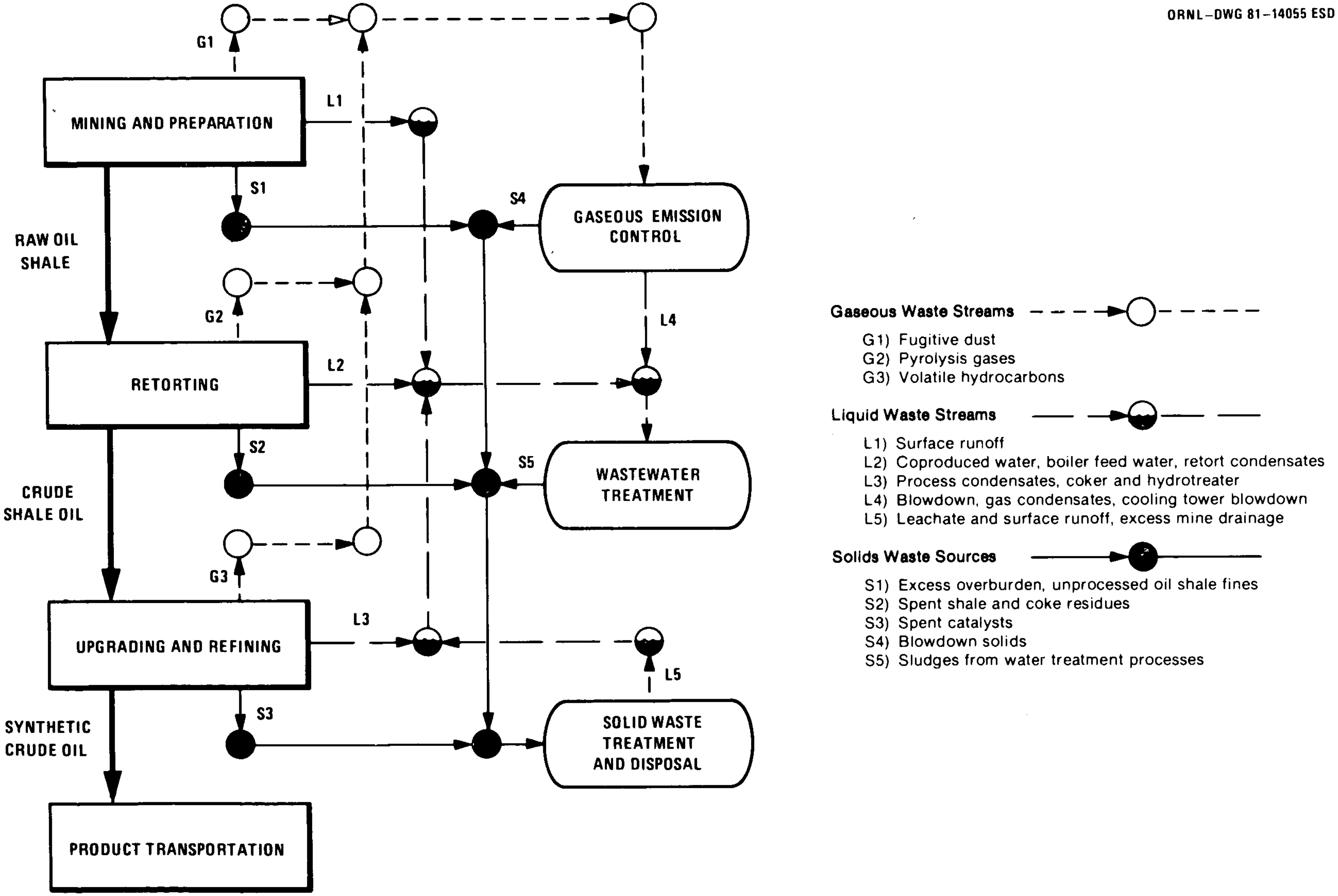

Fig. 2. Generalized oil shale flow diagram.

used. Three alternative approaches have been developed: aboveground retorting (AGR), true in situ (TIS) processing, and modified in situ (MIS) processing. The in situ processes are advantageous in that they require much less mining and transport of the raw shale. At the present stage of develoment, however, the TIS and MIS technologies are less efficient and more unpredictable than the AGR approach.

2.2.1 Mining

Mining activities associated with western oil shale development are likely to become some of the largest in the world. Both surface and underground mining will be required. In the Piceance Basin, 80% of the high-grade shale lies in deep deposits in the central part of the basin and, therefore, will require some type of underground mining methods or in situ extraction (Bates and Thoem 1980). Potential MIS and AGR oil shale mining operations required to produce 8000 m^3/d (50,000 bbl/d) from 125-L/Mg deposits would require mining shale at the rate of 26,000 to 64,000 Mg/d (29,000 to 70,000 ton/d), respectively. As the incentive to produce domestic shale oil increases, mining operations of even greater size will be contemplated.

2.2.2 Aboveground Retorting (AGR)

The AGR process relies on shale ore extraction by conventional surface or underground mining techniques. Open-pit mining may be suitable for relatively shallow deposits, while deep, high quality deposits may be profitably mined using the room and pillar underground mining technique. The mined ore is moved to the surface retorting facility where it is crushed and sized. The retorting process heats the ore to temperatures of at least 450°C to bring about pyrolysis of the kerogen and the production of oil and gas. This heating process may be either direct, creating a combustion zone within the retort itself, or indirect, using an external reactor or combustor to transfer heat to an internal retort (e.g., indirect heating in the TOSCO II AGR retort which uses hot ceramic balls to transfer heat into the reactor). Once oil and/or gas are obtained from the retort, they are usually upgraded and transported to a refinery for further processing. Recovery efficiencies as high as 100% have been demonstrated using AGR (OTA 1980). Commercial-scale equipment and operations, however, have yet to be successfully developed. The major disadvantage anticipated for using the AGR approach is the extensive surface disturbance caused by mining and disposal of shale wastes. Approximately 85% of the total weight of the initial shale remains after retorting and cannot be returned in its entirety to the mines from which it was extracted.

2.2.3 True In Situ (TIS) Retorting

The TIS approach heats the shale underground and recovers the oil and gas produced from holes drilled into the shale formation. The technique requires a minimum of conventional mining operations but instead utilizes natural or man-made fractures to provide access for injecting hot fluids or igniting a portion of the bed to provide heat for pyrolysis. Fracturing ("rubbling") of the shale may be necessary to promote permeability and fluid flow. Dewatering may also be required to remove groundwater prior to beginning the TIS operation.

The TIS is the least developed of the three technologies. Experimental results indicate that TIS will produce the lowest yields of the three retort processes unless significant advances can be made. A major advantage of the TIS process is that surface disturbance from mining and raw shale waste disposal are limited or nonexistent. Subsidence and potential contamination of groundwater are two potential areas of concern for TIS projects.

2.2.4 Modified In Situ (MIS) Retorting

The MIS technology relies on limited mining and underground explosions to reduce a section of an oil shale formation to rubble. Twenty to forty percent of the shale in the MIS retort zone is removed by underground mining to provide a void space for expansion of rubblized shale. Compared to the undisturbed oil shale, the increased surface area of this rubble zone allows relatively efficient retorting to occur. Access holes for air, exhaust, and oil and gas extraction are drilled into the rubble site. A combustible gas is introduced through an access hole to ignite the shale, and subsequent combustion is supported by hydrocarbons released from the shale during pyrolysis. Once combustion occurs, it soon becomes spontaneous and the flame front moves through the rubble, retorting the oil shale as it passes. Oil collects at the bottom of the rubble and is then pumped to the surface.

A major problem with MIS retorting is the limited control of in situ pyrolysis reactions that is achieved once combustion is initiated. Available control variables are the inflow of combustion gases, the pattern of rock fractures created in rubblization, and the size of the void space created in initial mining. Recovery efficiency is much lower compared to AGR because pyrolysis is incomplete and pillars within the shale deposit are left undisturbed for support. In situ project efficiencies can be increased when AGR is used to process the shale removed to provide the void spaces.

2.2.5 Upgrading and Distribution

Although the characteristics of raw shale oil (Table 2) depend on the recovery technology used, upgrading will be necessary because raw shale oil has a high pour point, viscosity, and nitrogen and oxygen content. The shale oil may either be converted to an intermediate product suitable for pipeline transport to offsite refineries, or it may be refined directly into finished products such as gasoline, diesel oil, aviation fuels, or heavy fuel oil. One reason for the initial upgrading of the crude shale oil is to remove undesirable constituents such as sulfur or heavy metals that can poison the catalysts used in the refinery process. Western shale oil is a desirable source of refinery feedstocks because it has a relatively low boiling point and contains lower residuals than either Alaskan North Slope or Arabian light crude oils.

2.3 POTENTIALLY SIGNIFICANT ISSUES

The environmental analysis should describe and analyze potentially significant environmental impacts associated with construction, mining, operation, and reclamation of proposed oil shale projects. In addition, information gathered on the affected environment should be reviewed to determine if any additional significant or controversial issues are apparent. For example, the review of background information on the affected environment may show that an historic site, portions of a 100-year floodplain, or a site of religious significance to local Indian tribes is present on the project property. In such a situation, the information content and analysis of the issue should be expanded.

The issues discussed in the following sections are most likely to be significant for oil shale projects and should be carefully reviewed.

2.3.1 Land Use

The development of western oil shale resources may be hindered by the complex pattern of federal, state, private, and Indian land ownership and mining claims (OTA 1980, NAS 1980, U.S. DOI 1973). Nearly 80% of the deposits in Colorado, Utah, and Wyoming lie beneath federal lands. Most of the private mining claims scattered throughout the region are located on small, noncontiguous tracts in areas having relatively low-grade resources. Full-scale commercialization is currently being delayed for a variety of reasons, including litigation over conflicting mining rights, lack of adequate economic incentives, negotiations for private or public land exchanges which could allow industry access to more desirable oil shale tracts, and uncertainties over design and productivity of available technologies.

Land use in the oil shale region is somewhat restricted by the rugged terrain and low annual precipitation. Most of the land is used for rangeland, watershed protection, recreation, wildlife, hay, and limited gas production. Commercial-scale oil shale development is likely to generate land-use conflicts when range, timber, mineral, and recreational lands are disrupted by mining, processing, and waste disposal operations, by the development of associated urban areas, and by secondary developments.

The amount of land surface disrupted by a commercial-scale oil shale operation will vary depending on the mining and retorting technology used and the approach adopted for disposing of spent shale. Surface mining and AGR operations are likely to have the greatest impact because the areas disrupted by mining and waste disposal will be large (OTA 1980). A facility using surface mining, retorting, and surface disposal of spent shale could disrupt hundreds to thousands of hectares of land.

The presence of significant archaeological and historic sites, Indian lands, national monuments, and other scenic and recreation areas either on or near the potential oil shale lands may conflict with development of specific projects. The aesthetic impacts of oil shale development are also likely to be severe because the oil shale region is rural and relatively undeveloped.

In addition to general baseline information, the analysis of land-use conflicts should provide detailed information on:

- present and planned land use for the project site and surrounding areas;
- present and projected land ownership;
- national parks, landmarks, and monuments, recreation areas, existing or proposed wilderness areas, and scenic, historic, or archaeologic sites in the vicinity of the project;
- visibility of the proposed site and associated facilities from public use areas, such as trails, canyon overlooks, and picnic/camping areas; and
- Indian-owned lands and areas sacred to local Indian tribes.

A land-use map showing the potential routes for heavy equipment and construction traffic associated with the project should be provided. The possibility of adverse effects from increased traffic through sensitive land-use areas (e.g., Indian lands or wilderness areas) should be addressed.

2.3.2 Air Quality

Atmospheric emissions will be generated from mining, processing, retorting, and waste disposal (Table 3). Because the mining operations will be novel only with respect to scale, control of particulate and dust emissions from raw shale mining, blasting, conveying, crushing, and screening can draw on experience with existing practices. The environmental analysis should characterize and quantify, to the extent possible, fugitive dust emissions from all sources (including disposal of spent shale) and describe plans for controlling fugitive dust.

Spraying rates should be carefully controlled because the use of water sprays along with other wetting agents to control fugitive dust will contribute to overall water needs of the project and may contribute to water pollution problems by increasing runoff and leaching. If recycled water is used in dust control, the chemical composition of the water becomes another potential problem in terms of uptake of toxic chemicals by vegetation and contamination of runoff waters. The plans for fugitive dust control should include a discussion of the use of water sprays and wetting agents and should address the problems of controlling contaminated runoff and uptake of toxic chemicals by vegetation.

Stack emissions will include particulates, sulfur oxides, oxides of nitrogen, hydrocarbons, and carbon monoxide as well as organic compounds such as polycyclic aromatic hydrocarbons (PAHs). Control of these pollutants is common to other industries (e.g., oil refineries), but the introduction of new pollutant sources into an area of the western United States with good ambient air quality will require careful analysis.

Individual commercial-scale plant emissions can probably be controlled by state-of-the-art pollution abatement technology. However, the cumulative impacts of a number of oil shale facilities, as well as other emission sources, may affect nearby Class I air quality regions. The cumulative impacts of nearby energy or mineral developments may severely limit the availability of Prevention of Significant Deterioration (PSD) increments and constrain the development of the oil shale resource.

Table 3. Summary of atmospheric emissions and sources.[a]

Atmospheric emissions	Mining activities	Transportation of raw shale	Preparation of shale	Retorting operations	Upgrading and refining	Pollution control tail gases	Solid waste disposal	Product distribution	Estimated release (Mg/d)[b]
Particulates									0.3-7.8
Fugitive dust	*	*	*	+			*	+	
Soot and ash				*	+	+			
Spent shale dust				+			*		
Carbon monoxide (CO)	+	+		*	*	+	+	+	0.4-1.9
Nitrogen oxides (NO_x)	+	+		*	*	+	+	+	6.2-64.0
Sulfur dioxide (SO_2)	+	+		*	*	+	+	+	0.2-58.0
Hydrocarbons	+	+		*	*	+	+	+	0.3-28.0
Mercury	+			+					
Lead	+			+					
Silica	+	+	+						
Trace elements									
(Ni, Cr, Fe, Mo, etc.)				*			+		
Hydrogen sulfide				*		+			
Organo-sulfide						+			

[a] + = minor source; * = major source.

[b] SOURCE: Bates and Thoem (1980).

General background information should be expanded to provide specifics on the following:

- all affected Air Quality Control Regions (AQCRs), with special emphasis on Class I areas;
- local meteorology (local airport data and onsite measurements), emphasizing those features that affect the dispersion of anticipated emissions;
- local air quality (U.S. EPA and/or state monitoring data; monitoring data from nearby facilities, as available; onsite baseline monitoring data, if required by state or federal agencies);
- proposed use of air pollution control devices, including an estimate of efficiency and downtime;
- characterization of atmospheric emissions and quantification of emission rates from both construction and operation activities;
- modeling of atmospheric dispersion;
- analysis of the effects of the project on visibility to the extent required by State Implementation Plans;
- identification of unknowns and uncertainties associated with the characterization and dispersion analysis of atmospheric emissions;
- identification of sensitive areas, both on and off the site (e.g., sensitive plant species or vegetation types) that may be affected by atmospheric emissions; and
- proposed air quality monitoring program.

2.3.3 Water Use

The availability of adequate water supply can be a significant limiting factor in the development of all types of energy resources in the arid, western United States. Therefore, careful consideration of interactions between project development and local or regional water resources must be a specific component of any environmental analysis for oil shale projects. Water quantity requirements included in a description of project construction and operation should be expanded toindicate the resource needs of various consumptive and nonconsumptive water uses. Plans for meeting these water needs should then be identified in the form of a comprehensive water management plan. Among the water-use categories that should be quantified are the following (Kinney et al. 1979):

- mining and delivery of raw shale,
- crushing and preparation of raw shale,
- retorting processes,
- upgrading processes,
- gas cleanup and pollution control processes,
- disposal of spent shale,
- reclamation and revegetation,
- power generation, and
- domestic consumption.

Water management plans should specify the sources for satisfying the requirements of each water-use category. More specifically, information should be provided to identify:

- surface water sources to be utilized, including descriptive hydrology of the watershed and planned withdrawal rates;
- groundwater sources to be utilized, including aquifer description and safe yields;
- dependence of project water sources on the construction of related water development projects;
- interrelationships between groundwater sources utilized and surface water, including other aquifers or recharge zones that might be affected by the project; and
- institutional, legal, and political arrangements involved in obtaining water supplies, including documentation of appropriate water rights, entitlements, or permits.

In considering institutional, legal, and political aspects of obtaining water, attention should be given to the quantity and projected sources of water over the estimated life of the project. State and federal water law governing the use of water in the Upper Colorado River Basin should be described in relation to the proposed project (OTA 1980). Specific institutional and legal arrangements for obtaining water from each of the designated sources should be specified. The availability of sufficient water supplies over the life of the project should be estimated. Where high and low estimates indicate a potential shortage, the competing uses for the water (e.g., irrigation, urban use, and industrial use), with their priorities and constituencies, should be described. Discussion of the legal, institutional, and economic arrangements for allocating scarce water, as well as developing additional sources (e.g., through interbasin diversion), should be included. In summary, it is necessary to describe both the societal and the physical arrangements for retaining water supplies over the life of the project.

The quality of water sources should be described to ensure that it meets project requirements. Necessary water treatment should be described. The project proponent should evaluate all opportunities for water recycling and conservation within the project design and should emphasize the consideration of these alternatives. Zero-effluent operations that maximize water reuse are desirable, both in terms of reducing impacts on ambient water quality and conservation of regional water resources (Bates and Thoem 1980).

2.3.4 Water Quality

Potential degradation of ambient surface or groundwater quality is another important issue associated with oil shale development. Even projects with zero-effluent designs under normal operating conditions should consider the implications of effluents released during abnormal operating periods (e.g., startup, shutdown, or equipment failures) or peak runoff events (Bates and Thoem 1980). Wastewater collection, treatment, and disposal, as well as any pollution mitigation plans, should be described in detail to ensure that all possible efforts are made to minimize the likelihood of adverse impacts on water quality. Table 4 summarizes the important constituents and sources of wastewater effluents from oil shale projects.

The effects of oil shale projects on groundwater resources can be direct or indirect. Direct effects include water quality changes caused when reinjection is used as a disposal method for mine dewatering effluents or by leachate from surface water percolation through solid waste disposal areas or MIS rubble zones. Indirect effects include the results of disrupting relatively impermeable shale layers, changing the interaction between existing aquifers of different water qualities. Even though these effects may involve questions beyond the present knowledge of the groundwater sciences, they should be addressed in project planning. Monitoring programs should be designed for early detection of significant impacts (Slawson 1979).

Special attention should be paid to describing the fate of toxic compounds known to have potentially high concentrations in effluents (Bates and Thoem 1980, Kinney et al. 1979). The environmental analysis should compare the expected composition of toxic compounds in receiving systems to baseline conditions and to applicable state and/or federal water quality standards. For a description of surface runoff and leachates, the chemical composition of raw and spent oil shales should be described, and the results of studies on leaching from these materials should be presented. It is desirable that composition and quantities of raw materials and effluents be described in sufficient detail to account for approximate material balances through a process flow diagram.

Guidance provided by the U.S. Environmental Protection Agency for Best Available Technologies and Best Management Practice in oil shale development suggests the following (Bates and Thoem 1980):

- no discharge of retort or oily process water,
- reinjection of mine water into aquifers having similar water quality,

Table 4. High-priority water quality parameters associated with impacts from oil shale projects

Parameters	Mine Drainage and Dewatering	Leachate and Runoff from Shale Piles	Cooling Water and Boiler Blowdown	Process Condensates (Retort and Refinery)	Air Emission Treatment Processes	Spent Catalyst Disposal
Alkalinity	*	*				
Aluminum (dissolved and total)		*				
Ammonia				*	*	
Arsenic		*				*
Boron		*				
Cadmium		*				
Calcium	*	*	*			
Chemical oxygen demand		*		*	*	
Chloride					*	*
Chromium			*			
Conductivity	*	*				
Copper		*				*
Cyanide					*	
Fluoride		*				
Hardness	*	*	*			
Iron		*				*
Lead		*				
Magnesium		*				
Manganese		*				
Mercury		*				
Molybdenum		*				*
Nickel						*
Nitrate		*				
Oil and grease		*		*		
pH		*				
Phenols (total phenolics)		*		*	*	
Polycyclic aromatic hydrocarbons (PAH)		*		*	*	
Potassium		*				
Selenium		*				
Sodium	*	*	*			
Sulfate		*	*			
Sulfide					*	
Temperature			*	*		
Total dissolved solids (TDS)	*	*	*			
Total suspended solids (TSS)	*	*				
Turbidity	*	*				
Zinc		*				*
Vanadium		*				

SOURCE: Kinney et al. (1979).

- diversion of surface runoff from process areas,
- collection of runoff from disturbed areas into sedimentation ponds,
- collection and containment of leachate and runoff from spent shale disposal sites and raw shale stockpiles,
- effluent TDS concentrations limited to 0.9 Mg/d (1.0 ton/d), and
- whenever practicable, treatment of process water before its disposal on spent shale piles.

Compliance with or deviation from these suggested practices should be clearly stated.

2.3.5 Impacts on Biota

Development of oil shale resources may have major effects on terrestrial and aquatic plant and animal communities and their associated habitats. Direct effects on biotic communities will be exacerbated by indirect effects related to the large population influx associated with the labor force. Effects on natural communities may be long term and may be cumulative with those from other energy developments (e.g., uranium, tar sands, and coal). The development and increased human presence associated with energy facilities could severely affect indigenous species (such as raptors) that are particularly sensitive to disturbance. Habitat destruction, increased legal and illegal hunting pressure, and increased mortality (e.g., road-kills and bird collisions with new power lines) may adversely affect wildlife populations.

Potential impacts on aquatic biota may result directly from project mining, construction, and operation or indirectly from the alteration of watershed hydrology. Increased erosion and sedimentation may degrade water quality in local streams. Water withdrawals may alter instream habitat, as well as lead to an increase in total dissolved solids concentrations in downstream portions of the Colorado River watershed (Bates and Thoem 1980). Toxic waste effluents may result in either acute or chronic stress on plankton, macrophyte, invertebrate, or fish populations.

Using baseline information on the affected environment, site survey data, and the project description, the environmental analysis should:

- describe the terrestrial and aquatic biota that may be affected, giving special attention to endangered, threatened, rare, or otherwise protected plant and animal species;
- characterize by dominant species and physical features all terrestrial and aquatic habitat types that will be disturbed;
- estimate the number of hectares of each type of habitat that will be disturbed during mining, construction, and operation;
- describe those features of reclamation plans for all disturbed areas that are designed to promote reestablishment of biotic communities, habitat features, and natural processes;
- evaluate the effects of the composite toxicity of individual waste effluents, and, where applicable, combined waste effluents on species of plants, invertebrates, fish, etc.; and
- include results of consultation with state and federal fish and wildlife agencies and conservation personnel.

2.3.6 Solid Waste Disposal

Successful disposal of the vast amounts of solid wastes produced by commercial oil shale projects is a major challenge. Because there is no previous experience with commercial-sized projects analogous to those proposed for western oil shale, careful planning will be required to prevent contamination of ground and surface waters and to achieve long-term stabilization and reclamation of spoil disposal areas. A western oil shale industry producing 1.6 x 10^5 m^3 (1 x 10^6bbl) of shale oil per day might process 450 x 10^3 Mg (500 x 10^6 tons) of shale per year and require the disposal of about 360 x 10^3 Mg (400 x 10^6 tons) of solid waste (Moore and Mills 1977). Four types of solid wastes will be generated:

- fine particles of unprocessed shale generated during crushing operations,
- spent catalysts utilized in the numerous steps of upgrading or waste treatment process,
- spent shale that remains after retorting, and
- sludge from wastewater treatment process.

Catalysts are used in many stages of shale oil production, including hydrogenation steps in upgrading and the unit processes associated with the treatment of waste streams (e.g., Claus processes to remove sulfur). Guard beds of metalic elements used to trap hydrogen sulfide also have limited life spans and will produce solid wastes which must eventually be disposed. Because these spent catalysts include potentially toxic heavy metals (e.g., nickel, cobalt, copper, zinc, and molybdenum), special provisions must be made for their disposal (Bates and Thoem 1980). Regeneration and reuse of spent catalysts are preferable to their disposal in spent shale piles.

Most current oil shale development plans call for the disposal of spent shale in isolated gullies or canyons. The primary effects of the surface disposal of spent shale include changes in the landscape, disruption of existing land uses, loss or significant modification of natural ecosystems, and degradation of water and air quality by erosion and leaching. Secondary impacts such as creation of fugitive dust or leachates that affect not only the immediate area but also the surrounding region can also contribute significantly to water quality degradation.

The sludges produced from the treatment of liquid waste streams coming from the retort and upgrading processes will contain elevated concentrations of insoluble inorganic materials and trace elements. Because most of the toxic constituents in wastewaters (Table 4) will also be present in these sludges, but in more concentrated forms, their disposal should be given special attention and integrated with the overall project plan for solid wastes and hazardous materials.

Solid wastes generated at all stages in oil shale processing should be described. Disposal sites and methods for handling and treating wastes from all sources should be identified. The reclamation plan presented in Sect. 2.3.7 should be clearly linked to the discussion of solid waste disposal. Guidance from the Environmental Protection Agency for Best Management Practices for solid waste disposal (Bates and Thoem 1980) calls for the following:

- record keeping and reporting of all hazardous wastes produced,
- isolation and containment of all hazardous wastes,
- impermeable layers (e.g., clay lenses) below spent shale piles and other waste disposal areas to protect against groundwater contamination, and
- avoidance of the 100-year floodplain, wetlands, critical wildlife habitat areas, and recharge areas for sole-source aquifers in locating disposal areas.

The interpretation and applicability of the Resource Conservation and Recovery Act (Pub. L. 94-580) should be determined by consultation with appropriate state and federal agencies. A summary of the results of these consultations should be included.

2.3.7 Reclamation

Reclamation of mined land and spent shale disposal areas is a major undertaking for any oil shale operation. Plans for reclamation should be described in detail. The objectives of reclamation should be to (1) reduce water and wind erosion from the disturbed landscape, (2) restore the disturbed areas to productive use, and (3) ensure that long-term contamination of ground and surface waters by leachates from the reclaimed areas does not occur.

Reclamation plans should include all areas disturbed during construction and operation of the proposed facility and describe:

- the location of all areas to be reclaimed (a map should be provided);
- handling and storage of topsoil;
- soil amendments to be used;
- irrigation plans and water sources;
- cover species to be used.
- measures to protect the reclaimed areas from grazing for sufficient time to allow establishment of new vegetation;
- a monitoring program to evaluate long-term success of reclamation; and
- schedule for implementation of specific portions of the plan.

2.3.8 Socioeconomics

Significant socioeconomic impacts may result from the development of an oil shale industry. Near-term development of oil shale is most likely to occur in the Piceance Basin of northwestern Colorado, which is rural and sparsely populated, as is true of the rest of the western oil shale region. Of the 12 towns that are likely to be affected by oil shale development in the Piceance Basin, only one has a population of over 5000.

Boomtown effects on small communities resulting from a rapid and large population influx have been demonstrated in the western coal regions (Gilmore and Duff 1975). Housing and municipal services in small communities are often insufficient to handle large population increases (Cortese and Jones 1979). Tax revenues from the energy facilities lag several years behind the rise in local government expenditures required to meet increased demand for services and may not reach all, or even most, of those jurisdictions experiencing project-induced impacts. High-paying energy jobs draw labor away from lower-paying local employers and local inflation may occur, causing particular damage to low income residents and those on fixed incomes. Rapid population increases may be accompanied by cultural disruptions and a rise in crime rates. Population increase can also exacerbate effects from the energy development itself on air quality, water availability and quality, and surrounding natural habitats. Effects from development of oil shale resources may also be cumulative with those of other nearby energy developments such as oil shale, uranium, and coal exploitation.

Water supply (Sect. 2.3.3) may be especially critical because there is little water in many areas of the west, and oil shale operations often consume significant amounts of water. Although some of this water may be processed and reused, the water demands associated with the development of oil shale projects may have adverse effects on local communities and the quality of life in the impact region.

The analysis of socioeconomic impacts should include projections and/or analyses of the following information:

- rate and magnitude of population increase during construction and operation of the project and probable residential location of in-movers;
- capacity of existing and planned housing stock to accommodate project-induced housing demand in affected communities;
- the amount and timing of increased revenues and expenditures for the impacted jurisdictions as a result of project-related growth;
- adequacy of local transportation networks to handle increased worker and heavy equipment traffic;
- adequacy of local public services (e.g., water supplies and domestic waste treatment systems) to serve expected increased populations in affected communities.
- direct and secondary employment to be created by the proposed project and project-induced changes in the local economic character;

- impacts on structure and management of local government and major local organizations; and
- impacts to existing life-style, cultural, and ethnic characteristics of the impact region.

2.3.8 Health and Safety

Recent studies (U.S. DOE 1979, OTA 1980, Bates and Thoem 1980, Walsh et al. 1981) discuss the potential health and safety issues associated with oil shale projects. These publications form the basis for the following discussion of occupational and public health issues. The potential issues discussed below should be discussed by identifying those problems pertinent to the project under review and describing plans for avoiding or mitigating any effects on human health and safety. The following control methods should be considered in this review and discussion:

- worker training programs,
- design and maintenance of safe working environments, and
- health and monitoring programs.

2.3.8.1 Occupational Health

Blasting and drilling during mining will generate hazardous materials (e.g., silica), and related activities (e.g., the handling of raw and spent shale) will produce fugitive dust (Sect. 2.3.2). Silica dust has long been recognized as a major health hazard of underground mining related to the development of silicosis, chronic bronchitis, and other pulmonary disorders. The potential for this dust hazard is difficult to assess for oil shale operations because very limited data are available. However, Costello (1980) and Rudnick et al. (1980) report no evidence of increased respiratory disease in miners working at the Anvil Point Shale Oil Facility near Rifle, Colorado. If commercial-scale production were to require a miner to spend an entire 8-h shift working under the present conditions at Anvil Point, the worker would receive an excessive exposure to dust (Rudnick et al.

1980). Personnel spending a full shift in crushing, retorting, and shale disposal operations would also receive excessive exposures. Gas and vapor levels for all stages of mining, however, do not exceed present exposure standards (Holland and Stafford 1981). Rudnick et al. (1980) suggest that maintenance personnel, often working in areas of high dust and low ventilation, should wear respiratory equipment.

Particulates, including fugitive dust emissions during surface or underground mining should be readily controlled by existing technology, such as wetting, baghouse filters, and various wet scrubbing schemes (Peterson et al. 1980). Mining equipment should incorporate water sprays for dust control. These water sprays need constant maintenance to ensure proper performance.

The degree of ventilation required within commercial-scale MIS mines has not been established. Peterson et al. (1980) note that retorting in one area will occur simultaneously with mining and processing in other areas, and the probability of leaks of fugitive emissions from an active retort into an adjacent area is unknown. Such leaks could expose workers to health hazards ranging from carbon monoxide poisoning to long-term toxic conditions. Careful planning and management, as well as proper ventilation procedures, are necessary to prevent these problems. Unused areas in the mines can be closed off with hanging cloths ("brattice" cloths) to improve ventilation in the areas of the mine that are in use.

A second health concern associated with mining is the possible release of polynuclear aromatic hydrocarbons (PAHs) and trace elements. Published data on the toxicity and carcinogenicity of oil shale materials used in animal studies are extensive. However, recent studies (Rudnick et al. 1980, Costello 1980) on workers employed at the Anvil Point Oil Shale Facility indicate no apparent incidence of chronic or acute disease directly attributable to exposure to oil shale or its retorting products. Both studies do show a greater correlation between pulmonary disorders or cancer and exposure to radioactivity or smoking rather than to exposure to oil shale. Costello (1980) points out, however, that the actual exposures to shale oil were brief, and it is too early to draw conclusions regarding carcinogenic risk because some forms of cancer have a long latent period for development. As with silica and fugitive dust, there are very limited data available, and the potential health risk for the oil shale industry is unknown.

A third potential health risk for oil shale miners is exposure to excessive noise levels. This is of particular concern in underground operations when the primary noise sources are booster fans, drills, blasting, conveyers, and mining machines. Most underground miners are chronically exposed to sound levels greater than the established standards. Such exposure can cause hearing loss, and some data suggest that deleterious effects to the cardiovascular and nervous systems may occur. Miners also experience short-term acute exposure from blasting. Rotation of workers may alleviate exposure to excessive noise levels. Each worker should be fitted with ear plugs. Periodic monitoring of worker's hearing acuity may signal any hearing loss and facilitate rotation to other areas.

Retorting oil shale at high temperatures will form some PAH-containing carcinogens. Some PAHs are undoubtedly released during the crushing and grinding processes due to the mechanical and thermal degradation of kerogen. Workers should be protected from inhalation of raw shale aerosol or dust and from repeated skin exposure to raw shale oil (Peterson et al. 1980). The carcinogenicity of these compounds is a major potential health hazard for retort workers, and the problems involved are basically similar to those of conventional oil refineries (Bates and Thoem 1980). In their report, Holland and Stafford (1981) discuss the presence of arsenic in oil shale, product streams from oil shale retorts, process waters, and crude oil products. Arsenic may be found in all fractions of crude shale oil at concentrations up to 1000 times that of natural crude levels (Bates and Thoem 1980). Because inorganic arsenicals, including nickel arsenides, have been shown to be carcinogenic, teratogenic, and embryotoxic, the release of these substances to the environment, or possible worker exposures to them, during oil shale recovery processes must be carefully monitored and controlled (Holland and Stafford 1981). Upgrading of product streams reduces carcinogenicity as well as toxic effects of chemicals in the crude shale oil. Therefore, any significant increase in health problems will occur during processing when the shale oils differ considerably from natural crude oils in physical and chemical properties (Bates and Thoem 1980).

In shale oil retorting and upgrading facilities and in conventional refineries, liquids and gases must be transported in air-tight pipes which are carefully maintained and observed to detect and repair leaks. Maintenance workers assigned to such tasks are those most likely to be exposed to PAHs and show higher than average mortality rates due to malignant neoplasms (Costello 1980). Engineering controls and improvements in materials of construction may reduce these risks. However, a program for proper fit and maintenance or personnel protective equipment should be implemented (Holland and Stafford 1981). Arsenic, nickel, chlorine, sulfur, nitrogen, and heavy metals are additional hazardous substances found in the crude oil.

2.3.8.2 Occupational Safety

The safety hazards associated with underground or open-pit mining of oil shale are in general similar to those of hard rock mining and would include accidents from rock falls, explosions and fires, electrocution, heavy mining equipment, and vehicular traffic. There are no data available on accidental deaths and injuries associated with oil shale mining, although the occupational health hazards are expected to be lower than those for mining an equivalent quantity of coal (U.S. EPA 1977). Because shale is relatively hard compared to coal, the probability of mine cave-in or collapse, which accounts for 40 to 50% of coal mine fatalities (Commonwealth of Kentucky 1979 and 1980, U.S. EPA 1977), is less. Hazards unique to oil shale operations would occur primarily in MIS processes. The high temperatures and fires associated with these processes may expose miners to risks not experienced by other underground miners.

The safety hazards arising from retorting and upgrading include explosions, fire and heat, electrocution, and exposure to hot liquids.

The degree of risk, however, is probably less than that for the mining phase. Safety risks associated with retorting and upgrading would be no higher than those associated with mineral processing and conventional petroleum refining.

2.3.8.3 Public Health and Safety

Operation of a large oil shale plant would result in large volumes of solid waste and air emissions as well as potential leachates from spent shale. Compliance with federal and state ambient air quality standards may constrain development of the oil shale industry because major potential releases of criteria pollutants, organics, and trace elements are likely to occur. Water used in oil shale processes will become contaminated with toxic chemicals, minerals, and trace elements, while water removed from shale beds will contain chlorine, carbonates, sulfates, mercury, selenium, arsenic, and various organic compounds such as phenols and carboxylic acids (U.S. EPA 1977). Peterson et al. (1980) suggest that mercury might be a particular problem as its fate during the retorting process is unknown and mercury contamination and toxicity pose serious risks. This potential problem needs a careful assessment. Industry goals include zero release into surface streams and groundwater supplies via incorporation of cleanup and recycling processes. To date, no satisfactory methods have been identified for treating wastewater problems encountered during in situ processes (U.S. EPA 1977). In situ processes present a significant challenge in finding ways to make environmental measurements that would ensure containment of emissions and effluents.

The greatest environmental health problem in oil shale development may be associated with the disposal of spent shale (Sect. 2.3.5) because approximately 1.4 x 10^3 kg of waste remain for every barrel of oil produced (U.S. EPA 1977). Health concerns are related to the potentially harmful amounts of mineral salts contained in spent shale, as well as to toxic trace elements that could be leached into surface water and groundwater. However, according to Resources Recovery and

Conservation Act criteria, leachate biotest studies by the Anvil Point Oil Shale Research Facility indicate that leaching from spent shale may not be a significant health problem (Heistand 1980).

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3. TAR SAND

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3.1 RESOURCE DESCRIPTION

Tar sand is any consolidated or unconsolidated rock (excluding coal, oil shale, or gilsonite) that contains hydrocarbon-bearing material with gas-free viscosity (greater than 100 Pascal seconds) at reservoir temperatures. Host rocks are usually sands, sandstones, or limestones of Mississippian age or younger, but any rock of any age may contain bitumen if the necessary porosity is present (Ball and Associates 1975).

The western hemisphere apparently has the majority of the world's tar sand resource, with the largest deposits occurring in Canada and Columbia (Table 5). In the United States, oil-impregnated rocks are known to occur in 22 states, with a total estimated resource of 4.8 to 5.2 x 10^6 m^3 (30-33 x 10^9 bbl) (deNevers et al. 1979, U.S. DOE 1979). Only six states (California, Utah, New Mexico, Texas, Alabama, and Kentucky) contain deposits which could be commercially exploited (Table 6). Utah has by far the largest known deposits, with more than 4.0 x 10^9 m^3 (29 x 10^9 bbl) in place.

Commercial development of tar sand deposits as a source of fossil fuel is most advanced in Canada, where the Athabasca deposits in northern Alberta are being mined. In 1978, these deposits were yielding more than 23,800 m^3 (150,000 bbl) of crude oil per day, with an additional capacity of 47,700 m^3 (300,000 bbl) per day under development.

In the United States, tar sand deposits have been used only as a source of paving asphalt. A recent estimate of the nation's recoverable

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Table 5. World tar sand resources (McRae et al. 1977)[a]

Area	Estimated resource (m^3)	Percent of world resources
North America		
Canada	1.4×10^{11}	41
Trinidad and Tobago	1.1×10^{10}	3
United States	4.3×10^{9}	1
South America		
Columbia	1.8×10^{11}	52
Venezuela	1.2×10^{10}	3
Africa		
Malagasy Republic	2.7×10^{8}	0.1
Europe		
Albania	6.4×10^{7}	0.1
Rumania	4.8×10^{6}	0.1
USSR	4.8×10^{6}	0.1

[a] Care should be taken in comparing resources among nations because the data used here were based on different economic considerations as well as on different degrees of mapping and exploration.

Table 6. Estimated commerical tar sand deposits in the United States (McRae et al. 1977)

State	Estimated resource (m^3)	Percent of U.S. resources
Alabama	1.9×10^{8}	4.3
California	4.7×10^{7}	1.1
Kentucky	5.4×10^{7}	0.6
New Mexico	9.1×10^{6}	0.2
Texas	2.1×10^{7}	0.5
Utah	4.0×10^{9}	93.3
Total commercial deposits	4.3×10^{9}	

reserves using proven technology (McRae et al. 1977) is only 0.3 to 0.9 x 10^9 m^3 (2.0 to 2.5 x 10^9 bbl). Not only are the reserves more limited than in Canada, but the bitumen is also more tightly bound to the sand and therefore more difficult to separate. Proposed in situ extraction techniques may allow more of the resource to be exploited, but the cost in energy and water is considerable (Kuuskraa et al. 1978).

Processes for extracting and separating bitumen from tar sand deposits fall into two general categories: those that extract the ore using surface mining techniques and those that use in situ extraction. The Canadian experience has been primarily with surface mining, whereas plans for developing the U.S. resource include in situ techniques as well. Deposits in the Athabasca region are generally highly saturated and continuous [15 m (50 ft) thick] and have few barren layers. In contrast, however, the U.S. deposits (especially in Utah) are about 6 m (20 ft) thick and have thick barren intervening layers. In addition, the bitumen in the U.S. tar sand is more tightly bound to the sand grains due to the absence or greatly reduced thickness of the water layer.

In general, the economics of underground mining are less favorable for tar sand recovery than in situ recovery. Although underground mining may be feasible for some consolidated deposits in Utah, unconsolidated deposits do not possess sufficient strength to permit underground mining.

3.2 TECHNOLOGY OVERVIEW

3.2.1 Surface Mining

Surface mining has proven to be technically feasible for some of the Athabasca tar sand deposits. Economic constraints on surface mining include depth of overburden, overburden to net pay ratios, bitumen content (weight percent), and size of the deposit. In Canada, deposits having overburden thicknesses of less than 46 m and overburden to net pay ratios of less than one are considered potentially minable.

The optimum size of a deposit in Canada is considered to be 80 x 10^6 to 160 x 10^6 m^3 (0.5-1.0 x 10^9 bbl) of minable ore.

Because U.S. deposits are relatively thin and overburden to net pay ratios are too high, surface mining may be greatly limited. Additional important considerations are the need for drilling and blasting and the steepness of the terrain. In the steep canyon terrain in which some Utah deposits occur, the long-wall stripping method currently used in coal mining may be adapted (U.S. EPA 1976).

3.2.2 Separation Processes

Where tar sand deposits are surface mined, bitumen must be separated from the sand after extraction (Fig. 3). In large operations, such as those of Great Canadian Oil Sand, Inc. (GCOS), and Syncrude, tar sand ore is first fed into large conditioning drums (tumblers), and then steam, hot water, and a small amount of sodium hydroxide are added to separate the bitumen from most of the coarse sand (Fig. 3). The processed coarse sand is returned to the mine for back filling (U.S. DOE 1979). The tar is discharged to a vibrating screen where large lumps of tar sand are removed for return to the conditioning drums. The oil slurry is pumped to separation cells where a froth is formed.

This oil froth, along with some sand and water, is skimmed off the surface, diluted with naphtha, and run through centrifuges for final separation (Fig. 3). Sand from the separation cells and centrifuges is sent to a tailings pond. A middlings stream is withdrawn from the layer beneath the froth in the separation cells. A portion of this stream is returned to the conditioning drum for additional treatment, and the remainder is sent to scavenger cells and froth settlers. Froth from the settlers goes to the centrifuges (U.S. DOE 1979).

An alternative approach being considered by Getty Oil Co. is a solvent extraction technique developed by the Dravo Corporation at Pittsburgh. A volatile hydrocarbon solvent would initially be used to wash the sand from the oil, followed by a multistep distillation process that would separate oil, water, and solvent.

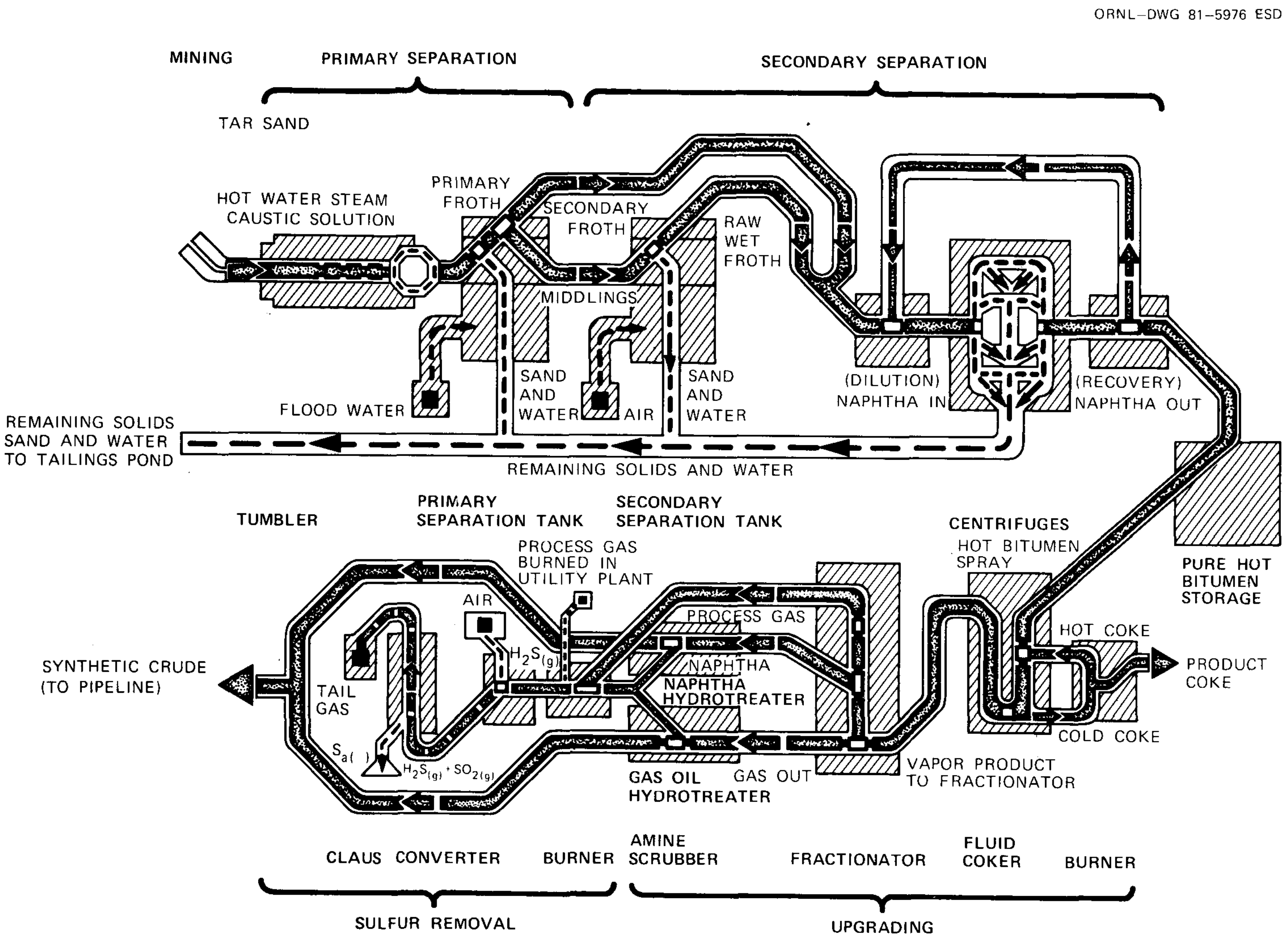

Fig. 3. Synthetic crude oil process flow from surface-mined Athabaska tar sand. [SOURCE: Maugh 1978. (Copyright 1978 by the American Association for the Advancement of Science). Redrawn with permission from T. H. Maugh, II, and AAAS.]

3.2.3 Upgrading Processes

The raw tar sand oil must be upgraded to remove mineral fines, sulfur, and trace metals and to decrease the density, viscosity, and carbon-hydrogen ratio of the product. This upgrading is accomplished in both the GCOS and Syncrude operations by coking (i.e., heating the bitumen to a temperature where it decomposes) (Fig. 3). When the process is complete, a gaseous product, a liquid product, and a solid coke result (Baughman 1978).

The liquid from the coker goes through three hydrotreaters (Fig. 3) that distill naphtha, kerosene, and gas oil. The three liquids are then blended to make synthetic crude oil for marketing (deNevers et al. 1979). Gaseous waste products of hydrotreating are combined with gas from the coker and sent to an amine scrubber to remove hydrogen sulfide. This gas is then treated in a Claus converter to yield elemental sulfur. The cleaned fuel gas is used for plant heating or is fed to the hydrogen plant which supplies the hydrotreaters (U.S. EPA 1976). The solid coke produced by GCOS is used as fuel for heat and electricity generation at its facilities. Syncrude disposes of its coke as a waste product.

Other approaches to upgrading include Shell Canada's plans to replace coking with a combination of vacuum flashing and solvent deasphaltation (Land et al. 1975) and an anhydrous solvent extraction process. In this latter process, fresh tar sand is mixed with solvent and water. The mixture is run through a three-stage countercurrent wash. At the end of each stage the sand is allowed to settle, and the fluids are drained through the sand until no fluid is left. This step removes the bitumen from the sand in much the same way as the rinse cycle in a washing machine removes the dirt and soap from the laundry. The solvent-bitumen and solvent-solids systems are then separated, with the solvent being recycled, the bitumen being sent for further upgrading, and the sand being removed for disposal.

Currently active or proposed tar sands projects will produce an upgraded crude oil on the site, and offsite refineries will be used for further distillation.

3.2.4 In Situ Extraction

Deposits that lack the competence to be mined by underground mining methods and are too deep (greater than 46 m) to use surface mining techniques will probably be exploited by some form of in situ processing. In situ methods involve lowering the viscosity of the bitumen in the ore zone so that the product can be pumped to the surface. Proposed in situ methods include chemical solvent injection, steam-hot water injection, and combustion.

The chemical injection method injects a chemical solvent of either hydrocarbon-based solvents or aqueous alkaline surfactants into the tar sand deposit to dissolve the bitumen. Such injections have been successfully used in California's heavy-oil fields using naphthenes and aromatic solvents (U.S. Bureau of Mines 1972), but the viscosities of these heavy oils are considerably less than those of bitumen. On the other hand, Shell Canada has experimented with both miscible solvents and a combination of aqueous-based emulsifying fluids and sodium hydroxide, but neither approach has proven to be economically feasible (Doscher 1967). Injection of solvents is sometimes preceded by hydraulic or explosive fracturing (U.S. Bureau of Mines 1972). While chemical injection techniques work well in oil fields, more study is needed to demonstrate their effectiveness in tar sand deposits.

Steam injection methods include cyclic injection and steam flooding. Cyclic steaming has been successfully used to increase production in heavy oil fields. The process involves drilling a closely-spaced pattern of wells into the deposit and injecting up to 4000 m^3 (25,000 bbl) of 260° to 370°C steam into each well. Once the steam has been injected, the wells are shut off and allowed to soak, then opened again for production (U.S. EPA 1976). Imperial Oil, Ltd., installed a 795-m^3 (5000 bbl) per day pilot project in the Cold Lake oil sands in Alberta (Anonymous 1975). The process consumed 3 m^3 of water for each cubic meter of oil produced, with recovery of only 20 to 30% of the oil in place. At the time of the pilot project, a question arose about the economic and energy balance feasibility; specifically, was the 3:1 water:oil ratio with only 20 to 30% oil recovery an economic process? More research on the suitability of cyclic steaming is underway.

With the steam flooding technique, injected steam reduces the viscosity of the bitumen and drives it toward a nearby production well. A surfactant emulsifier is generally injected with the steam to enhance viscosity reduction. In a pilot project conducted by Shell Canada, 4 m^3 of steam and caustic were injected for each cubic meter of oil produced (Baughman 1978). An estimated 50 to 70% recovery of oil could be realized, but the commercial feasibility would depend on reducing the required energy and water impacts.

The U.S. Department of Energy Laramie Energy Technology Center conducted a steam flooding experiment at the Vernal, Utah, site (Lindberg 1980). An average production rate of 1.1 m^3/d (oil) and 6.3 m^3/d (water) was achieved. These results were encouraging enough to continue further evaluations of the technical feasibility of steam flooding tar sand deposits (Johnson et al. 1981).

Combustion of bitumen in place provides heat to lower the viscosity of surrounding hydrocarbons. Oxygen for combustion and for driving the produced hydrocarbons to a production well is provided by the injection of high pressure air from the surface (Doscher 1967). Fracturing may be required to ensure good interconnection between injection and production wells.

A forward combustion or a reverse combustion strategy may be used. In the former case, ignition is started in the injection well, and the combustion front moves through the formation toward the production well. The injected air is heated to 315° to 480°C in the burn zone and mobilizes the lighter constituents of bitumen in front of the combustion front, driving them toward the production well. The mobilized hydrocarbons, however, tend to condense on entering the cold zone between the burn front and the production well, plugging the pores and restricting flow to the production wells (Doscher 1967).

In reverse combustion, ignition occurs at the production well while air is pumped into the injection well. The burn front migrates toward the injection well, counter to the direction of air flow. The mobilized bitumen is conducted through the hot burned-out zone to the production well to prevent condensation. The oil produced is of higher quality than that produced by forward combustion because the bitumen has been thermally cracked (Cupps et al. 1975). Field and laboratory experiments of reverse combustion carried out by the Laramie Energy Technology Center (Land et al. 1975, 1977) showed that the temperatures achieved were much lower than expected. The resulting product was much more viscous than anticipated and congealed in the surface pipelines. Laboratory tests indicated 50% recovery of bitumen in place was possible with 40% remaining in the deposit and 10% consumed in combustion (Land et al. 1975). A second test was performed using a reverse combustion phase followed by a forward combustion phase (echoing). Approximately 25% (92.2 m^3 or 580 bbl) of the in-place bitumen was produced, and 49% air return was achieved. The volume of the oil produced and percent air return make the scheme look very promising.

A combination forward combustion-water flood process has been developed by Amoco Production Company to produce bitumen from the Gregoire Lake area in northern Alberta. The process starts as a forward combustion burn until the reservoir reaches 815°C. Water is then injected with the air, lowering the combustion temperature and generating steam that transmits heat into the formation and rapidly accelerates the recovery process (Doscher 1967). Air requirements are much less than those for standard forward combustion. Field results from a small plot yielded 32% of the bitumen in place. This method is considered superior to ordinary combustion techniques because a higher quality oil is recovered.

3.3 POTENTIALLY SIGNIFICANT ISSUES

Potentially significant environmental impacts associated with construction, mining, operation, and reclamation of proposed tar sand projects should be assessed as appropriate to the project under review. The following issues are those most likely to be significant for tar sand projects and should be carefully reviewed. If this review shows that the issue is not relevant to the proposed project, then the the reasons for not presenting a detailed analysis should be briefly discussed.

3.3.1 Land Use

Over 90% of the nation's tar sand deposits are in Utah (Table 6). Development of the southeastern Utah deposits has the greatest potential for conflict with national parks, monuments, and recreation areas; in fact, some of the deposits are within the boundaries of such protected areas. In both southeast and northeast Utah, conflicts with established and proposed U.S. Forest Service and U.S. Bureau of Land Management wilderness areas may occur. Extensive Indian lands in the Uinta Basin may also coincide with tar sand deposits.

A commerical-size surface mining operation will disturb several hundred to a few thousand hectares of land and commit several hundred more to settling ponds for spent ore sands (Norman and Norman 1978). In situ recovery methods will also involve considerable land disturbance because wells are closely spaced. Mining disturbance, combined with construction of plant facilities for separation and upgrading of bitumen, will represent an intrusion into the present natural setting of the region. Increased traffic and numbers of people could also adversely affect surrounding lands.

Although tar sand developments in California, Texas, New Mexico, and Alabama may have a lower probability of extensive land-use conflicts than similar developments in Utah, some adverse effects on land use are nevertheless likely and should be carefully reviewed.

For the project site and surrounding area, the following should be described:

- 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;
- the visibility of the proposed site and associated facilities from public use areas (e.g., trails, canyon overlooks, and picnic/camping areas); and
- Indian-owned lands and areas sacred to local Indian tribes.

A map should be included to show surrounding land uses and potential routes for heavy equipment and construction 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 wilderness areas) should be addressed.

3.3.2 Air Quality

Some tar sand resources are within or adjacent to Class I air quality regions, such as national parks (Sect. 3.3.1), where release of criteria atmospheric pollutants will be severely restricted by prevention of significant deterioration (PSD) provisions. Furthermore, in Utah, effects on air quality from nearby oil shale, uranium, and coal developments will be cumulative with those from tar sand, and PSD increments may not be available.

Surface mining of tar sand deposits has the potential to release large quantitites of particulates as dust. Mining will also expose large areas of fresh bitumen ore, possibly releasing volatile hydrocarbons to the atmosphere (U.S. EPA 1976). Hydrocarbons will also be emitted during bitumen separation (especially by the solvent extraction process) and during upgrading, storage, and transfer of the produced oil. Potentially large emissions of sulfur oxides (SO_x) could come from combustion of coke or product fuel to provide process heat for bitumen separation and from the tail-gas stream of the Claus plant associated with the upgrading of the separated bitumen. The potential for SO_x releases will be greatest in southeast Utah where the bitumen is about 5% sulfur, as compared to only 0.5% sulfur in the

Uinta Basin deposits (deNevers et al. 1979). Combustion of product fuel and in situ processes that use combustion will also release quantities of nitrogen oxides, particulates, and hydrocarbons.

In addition to general background information, specific information should be developed on the following:

- all affected Air Quality Control Regions (ACQRs), with special emphasis on Class I areas;
- local meteorology (local airport data and onsite measurements);
- local air quality (U.S. EPA and/or state monitoring data, monitoring data from nearby facilities, as available, and onsite baseline monitoring data, if required);
- proposed use of air pollution control devices, including a realistic estimate of efficiency and downtime;
- availability of other mitigation measures (e.g., siting facilities to maximize dispersion of atmospheric emissions); and
- any proposed air quality monitoring program.

3.3.3 Water Use

The availability of sufficient quantities of water for tar sand projects is a potential major environmental issue. Extraction techniques involving steam injection were estimated to consume from 3 to 6 m^3 of water per cubic meter of oil produced based on experience in Canada (deNevers et al. 1979). Other water uses range from dust control to domestic water requirements for the increased population associated with the project work force. Because high quality tar sand deposits are found predominantly in regions of the United States in which freshwater resources are a limited commodity, project environmental analyses must evaluate water resource availability and the implications of project water use to other regional water users.

The following should be included:

- sources of water available for project development;
- best estimates of quantities required under various consumptive and nonconsumptive water-use categories;
- for projects using groundwater resources (e.g., aquifer yield, quality, and recharge capacity), evaluation of the effects on and interrelationships with surrounding groundwater uses;
- 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; and
- dependency of project operation on the construction of related water projects.

All opportunities for water recycling and conservation within the project design should be evaluated, and those adapted for the project should be emphasized. Zero-effluent operations are desirable, whenever achievable, to minimize effects on ambient water quality.

3.3.4 Water Quality

Potential mechanisms for groundwater and surface water pollution that are involved in the development of tar sand deposits include:

- increased erosion and sediment loading from mining and construction activities;
- leaching or overflow from tailings retention basins;
- runoff from exposed ore deposits, stockpiled materials, and solid waste disposal sites;
- contamination of groundwater aquifers by injection fluids, high temperature, salinity, or soluble organics and metals;

- point-source discharges of waste effluents from surface extraction and upgrading processes; and
- accidental spills of process and waste streams and finished syncrude or petroleum products.

Each of these mechanisms should be discussed where appropriate. Pollution control strategies and monitoring plans should be presented to ensure that water quality degradation does not occur from these sources. Effects on groundwater quality are most likely to occur with projects using in situ extraction techniques or aquifer reinjection as a method for aqueous waste disposal. Surface water quality effects will be related to disturbance of land surfaces associated with mining, construction, and disposal of solid wastes. Point source effluents will originate from water coproduced during bitumen extraction and from process waste streams associated with sulfur removal, backwash, upgrading condensates, and cooling tower and boiler feed blowdown.

Specific pollutants from tar sand processing are similar to those from coal or uranium mining, enhanced oil recovery, petroleum refining, and the coal conversion/synfuels industry. Some of the potential waste constituents that require attention are listed in Table 7.

Table 7. Potential waste constituents from tar sand processing

Biochemical oxygen demand (BOD)
Total suspended solids (TSS)
Acidity or alkalinity
Ammonia
Sulfur compounds
Heat
Chemical oxygen demand (COD)
Oil and grease
Total dissolved solids (TDS)
Cyanide
Chlorides
Phenolics
Polynuclear aromatic hydrocarbons (PAHs)
Trace metals (As, Cd, Cr, Cu, Pb, Hg, Ni, Ag, Zn, Mn)

To address water quality issues, the environmental analysis should contain information on the predicted composition of effluents, comparisons to ambient water quality conditions, and applicable water quality standards. Chemical composition and leachability of specific tar sand ores should also be included. Composition and quantities of process effluents should be identified in sufficient detail to account for approximate material balances through a process flow diagram. Required surface discharge or aquifer reinjection permits should be listed along with applicable water quality limitations.

3.3.5 Impacts on Biota

Large-scale tar sand development are likely to destroy many hectares of natural vegetation and terrestrial and aquatic habitat as a result of both the energy facilities themselves and the large population influx associated with the labor force. Effects on natural communities will be cumulative with those from other energy developments such as uranium, oil shale, and coal in Utah. The development and increased human presence associated with energy facilities could severely affect species, such as raptors, that are sensitive to disturbance. Habitat destruction, increased legal and illegal hunting pressure, and increased mortality (e.g., from road-kills and bird collisions with new power lines) could adversely affect wildlife populations.

Potential impacts on aquatic biota may result from either point or nonpoint effluents originating from project mining, construction, and operation. Increased erosion and sedimentation may degrade water quality in local streams. Consumptive water withdrawals may alter instream habitat conditions, and project effluents could lead to an increase in total dissolved solids concentrations in downstream portions of the watershed. Toxic waste effluents, including point or nonpoint discharges and intermittent overflows from holding ponds, may result in either acute or chronic stress on plankton, macrophyte, benthic macro-invertebrate, or fish populations.

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

- describe the terrestrial and aquatic biota affected by the proposed project, with special attention paid to endangered, threatened, rare, or otherwise protected plant and animal species;
- characterize by dominant species and physical features all terrestrial and aquatic habitats that will be disturbed;
- estimate the number of hectares of each type of habitat that will be disturbed during mining, construction, and operation;
- present a reclamation plan for all disturbed areas (Sect. 3.3.8);
- evaluate the effects of the composite toxicity of individual waste effluents, and, where applicable, combined waste effluents on target species of plants, invertebrates, and fish; 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 federal action agency).

3.3.6 Noise

Because much of the tar sand area is remote and undeveloped and has a high recreational value, project-induced noise levels may cause a significant impact. Surface mining will require blasting in the consolidated formations of Utah. Heavy machinery and traffic on haul roads may be a significant source of noise. Operations at the separation and upgrading facilities may produce noise levels in excess of 100 dBA in the plant vicinity (Norman and Norman 1978).

Estimates of the level of noise produced by project activities should be supplied. 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.

3.3.7 Solid Waste Disposal

Solid waste generated at all stages in tar sand processing should be accounted for. Sources of solid wastes include:

- spent mineral tailings separated from bitumen,
- coal or shale in overburden handled but discarded in the mining process,
- sludge produced in waste treatment processes,
- fly and bottom ash from boilers,
- spent catalysts used in upgrading processes, and
- conventional domestic solid wastes.

The environmental analysis should identify all the types of solid wastes that will be produced by the proposed project, indicate which wastes are hazardous and which are nonhazardous, estimate the quantities of each type of waste that will be produced on an annual basis and over the lifetime of the project, and describe the steps that will be taken to identify which of the wastes are hazardous and which are not. This section should clearly outline the proposed plans for disposal of both hazardous and nonhazardous wastes.

Disposal sites and methods for handling and treating wastes from each of the sources listed above should be identified. The design of onsite disposal areas should include the following considerations for the control and collection of leachates: the placement of liners in holding ponds to minimize seepage, construction of dikes and ditches to collect surface runoff and leachate, and the use of cover material over long-term storage or disposal sites. Reclamation plans (Sect. 3.3.8) outlining the long-term use of disposal sites should also be discussed.

Canadian experience has revealed several problems associated with disposal of tar-sand tailings (deNevers et al. 1979). Colloidal materials associated with tailings from surface-mined tar sand have very slow settling velocities. Evaporation rates from settling ponds can also be low, especially when surface films of residual organics accumulate. Effluents produced from settling pond overflows have been found to be toxic to fish and wildlife. Therefore, special attention should be devoted to design of tailings ponds to reduce the probability of water quality impacts.

3.3.8 Reclamation

Reclamation of mined land and disposal areas is a major problem area in any tar sand operation. Plans for reclamation should be described in detail. The objectives of reclamation should be to (1) reduce water and wind erosion from the disturbed landscape, (2) restore the disturbed areas to productive use, and (3) ensure that long-term contamination of ground and surface waters by leachates from the reclaimed areas does not occur.

The reclamation plan should include all areas disturbed during construction and operation of the proposed facility and describe:

- the location of all areas to be reclaimed (a map should be provided);
- handling and storage of topsoil;
- soil amendments to be used;
- irrigation plans and water sources;
- cover species to be used.
- measures to protect the reclaimed areas from grazing for sufficient time to allow establishment of new vegetation;
- a monitoring program to evaluate long-term success of reclamation; and
- schedule for implementation of specific portions of the plan.

3.3.9 Socioeconomics

The majority of the tar sand resource is located in areas characterized by small isolated communities. Boomtown effects on small communities resulting from a rapid and large population influx have been demonstrated in the western coal regions (Gilmore and Duff 1975). Housing and municipal services in small communities are often insufficient to handle large population increases (Cortese and Jones 1979). Tax revenues from the energy facilities lag several years behind the rise in local government expenditures required to meet increased demand for services and may not reach all, or even most, of those jurisdictions experiencing project-induced impacts. High-paying energy jobs draw labor away from lower-paying local employers, and local inflation may occur, causing particular damage to low income residents and those on fixed incomes. Rapid population increases may be accompanied by cultural disruptions and a rise in crime rates. Population increase can also exacerbate effects from the energy development itself on air quality, water availability and quality, and surrounding natural habitats.

Boomtown effects should be anticipated as a result of large tar sand development in eastern Utah and to a lesser extent in other areas. Effects from development of tar sand resources may also be cumulative with those of other nearby energy developments such as oil shale, uranium, and coal exploitation. Adverse effects could be especially critical in areas of southeast Utah where population increases from both tar sand and other energy developments could affect communities with populations of fewer than 5000 people.

Water supply (Sect. 3.3.3) may be especially critical because there is little water in many areas of the west, and energy extraction processes often consume significant amounts of water. Frazier et al. (1976) note that degradation of water quality will result from surface mining of tar sand and that some in situ technologies will require substantial amounts of water. Although some of this water may be processed and reused, the water demands associated with the development of tar sand projects may have adverse effects on local communities and the quality of life in the impact region.

The analysis of socioeconomic impacts should include projections and/or analyses of the following information:

- rate and magnitude of population increase during construction and operation of the project, and probable residential location of in-movers;
- capacity of existing and planned housing stock to accommodate project-induced housing demand in affected communities;
- the amount and timing of increased revenues and expenditures for the impacted jurisdictions as a result of project-related growth;
- adequacy of local transportation networks to handle increased worker and heavy equipment traffic;
- adequacy of local public services (e.g., water supplies and domestic waste treatment systems) to serve expected increased populations in affected communities.
- direct and secondary employment to be created by the proposed project and project-induced changes on the local economic character;
- impacts on structure and management of local government and major local organizations;
- impacts to existing life-style, cultural, and ethnic characteristics of the impact region; and
- local support or opposition to the proposed project.

The assumptions used for the projections and/or analyses listed above (e.g., the multipliers used) should be discussed. In addition, the environmental analysis should include plans for monitoring and mitigation.

3.3.10 Health and Safety

Although commercial utilization of tar sand in Canada has occurred since 1968, there are little or no available toxicological or bioassay data available, nor is there any published documentation of industrial hygiene programs. Jackson (1979) and MacFarland (1979) briefly discuss the occupational health and safety problems that will most likely be associated with the processing of tar sand to produce synthetic crude oil. The product is essentially a heavy petroleum, and potential health hazards appear to be similar to those found in refining crude petroleum oil or coal conversion and oil shale recovery processes.

Mining of tar sand will result in occupational hazards much like those associated with open-pit or strip mining. Increased dust levels and noise from heavy equipment will be inherent in the mining operations. Although sand grains composed of 40 to 50% silicon comprise about 83% of the weight of tar sand, the sticky nature of the sand will help to reduce dust levels during mining. However, after the bitumen has been removed from the sand during reclamation or disposal, increased dust levels and resulting exposure to silica may be experienced (Jackson 1979). The development of silicosis, chronic bronchitis, and other respiratory disorders as a result of silica dust exposures cannot be discounted, and dust levels must be evaluated critically during mining and disposal.

Various process streams of tar sand retorting facilities as well as the resulting crude oil may contain known mutagens and carcinogens such as aliphatic or aromatic hydrocarbons. Dermal contact with these materials should be avoided.

Fractional distillation, used to separate product fractions by boiling point, is accompanied by the use of catalysts to obtain the desired products. Benzene, now regarded as a carcinogen thought to produce leukemia at high exposure levels, may be present during this process, as well as n-hexane, which may induce peripheral neuropathy following systemic absorption (McFarland 1979). Exposures to carbon monoxide, naphtha vapors, and metal-catalyst carbonyls during extraction, coking, and hydrotreating present potential health hazards. Because tar sand contains up to 6% organically bound sulfur, the escape of hydrogen sulfide during refining processes is a hazard that must be assessed (Jackson 1979). Workers may also be exposed to heat, noise, high pressure steam, and coke dust (McFarland 1979).

The major solid waste produced will be sand that may be coated with a layer of coke produced in the retort. This sand may be returned to the mined-out area. No data were found on releases from tar sand retorting processes that would permit a discussion of potential public health concerns. Releases of SO_x, NO_x, some particulates, and trace elements are possible.

The analysis should address those health and safety issues that are of concern and should include plans for minimizing the risk to workers and the public. Any monitoring programs should be clearly described.

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4. COAL GASIFICATION AND LIQUEFACTION

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4.1 RESOURCE DESCRIPTION

In terms of volume and gross energy potential, coal is the most significant fossil fuel resource in the United States. Coal reserves constitute about 90% of the nation's fossil fuel reserves (Parker and Thompson 1976, U.S. GAO 1977) and are widely distributed (Fig. 4). Use of this important natural resource has, in the past, been limited by problems such as mining impacts, transportation of the product to the markets, and environmental pollution. Although mining and transportation problems can be largely solved with existing technology, environmental issues such as potential air and water pollution are persistent problems (U.S. DOE 1978a,b; Braunstein et al. 1977a).

Coal-derived synfuels (CDS) can be produced by gasification and/or liquefaction, conversion processes that transform coal from its original, heterogeneous form (Table 8) into more homogeneous gaseous, liquid, or solid products. The intent of creating synfuels from coal is threefold: (1) to develop alternative energy sources that are compatible with existing environmental protection criteria, (2) to increase the use of domestic energy supplies consistent with the national goal of energy independence, and (3) to produce fuels that are compatible with existing delivery systems and markets. These objectives can be met by isolating the hydrocarbon fraction of coal, enriching the hydrogen to carbon ratio of the products relative to the raw material, and removing undesirable inorganic constituents such as

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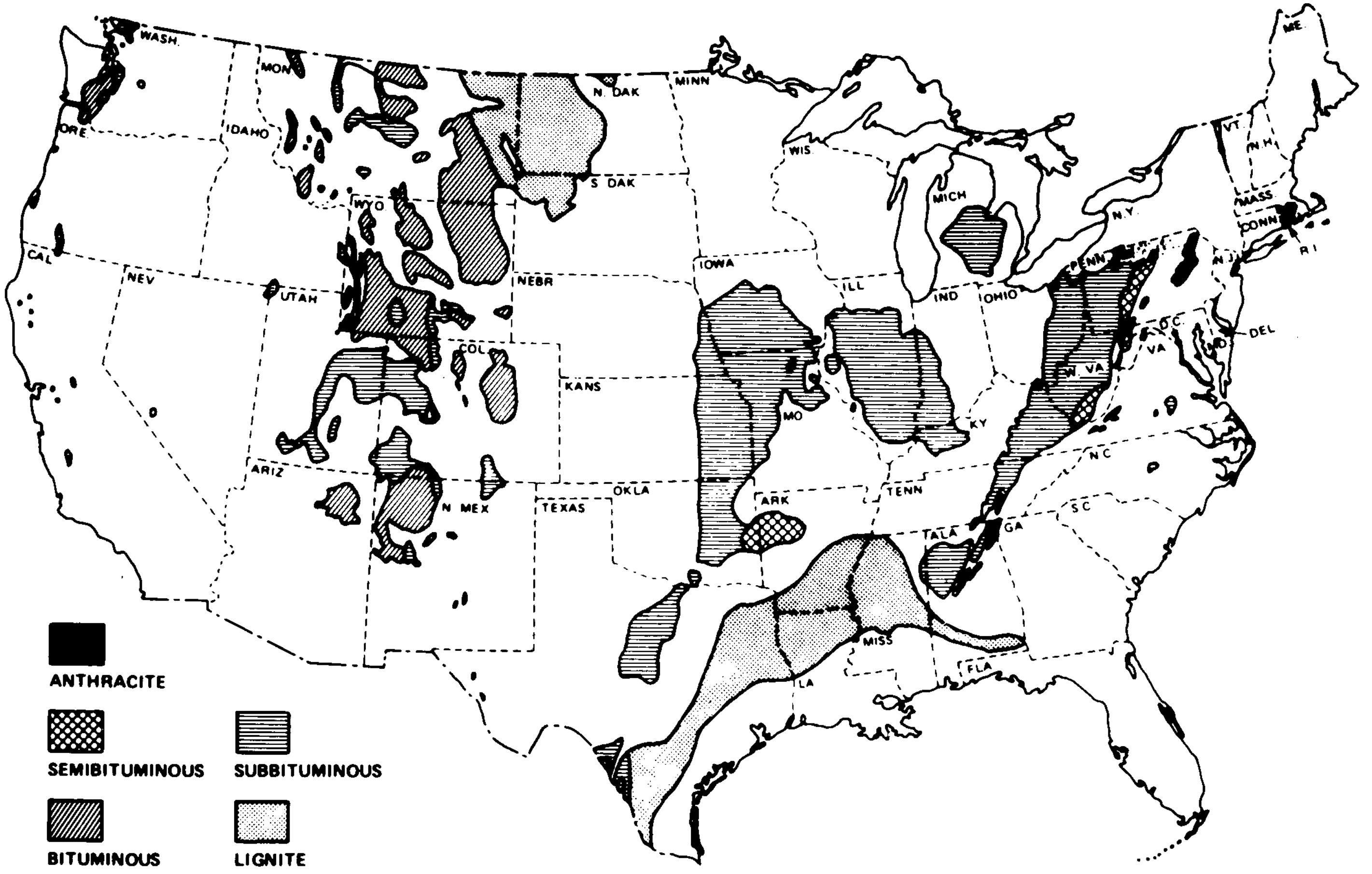

Fig. 4. Geographic distribution of coal deposits in the United States (U.S. DOE 1979).

Table 8. Mean analytical values for 101 coal types.

	Mean	Standard deviation	Minimum	Maximum
Arsenic, ppm	14.02	17.70	0.50	93.00
Boron, ppm	102.21	54.65	5.00	224.00
Beryllium, ppm	1.61	0.82	0.20	4.00
Bromine, ppm	15.42	5.92	4.00	52.00
Cadmium, ppm	2.52	7.60	0.10	65.00
Cobalt, ppm	9.57	7.26	1.00	65.00
Chromium, ppm	13.75	7.26	4.00	54.00
Copper, ppm	15.16	8.12	5.00	61.00
Fluorine, ppm	60.94	20.99	25.00	143.00
Gallium, ppm	3.12	1.06	1.10	7.50
Germanium, ppm	6.59	6.71	1.00	43.00
Mercury, ppm	0.20	0.20	0.02	1.60
Manganese, ppm	49.40	40.15	6.00	181.00
Molybdenum, ppm	7.54	5.96	1.00	30.00
Nickel, ppm	21.07	12.35	3.00	80.00
Phosphorus, ppm	71.10	72.81	5.00	400.00
Lead, ppm	34.78	43.69	4.00	218.00
Antimony, ppm	1.26	1.32	0.20	8.90
Selenium, ppm	2.08	1.10	0.45	7.70
Tin, ppm	4.79	6.15	1.00	51.00
Vanadium, ppm	32.71	12.03	11.00	78.00
Zinc, ppm	272.29	694.23	6.00	5350.00
Zirconium, ppm	72.46	57.78	8.00	133.00
Aluminum, %	1.29	0.45	0.43	3.04
Calcium, %	0.77	0.55	0.05	2.67
Chlorine, %	0.14	0.14	0.01	0.54
Iron, %	1.92	0.79	0.34	4.32
Potassium, %	0.16	0.06	0.02	0.43
Magnesium, %	0.05	0.04	0.01	0.25
Sodium, %	0.05	0.04	0.00	0.20
Silicon, %	2.49	0.80	0.58	6.09
Titanium, %	0.07	0.02	0.02	0.15
Organic sulfur, %	1.41	0.65	0.31	3.09
Pyritic sulfur, %	1.76	0.86	0.06	3.78
Total sulfur, %	3.27	1.35	0.42	6.47
Sulfur by X-ray fluorescence, %	2.91	1.24	0.54	5.40
Air-dry loss, %	7.70	3.47	1.40	16.70
Moisture, %	9.05	5.05	0.01	20.70
Volatile matter, %	39.70	4.27	18.90	52.70
Fixed carbon, %	48.82	4.95	34.60	65.40
Ash, %	11.44	2.89	2.20	25.80
Carbon, %	70.28	3.87	55.23	80.14
Hydrogen, %	4.95	0.31	4.03	5.79
Nitrogen, %	1.30	0.22	0.78	1.84
Oxygen, %	8.68	2.44	4.15	16.08
High-temperature ash, %	11.41	2.95	3.28	25.85
Low-temperature ash, %	15.28	4.04	3.82	31.70
Heating value, MJ/kg	29.65	1.08	26.89	33.41

SOURCE: Ruch et al. 1974.

sulfur, trace metals, and other inert materials. The synthetic products which can be generated include:

- high, intermediate, or low Btu gases;
- liquids such as naphtha, methanol, gasoline, diesel oil, or No. 2 and No. 6 fuel oils; and
- low-melting-point solids for use as boiler fuel with low-sulfur, low-ash content.

Other commercially valuable by-products that can be obtained through the production of CDS include ammonia, elemental sulfur, phenol, and coke.

Depending on their chemical composition, gaseous synfuels fall into one of three heating value classifications. Low Btu gas, also called synthesis gas, consists primarily of hydrogen (H_2), carbon monoxide (CO), and nitrogen gas species; its heating value is less than 7.5 MJ/m^3 (approximately 200 Btu/scf). Intermediate Btu gas has comparatively more methane (CH_4) and less nitrogen than does low Btu gas. Heating values of intermediate Btu gas range up to 17 MJ/m^3 (approximately 450 Btu/scf). Intermediate and low Btu gases contain significant amounts of impurities such as hydrogen sulfide (H_2S), carbon dioxide (CO_2), hydrogen cyanide (HCN), phenols, and higher molecular weight hydrocarbons. Direct uses of these coal gases are primarily in local industry as boiler feeds. Synthesis gas, however, is more commonly used as the precursor for the production of higher grade synfuel or as a chemical feedstock (i.e., source of H^2 and/or CO for production of ammonia or other petrochemicals).

High Btu gas, which is almost pure CH_4, has a heating value of greater than 33 MJ/m^3 (900 Btu/scf). Substitute pipeline gas (SPG), a high Btu gas suitable for distribution within existing natural gas pipeline systems, is an example of this type of CDS. Because strict quality standards exist for allowable concentrations of carbon monoxide, carbon dioxide, hydrogen sulfide, total sulfur, water vapor, and higher molecular weight hydrocarbons in SPG (Strakey et al. 1975), plants producing SPG include additional processes to remove these impurities.

The syncrudes from which liquid CDS products are refined differ from petroleum crude oil in several important ways. Although the original coal type and the specific conversion process determine syncrude characteristics, coal-derived syncrudes are generally higher in nitrogen, sulfur, cyclic hydrocarbons, and trace elements than is petroleum crude oil. Coal syncrudes can be hydrotreated to produce a CDS compatible with standard oil-refining techniques (NAS 1977, Sullivan et al. 1981). However, the concentrations of polycyclic aromatic hydrocarbons (PAHs) and acidic organic compounds such as phenols and cresols will still exceed those in petroleum products, especially in heavier CDS products (Braunstein et al. 1977a).

An example of solid-phase CDS products is the low-sulfur, low-ash, solid fuel synthesized by the Solvent Refined Coal (SRC-I) process (U.S. DOE 1981b). This synfuel has been demonstrated to be as acceptable a boiler feedstock as coal (Bechtel National, Inc. 1979). The SRC solids have less than 0.96% sulfur and 0.16% ash. Heating values are about 37 MJ/kg (16,000 Btu/lb), higher than the original coal. The major benefits of retrofitting power plants to use SRC solids are the decreased atmospheric emissions which result from using this cleaner burning fuel.

A large number of design variations among specific CDS projects are possible, depending on the desired end products and the conversion strategy used. While the distinction between coal gasification (production of gaseous synfuels) and liquefaction (production of liquid synfuels) is clear, the route that can be taken to produce any one particular CDS is far from unique (Fig. 5). For example, SPG can be produced via coal gasification followed by methanation, or it can be a secondary product of a liquefaction scheme, being produced from coal char left over from pyrolysis or solvation processes of liquefaction (the previously proposed ICGG project in southern Illinois was an example of the latter). Similarly, gasoline can be produced by refining naphtha produced in a direct liquefaction process (e.g.,

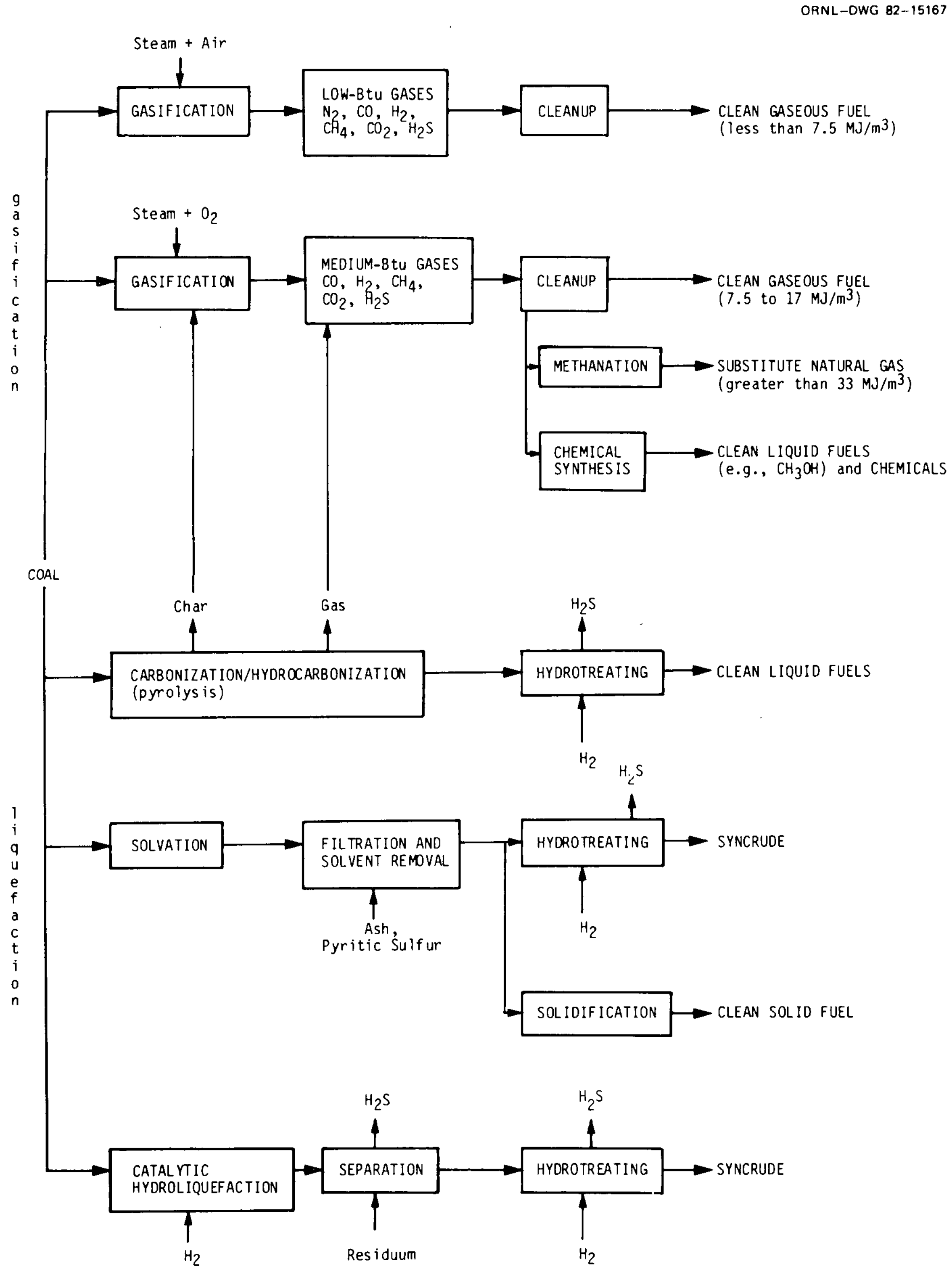

Fig. 5. Alternative processes for synfuel production from coal (modified from Gehrs 1977).

SRC II), or it can be derived indirectly by catalytic reformation of methanol produced from synthesis gas (hence the term "indirectliquefaction"). When gasification and liquefaction are used to supplement each other (e.g., where the hydrogen gas required in hydrogenation reactions of liquefaction is produced onsite by a parallel gasification process), CDS project design is complicated further. Economic pressure to increase the conversion efficiency of synfuel production may lead to an increased number of projects incorporating both gasification and liquefaction processes into the same coal conversion scheme.

4.2 TECHNOLOGY OVERVIEW

4.2.1 Coal Gasification

The central element in all gasification design schemes is a reactor vessel called the gasifier in which the initial carbon monoxide/hydrogen synthesis gas mixture is produced from coal or coal char. The gasifier is usually a high temperature, pressurized vessel where both combustion (Table 9, Eq. 1) and gasification (Table 9, Eq. 2) occur. Gasifier designs are divided into three types, depending on the method used to introduce the coal feed into the reactor. Fixed bed gasifiers support input coal on rigid rack systems and pass gases over the bed at low velocities. Fluidized-bed gasifiers operate with high gas velocities (usually upflow) and small coal particle sizes in such a way that the solid particles are freely suspended. Entrained-bed gasifiers also use a high velocity stream of oxidant (air or O_2) and steam to carry coal particles into the reactor vessel but fluidization velocities are not maintained.

Other important variables in gasifier design are the temperature and pressure conditions and oxidant type. High pressure aids the hydrogasification reaction (Table 9, Eq. 3), which produces synthesis gas with a relatively higher heating value (more CH_4). Use of pure oxygen as the oxidant in place of air also produces a higher grade product because the resultant heating values are not depressed by the

Table 9. Principal chemical conversions involved in coal-derived synfuels production

Reaction	ΔH_f(kJ)[a]	Equation No.
COMBUSTION		
Coal, air (or O_2) $\longrightarrow$ Heat, CO_2, H_2O, ash, CO, NO_x, SO_x		(1)
SYNTHESIS GAS PRODUCTION (gasification)		
Coal, $H_2O_{(g)}$, heat $\longrightarrow$ CO, H_2, CO_2, CH_4, other hydrocarbons, H_2S, char, ash		(2)
HYDROGASIFICATION		
Coal, H_2 $\longrightarrow$ CH_4, other hydrocarbons, char		(3)
SHIFT CONVERSION		
$CO + H_2O_{(g)} \rightleftharpoons CO_2 + H_2$	-1.9 to -2.4	(4)
METHANATION		
$CO + 3H_2 \xrightarrow[\text{catalyst}]{} CH_4 + H_2O$	-11.9 to -12.9	(5)
$CO_2 + 4H_2 \xrightarrow[\text{catalyst}]{} CH_4 + 2H_2O$	-14.1 to -14.9	(6)
METHANOL SYNTHESIS		
$CO + 2H_2 \xrightarrow[\text{catalyst}]{} CH_3OH$		(7)
$CO_2 + 3H_2 \xrightarrow[\text{catalyst}]{} CH_3OH + H_2O$		(8)
CARBONIZATION (Pyrolysis)		
Coal, Heat $\longrightarrow$ Volatile hydrocarbons, coal gas, char		(9)

[a] 1 kJ = 0.239 kcal.

presence of nitrogen. A devolatilization gasifier emphasizes the hydrogasification reaction only by combining hydrogen and coal at high temperature and pressure in the absence of any oxidants.

The raw synthesis gases undergo a series of cleanup processes after leaving the gasifier. The first step is gas quenching, which consists of passing the gas stream through a spray of water forcing condensation and removal of nongaseous by-products. The aqueous waste stream from quenching (i.e., process condensate) contains oils, tars, phenolics, polycyclic aromatic hydrocarbons (PAHs), and entrained ash particles. The gaseous product stream after quenching contains the desired CO, H_2, and CH_4 plus impurities such as H_2S that must be removed before further processing of the synthesis gas.

Acid gas removal is a unit process used to purge undesirable sulfur compounds and carbon dioxide. The operation is carried out by either physical or chemical absorption of acidic gases into either a liquid phase or solid precipitate. Absorption liquids include hot carbonate, methanol, amine solutions, and dimethoxy tetraethylene glycol. A filter bed of iron or zinc oxides can also be used to remove H_2S. The sour (acidic) liquid waste streams from this process are routed through a regenerator, recycled to a wastewater treatment process, or used in another stage in the conversion scheme (e.g., gas quenching). Acid gas removal in the gasification scheme can be done either before or after the shift conversion reaction, but it must precede any catalytic processes because H_2S inactivates most catalyst beds critical in later conversion processes.

The shift conversion process (Table 9, Eq. 4) is an intermediate step essential to optimize the catalytic conversions that produce CH_4 or methanol (CH_3OH). The reaction consists of saturating a CO-rich gas with steam and passing it through a catalytic reactor (e.g., chromium or iron oxide) to produce H_2 and CO_2. Carbon dioxide can then be removed in an acid wash step to result in a net change in H_2:CO ratios. The presence of a catalyst is most important at lower temperatures (e.g., less than 370°C) to force the reaction to equilibrium. Usually only part of the purified synthesis gas stream undergoes shift conversion to produce sufficient H_2 for subsequent catalytic conversion reactions. Optimal molar ratios of H_2 to CO_2 are 3:1 for methanation and 2:1 for methanol production. Shift conversions will generate a minor aqueous waste stream consisting of excess water and a small amount of condensed hydrocarbons.

Methanation is the last major step in the production of SPG. Effective catalysts for the methanation reactions (Table 9, Eqs. 5 and 6) are ruthenium, nickel, cobalt, iron, or molybdenum (Strakey et al. 1975). Deactivation and fouling of the catalysts is a serious problem. Because the reactions producing CH_4 are highly exothermic, cooling of the methanation reactor is required to keep temperatures in a range to maintain long catalyst life. Poisoning by sulfur compounds can occur if inflow gases have not been cleaned. Careful control over pressure and H_2:CO_2 ratios is necessary to avoid heterogeneous decomposition to CO and CH_4 and the formation of elemental carbon deposits that result in catalyst fouling.

4.2.2 Coal Liquefaction

The overall objectives of coal liquefaction are the same as coal gasification: isolation of the hydrocarbon fraction of the raw coal feedstock and enrichment of the hydrogen-to-carbon ratios in liquid CDS products (NAS 1977). Conversion processes differ only in terms of emphasizing different types of endproducts. In addition to the indirect liquefaction schemes which operate on synthesis gas feedstocks (Salmon et al. 1980), three general techniques are available for direct coal liquefaction (Fig. 5; NAS 1977, Braunstein et al. 1977a): (1) carbonization (pyrolysis) or hydrocarbonization (pyrolysis in a hydrogen-enriched atmosphere), (2) solvation, and (3) catalytic hydroliquefaction (hydrogenation). The last two processes use solvent extraction. However, catalytic hydroliquefaction includes the addition of catalysts to the initial reaction process to enhance rates of hydrogenation.

Liquefaction schemes based on pyrolysis (Table 9, Eq. 9) accomplish the thermal decomposition of coal by heating it in the absence of an oxidizing atmosphere (air or O_2). The initial products are a complex mixture of volatile hydrocarbons condensed from pyrolysis gases, purified coal gases, and a high carbon char. Elevated H_2 concentrations in the pyrolysis reactor help stabilize radical hydrocarbons and increase final H:C ratios in the products. However, the liquid products from pyrolysis reactors are generally lower in both quantity and quality compared with those derived from other liquefaction schemes (NAS 1977). Although the operating temperatures and pressures are less severe in the carbonization processes than those in other types of liquefaction, and the overall designs are less complex, major problems remain to be solved, including wear and erosion of valves and piping, entrained-flow reactor plugging due to agglomeration of coals, and coal caking in fluidized-bed reactors.

Liquefaction schemes using solvation techniques begin by mixing crushed coal with an organic solvent. This slurry is then pumped to a pressurized (13.8-17.2 MPa) and heated (425-480°C) reaction vessel where it is mixed with hydrogen gas and the coal materials are dissolved. During this process, a combination of mild pyrolysis and hydrogenation takes place. In many process designs, the solvent serves a secondary purpose of being a hydrogen donar to radical hydrocarbons (the Exxon Donar Solvent process; Epperly et al. 1981). A filtration step is necessary after the coal/solvent mixture leaves the dissolution reactor to recover the solvent for recycle and to remove ash and other unconverted coal particles from the coal liquids. This solids separation process has caused many design problems (e.g., persistent clogging) due to the difficulty in separating solids from the very viscous mixture of hydrocarbons.

Catalytic hydrogenation can use catalysts in two different methods to increase the quality (i.e., lower boiling point and viscosity and higher H:C ratios) of initial CDS products. The use of catalysts usually requires higher pressures in the liquefaction reactor than any other liquefaction designs (e.g., the H-Coal process operates at pressures in the region of 20.7 MPa (3000 psig); Eccles and DeVaux 1981). These higher pressures increase equipment wear and cause more difficulty in introducing the coal-slurry feed into the liquefaction reactor. Catalysts can be either mixed directly with the crushed coal, transported into the liquefaction reactor, and discarded after the solids separation step (e.g., the Dow liquefaction process; Moll et al. 1981), or located in a fixed position inside the liquefaction reactor (e.g., the H-Coal process; Eccles and DeVaux, 1981).

Indirect liquefaction of coal is more analogous to high-Btu gasification processes than direct liquefaction processes (C. F. Braun & Co. 1979, Salmon et al. 1980, Wham et al. 1981). Synthesis of CH_3OH or gasoline is the most frequent objective of indirect liquefaction. The process flow proceeds from coal to synthesis gas to CH_3OH (Table 9, Eqs. 1-7 and 1-8) and, if desired, gasoline or other reformed hydrocarbons. The CH_3OH synthesis reactions occur in pressurized, catalytic reactors similar to those used in methanation, but different catalysts (e.g., zinc-chrome or copper-zinc combinations), higher pressures [often greater than 10 MPa (100 atm)], and synthesis gas with $H_2/(CO+CO_2)$ ratios only slightly greater than 2 are necessary to optimize the CH_3OH synthesis reactions (Salmon et al. 1980). As with methanation, the conversion reactions are exothermic and have significant cooling requirements. Simple condensation and distillation systems purify the crude methanol produced. Although a synthesis gas feedstock can come from any coal gasification process, recent studies indicate that entrained-bed gasifiers with high operating pressures are more suitable for coupling with CH_3OH synthesis due to higher flow-through volumes, higher H_2/CO composition, less need for pressure changes between reactors, and smaller concentrations of undesirable by-products (Salmon et al. 1980). Fischer-Tropsch and M-Gasoline processes are two indirect liquefaction schemes with strong commercial potential that convert CH_3OH into larger hydrocarbons by catalytic reformation (Rogers et al. 1978).

4.2.3 Auxiliary Processes

The unit processes along the main conversion stream in CDS production (i.e., those processes directly linked to the gasifier and liquefaction reactors) constitute only part of an overall project design. Other important processes prepare raw materials for input to the main conversion stream, extract by-products, or treat the waste streams created in the various stages of coal conversion (Fig. 6). The design and operation of these auxiliary processes are as important to the evaluation of CDS projects as are the central gasification or liquefaction processes because they are involved in the use of raw materials and the removal of pollutants before they are released to the environment. To understand potential project impacts, each of these processes should be identified in a project flow diagram of inputs, outputs, and fates of waste constituents.

4.3 POTENTIALLY SIGNIFICANT ISSUES

Potentially significant environmental impacts associated with construction and operation of proposed CDS projects should be described in detail. In addition to addressing these issues, general background information on the affected environment should be reviewed to determine if any additional significant or controversial issues are apparent. For example, a review of this background information could show that an historic site is present on the project property and that portions of a 100-year floodplain could be affected. In such a situation, the applicant should upgrade the information and analysis as appropriate.

The following issues are those most likely to be significant for CDS projects and should be carefully reviewed. If this review shows that the issue is not relevant to the proposed project, then the reasons for not presenting a detailed analysis should be discussed.

4.3.1 Land Use

The types of information needed to assess the impacts of CDS projects on land use are generally similar to those needed for any other project involving construction and operation of a large-scale

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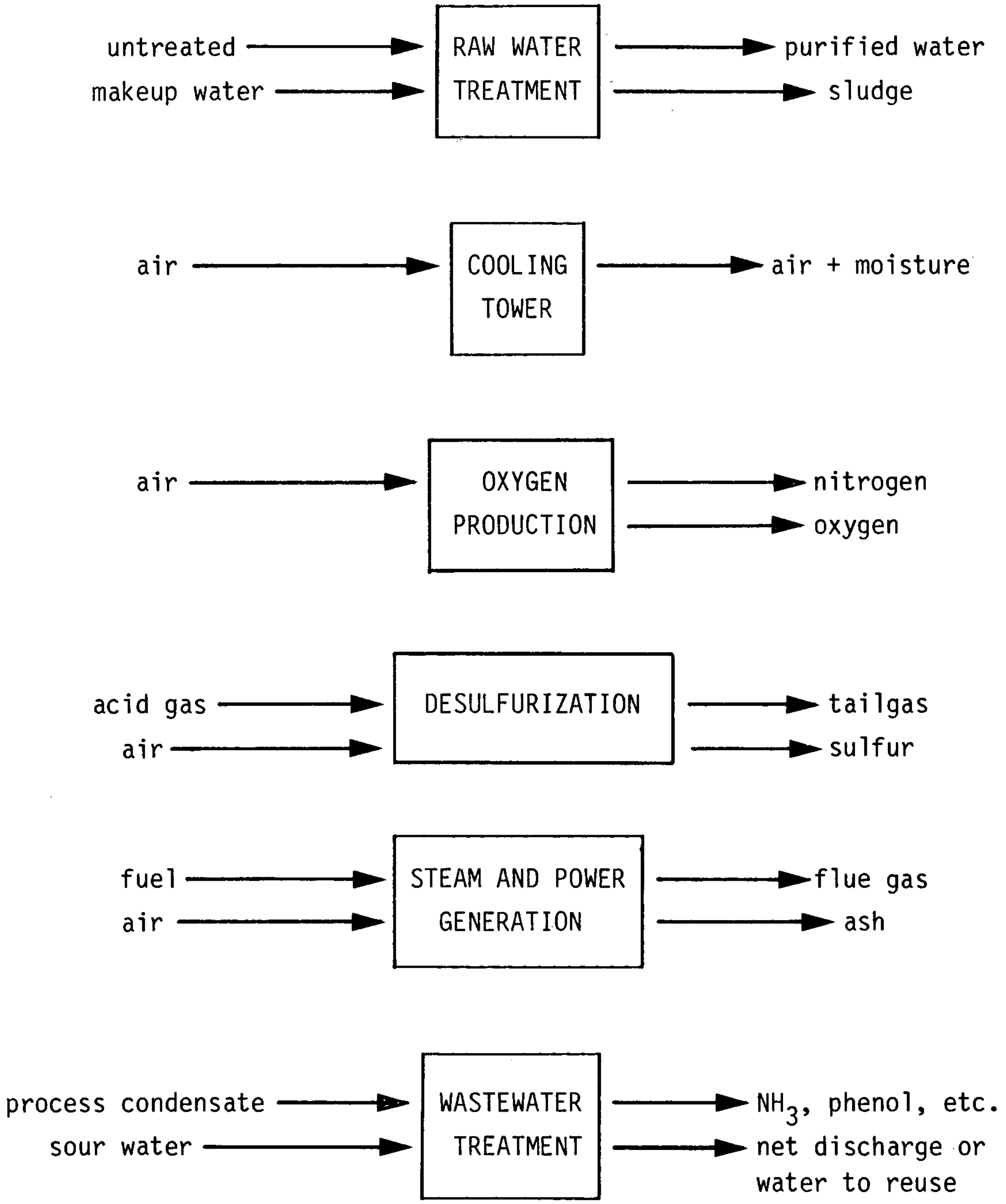

Fig. 6. Examples of auxiliary processes supporting the main coal-derived synfuels production process.

facility. Land-use impacts of CDS facilities can result from onsite activities, coal mining, construction of transmission lines and pipelines, solid waste disposal, product spills, and secondary urban growth. The need for coal conversion facilities to locate adjacent to navigable waters for barge facilities and process and cooling water may result in adverse impacts on river bottomlands, floodplains, wetlands, prime farmlands, and shorelines. However, it is possible for coal conversion plants to locate in uplands distant from navigable waters, and this alternative should be thoroughly explored.

The need for CDS plants to be located near coal mines can contribute to significant cumulative impacts on land use within coal mining regions. In addition, the large work force associated with the construction and operation of CDS plants usually requires temporary housing (e.g., mobile home parks) and residential developments that can cause land-use conflicts.

Gaseous and particulate emissions to the atmosphere from CDS operations could potentially alter agricultural land use through effects on crop plants. The environmental analysis should address the potential occurrence of such impacts by using data on projected atmospheric emission concentrations (Sect. 4.3.2) and known sensitivities of crop species grown in the area.

Information should be developed on the quantity of land area affected by onsite and offsite facilities, coal mining required to support plant operation, and disposal areas or land fills. Although the specific impacts of coal mining on land use are not normally considered in the environmental review of a CDS facility, general information should be provided on impacts associated with the opening of new mines to provide feedstock for the proposed facility. In addition, if the proposed facility is a mine-mouth operation, the environmental impacts, including those on land use, should be evaluated. Alternatives for reducing impacts on prime farmlands, wetlands, floodplains, and shorelines should be thoroughly discussed.

4.3.2 Air Quality

Prediction of gaseous and particulate emissions from CDS facilities is currently somewhat conceptual because knowledge of plant designs and experience with the operation of large commercial plants are lacking. The analysis should draw on information from the technical literature and current operating data from functioning pilot, demonstration, and commercial facilities. The following reports and EISs are examples of references that should be consulted: U.S. EPA 1973, 1978a, 1978b; Acurex Corp. 1977; Murin et al. 1980; PEDCO 1976; U.S. DOE 1981b,c,d.

Major air quality issues associated with coal conversion include degradation of air quality through the release of criteria and noncriteria pollutants including known carcinogens. Much research is needed to determine the effects of the CDS industry on air quality and the general public. The research needs have recently been documented for the Federal Interagency Committee on the Health and Environmental Effects of Energy Technologies (MITRE 1981a, 1981b).

Estimates should be made, if practicable, of all gaseous and particulate emissions including controlled emissions from stacks; cooling tower emissions (which may include process chemicals leaking into the cooling system and treated process "water" used as cooling tower makeup); fugitive emissions (e.g., leaks from pump seals, valves, etc.); emissions during product storage and shipping; and windblown dusts from coal piles, transported slag, and coal in transit both offsite and onsite. Estimates during plant startup and shutdown, routine operation, and upset and emergency conditions should be provided. The bases for the estimates (e.g., coal composition, control equipment efficiency, literature, assumptions) and any conservative biases employed in the calculations should be indicated. In many cases the existing impact statements on proposed CDS facilities (U.S. DOE 1981b,c,d) can serve as models of the specific types of information that should be presented.

The following gaseous and particulate substances may be emitted from CDS facilities, and the best estimates of emissions for each should be provided (MITRE 1981b):

- criteria pollutants: oxides of sulfur and nitrogen, carbon monoxide, lead, nonmethane hydrocarbons, and total suspended particulates;
- inorganic gaseous pollutants (e.g., hydrogen cyanide, metal carbonyls, hydrogen sulfide, and other reduced species that may be produced, such as AsH_3, SbH_3, PH_3, H_2Se, H_2Te, etc.);
- gaseous, particulate, and particulate-adsorbed organic pollutants [e.g., aromatics (benzene, etc.), polynuclear aromatics (with emphasis on nitrogen-containing or oxygen-containing PNAs), oxygen-containing organics (phenols, carbonyls, ethers, peroxides, acids, etc.), nitrogen-containing organics (amines, nitrosoamines, etc.), and sulfur-containing organics (carbonyl sulfide, etc.)];
- size distribution of particulates;
- inorganic constituents of particulate matter: lead, cadmium, mercury, nickel, chromium, beryllium, thallium, tellurium, selenium, arsenic, molybdenum, aluminum, iron-containing compounds, fluorides, nitrates, silicates, sulfates, and sulfites; and
- thorium and uranium and their daughter products.

Ground-level concentrations of pollutants should be estimated by dispersion modeling for comparison with the appropriate national ambient air quality standards and guidelines. Estimates should be made for SO_2, NO_2, CO, lead, nonmethane hydrocarbons, and total suspended particulates. Existing ambient levels of these pollutants based on monitoring at the site and at appropriate offsite monitoring stations should also be provided. Consumption of Prevention of Significant Deterioration (PSD) increments and effects on air quality in Class I, II, and III areas should be discussed, including consideration of interaction of emissions with those of other proposed facilities and facilities under construction in the region. Ozone, a secondary pollutant, and odors that may be a nuisance to the local populace should also be discussed.

The methods and equipment used to control emissions, their projected efficiencies, and a directed maintenance program to limit fugitive emissions should be described in detail. Alternatives considered should be indicated. The types of emissions resulting from end-use combustion and proposed monitoring of process streams and emissions should be described.

4.3.3 Water Use

Projects producing CDS will be consumers of significant amounts of water (e.g., Whitlach 1977). Estimates of net water consumption at proposed demonstration projects range from 2.5 to 3.6 L/kg (600 to 860 gal/ton) of coal processed (U.S. DOE 1981b,c,d). Goldstein and Yang (1977) projected slightly smaller net water demands for SRC projects in New Mexico and North Dakota, ranging from 0.8 to 1.2 L/kg (190 to 330 gal/ton) of coal processed. Although CDS projects may be located in regions not usually considered to be water-resource limited, their direct and cumulative impacts can introduce new water demands that compete with existing water uses (e.g., Appendix CC in U.S. DOE 1981b or Fuessle et al. 1978). Adequacy of local water supplies and the regional implications of new water uses must be carefully examined.

The water quantity requirements should be in sufficient detail to indicate water needs for specific consumptive and nonconsumptive categories of water use. Plans for meeting these requirements should then be identified in the form of a comprehensive water management plan (sources, sinks, and volumetric flow rates). Among the water-use categories that should be covered are the following:

- coal preparation and crushing,
- cooling,
- ash quenching and disposal,
- process make-up water,

- scrubbing of off-gases (e.g., desulfurization),
- domestic consumption,
- fire protection,
- reservoir evaporation, and
- dust control.

In addition to flow diagrams, water management plans should specify the sources for satisfying the requirements of each water-use category. More specifically, information should be provided to identify:

- surface water sources to be utilized, including descriptive hydrology of the watershed and planned withdrawal rates;
- groundwater sources to be utilized, including aquifer description and safe yields;
- dependence of project water sources on the construction of related water development projects;
- interrelationships between groundwater sources utilized and surface water, other aquifers, or rechange zones which might be affected by the synfuel project; and
- institutional, legal, and political arrangements involved in obtaining water supplies, including documentation of appropriate water rights, entitlements, or permits.

The quality of water sources should be described to ensure that it meets project requirements. Necessary water treatment should be described. All opportunities for water recycling and conservation within the project design should be evaluated and should be emphasized in the consideration of these types of alternatives (Fig. 7). Zero-effluent operations that maximize water reuse are desirable both in terms of reducing impacts on ambient water quality and conserving regional water resources. However, the possibilities of excessive

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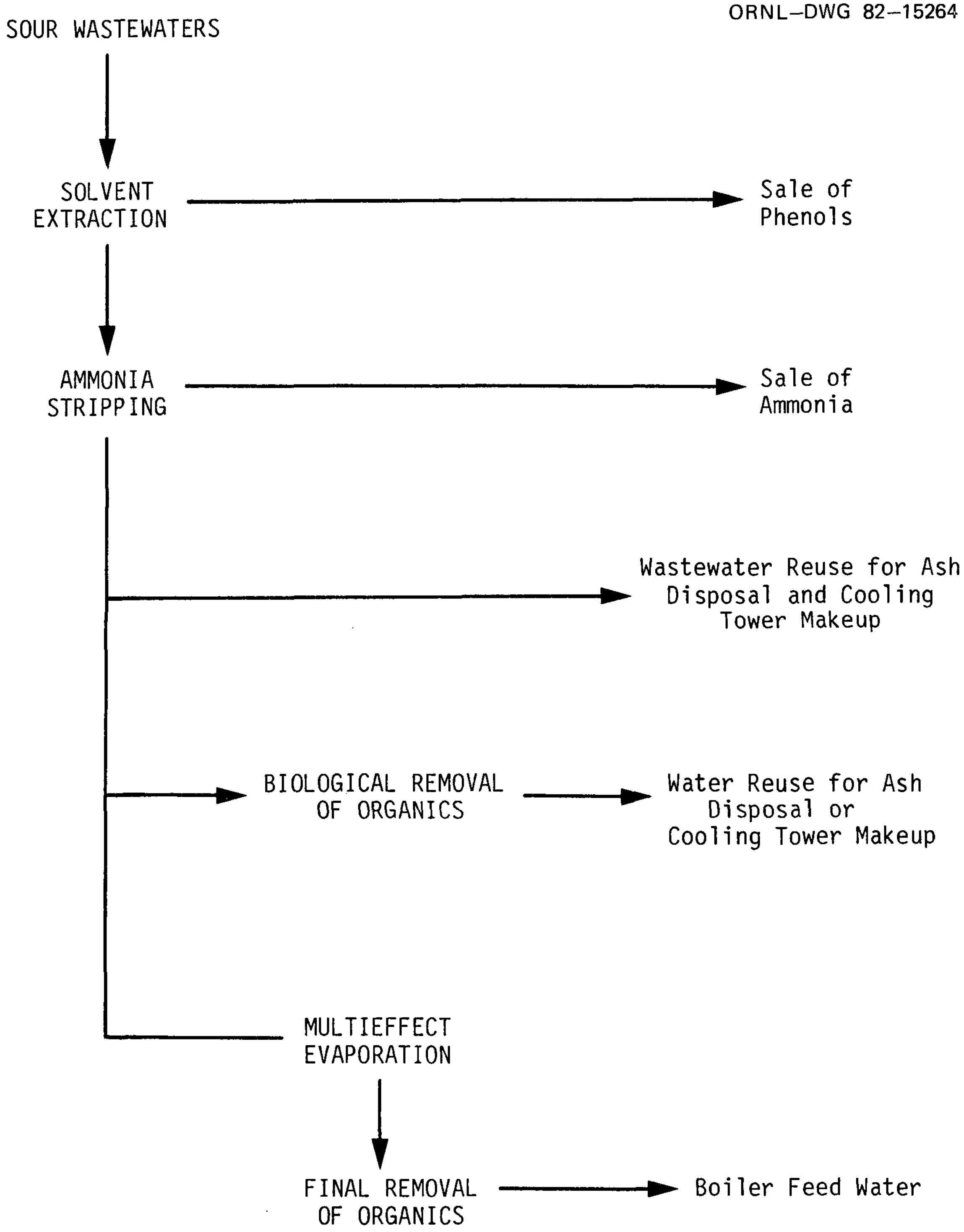

Fig. 7. Examples of wastewater reuse alternatives (Goldstein and Yang 1977).

buildup of inorganic substances (e.g., chlorides) that may occur during water recycling should be examined especially in zero-effluent designs.

4.3.4 Water Quality

Potential water pollution problems associated with coal gasification and liquefaction result from three principal sources: (1) point-source effluents from waste treatment facilities; (2) surface runoff or leachate from solid waste disposal areas, coal stockpiles, or the other parts of the plant site; or (3) accidental spills that may occur during storage or transportation of liquid CDS. Consumptive water withdrawals may also reduce the dilution capabilities of local surface waters and thereby increase the impact of proposed or existing wastewater effluents. To evaluate the potential adverse effects on water quality, sufficient information should be developed to describe ambient, pre-project water quality conditions and to estimate post-project water quality conditions under various modes of operation. Even projects with zero-effluent designs under normal operation should consider the implications of wastewater discharges during abnormal operating periods (e.g., startup, shutdown, or equipment failure). Because these discharges are likely to contain the highest concentrations of hazardous or toxic wastes, the waste treatment procedures and chemical composition of all process condensates, sour waters, gas-stripping wastes, and cooling water blowdown should be described.

The specific pollutants formed during the production of CDS include a large number of inorganic, organic, and trace elements. All of the inorganic constituents of coal (Table 8) are potential constituents of the wastewaters discharged from CDS projects. In addition to these inorganic and trace elements, many complex organic molecules will be released by CDS projects. Several of these pollutants are among the 64 priority pollutants for which the U.S. Environmental Protection Agency has published water quality criteria (Table 10). For other potential effluent constituents, especially PAH compounds, there is little or no available information concerning

Table 10. U.S. EPA water quality criteria for potential pollutants from coal gasification and liquefaction processes (*all units are ug/L*)

	Criteria for freshwater aquatic life[a]		Toxicity to freshwater aquatic life		Human health
	24-h average	Not to exceed	Acute	Chronic	
Trace elements					
Arsenic	--	440	--	--	0
Cadmium	exp[1.05 ln(h)-8.53]	exp[1.05 ln(h)-3.73]	--	--	10
Chromium (hexavalent)	0.29	21	--	--	50
Chromium (trivalent)	--	exp[1.08 ln(h)+3.48]	--	--	170,000
Copper	0.29	exp[0.94 ln(h)-1.23]	--	--	1000[b]
Lead	exp[2.35 ln(h)-9.48]	exp[1.22 ln(h)-0.47]	--	--	50
Mercury	0.00057	0.0017	--	--	0.000144
Nickel	exp[0.76 ln(h)+1.06]	exp[0.76 ln(h)+4.02]	--	--	13.4
Selenium	35	260	--	--	10
Zinc	47	exp[0.83 ln(h)+1.95]	--	--	5000[b]
Industrial wastes					
Cyanide	35	52	--	--	200
Phenol	--	--	10,200	2,560	3500, 300[b]
2-4 dimethylphenol	--	--	2,120	--	400[b]
Aromatic hydrocarbons					
PAH	--	--	--	--	0
Naphthalene	--	--	2,300	620	Insufficient data
Fluoranthene	--	--	3,980	--	42
Acenaphthene	--	--	1,700	520	20[b]

[a] h = water hardness measured as mg/L $CaCO_3$.
[b] Based on taste and odor thresholds.

SOURCE: U.S. EPA 1980.

environmental effects or acceptable concentrations in receiving waters. The analysis should identify all available water quality standards (federal and state) for the individual waste constituents identified in project effluents.

The major nonpoint source of water pollution will occur as a result of surface runoff and leachate from coal CDS solids and ash storage and disposal areas (Wachter and Blackwood 1978). Plans should be discussed for covering stockpiles to minimize leachates and provisions for collection and/or treatment of surface runoff. Leachate test results for any solid waste generated by the project should be presented in discussing potential water quality degradation.

Prediction of the fate of pollutants as complex as those resulting from coal liquefaction or gasification is a difficult task requiring continued research. For example, PAHs released into aquatic environments undergo a combination of processes including dilution, dispersion, volatilization, photolysis, sorption, sedimentation, bioaccumulation, and metabolism by microorganisms (Herbes et al. 1980). These processes are controlled by both the characteristics of the aquatic environment and properties of the specific pollutant. To provide a basis for assessing risks to water quality, the environmental analysis should carefully describe properties of the receiving system, including:

- wind and water velocity patterns in the vicinity of effluent outfalls;
- other climatic factors such as temperature and sunlight regimes;
- morphology (e.g., depth and width) beginning at outfall locations and extending a reasonable distance downstream;
- descriptive hydrology of receiving water bodies; and
- ambient water quality, such as turbidity and suspended solids loads, that affect the fate of toxic pollutants.

Accidental spills of liquid CDSs can also have adverse consequences in aquatic ecosystems. Because chemical and physical properties of petroleum crude oil and CDS liquids differ (e.g., higher phenolic, PAH, and nitrogen content and specific densities greater than 1.0), CDS spills will behave differently than petroleum spills (e.g., Appendix Z in U.S. DOE 1981b). Data that should be included to assess the impacts of accidental spills are the following:

- likely transportation routes, transportation methods, and volumes of final CDS products to be shipped to various markets;
- chemical composition and physical properties of final products;
- proximity of transport routes to sensitive areas such as public water supply intakes, commercial and sport fisheries, or water-based recreation areas; and
- physical and hydrologic descriptions of receiving systems for potential CDS spills.

In most cases, one or two scenarios of spill events and locations will be adequate to assess the risks involved with accidental releases of CDS products into aquatic environments.

4.3.5 Solid Waste Disposal

Large volumes of solid waste will be generated during coal gasification and liquefaction processes. Between 20 and 40% of the coal feedstock in the conversion process will remain as solid wastes requiring disposal. These wastes will include:

- refuse from coal-cleaning operations;
- ashes, slag, and char remaining after the conversion processes;
- spent catalysts; and
- sludges produced in water and wastewater treatment and flue-gas desulfurization.

Plans should be described for disposal of these wastes in an environmentally acceptable manner. The applicability of current federal or state regulations (e.g., Resource Recovery and Reclamation Act/hazardous waste regulations) concerning the disposal of solid wastes should be determined at the time of the project proposal by consultations with appropriate authorities, and the results of these consultations should be documented.

4.3.6 Impacts on Biota

Alterations in air and water quality and modifications in land-use patterns associated with the construction and operation of proposed CDS projects can result in major impacts on surrounding ecosystems. The primary impacts on terrestrial biota by industrial developments such as these are usually associated with loss of habitat. In addition to land-use changes which disturb natural habitats, atmospheric emissions can cause adverse effects on plant community productivity or species composition and thus result in indirect impacts on wildlife. The environmental analysis should discuss the sensitivity of local plant communities to acute and chronic stress that may be caused by atmospheric emissions. Other long-term phenomena such as deposition of trace elements and organics and their accumulation in soils and vegetation should also be assessed.

The increased human presence associated with accommodating a new workforce (Sect. 4.3.7) exacerbates the direct effects of the project on terrestrial biota. Indigenous species that are especially sensitive to disturbance (e.g., raptors) will be affected the most. Cumulative impacts leading to potential reductions in natural wildlife populations from such causes as habitat destruction, increased legal and illegal hunting pressure, and other sources of mortality (e.g., road kills or bird collisions with power lines) should be assessed.

Potential impacts on aquatic biota result from mechanisms similar to those acting on terrestrial biota. Wastewater effluents (Sect. 4.3.4) are a major concern, as are aquatic habitat loss and impingement or entrainment impacts associated with surface water withdrawals. Project effluents containing PAHs and other organic pollutants have a variety of adverse effects on aquatic biota, including acute and chronic toxicity, sublethal behavior modifications, bioconcentration, carcinogenicity, mutagenicity, and fish-flesh tainting (Braunstein et al. 1977b). All trophic levels can be affected, including algae which are as sensitive or more sensitive than higher organisms to the effects of many of the PAHs generated during CDS production (Giddings and Washington 1981).

The impacts of consumptive and nonconsumptive water withdrawals on aquatic biota can be significant, but are highly dependent on seasonality and cumulative effects of other water users. Worst-case scenarios during low-flow periods of the year should be used to examine any impacts on aquatic ecosystems, including habitat loss, water quality alterations, and entrainment/impingement of organisms. The seasonal requirements of sensitive life stages of affected aquatic species must also be recognized.

Using general background information on the existing environment, onsite habitat inventory data, and the project description, the environmental analysis should:

- describe impacts on terrestrial and aquatic biota, with special attention paid to endangered, threatened, rare, or otherwise protected plant and animal species;
- estimate the area of each type of habitat that will be disturbed during construction and operation;
- present a reclamation plan for all disturbed areas;
- evaluate the effects of the combined toxicity of individual waste constituents and, where applicable, combined waste effluents on species of affected plants and animals; and
- include results of consultations with state and federal fish and wildlife agencies and conservation personnel.

4.3.7 Socioeconomics

Coal-derived synfuels (CDS) projects will be large-scale complexes involving not only the industrial facility and its transportation systems but also a variety of government and private institutions, workers, consumers, and other interested parties. A wide range of possible social and economic impacts, which in turn may influence development decisions, will occur within this network of project elements. It is particularly difficult to generalize about the probable critical impacts because the nature of the delivery system will vary with the technology and the site. However, factors related to population growth and water availability will clearly be of concern for most projects.

Potential benefits accruing from CDS developments include increased employment, broader tax base, community improvements in a range of available services and facilities, and the stimulation of secondary businesses. These benefits, however, must be balanced against potential impacts such as housing shortages, strains on public services and utilities, symptoms of social stress, small business failures, water shortages, solid waste disposal problems, and perceived decrease in "quality of life" by some residents.

For large-scale CDS projects where significant impacts are anticipated, baseline data needs should provide the following kinds of information:

- population size and composition (ethnic, age, sex, education, and urban/rural mix);
- population change rates (migration, fertility, and mortality);
- local governmental characteristics (jurisdiction, intergovernmental unit coordination and revenue mechanisms, tax and bonding structures, planning and zoning capabilities, political systems);
- economic structure (businesses, financial institutions and resources, trade);

- labor force characteristics (number and type of jobs, income levels, unions);
- public services (water, sewer, police, fire, health, education, transportation, welfare, parks, churches);
- housing stock;
- local organizations and interest groups (supporters and opponents of the proposed project and energy developments in general);
- social structure and life-styles (orientations, salient concerns, attitude to newcomers);
- quality of life features (cost of living, marriage and divorce rates, crime rates, recreation access, transportation);
- institutional, economic, and legal aspects of water supply issues for the facility; and
- institutional, economic, legal, and social issues involved in facility siting and solid waste disposal.

Projections from these data, both with and without development (including alternatives under consideration), can be used to identify potential impacts. The coal conversion facility itself will demand certain services in addition to those required by additional residents. Demands on utilities, including transportation, water, and power, may compete with other users.

The types of potential impacts to be considered are:

- rapid population growth and subsequent decline over the life of the project (construction, operation, and decommissionings);
- project-induced housing shortages;
- public service shortfalls (including transportation impacts);
- temporal and jurisdictional dissociations of costs and benefits for local governments;

- institutional, economic, and social effects of competition for the local water supply;
- institutional, economic, and social effects of land-use changes and solid waste disposal needs;
- significant changes in political, economic, and social structures, with special consideration of their effects on the life-styles of residents;
- community disruption or project delays from local opposition and support to the proposed project; and
- project-induced special needs such as occupational health problems, demand for psychological counseling, etc.

The analysis of impacts should also consider the possibility of secondary developments as well (e.g., sulfur processing and supplier industries). Long-term effects should be contrasted with immediate impacts. Possible concerns to be considered include long-term constraints on local and regional development as the coal conversion facility competes for water, contributes to air quality degradation, etc.

Given current uncertainties, attention should be paid to the institutional, legal, and economic aspects of health problems posed by the proposed coal gasification or liquefaction facilities (Sect. 4.3.8). Popular and institutional perceptions of risks to workers and to neighbors should be considered along with possible mitigation strategies. Controversy could develop over such perceptions of health risks as well as other issues of environmental degradation. Federal and state regulatory requirements and potential legal issues (e.g., water availability or surface mining rights) should be noted. Local attitudes toward all issues should be obtained directly whenever possible. The development of communication channels between resident groups, developers, and governmental bodies is highly desirable.

Significant degradation of existing aesthetic, historic, cultural, and archaeological resources could result from project-related mining, construction, air and water degradation, road traffic, coal transportation, and secondary development. Effects of odor and noise on residents should be noted. Visual concerns should be addressed in light of terrain and local sensitivity with consideration of such features as cooling towers, new power lines, reclamation plans, and secondary commercial and population growth activities.

Finally, special emphasis should be placed on identifying the amount and sources of funds available for mitigation of potential adverse impacts.

4.3.8 Health and Safety

Production of carcinogens and mutagens are of special concern during coal liquefaction and gasification. Biologically active agents are usually associated with the potential emission of hydrocarbons, particularly the polycyclic aromatic hydrocarbons (PAHs) and polycyclic aromatic amines (PAAs). The accumulated evidence supports the possibility of a strong association between worker exposure to high concentrations of coal carbonization products and risk of cancer. However, establishment of dose-response or exposure-response relationships based on exposure to one or a few constituents of coal carbonization is extremely difficult. Although PAHs with known carcinogenic properties [e.g., benzo(a)pyrene] have been measured in coal carbonization products, the production of CDS includes highly complex mixtures of hundreds of hazardous organic compounds and inorganic materials (e.g., sulfur compounds, trace metals and their compounds, and radioactive materials - in short, anything in coal plus any compounds produced in the conversion process). While numerous potential carcinogens have been identified in coal conversion process streams, effluents, and products (Attari 1973; Fourney et al. 1974; Braunstein et al. 1977a,b), current toxicological, epidemiological, and theoretical information is insufficient for precise extrapolation to human health impacts.

Potential risks to the general public associated with synthetic fuels must await further research before they can be assessed. Possible emissions from coal conversion processes include particulates, carbon monoxide, hydrocarbons, nitrogen sulfur compounds, and trace elements. Final product use will be one exposure determinant. For example, although levels of carcinogens may be high in syncrudes, the potential chemical reactions between these materials during distillation or refinement is unknown. It is possible that carcinogens may be reduced in quantity as crude materials are refined.

In preparing an environmental analysis, the following health and safety issues should be considered and addressed as appropriate to the types of processes being proposed:

- exposure to PAHs and other potential carcinogens and mutagens released during the gasification and liquefaction processes;
- exposure to potentially toxic materials emitted during coal cleaning processes, including organic solvents used to clean coal (U.S. DOE 1979);
- acute effects such as inhalation, severe respiratory irritation, and chemical and thermal burns in workers exposed to fugitive emissions, leaks, and spills;
- potential fire and explosion risks associated with the production and handling of flammable materials at high temperatures and pressures (Harris et al. 1980);
- exposure to synthetic crude products which have been found to be more carcinogenic than natural crudes (Epler 1978; Holland et al. 1978) and which contain polycyclic aromatic amines (PAAs) that exhibit exceptionally high mutagenicities (Guerin et al. 1980); and
- exposure to high noise levels associated with coal preparation and other plant operations.

A series of new regulations are emerging under the Clean Air Act, Water Pollution Control Act, Resource Conservation and Recovery Act, Toxic Substances Control Act, and OSHA criteria documents. Adequate control technologies and workplace monitoring will need to be deployed to reduce emissions and wastes to a level sufficient to protect the health and safety of workers and the public as outlined in these evolving regulations (U.S. DOE 1978a,b).

The design and implementation of industrial hygiene and safety programs will be necessary to reduce worker exposures to a variety of mutagenic and carcinogenic materials as well as trace metals. These programs should include medical surveillance of workers, training in personal hygiene, and decontamination procedures (U.S. DOE 1978a,b).

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5. PEAT

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5.1 RESOURCE DESCRIPTION

Peatlands are wetland ecosystems in which more organic matter is produced than is decomposed, resulting in the formation of an organic deposit. A lack of free oxygen, usually associated with a water-saturated substrate or standing water, slows organic matter decomposition. Most peatlands have formed over the past 10,000 to 12,000 years, with many being only 2000 to 5000 years old. The composition of peat deposits is rarely homogeneous and usually varies with depth, reflecting past changes in climate and vegetation. Important factors contributing to the development of a particular peatland are climate, topography, drainage, sources of nutrients, vegetation, and history of development and disturbance. These factors need to be evaluated and understood in predicting environmental impacts resulting from harvesting peatlands.

The size of the world peat resource is poorly known at the present timing especially in tropical regions. Published estimates have ranged from 165 x 10^6 to 421 x 10^6 ha (U.S. DOE 1979a, Kivinen and Pakarinen 1980). Table 11 shows that the nations having the largest areal extent of peatlands are Canada, the Soviet Union, and the United States, while resources in at least 11 other countries exceed 1 x 10^6 ha. Data on peat resources in developing countries (e.g., Burundi, Sri Lanka, and Brazil) are just beginning to be collected. Such information will undoubtedly increase estimates of the size of the world's peat resource significantly.

Characteristics of potentially exploitable peat deposits differ by geographic location and history of development. Peat forms in one of

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Table 11. World peat resource estimates[a]

Region	Area (10^6 ha)
EUROPE	28.2
Finland	10.4
Sweden	7.0
Norway	3.0
United Kingdom of Great Britain and N. Ireland	1.6
Poland	1.4
Republic of Ireland	1.2
West Germany	1.1
Iceland	1.0
Others	1.5
ASIA	182.1
USSR	150
Indonesia	26
China	3.5
Malaysia	2.4
Japan	0.2
NORTH AMERICA	210.2
Canada	170
United States	40.2 (61.0)[b]
OTHERS	0.60
TOTAL	421.1

[a] Kivinen and Pakarinen 1980.

[b] Farnham 1980.

two general ways: (1) by lake-filling processes in which organic materials accumulate in shallow, poorly drained basins (e.g, former ponds, lakebeds, or poorly drained terraces), and (2) by paludification (i.e., swamping) in which sphagnum mosses and associated wetland plants gradually invade flat to moderately sloping mineral soils modifying existing drainage patterns thereby creating waterlogged conditions. Depths of deposits can vary from a few centimeters to more than 6 m.

Although peat deposits are found in the western states (Cameron 1980), proposals for using peat for energy have primarily been restricted to the north-central, northeastern, and southeastern regions of the United States. In the northern Midwest and New England, peat deposits have formed on poorly drained landscapes left by receding glaciers. A variety of peatland types occur in these areas, including (1) raised bog deposits in Maine; (2) numerous small, deep basin deposits in Wisconsin, New York, and New England (Cameron 1980); and (3) extensive complex patterns of raised peatlands in Minnesota (Heinselman 1970). On the southeastern coastal plain, extensive peat deposits formed in large swamps and marshes as sea levels rose and fell during the past 10,000 years (Whitehead 1972, Heath 1975). In North Carolina, for example, three major types of peatlands have been distinguished (Otte and Ingram 1980): (1) pocosins (i.e., evergreen shrub bogs on the southeastern coastal plain) occurring in extensive shallow depressions (e.g., the Dismal Swamp and the Pamlimarle Peninsula), (2) floodplain peats along major rivers draining the coastal plain, and (3) elliptical-shaped Carolina Bays of unknown origins.

Peatlands have been considered a potential energy resource for many years, but only recently has any serious consideration been given to developing U.S. peat deposits for this purpose. Estimates of the energy availability in proven reserves of peat in the United States are tentative, but Farnham (1978) made a preliminary estimate that these reserves may contain as much as 1524 EJ (1443 quads). Recent surveys in some states (e.g., North Carolina) found much less peat than predicted by Farnham (Otte and Ingram 1980), while surveys in other states (e.g., Alaska) found much more (Farnham 1980).

Peat deposits are present in 42 states (Cameron 1980). A recent evaluation of the peat resource in the United States found that Alaska has the largest extent of peatlands, with approximately 51 x 10^6 ha, of which only 2.2 x 10^6 ha are believed to be fuel-grade quality (Farnham 1980). The total U.S. resource is estimated to be approximately 61 x 10^6 ha (Table 12). Figure 8 shows the distribution of major peatland regions in the 48 conterminous states. Fifty-seven percent of the resource is in the north-central states of Minnesota, Michigan, and Wisconsin; 24% is on the southeastern coastal plain (North Carolina, Florida, and Louisiana); and the remaining 20% is scattered throughout the remainder of the Southeast, New England, the Rocky Mountain States, and the West Coast.

Although the general distribution of the U.S. resource is fairly well known, many peat deposits do not contain fuel-grade peat or are

Table 12. United States peat resources

	Hectares[a] X 10^6	Percent of total (excluding Alaska)
Alaska	50.59	
Minnesota	2.91 (2.4)[b]	28.0
Michigan	1.83	17.6
Florida	1.21	11.7
Wisconsin	1.15	11.1
Louisiana	0.73	7.0
North Carolina	0.49 (0.24)[c]	4.7
Maine	0.31	3.0
New York	0.26	2.5
Others	1.49	14.4
Total	60.97	100.0

[a] Data from Farnham (1980) except as noted.

[b] Mundale 1981.

[c] Otte and Ingram 1980.

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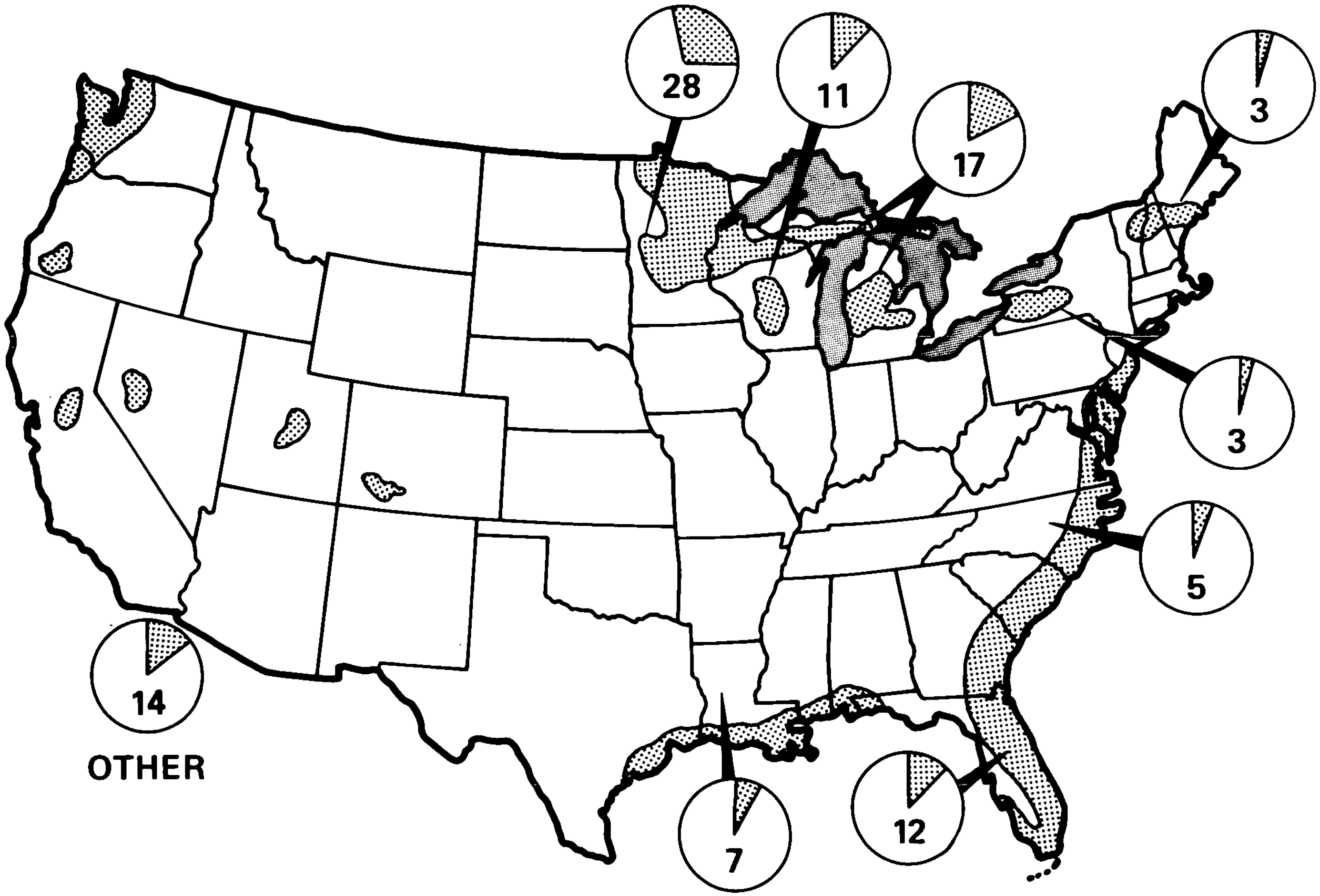

Fig. 8. Distribution of peat resources in the United States, excluding Alaska and Hawaii. Numbers indicate the proportion (%) of the resource in the 48 contiguous states that is present in individual states. Adapted from U.S. DOE (1979).

too widely scattered to be economically recoverable. In a number of states, the U.S. Department of Energy has been sponsoring detailed inventories of peat resources. The data from these efforts, however, will not be available for several years (Mayer and Christianson 1982).

5.2 TECHNOLOGY OVERVIEW

A major restriction to development of peat for energy is the high economic cost associated with transporting the unprocessed peat. Peat has a low energy content compared to coal and has a high moisture content (often in excess of 90%) before it is dewatered. Peat projects will, therefore, normally be located close to peat deposits and will combine mining, dewatering, and energy conversion operations to reduce transportation costs. An exception is the First Colony Farms, Inc., operation in North Carolina that is primarily oriented toward harvesting the peat for sale as a horticultural supplement or as a fuel and using the mined peatlands for agriculture. However, even in this case, proposed energy conversion facilities will be located near the harvest site (Edelman and Manfred 1982, Rea 1982).

The following discussion of peat energy technology addresses four basic steps in the peat fuel cycle: (1) peatland preparation, (2) harvesting (mining), (3) dewatering, and (4) energy use or conversion. Alternative approaches for each step are considered.

5.2.1 Peatland Preparation

The type of peatland preparation required for a particular project depends on whether a wet or dry harvest method is used. With dry harvest methods, a drainage system is established, surface vegetation and obstructions (e.g., rocks or stumps) are removed, the peatland surface is sloped toward the ditches to promote surface drainage, and access roads for machinery are constructed. The spacing and pattern of ditches depends on factors such as the type of harvest equipment to be used, the difficulties of establishing adequate drainage flow, and the system for transporting peat to the site of use. Preparing for harvest normally requires two to five years (Allen 1982, Campbell 1981, Tomiczek et al. 1982). Wet harvest methods require removal of trees and brush and management of water levels to permit the use of floating barges for dredging operations. Dikes may be required to ensure that adequate water levels are maintained.

5.2.2 Harvesting

Dry harvest methods produce milled or sod peat, while wet harvest methods produce a peat-water slurry or bulk wet peat. The method of harvest depends on: (1) the amount of peat required, (2) climatic conditions (e.g., length of harvest and drying seasons), (3) peatland location and physical characteristics (e.g., ease of access and feasibility of implementing drainage), and (4) need for a continuous supply of peat and the problems associated with stockpiling.

5.2.2.1 Milled Peat

The milled peat harvest method is widely used in the Soviet Union and Europe and to a limited extent in the United States and Canada. Special machinery removes a thin layer of peat (0.6 to 5.0 cm) from the peatland surface. This loose material is turned one to several times to promote drying and is then windrowed or is collected with large vacuum harvesters for eventual transport to stockpiles. By turning the milled peat every half hour under favorable conditions, a 30% moisture content can be obtained in 2 to 3 h (Allen 1982, Campbell 1981). In North Carolina, the First Colony Farms, Inc., has had to modify machinery and procedures to handle the large quantities of buried wood that is present in their deposits.

5.2.2.2 Sod Peat

Sod peat is removed with a cutting machine that extrudes a sod approximately 10 cm in diameter and 20 to 30 cm long. These sods are spread on the field to dry and then windrowed for further drying and removal to stockpiles. First Colony Farms has found that sod peats can be dried to 30% moisture content within 7 to 12 d (Allen 1982).

5.2.2.3 Wet Peat

A wet harvest method is generally used if (1) the bog will not support heavy machinery, (2) climatic conditions are unfavorable for dry harvest, or (3) the terrain is unsuitable for drainage. Wet harvest methods generally use water to form a peat-water slurry for transporting peat to the conversion site. Harvest techniques include: (1) washing peat from the sides of exposed ditches with high pressure streams of water, followed by pumping the peat-water slurry in the ditches to the conversion site or (2) using floating dredges or draglines to excavate the peat, followed by mixing and screening the excavated material to form a slurry for pumping to the site. An important difference between wet and dry harvest methods is that wet harvesting is a one-pass operation that excavates all the harvestable peat from one part of the peatland before moving on to the next part. In contrast, dry harvest operations remove a thin layer of peat from the entire peatland surface at each pass, continuing until the harvestable area is mined out, usually involving several to many years.

5.2.3 Dewatering

Because peat harvested by either wet or dry methods has a high moisture content (often exceeding 90%), dewatering to a moisture content of 50% or less is required. To obtain 50% moisture peat from 90% moisture peat, 8 kg of water must be removed from each kg of dry peat (dry weight basis)(Tsaros 1982).

If dry harvest methods are used, the sod or milled peat is spread over the peatland surface to dry in the sun (Lindstrom 1980, Campbell 1981, Mundale 1981). Field drying can produce peat having moisture contents from 30 to 55% but is limited by favorable weather and by the amount of land surface needed to dry the peat. For example, if milled peat were to be used for a 264×10^{12} J/d substitute natural gas (SNG) facility, more than 52,000 ha of peatland would be dedicated to peat harvesting to provide the 52×10^{9} kg of 50% moisture peat needed per day (Tsaros 1982).

For wet harvest operations, alternative approaches for dewatering the peat-water slurry include: (1) mechanical dewatering; (2) solvent extraction; (3) wet carbonization; and (4) partial wet oxidation. Mechanical dewatering uses a press similar to that used for dewatering sludges or paper pulp. By combining mechanical dewatering to reduce the moisture content to 70% with thermal drying (often using process or waste heat), 50% moisture peat can be produced.

Solvent extraction dewatering involves mixing wet peat with an organic solvent. The solubility of water in the peat is increased by subjecting the mixture to elevated temperatures and pressures. Most of the water in the peat dissolves in the solvent, and the solids and liquids can then be separated. Laboratory experiments by the Institute of Gas Technology, using a variety of solvents, showed that as much as 90% of the water in the peat could be removed with this technique using benzene as a solvent (Paganessi et al. 1980).

Wet carbonization is a beneficiation process that heats the wet peat under pressure (e.g., 3.4×10^6 Pa·s at 204°C). The colloidal structure of the peat is broken down in the process, allowing the product to be mechanically dewatered to a moisture content of 35% (Tsaros 1982). Partial wet oxidation is similar to wet carbonization with the exception that the heat needed for the reaction is generated by partially combusting the peat within a reactor, thus using some of the energy content of the potential product.

The dewatering process may be bypassed if complete oxidation processes, which burn as much as 98% of the Slurry organic matter, are used to produce heat and steam. In addition, biogasification uses a wet peat-water slurry directly in fermentation to produce methane, thereby bypassing the dewatering phase (Ghosh and Klass 1979, Smith 1981).

5.2.4 Use or Conversion

Peat can be used directly as a boiler fuel or indirectly as a feedstock for gasification or liquefaction facilities. Direct combustion to produce steam for electricity generation or heating is a proven technology in Europe and the Soviet Union. Peat gasification and liquefaction technologies are under development in the Soviet Union, Scandinavia, and the United States. The size of direct combustion facilities can vary from small plants designed to provide a restricted supply of electricity and/or heat for a local industry or community to a large power or heating plant that can significantly contribute to regional energy demands. Gasification and liquefaction plants will most likely be large facilities, [e.g., one that was proposed for the Minnesota Gas Company would have produced SNG equivalent to 260 x 10^{12} J/d (Punwani et al. 1977)].

5.2.4.1 Direct combustion

Hand-cut peat has been used for domestic heating and cooking for thousands of years. The technology for using peat as a boiler fuel to produce electricity and heat was first developed in the Soviet Union in 1922. Currently the USSR has over 70 peat-fired power plants, the largest of which is rated at 723 MWe (Punwani 1982). Since 1950, ten peat-fired power stations, ranging in size from 20 to 40 MWe, have been built in Ireland and currently provide approximately 16% of that nation's electricity (Brophy 1982). Finland has a rapidly expanding peat energy program with 19 electrical power stations and district heating plants in operation.

Peat-fired power and district heating plants are similar to coal-fired facilities in most respects. The facilities are typically located near the source of fuel because transporting peat long distances is uneconomical. Peat stockpiles are usually located on or immediately adjacent to the peat fields except for relatively small ready reserve piles at the combustion site. Transportation of the peat to the facility may be by narrow-guage railroad, truck, conveyer, or slurry pipeline depending on the distance and the type of harvesting and dewatering operation.

Field-dried peat fuel can have a highly variable moisture content, especially if the peat comes from several sources. Irish experience has found that by blending peats from different sources the moisture content of the fuel can be controlled within two percentage points of the average, thereby stabilizing combustion conditions (Brophy 1982).

Residues of combustion include boiler and fly ash which may be used as a soil supplement in peatland reclamation or may require landfill disposal. The high lime ash produced in Irish peat-burning facilities clogs ash handling equipment, and special techniques are needed to move it from the combustion facility to disposal ponds (Brophy 1982). Dry ash is very finely divided (i.e., powder) and is difficult to handle.

Dried peat is a highly reactive fuel, with low bulk density, high volatility, high oxygen and nitrogen, and low sulfur and ash content (Table 13). The high nitrogen content may cause air pollution problems (King et al. 1980).

5.2.4.2 Thermal gasification

Peat gasification technologies are generally similar to those being developed for coal. A discussion of the basic technology for gasification processes is presented in Sect. 4.2.1 of this report. Peat provides an excellent feedstock for conversion to substitute natural gas (SNG), because it tends to form more hydrocarbon gases than lignite and subbituminous coals (Punwani et al. 1980).

One approach for producing SNG is to use a single-stage peat gasifier with a fluidized bed or an entrained bed. A synthesis gas is produced by gasifying the peat with steam and oxygen and then processing the gas to produce SNG. Although this approach is limited to producing a single product (i.e., SNG) and produces large amounts of tars, it has the major advantage of using commercially available fluidized and entrained bed equipment (Kopstein 1982).

An alternative approach to single-stage gasification is the two-stage hydrogasifier developed at the Institute of Gas Technology (IGT) with support from the U.S. Department of Energy and Minnegasco. In addition to SNG, a number of liquids are produced, including gasoline-blending stock (benzene, toluene, and xylene) and fuel oil, that have greater end-use flexibility. The distribution of products

Table 13. Analyses of peat samples (moisture free)

	North Carolina[a]	Maine[b]	Minnesota[c]
<u>Proximate analyses</u>			
Moisture as received (%)	61.8 - 93.3	82.0 - 94.9	-
Volatile matter (%)	36.3 - 67.4	61.3 - 74.9	65.0
Fixed carbon (%)	21.6 - 39.5	24.3 - 33.0	23.7
Ash (%)	1.2 - 42.1	0.5 - 6.7	11.3
<u>Ultimate analyses</u>			
Hydrogen (%)	3.1 - 6.0	4.8 - 5.9	5.1
Carbon (%)	36.1 - 64.2	51.8 - 60.5	49.9
Nitrogen (&)	0.9 - 2.1	0.5 - 2.2	2.7
Sulfur (%)	0.1 - 0.5	0.1 - 0.6	0.3
Oxygen (%)	17.5 - 33.8	26.5 - 40.7	30.7
<u>Heating value</u>			
MJ/kg	13.6 - 25.9	20.0 - 24.2	19.8
Btu/lb	5860 - 11,180	8620 - 10,417	8506

[a] Range based on 82 samples of Pamlimarle Peninisula peat (Otte and Ingram 1980).

[b] Range based on 70 samples of Great Heath peat (Davis 1980).

[c] Single values reported by Punwani et al. (1980).

can be controlled by regulating the temperatures in the hydrogasifier stage. Based on bench-scale and process development unit studies, maximum SNG production is obtained at relatively high temperatures (760°C), while liquids production is limited to about 15% of the feed carbon. At approximately 540°C, less SNG is produced and direct liquid yields are about 30% of the feed carbon (Punwani et al. 1977).

The IGT has developed a process design for a complete SNG facility using Minnesota peat and producing 264 x 10^{12} J/d SNG (Fig. 9) (Arora and Tsaros 1980). This facility would require a daily input of 52 x 10^{9} kg of peat, of which 75% is process peat and the remainder is used for boiler and dryer fuel. Essentially all of the sulfur produced is converted into hydrogen sulfide and removed along with carbon dioxide in the acid gas removal system (Fig. 9). By-products include substantial amounts of benzene and crude aromatic oils as well as anhydrous ammonia and sulfur.

Additional research and development activities on peat gasification are being conducted by Rockwell International in the United States and by private and governmental agencies in Finland and the Soviet Union (Kopstein 1981, 1982; Punwani 1982).

5.2.4.3 Biogasification

An alternative approach to thermal gasification is the anaerobic digestion of peat to produce methane. Biogasification of peat is initiated by concentrating and pretreating a peat slurry with sodium carbonate and then partially oxidizing it to form a mixture of water-soluble aromatic compounds. This mixture is pumped to tanks where anaerobic fermentation occurs producing methane and carbon dioxide. Pipeline quality gas is produced by scrubbing to remove the carbon dioxide and hydrogen sulfide. The organic materials that are not solubilized in the pretreatment steps and the residual peat materials from the fermentation step can be concentrated and used as animal feed or as soil amendments. The advantages of biogasification are that (1) minimal dewatering is needed, (2) the pretreatment and fermentation steps operate at relatively low temperatures (e.g., 60°C), and

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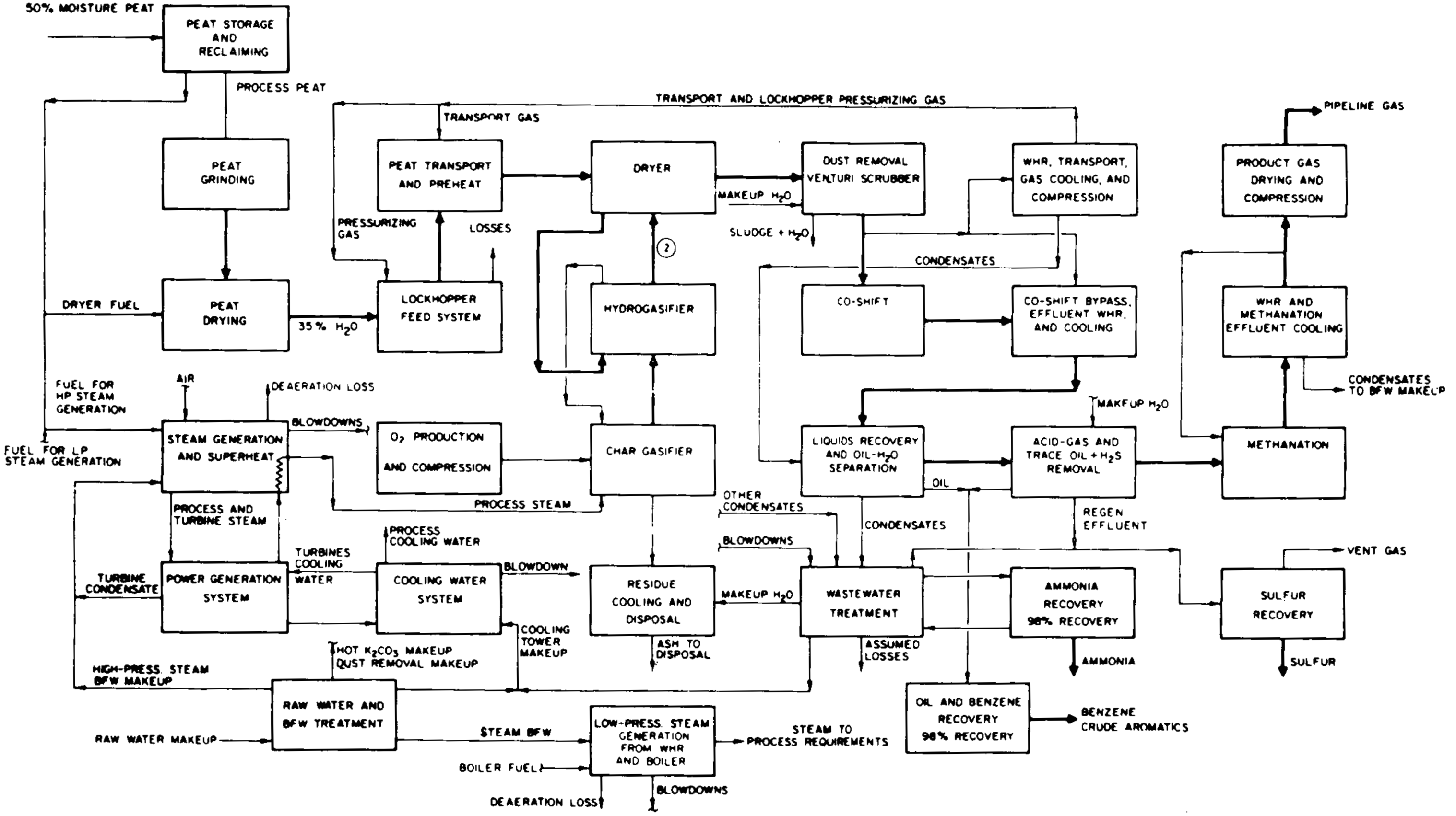

Fig. 9. Process design for Minnesota SNG plant (modified from Arora and Tsaros 1980).

(3) waste streams appear to need minimal treatment. The major disadvantage is that the reactions are slow compared to thermal gasification. Although research on peat biogasification is in its earliest stages of development (Kopstein 1982), the technology for anaerobic digestion using other feedstocks (e.g., sewage sludges and industrial wastes) is well established (Ghosh 1980).

Experiments on in situ biogasification at peat bogs have been conducted in Sweden. Naturally produced methane is present in groundwater from the bogs and is pumped to a degassing station for separation. Although this approach involves low operating costs, the period during which favorable temperatures are present may limit the production potential. In addition, some consideration has been given to combining biological and thermal gasification processes. Digested peat from the biogasification process would be used as a feedstock to produce SNG in a thermal gasification process, thus avoiding the costly step of dewatering that would otherwise be required (Ghosh 1980).

5.2.4.4 Liquids Production

Liquid fuels can be produced from peat in several different ways (Kopstein 1982, Punwani 1982): (1) production of benzene during hydrogasification, (2) indirect liquefaction of synthesis gas (methanol) produced by thermal gasification, (3) direct liquefaction, and (4) conversion of peat to ethanol. The only technology that has commercial potential in the near term is the production of methanol by indirect liquefaction. Two commercial peat methanol plants having a capacity of 2500 m^3/d are under construction in the Soviet Union, and plants of 1000 to 2000 m^3/d are being evaluated in Finland (Solantausta and Asplund 1980). In North Carolina, construction of a peat methanol plant is being planned by Peat Methanol Associates (Rea 1981). This facility using peat from the First Colony Farms, Inc., would incorporate an entrained bed gasifier and have an initial capacity of 650 m^3/d. Methanol production in the United States is currently limited by the available market for the product. If methanol becomes an economic fuel or fuel additive, additional peat methanol projects are likely to be developed. The advantage of producing methanol and other liquid fuels from peat is that a more versatile product than SNG is produced (Mundale 1981).

5.3. POTENTIALLY SIGNIFICANT ISSUES

Peatlands are important components of regional ecosystems and significantly influence regional hydrology, water chemistry, and biota. Because they are often located at headwater or interstream positions of the landscape, peatlands affect regional runoff patterns by reducing subsurface water movement and by increasing overland flow. Peatlands act as nutrient sinks by assimilating nutrients in the surface vegetation and by retaining assimilated nutrients in the organic substrate and on the peat exchange complex. The chemistry of water moving over or through a peat deposit, therefore, can be significantly modified as nutrient exchange takes place. In addition, peatlands provide habitat for a variety of specialized plants and animals and are frequently the last remnants of undisturbed land within a region. These areas may provide important refuge, foraging, breeding, and nursery areas for a variety of wildlife species. Peatlands are often adjacent to and closely associated with other wetlands and aquatic ecosystems in a mutually interacting, complex pattern (Heinselman 1970, Glaser et al. 1981).

The following issues are those most likely to be significant for peatland projects and should be carefully reviewed. The content of this section is based primarily on two recent reviews of the peat literature (Reed et al. 1982a,b).

5.3.1 Land Use

Although peatlands are frequently regarded as being unproductive in their natural state, they are often used for agriculture, forestry, wildlife management, recreation, or wilderness areas. Conflicts may, therefore, arise if mining of such areas is proposed. In many parts of the country, peat soils have been drained and the land converted to high quality farmland. In North Carolina, for example, drainage and clearing of peatlands for agriculture is occurring rapidly (Richardson et al. 1981). In Scandinavia, drainage of organic soils is a common practice to promote reforestation. Because peatlands are often located in remote regions, they may provide important wildlife habitat or be parts of wildlife, recreational, and/or wilderness areas (e.g., the Boundary Water Canoe Area in Minnesota). In addition, peatlands representative of a region and/or supporting unusual species may have been set aside by government agencies or conservation groups as protected areas (Kivinen and Pakarinen 1981, Worley and Klein 1980).

The main use of peat in the United States is currently for horticultural purposes. In 1980, the United States produced 712 x 10^6 kg of peat for uses such as ingredients for potting soil, general soil improvement, mushroom beds, packing flowers, plants, shrubs, and vegetable growing (Davis 1980). Peat has also been used for a chemical feedstock, for medicinal purposes, for coke and charcoal production, and for treatment of municipal wastewaters (Kadlec 1978, Fuchsman 1980, Guntenspergen et al. 1980).

The present land use of peatlands proposed for mining should be evaluated, and alternative uses should be described. Background information on land use should be developed to provide details on:

- the existing land use of the peatland to be mined and the areas to be occupied by proposed facilities for energy conversion;
- the past use of the peatland, including past attempts to drain it or use it for agriculture, forestry, etc.
- trends in development of peatlands for the region in which the peatland is located (e.g., the North Carolina coastal plain);
- any other proposed uses for the peat deposit (e.g., production of sphagnum peat moss or commercial production of cranberries);

- the impact of the project on surrounding land uses (e.g., conservation or cropland areas) during the lifetime of the proposed project and after reclamation has been implemented; and
- conservation values associated with the peatland and efforts that have been made to preserve the peatland.

5.3.2 Air Quality

Most peatlands are located in remote, sparsely populated regions where air quality is generally good and the potential for significant deterioration is high. Air quality may be degraded by dust and fine debris produced by dry peat harvesting methods, especially the milled peat method. Because fine peat debris has a low specific gravity and irregular, fibrous shape, it may remain airborne for great distances (Conklin 1978). Draining a peatland dries out the surface and makes it susceptible to fire. The milled peat harvesting method is particularly susceptible to fire because of the finely divided product that is produced and dried on the bog surface. Machinery, a lightning strike, or a wildfire from surrounding areas can ignite a peat deposit, starting a fire that can burn out of control for long periods of time. The smoke from such a fire can degrade air quality throughout large areas (Conklin 1978). Drainage systems that permit the peat surface to be reflooded if a fire occurs can substantially reduce the risk and should be given serious consideration when developing drainage programs.

Compared to coal combustion, direct combustion of peat results in low sulfur and particulate emissions. The present technology of electrostatic precipitators should limit particulate emissions to acceptible levels (Punwani et al. 1977, RTI 1979). Nitrogen oxide emissions, however, may exceed emission standards (King et al. 1980), and control of nitrogen gases may be required.

Atmospheric emissions from peat gasification plants will include carbon monoxide, hydrocarbons, particulates, sulfur dioxide, ammonia, hydrogen and organic sulfides, and perhaps trace elements such as mercury, beryllium, lead, arsenic, and selenium. Hydrogen sulfide and organic sulfide may cause local odor problems.

Large-scale exploitation of peatlands may contribute to increases in atmospheric CO_2 levels and projected climate changes resulting from these increases (Hansen et al. 1981). Globally, the organic carbon in peat reserves is estimated to be from 150 to 300 Pg C (Moore and Bellamy 1976, Bamryd 1979, Sjors 1980), slightly less than one-half that in the atmosphere as CO_2. Oxidation of a significant portion of this reserve, either by direct conversion to usable energy or indirectly by widespread draining of peatlands for agricultural or other purposes, may contribute to an increase in atmospheric CO_2. This issue, however, must be addressed at regional, national, and international levels rather than on the level of specific projects.

To evaluate the significance of atmospheric effects of proposed peat projects, the analysis should consider:

- the effects of dust and fine debris produced during peat harvesting operations on local and regional air quality;
- the potential for fires to occur, measures to minimize their occurrence, and plans for controlling them if they do occur;
- data on the predicted atmospheric dispersion of emissions from combustion or gasification facilities; and
- information on regional increases in atmospheric CO_2 levels, and possible effects caused by the proposed facility.

5.3.3 Hydrology

Peatlands may form a perched water table and normally have an integral relationship to the groundwater hydrology of the surrounding region. Removal of peat from a deposit will lower the water table, modify the quantity and pattern of surface flow, and alter the water storage capacity of the former peatland (Boelter and Verry 1977, Brooks and Predmore 1978). The extent of this modification will depend on the type of drainage system developed and the water management program implemented after the peat has been mined. Removal of surface vegetation reduces evapotranspiration and may increase annual surface runoff. If the mined peatland is developed for agriculture, the infiltration characteristics of the mineral soil underlying the peat may be modified by cultivation practices, and subsurface flow could be affected. In coastal areas, modification of the hydraulic head associated with the peatland could lead to saltwater intrusion and the resultant contamination of existing freshwater aquifers (Heath 1975, Hughes 1979). Saltwater intrusion may also limit the agricultural potential of mined lands by raising the salinity of the reclaimed soils.

In addition to general baseline information on the affected environment, the analysis of impacts on hydrology should include consideration of:

- existing hydrology of the area in which the peatland is located;
- plans for draining the peat deposits;
- impacts of peat mining on existing surface and subsurface flows and associated aquifers;
- effects on ground and surface waters from use of the reclaimed peatland (e.g., from agricultural or silvicultural use); and
- the potential for the project to increase saltwater intrusion of freshwater aquifers in coastal areas.

5.3.4 Water Quality

Peat harvesting may cause significant deterioration of ground and surface water quality by erosion, release of nutrients and metals from peat oxidation, reduction in ecosystem retention of cations, and mobilization of elements from underlying mineral soils. The clearing of surface vegetation and harvesting operations will increase peat erosion, thereby increasing particulate loading to surface drainage waters (Crisp 1966, Gilliam and Skaggs 1981). The oxidation of adsorbed NH_4^+ accompanying peat drainage may release large quantities of NO_3^- to receiving systems and encourage eutrophication (Given 1975).

Because peat has a high cation exchange capacity and surface reactivity (Given 1975), its removal will reduce retention of atmospheric inputs and thus increase outputs of these cations to the receiving systems. In addition, removal of peat may expose the underlying mineral soil, thereby increasing the rate of weathering and nutrient release. The type of reclamation planned for the mined peatland can significantly influence the severity of such problems.

Liquid effluents from peat energy conversion facilities may include ammonia, phenols, sulfides, suspended solids, oxygen-demanding materials, and trace elements.

Potential project effects on water quality should be considered in detail. This analysis should include:

- evaluation of water quality changes (i.e., characterization of pollutants released from the peatland and from the conversion facilities), including identification of (1) the types and amounts of specific pollutants and (2) the aquatic systems receiving drainage or process waters from mined peatlands and from combustion and gasification facilities;
- identification and predicted releases of potentially toxic substances (e.g., heavy metals and organics) from the peatlands being mined, storage and waste disposal areas, and facility operations;
- plans for treating drainage and process waters; and
- evaluation of potential long-term water quality changes resulting from post-mining land use (e.g., agriculture or forestry).

5.3.5 Solid Waste Disposal

Solid wastes are produced in all phases of peat projects. During the clearing of a peatland, trees, shrubs, and other biomass residues are cut and generally require disposal. In some situations, these materials may be shredded and mixed with the surface layer of peat. This mixed layer is then harvested in the initial milling operation (Allen 1982). Alternatively, these biomass wastes may be removed from the peatland and burned.

Dewatering and pretreatment operations may produce some solid materials that are not used in energy conversion processes (e.g., the unsolubilized organic materials resulting from alkali pretreatment in biogasification). These materials are often used for fuel to generate process heat.

Peat combustion and gasification processes generate ash similar to that produced by combustion and gasification of coal (Sect. 4). Although the ash content of peat is comparable to that of coals, the greater volume of peat required to obtain the same energy output may result in a larger volume of ash. The ash may be used as a soil amendment during reclamation of mined peatlands, but the heavy metal content of some peats may preclude such use and require landfill disposal of the ash. Biogasification of peat produces liquid effluents and sludges that contain high concentrations of nitrogen and trace elements. These wastes may require special treatment before discharge or disposal.

Background information describing the project and existing environment should be supplemented as necessary to permit a detailed evaluation of:

- the types and quantities of solid wastes produced during clearing, mining, pretreatment, and energy conversion steps;
- the physical and chemical composition of these wastes;
- the plans for disposal or use of the wastes; and
- the impacts of waste disposal on existing or newly planned landfills; and
- the applicability of current federal, state, and local solid waste standards.

5.3.6 Impacts on Biota

Because peatlands are primarily found in remote and relatively undisturbed regions, they frequently provide important habitat for rare, threatened, endangered, and commercially important plants and animals. In Minnesota, for example, endangered and threatened species occurring in or using peatlands include 18 plant species and four animal species (MDNR 1981). Peatlands may provide specialized habitat conditions for some species with restricted distributions (e.g., orchids) (MDNR 1981). Big game populations such as moose in Minnesota (MDNR 1981) and black bear in North Carolina (Monschein 1981) may use peatland habitats for feeding and refuge from human disturbance. Cedar swamp habitats associated with Minnesota peatlands provide wintering yards for white-tailed deer and important habitat for birds (MDNR 1981). Peatlands are often closely associated with other wetlands that provide habitat for migratory waterfowl and animals such as reptiles and amphibians.

Harvesting peatlands can destroy special habitat conditions for species either directly by destroying the habitat itself or indirectly by modifying hydrological conditions or the water quality of habitats downstream from the harvested peatlands. Input of acidic peatland waters to downstream receiving systems during drainage and subsequent reclamation may adversely affect sensitive biota that are ecologically or economically important. In coastal regions, additions of NO_3^- may be particularly important because nitrogen is a limiting nutrient in estuaries and eutrophication may have an adverse effect on important shell fisheries, nurseries, and spawning grounds. Other adsorbed cations (Sect. 5.3.4), particularly metals, may also be released to surface waters during peat drainage and affect ecological processes in downstream receiving systems.

In addition to general descriptive information, data should be developed from a detailed survey of the plant and animal life of the affected peatland, emphasizing rare, threatened, and endangered species, species with highly specialized adaptations to the peatland habitat (e.g., orchids and bog lemmings), and commercially or recreationally important species (e.g., moose, bear, and furbearers) dependent on the peatland habitat. Any disruption to such species should be evaluated within the context of the status of regional populations and the presence of equivalent habitat that will be left undisturbed (Reed 1979).

5.3.7 Impacts on Unique Ecosystems

Peatlands have a number of unique features that may in specific cases argue for preservation rather than exploitation. In addition to providing habitat for rare and commercially important species (Sect. 5.3.6), peatlands may have scientific and educational values related to geological, biological, and hydrological developmental processes. For example, the "Big Bog" in Minnesota is the largest contiguous peatland in the conterminous United States (116,550 ha).

As peat deposits develop, pollen grains from the peatland and surrounding areas are trapped and preserved in the organic sediments. Palynologists (i.e., specialists who study pollen grains preserved in peat profiles) can remove vertical cores from the peat deposits and reconstruct the types of pollen deposited in the vicinity of the peatland over the period of its development (e.g., up to 12,000 years). This type of study has contributed a great deal to the understanding of past changes in climate and vegetation (e.g., Amundson and Wright 1979, Whitehead 1972) and is currently being used to interpret the significance of past changes of atmospheric carbon dioxide levels in the biosphere (Auerbach et al. 1981, pp. 53-54). Because peatlands are sinks for nutrients and pollutants, they may also provide a long-term record of changes in vegetation and pollutant levels associated with atmospheric emissions. In areas of extensive peatland deposits, representative peatlands should be preserved to allow for future palynological studies. In many cases, where peat deposits are to be harvested, it may be appropriate to collect and preserve cores so that a record of regional variations in peatland features and development is preserved for future study.

The loss of wetlands has become an important national concern (Executive Order 11990 1977, CEQ 1978, Horwitz 1978), and federal and state governments have adopted policies to stem this loss and to avoid taking actions that would lead to the destruction or modification of wetlands. Peatlands are classified as wetlands by the U.S. Fish and Wildlife Service (Cowardin et al. 1979) and are often closely associated with other adjacent wetland areas. Extensive environmental review may be required by state and federal government agencies before permitting peat mining (U.S. DOE 1979b, 1981).

An assessment of the uniqueness of peatlands should be based on both a detailed evaluation of the peatland to be mined and an overall evaluation of similar and related regional ecosystems (Reed 1979).

5.3.8 Reclamation

The reclamation of harvested peatlands is considered by many to be a major advantage in using peat for energy because the "nonproductive" peatland can be converted to "productive" use (e.g., agriculture or silviculture). Such major changes in land use and disruption of existing ecosystems, however, can have major environmental consequences if reclamation is not adequately planned and achieved. Proposals for post-harvest land use have included developing the site for cropland, pasture, forest production, or biomass energy plantations (Farnham 1978). Such uses require the installation and maintenance of permanent drainage systems and often involve intensive cultivation and other management practices. Potential environmental effects from these types of activities can include permanent alteration of freshwater flow regimes, increases in the sediment load to downstream receiving systems, addition of pesticides and herbicides to drainage waters, and permanent displacement of wildlife populations dependent on peatland habitat. In addition, cultivation of the mineral soils underlying the peat deposits could alter the porosity of the substrate and promote contamination of shallow aquifers. Harvested peatlands along the coastal plain of the Southeast may be at or below sea level and thus subject to saltwater intrusion and flood damage during major storms. If the harvested peatland is to be flooded permanently, construction of dikes may be required and management of water levels may be required to avoid disrupting established flow patterns. Although reclamation potential is high for many harvested peatlands, the development of new land uses is accompanied by different environmental impacts, and their evaluation should be part of project planning.

The discussion and evaluation of proposed reclamation plans should include a detailed consideration of:

- impacts on water and air quality associated with the reclaimed land use;
- impacts on wildlife populations caused by permanent elimination of the mined peatland habitat;
- alternative reclamation possibilities and the rationale for selecting the proposed plan;
- long-term changes in surface and groundwater hydrology as compared to pre-project conditions; and
- available mitigation measures and proposed monitoring programs.

5.3.9 Socioeconomics

Most peat resources are located in relatively remote regions (Fig. 8) that are often economically depressed (RTI 1979, Radian Corp. 1980). Usually these regions have no other domestic fossil energy reserves, although biomass energy production is often feasible (RTI 1979). Usually these regions are net importers of electricity, natural gas, and other fuels. Development of peat energy projects is, therefore, seen as a positive economic stimulus.

The impact of peat energy projects on the local economy and communities must be carefully considered to avoid rapid population growth with its incumbent stress on the local supply of goods and services and potential decrease in quality of life. The extent of socioeconomic impacts will vary with project size and the region in which the project is located. Development of a number of small peat-fired power plants throughout a region is unlikely to cause significant, long-term socioeconomic problems. However, large-scale facilities such as the 260 x 10^{12} J/d SNG plant proposed by the Minnesota Gas Company would employ large numbers of workers during construction and operation and would have major impacts on local communities.

Potential benefits accruing from peat developments include increased employment, broader tax base, community improvements in a range of available services and facilities, and the stimulation of secondary businesses. These benefits, however, must be balanced against potential impacts such as housing shortages, strains on public services and utilities, symptoms of social stress, small business failures, water shortages, solid waste disposal problems, and perceived decrease in quality of life by some residents.

For large-scale peat projects where significant impacts are anticipated, analysis of the following types of project impacts may be needed:

- rapid population growth and subsequent decline caused by the project (i.e., boom and bust cycle);
- project-induced housing storages;
- public service shortfalls (including transportation impacts);
- temporal and jurisdictional dissociations of costs and benefits for local governments;
- institutional, economic, and social effects of land use changes, solid waste disposal needs, and competition for water;
- significant changes in political, economic, and social structures, with special consideration of their effects on the life-styles of residents;
- community disruption or project delays resulting from local opposition to and support of the proposed project; and
- project-induced special needs such as occupational health problems and demand for psychological counseling.

The analysis should also consider the socioeconomic impacts of secondary developments such as industries developed to supply the peat facility and to market by-products such as sulphur. Long-term effects should be contrasted with immediate impacts. Possible concerns to be considered include long-term constraints on local and regional development as the peat facility competes for water, contributes to air quality degradation, etc.

Given present uncertainties, attention should be given to the institutional, legal, and economic aspects of health problems (Sect. 5.3.10) posed by the proposed peat combustion or gasification facilities. Popular and institutional perceptions of risks to workers and to neighbors should be considered. Controversy could develop over such perceptions of health risks as well as other issues of environmental degradation. Federal and state regulatory requirements and potential legal issues (e.g., water availability or surface mining rights) should be noted. Local attitudes toward all issues should be obtained directly whenever possible. The development of communication channels between resident groups, developers, and governmental bodies is highly desirable.

Significant degradation of existing aesthetic, historic, cultural, and archaeological resources could result from project-related mining, construction, air and water degradation, road traffic, peat and product transportation, and secondary developments. Effects of odor and noise on residents should be considered (noted). Visual concerns should be addressed, with consideration of such features as cooling towers, new power and pipelines, reclamation plans, and secondary commercial and population growth activities.

Finally, in cases where significant adverse impacts are likely to occur, special emphasis should be placed on identifying the amount and sources of funds available for implementing mitigation measures.

5.3.10 Health and Safety

In general the health and safety issues associated with using peat for energy will be similar to those for coal. Peat mining is essentially a surface mining operation, and the principal hazards are those associated with the operation of large equipment. Peat deposits are generally on flat, wet terrain, and the hazards of rock falls and slumping of overburden piles associated with coal mining are not present. Drained peatlands are susceptible to fire caused by lightning, sparks from equipment, or the spread of wildfires from surrounding lands. Dry harvest operations involve considerable fugitive dust, and equipment operators should be protected from inhalation of these materials.

A major concern in handling and processing dry peat for either direct combustion or peat gasification is the hazard of dust explosions and fire. Careful manipulation of moisture content and elimination of ignition sources can reduce this hazard considerably. Peat stockpiles must be properly formed to limit the danger of spontaneous combustion (Jones 1979). First Colony Farms, Inc., found that moisture content of stockpiles does not change appreciably except in the surface layer and protection from rewetting is not required.

Although there is little information available on emissions and products from peat gasification processes, health risks should be essentially similar to those from coal gasification facilities. Section 4 reviews the risks to workers and the public from exposure to potentially toxic and carcinogenic emissions from coal gasification. Substances of particular concern include polynuclear aromatics, phenols, thiophenes, aromatic amines, benzene, and soluble heavy metal compounds and complexes (King et al. 1980).

The analysis of health and safety issues should evaluate the following issues as appropriate to the proposed project:

- exposure of workers to fugitive dust in harvesting, handling, and processing of mill and sod peat;
- prevention and control of fires on peatlands being mined;
- prevention and control of explosion and fire in the handling, transportation, and processing of dry peat for combustion and gasification;
- exposure to PAH's and other potential carcinogens and mutagens released during gasification processes;
- exposure to potentially toxic materials emitted during pretreatment and processing of peat;

- acute effects such as inhalation, severe respiratory irritation, and chemical and thermal burns in workers exposed to fugitive emissions, leaks, and spills;

- exposure to synthetic crude products which have been found to be more carcinogenic than natural crudes and which contain polycyclic aromatic amines that exhibit exceptionally high mutagenicities;

- exposure to high noise levels associated with peat harvesting and plant operations; and

- worker exposure to the risks involved in operating and maintaining large harvesting machinery using cutting blades, macerators, etc.

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