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FINAL REPORT

ONSHORE PERMITTING SYSTEMS ANALYSIS FOR COAL, OIL, GAS, GEOTHERMAL AND OIL SHALE LEASES

Prepared by:
Energy Resources Co.
Cambridge, MA
and Vienna, VA

Prepared for:
Department of Energy
Germantown, Md.

Contract No. DE-AC01-81RA50183
ERCO Project No. 7790

September 1982

MASTER

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SECTION ONE

EXECUTIVE SUMMARY

This report assesses the impact of permitting processes on energy resources development on onshore federal lands.

Permit processes connect government regulatory authorities with industry developers subject to regulation. The processes represent extremely important and visible means of protecting the public interest at the earliest stages of industry activity. Permits are the means by which government authorities convey and enforce the substance of regulations.

Government regulations, however, have become increasingly complex. Legislators attempt to protect the public interest while not hindering industrial progress or ignoring other objectives such as equity and equality. Permit processes, in direct response, have become similarly complex, with occasionally lengthy review processes, mandates for public involvement and comment and, in a few cases, controversies over difficult computer modeling questions (e.g., prediction of air quality impacts as required under the Clean Air Act). As a result, permit-related activities are themselves important. Firms seeking to initiate new projects may count on two or more years of activities in preparing for and completing the permit processes.

The magnitude and complexity of permit processes raises a question as to their impact on the rate and scope of industrial development activity. One particular area where this issue is of concern is in new energy extraction and development activities. The initiation of new energy projects has

been a national priority for several years. But, energy projects, because of their potential for creating land disturbances, are subject to many environmental and other regulations. Because of this, the permitting required of energy resource developers is extensive.

Within the energy field, a major portion of development activities occurs on federal lands. This is particularly true in the Rocky Mountain states and Alaska where the principal landholder is the federal government. The permitting requirements for federal lands' development differ from those for private lands.

This report assesses the impact of permitting processes for energy resource development on federal lands. The permitting processes covered include all of the major environmental, land-use, and safety permits required by agencies of federal and state governments.

The lands covered include all federal lands, with emphasis on eight states with major development activities. The geographic coverage of the study is portrayed in Figure 1-1.

1.1 Legislation Governing Access to Federal Lands

A complex history of legislation defines the guidelines for management of resources on federal lands. The legislation has evolved in response to needs for protecting public lands and for the orderly development of the associated mineral resources.

Figure 1-1. Geographic Coverage of Permitting Study.

The relevant body of legislation may be roughly classified according to (1) mining and associated energy legislation, and (2) environmental legislation. The major laws in each category are listed in Table 1-1.

The primary objective of the mining and energy legislation was to define leasing programs or, in more general terms, avenues for resource extraction on public lands. The Mining Laws of 1872 provided a first attempt at orderly land development by establishing a claims system for appropriating resources on federal lands. Abuses in this system led to the Mineral Leasing Act of 1920 under which the Secretary of the Interior retains title to lands leased for purposes of mineral extraction. Later legislation has added to the authority provided for in the Mineral Leasing Act of 1920. In 1947, the Acquired Lands Leasing Act extended the authority of the 1920 law to lands newly acquired by the federal government. The Geothermal Steam Act of 1970 allows leasing of lands expressly for geothermal development, a land use not covered in the 1920 law.

Other legislation such as the Multiple Use-Sustained Yield Act of 1960 and the Federal Land Policy & Management Act of 1976 established mandates for land use planning by the major federal agencies. The Forest Service and the Bureau of Land Management were thus charged with setting land use policies and were provided with additional authority for selecting among potential competing land users (e.g. forest interests vs. energy interests on a given land tract).

While leasing and land-use legislation defines the basic rules of access and use of federal lands, a number of environmental laws place restrictions on such use. These laws are of a more recent vintage.

TABLE 1-1

MAJOR LEGISLATION AFFECTING ACCESS TO
AND USE OF FEDERAL LANDS

<u>MINING AND/OR ENERGY LEGISLATION</u>	<u>ENVIRONMENTAL AND/OR GENERAL LEGISLATION</u>
Mining Laws of 1872	National Environmental Policy Act (1969)
Mineral Leasing Act of 1920	Clean Air Act (1970)
Acquired Lands Leasing Act (1947)	Federal Water Pollution Control Act of 1972
Multiple Use-Sustained Yield Act of 1960	Endangered Species Act (1973)
Geothermal Steam Act of 1970	Safe Drinking Water Act of 1974
Department of Energy Organization Act (1977)	Resource Conservation and Recovery Act of 1976
Federal Coal Leasing Amendments Act of 1976	
Federal Land Policy & Management Act of 1976	
Surface Mining Control and Reclamation Act of 1977	

The National Environmental Policy Act (NEPA), passed in 1969, established the requirement for preparation of an EIS for major federal actions affecting the environment. Other environmental laws produced permitting programs of importance: The Clean Air Act (and Clean Air Act Amendments of 1977) define the Prevention of Significant Deterioration (of air quality) permit programs, and national standards for air quality control. The Federal Water Pollution Control Act of 1972 established the National Pollutant Discharge Elimination System permit for point source water releases. The Endangered Species Act, along with other wildlife legislation, provides permit and enforcement authorities for protection of selected wildlife. Finally, the Resource Conservation and Recovery Act of 1976 mandates permitting and regulation of hazardous and solid waste disposal.

The Surface Mining Control and Reclamation Act of 1977 (SMCRA) is the major legislation now governing coal mining operations in the United States. Regulations passed under the SMCRA authority were promulgated in 1979 and are undergoing major revisions in the summer of 1982.

Numerous additional laws provide for more specialized control of energy projects. The Federal Mine Safety and Health Act (MSHA) authorized a new agency for promulgation of regulations governing mine construction and operation and personnel training. Archaeological resources are protected under the Antiquities Act of 1906 and the Archaeological and Historic Preservation Act of 1974.

1.2 Permits Required by the Federal Government

In implementing its responsibilities under environmental and land-use statutes, a number of permitting requirements have been established. An accounting was made of the permits required by the federal government with potential applicability to energy extraction projects. The listing of permits includes permits commonly or occasionally required of energy developers in the conduct of operations of federal lands.

A summary tally of the permits identified is provided in Table 1-2 with the main sponsoring agency for each category of permit shown. A total of 73 permits were listed, with the largest single grouping (28) due to energy development control permits issued by the Minerals Management Service. The Minerals Management Service (MMS; formerly the Conservation Division of the U.S. Geological Survey) is responsible for regulation of all energy activities on federal lands. The MMS issues separate permits in each area of oil and gas, coal, geothermal, and oil shale development. The Office of Surface Mining approval process for coal mine plans is included in this total.

The next highest total (16) is due to the numerous variations of rights-of-way or special land use permits which can be issued by federal landholding agency. Basically, each federal agency with landholdings issues rights-of-way permits of some type to allow passage over lands in the course of energy/industrial activities. Such permits are most commonly needed in energy projects for road construction or improvements for movement of heavy equipment.

TABLE 1-2

SUMMARY OF FEDERAL PERMITS APPLICABLE TO ENERGY PROJECTS

AREA	NUMBER OF POTENTIALLY APPLICABLE PERMITS	MAIN SPONSORING AGENCY
Environmental	9	Environmental Protection Agency
Fish and Wildlife	4	Fish & Wildlife Service (DOI)
Energy Development Control	28	Minerals Management Service (DOI)
Land Use or Land Access Controls	16	All landholding agencies
Safety	5	Mine Safety and Health Administration (DOL)
Other	11	Not applicable
Total	73	

Source: ERCO estimates. Permits tallied are those considered of general or occasional applicability to basic energy extraction operations. Some special case permits, or permits for activities beyond the resource extraction stage (e.g., refining) are not included. The number of distinct permits (not counting repetitive permitting requirements) for a given project will generally be well below the total shown.

Environmental permits, although the most consistently controversial, are not numerous, with only nine distinct environmental permits identified. This total includes the PSD and NPDES permits. Also, the Environmental Impact Statement process, although not strictly a permit process, is included in this total.

The permit total, 73, provides an indication of the variety and magnitude of the permitting activities which can be involved for energy projects. The permit total itself should not be used as an absolute quantitative expression of the number of approval processes in existence. Different researchers have developed other permit totals because of differing interpretations in the definition of permits as opposed to other approval processes or reviews which occur in federal agencies. Also, some groupings of permits were made for convenience. Furthermore, this survey focused only on basic extraction activities; "downstream" energy operations were not included.

1.3 State Permits Required for Energy Projects

Listings of state permits applicable to energy projects were prepared as supplements to the federal permit listing. Combined, the federal and state permits nearly exhaust the permits which would be applicable to any energy project. Remaining permits of note are county approvals for land use and, in some areas, county health department clearances. The land use permits of the counties are major permits in some cases, as where local opposition to a project may exist. However, such opposition is not usually evident for conventional energy projects.

A tally of the state permits identified, with a categorization of the permits according to the types of energy

projects to which they may apply, is provided in Table 1-3. As for the federal permit listings, caution should be used in accepting the total shown because of the numerous judgments made concerning the potential applicability of a given permit to energy projects. Also, the energy projects under consideration were restricted to basic extraction and development operations.

The largest permit totals were identified in Colorado, Wyoming, and Alaska. Of these, Colorado has more mining safety-related permits than other states, as well as detailed environmental permits. Wyoming has numerous energy development controls, reflecting perhaps the extent of resource activities in the state. Alaska applies more permitting requirements in the course of environmental protection than do other states, indicative of the sensitive environmental resources of some areas.

The number of distinct permits applied to each resource area varies minimally among states. Coal and oil shale projects require a slightly greater number of permits than oil and gas or geothermal projects in most cases. The simple permit tally underestimates the difference in regulatory controls between coal and oil shale projects, which create major land disturbances, and oil and gas or geothermal projects, which generally do not.

Among states, the nature and extent of permit requirements is quite similar. The similarities in state processes are much more notable than the differences. Although permit totals are varied, energy project developers will encounter permits for certain basic and subsidiary project operations in any state.

TABLE 1-3

SUMMARY OF STATE PERMITS IDENTIFIED

STATE	TOTAL PERMITS IDENTIFIED	PERMITS POTENTIALLY APPLICABLE TO EACH RESOURCE			
		OIL & GAS	COAL	GEO THERMAL	OIL SHALE
Alabama	22	16	15	NA	15
Alaska	32	28	26	22	NA
California	24	21	NA	21	NA
Colorado	43	25	31	24	34
Montana	27	16	16	19	19
New Mexico	25	19	20	17	NA
Utah	32	25	26	28	25
Wyoming ^b	33	21	23	21	25

^aERCO estimates.

^bNine distinct approvals of the Wyoming Oil and Gas Commission which apply to various drilling operations were categorized as one permit for this tally in order to maintain consistency in coverage among the state listings.

NA Not applicable.

1.4 Network Presentations of Permitting Systems

The federal and state permits were integrated into representative project development schedules for each resource area resulting in project/permit network diagrams. The networks describe the place of permitting activities among the numerous tasks that constitute a new energy project. The technique of network presentation used here is that of PERT (Program Evaluation Review Techniques), which is often used for construction project scheduling. For each network, a critical-time path is defined. Activities along the critical path determine the minimum time period required for completion of the project.

The PERT network technique allows analysis of the impact of permitting on project leadtimes. The impact was relatively small for oil and gas operations, but more substantial for other resource areas.

1.4.1 Oil and Gas Project Networks

The project/permit network diagram for an oil and gas plan on federal lands was based on an estimate of a representative project by a medium-sized oil company operating in the lower 48 states. The project/permit network is shown in Figure 1-2, with the permit data from the figure summarized in Table 1-4. The network describes a critical path of 98.5 months from initial exploration work to full-scale production. Duration times and float times are shown for each activity. (Float refers to the time allowance for completion of a given task before the lack of completion delays the entire project.) The times are rough approximations given the wide variations in project scheduling and development that occur.

Figure 1—2. Network Presentation of Representative Oil and Gas Projects on Federal Lands.

TABLE 1-4

FEDERAL PERMITS APPLICABLE TO
NETWORK ANALYSIS OF OIL AND GAS PROJECTS

ACTIVITY BRANCHES (FIG. 6-2)	COMMONLY REQUIRED PERMITS	TIME ALLOTTED	FLOAT TIME	COMMENT
2-2a	Notice of Intent to Explore/ Mineral Management Service (MMS)	1 day	Not applicable	Routine notification Separate notices required for each distinct explor- ation operation.
2b-2c	Notice of Completion of Exploration/MMS	1 day	Not applicable	Routine notification.
8-11	Pre-Staking Clearance (PSC) and Application for Permit to Drill (APD)/MMS	3 months	None	PSC and APD required for each well on federal lands.
8-10	Rights-of-Way/Bureau of Land Management or Forest Service	3 months	None	Rights-of-way issuance and APD generally granted simultaneously.
15-15a	Filing of Notice of Well Completion/MMS	1 day	Not applicable	Routine notification required by MMS after completion.
15-15b	Sundry Notices and Reports on Wells/MMS	1 day	Not applicable	Routine notification required by MMS for mod- ifications of operations

TABLE 1-4 (CONT.)

ACTIVITY BRANCHES (FIG. 6-2)	COMMONLY REQUIRED PERMITS	TIME ALLOTTED	FLOAT TIME	COMMENT
15-15c	Submittal of Modified Multi-Point Surface Use and Operating Plan (MSUOP)/MMS	1 day	Not applicable	Routine submittal to MMS, modifying MSUOP submitted with original APD.
15-18	Authorization for Disposal of Produced Waters/MMS	1 month	2 months	Operation must submit plan for water disposal.
20-21	NPDES and Other Federal Operating Permits/ Various Agencies	6 months	2 months	The NPDES review, taking 6 months, is the only federal environmental permit listed. PSD permits are not generally applicable.
1-15				
<u>Additional Permits of Potential Applicability</u>				
Prevention of Significant Deterioration of Air Quality Permit/Environmental Protection Agency (EPA)	Migratory Bird Permits/F&WS			
Spill Prevention, Containment and Control Plans/EPA	Bald Eagle Permits/F&WS			
Underground Injection Well Operation Permit/ EPA	Approval of Transfer of Operating Rights in an Oil and Gas Lease/Minerals Management Service (MMS)			
Discharge of Dredge or Fill Material to U.S. Waters/ Army Corps of Engineers	Approval of Communitization/MMS			
National Wildlife Refuge - Special Use Permit/Fish and Wildlife Service (F&WS)	Agreement for the Subsurface Storage of Gas/MMS			
Endangered Species Permit/F&WS	Permit for Structures on or Work In Affecting Navigable Waters/COE			
Threatened Species Permit/Fish and Wildlife Service (F&WS)	Permit for Dams and Dikes in Navigable Waters/COE			

TABLE 1-4 (CONT.)

Bridge Permit/Coast Guard	Notice of Proposed Airspace Obstruction/ Federal Aviation Administration (FAA)
Antiquities Act Permit/Department of the Interior	Notice of Proposed Construction - Alteration of Airports/FAA
Application for Permit to Conduct Archaeological Explorations/Forest Service	Natural Gas Certificate of Public Convenience and Necessity/Department of Energy, Federal Energy Regulatory Commission
Timber Sale Contracts/Forest Service	Permit for Bridges over Navigable Waters/ Department of Transportation
Temporary or Permanent Exemption from FUA Prohibitions/ Department of Energy	

In the oil and gas network, permitting activities represent a small portion of the critical path. The federal Application for Permit to Drill (APD) process occupies 3 months of the critical path. (The 3-month estimate for the APD is based on average processing times in field offices of the Minerals Management Service as estimated in 1980.) The oil and gas operator would also request rights-of-way, if needed, across adjoining federal lands at the time the APD is submitted. Environmental or other state operating permits are typically not on the critical path for oil and gas operators. Other Minerals Management Service permits are minor approvals for well operations and activities. A qualitative summary of state permit issues is given in Table 1-5.

An approximate judgment of the difficulty of the federal or state processes was made. The categories for the difficulty judgments are defined as follows:

Difficulty
Rating

1. Permitting delays or related regulatory difficulties have been noted for firms operating in the state (or on federal lands).
2. Some complaints have been registered concerning permit processes but actual delay occurrences appear to be sporadic.
3. Most operators report only occasional delays in projects due to permitting requirements. No major complaints are evident.

Alaska and California were rated as states with difficult permit processes. Alaskan operations are subject to some regulatory duplication because of the lack of state

TABLE 1-5

SUMMARY OF STATE PERMIT ISSUES FOR OIL AND GAS PROJECTS

RELATIVE DIFFICULTY OF FEDERAL OR STATE PROCESSES ^a		NOTABLE PERMIT PROCESSES	SPECIAL OPERATING ISSUES
Federal	1	Application for Permit to Drill Rights-of-Way	- Delays in APD, rights-of-way approval
Alabama	3	Permit for Work in Navigable Water	- Wetland drilling involving COE permits, may be delayed
Alaska	1	State and federal water permit approvals; solid waste permit for reserve pits	- Sensitive permafrost environment - Lack of state authority for environmen- mental permits - State permit for oil field reserve pits
California	1	Air pollution permits	- Permitting of steam generators for thermal recovery - Endangered species issues in federal APD process
Colorado	2	Water well permits	- In some areas, delays in water well approvals
Montana	3	None	- None
New Mexico	3	Effluent discharge plan	- Some discharges restricted for water aquifer or surface water protection
Utah	3	Air pollution permits	- All pollution sources must be permitted
Wyoming	3	None	- None

Source: ERCO estimates.

^aState processes were rated according to the following scale:

- 1 - Relatively difficult; lengthy delays due to permit or regulatory problems have occurred.
- 2 - Average; selected processes are lengthy but few problems noted.
- 3 - Relatively easy; no consistently lengthy processes noted.

authority for environmental programs. Also, the state's regulations for oil and gas development are more stringent than other states'.

California is the site of major heavy (low viscosity) oil which is produced using thermal recovery operations. The heat for steam injection requires use of large oil-fired field generating units, which emit sulfur oxide emissions. In brief, the special recovery operations transform normal oilfield operations into major industrial air pollution sources, resulting in more complex permitting requirements.

Federal permits were classified as relatively difficult because of the widespread complaints about the APD process, and about delays in obtaining rights-of-way clearances. These permit procedures are currently being revised.

1.4.2 Coal Mine Project Networks

The PERT network technique was also applied to a coal mine project on federal lands. The assumed "representative" coal mine project is a large Western surface mine.

Coal mining operations involve a lengthy design, planning, equipment procurement, and construction process. The project/permit network for coal mining is shown in Figure 1-3, with the network permits listed in Table 1-6. The total critical path for the surface mine is 110 months, or over 9 years. Of this, 33 months are accounted for by permitting-related activities. However, the regulatory activities only lengthen the lead time by 12 months, because of overlaps with non-regulatory activities. In other words, if all mining regulations were eliminated, the project lead time would be reduced by only 12 months.

LEGEND

- Activity
- Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months, Second Entry is Float Time.
Ex.—Activity Requires 10 Months Float Time Allowance is 11 Months.
- (ND) Activity Time is Not Determined or Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine Diagram. Letters Denote State Permits.

Figure 1—3. Network Presentation of Representative Coal Projects on Federal Lands.

The dominating permit is the mine plan submittal to the Office of Surface Mining. The pre-application environmental studies and the mine plan review itself occupy a 30-month time period during which all other permits may also be obtained. In coal mining, as for other resource areas, most permits are independent of each other, and can be obtained concurrently.

Unlike the oil and gas network, the state coal mine networks were allowed to vary in length for some activities, reflecting the different scales of operation among the states. The critical paths of the state networks are shown in Table 1-7. In all the states the SMCRA-program mine plan review is the dominant permitting activity. Also, as long as federal lands are involved, the Office of Surface Mining retains responsibility for the final approval of the environmental protection provisions of the mine plan under the NEPA program responsibilities. Thus, the mine plan review process among states will have an invariant component reflecting the consistent federal involvement. No variations in the state networks for the mine plan review were modeled despite the differing state deadlines and procedures for mine plan reviews; all states showed 12 months of the mine lead time as being due to regulations.

The mines in Alabama, Alaska, Colorado, and Utah were estimated to require shorter development times, so lead times for mines in these states were estimated at 86 months. The largest mining operations are in Montana and Wyoming where leadtimes of 122 months were forecast.

An overview of the character of mining operations and permit processes for each state is shown in Table 1-8. Only Alaska and California, which have very limited coal mining

TABLE 1-6

FEDERAL PERMITS APPLICABLE TO COAL MINING
PROJECT NETWORK

ACTIVITY BRANCHES FIG. (7-1)	COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
1-2	Coal Exploration License/ Bureau of Land Management	6 months	None	Allows land entry and drilling on federal lands.
1-3	Approval of Exploration Plan/Minerals Management Service	3 months	3 months	One element in system of control of mineral re- sources.
13-15	Rights-of-Way Permits/ Various Federal Agencies	3 months	15 months	Permits may be needed for off- lease road con- struction. Rights- of-way of a short length are assumed here.
13-16	NPDES Permit/Environmental Protection Agency	6 months	12 months	Multiple discharge points covered under one permit.
13-17	Wildlife Permits/Fish & Wildlife Service	3 months	15 months	Includes permits for activities affecting endangered and threatened species and bald eagles.

TABLE 1-6 (CONT.)

ACTIVITY BRANCHES FIG. (7-1)	COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
13-18	Safety Plan Approvals/ Mine Safety and Health Administration	2 months	16 months	Covers a variety of separate safety plans concerning mine construction and operation.
13-19	Misc. Federal Permits/ Federal Communications Commission and the Alcohol, Tobacco and Firearms Div., Treasury Dept.	4 months	14 months	Covers permits for radio systems and explosives use.
25-30	Mine Plan Review/Office of Surface Mining	6 months	None	The principal mining permit.
24-29	Environmental Assessment or the Environmental Impact Statement/Office of Surface Mining	12 months	None	The extent of the environmental review depends upon the serious- ness of expected impacts.

TABLE 1-6 (CONT.)

ACTIVITY
BRANCHES

FIG. (7-1)	COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
<u>Additional Permits of Potential Applicability</u>				
	Discharge of Dredge or Fill Material Permit		U.S. Army Corps of Engineers	
	Solid Waste Management Facility Permit		Environmental Protection Agency	
	Bridge Permit		U.S. Coast Guard	
	Certificate of Public Convenience and Necessity for Construction and Operation of Rail Lines		Interstate Commerce Commission	
	Notice of Proposed Airspace Obstruction		Federal Aviation Administration (FAA)	
	Notice of Proposed Construction Alteration of Airports		Federal Aviation Administration (FAA)	
	Airport Lease		BLM	
	Permit for Structures on or Work in Affecting Navigable Waters		U.S. Army Corps of Engineers	
	Permit for Dams and Dikes in Navigable Waters		U.S. Army Corps of Engineers	
	Antiquities Act Permit		Department of the Interior	
	Application for Permit to Conduct Archaeological Explorations		Forest Service	
	Timber Sale Contracts		Forest Service	
	Temporary or Permanent Exemption from FUA Prohibitions		Department of Energy	

TABLE 1-7

COMPARISON OF COAL MINE LEADTIMES BY STATE
(months)

STATE	AVERAGE MINE SIZE CLASS	LENGTH OF CRITICAL PATH	LENGTH OF REGULATORY ACTIVITIES ON PATH ^a	LENGTH OF PATH WITHOUT REGULATION	LEADTIME DUE SOLELY TO REGULATION
Alabama	Small	86	33	74	12
Alaska	Small	86	33	74	12
Colorado	Small	86	33	74	12
Montana	Large	122	33	110	12
New Mexico	Medium	110	33	98	12
Utah	Small	86	33	74	12
Wyoming	Large	122	33	110	12

^aThe length of the OSM review varies with mine size, although the data available are too limited to allow state-by-state comparison.

Source: ERCO estimates.

TABLE 1-8

OVERVIEW OF STATE PERMIT PROCESSES FOR COAL MINING

STATE	STATUS OF SMCRA PROGRAM	CHARACTER OF MINING ACTIVITIES	MINE PLAN REVIEW PROCESSES	OTHER NOTABLE STATE CHARACTERISTICS
Alabama	Permanent	Small federal coal reserves	AL is committed to brief reviews	Other permit processes are generally expeditious
Alaska	Interim	Limited coal mining to date	Has permit assistance mechanisms in place	AK has important environmental and wildlife permits
California	Interim	Very small coal reserves	SMCRA Program is not being developed	CA has established state NEPA program
Colorado	Permanent	Has surface and underground mining	Has instituted program with brief review deadlines	Any of several state permit processes could be as lengthy as the mine plan review in state.
Montana	Permanent	Has large surface mines, most include federal lands	MT performs nearly entire review of federal mine plans	MT has state NEPA. State requires PSD review
New Mexico	Permanent	Has large surface mines	Only one mine review, of non-federal mine, has been completed: 8 months were required	Water appropriation permits are difficult in some areas

TABLE 1-8

(Cont'd)

STATE	STATUS OF SMCRA PROGRAM	CHARACTER OF MINING ACTIVITIES	MINE PLAN REVIEW PROCESSES	OTHER NOTABLE STATE CHARACTERISTICS
Utah	Permanent	Has underground mining operations	UT mine reviews do not have exceptional review schedule	Developers have avoided water appropriation difficulties. Underground mines cause less surface disturbance.
Wyoming	Permanent	Has large surface mining operations; most include federal lands	Has instituted program with relatively brief review times	Industrial siting permit may apply to large mines. Water appropriation has been relatively easy.

activities, have not been granted authority to operate state SMCRA programs. Among the other states, the conduct of the SMCRA program and other permit programs varies significantly. Alabama and Colorado have the greatest commitments to rapid permitting processes. However, a number of states have backlogs of mine plan applications and actual patterns of efficiency and expediency among the states are difficult to judge.

1.4.3 Geothermal Project Networks

The network analysis was also applied to alternative energy sources, namely geothermal and oil shale. Geothermal project permits are considered first.

Geothermal projects on federal lands involve close monitoring by the Minerals Management Service from initial exploration to resource utilization. A 90-month project/permit network for a "representative" geothermal project is shown in Figure 1-4. The network presents the stages of a geothermal project including exploration (general), surface exploration, exploratory drilling, resource characterization and development drilling, production well drilling, and production. Because of the unique nature of the geothermal resource, a second line of activity covering (in general terms only) the associated power plant development is also shown.

The MMS provides a series of operating plan reviews. The reviews include the following:

1. Plan of Exploration Review (1 month)
2. Plan of Development Review (6 months)

LEGEND

- Activity
- - - - - Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months, Second Entry is Float Time.
Ex.—Activity Requires 10 Months Float Time Allowance is 11 Months.
- (ND) Activity Time Is Not Determined or Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine Diagram. Letters Denote State Permits.

Figure 1—4. Network Presentation of Representative Geothermal Projects on Federal Lands.

3. Plan of Injection Review (6 months)
4. Plan of Baseline Data Collection Review (2 months)
5. Plan of Utilization Review (12 months)
6. Plan of Production Review (6 months)

At each stage of a geothermal project, the developer thus presents his plans to the MMS for approval. Each plan review consists primarily of an environmental survey. The careful consideration of environmental issues in geothermal developments is partly due to the fact that the Geothermal Steam Act of 1970, which authorized leasing of geothermal lands, was the first major resource law passed after the National Environmental Policy Act of 1969.

State permits of potential applicability to geothermal projects were reviewed for California and Utah. California has seen the greater level of geothermal activity, and Utah is typical of the several other states which have some geothermal resources. In California, 20 distinct permits may apply to a geothermal project, if power plant development is not considered. The major permits include injection authority from the California Division of Oil and Gas, air emission permits, and waste discharge permits. In addition, permits of the Department of Fish and Game for operations near stream or lake beds have occasionally proven difficult for developers to obtain.

In Utah, 25 permits were identified as being potentially applicable to geothermal projects. Water appropriation permits are included in the Utah listing. Under Utah state water law, even the deep water resources of geothermal energy are considered an appropriation and thus must be approved through the State Engineer's Office.

1.4.4 Oil Shale Project Network

The most extensive permitting requirements are those applied to oil shale projects. The extent of the land disturbance and the potential quantity of pollutant discharges cause oil shale projects to be very closely monitored by the regulatory authority.

The project/permit network for oil shale was based on operating histories and the projected schedules for the existing oil shale projects. The project/permit network is shown in Figure 1-5. The critical path for the network is 175 months. Numerous project development plans filed with the Minerals Management Service included staged production plans of the type shown.

Permitting requirements, as for geothermal, include major approval processes of the Minerals Management Service. The key review is that for the Detailed Development Plan, and is stated by MMS to require 6 months. In projects developed thus far, numerous revised DDPs are submitted sequentially to MMS for review as engineering design and construction work progresses.

Other major environmental permits are also required. In the representative case, these can be obtained without becoming critical path items.

On the state level, a total of 31 Colorado permits and 23 Utah permits were identified as potentially applying to oil shale projects. The most important state permits are mine plan reviews by the same state agencies which handle the SMCRA coal mine program.

1.5 The Extent of Project Delays Due to Regulation

The numerous permits which must be obtained by energy firms have differing potentials to create project delays. The majority of permits are obtained without controversy. The cases where delay or controversy are common are of greatest interest here.

A summary of the historical permitting experience in the states covered is shown in Table 1-9. Judgments were made of frequency with which the major permit programs led to project delays. Data on permit review periods or the frequencies of delays are limited; the judgments shown are based on literature reviews and subjective analyses of contacts with industry and governmental personnel. In the cases where permit difficulties are fairly common, no presumption is made that government authorities are responsible. The judgments reflect only the frequency with which delays or controversies occur.

Most permits for oil and gas and coal operators have not regularly produced delays. Major permits in the environmental areas, while not quickly obtained, have only occasionally delayed conventional projects. For oil and gas operators, air pollution permits for the steam generating equipment needed in Southern California oilfields are the most consistently difficult to obtain. This tendency reflects the extent of air emissions generated by the large oilfield installations needed. For coal mining projects, environmental issues are generally resolved through the OSM mine plan review.

The permits which have caused "systematic" delays are the federal Application for Permit to Drill process and the

Figure 1-5. Network Presentation of Representative Oil Shale Project on Federal Lands.

TABLE 1-9

SUMMARY OF PERMIT DIFFICULTIES FOR OIL AND GAS AND COAL DEVELOPMENTS

	OIL AND GAS	COAL
	FREQUENCY OF DIFFICULTY / COMMENT	FREQUENCY OF DIFFICULTY / COMMENT
EIS Requirement	Rare / Requirement is applicable to few projects	Episodic / Approx. 15% of mines are subject to requirement
Air Emission Permits		
California	Regular / Lead times for some projects are increased	Not applicable
All other	Episodic / Occasional delays for sour gas processing plants occur	Rare / Future constraints on mining are possible. Federal PSD does not apply
NPDES Permits	Episodic / Some delays noted for Alaskan operations	Rare / Control technology is well established
Solid Waste Disposal	Rare / Permitting through oil and gas agencies is most common	Not applicable / Covered under SMCRA program
Water Appropriation	Rare / Alternative water supply methods often possible	Episodic / Future constraints on mining are possible
Permits to Drill		
Federal	Systematic / Delays limited to some MMS offices. Procedures are under review	Not Applicable
State	Rare / Rapid processing is most common	Not Applicable
Permits to Mine	Not applicable	Systematic / Lengthy, complex reviews occur for new mines or major modifications. Some states have backlogs
Other		
Rights of Way	Regular / BLM procedures have been streamlined in past year	Rare / Permits are not a major issue
Wildlife	Rare / Delays have occurred for wildlife reviews in APD process	Rare / Wildlife issues covered in SMCRA
Safety	Not applicable / MMS standards must be met	Episodic / Many reviews are brief

KEY (Interpretation Guide for Measures of the Frequency of Difficulty)

Rare - Very few projects have been impacted.

Episodic - Occasionally permit difficulties have arisen. The controversy is generally project-specific. A small percentage (less than 5%) of all projects are affected.

Regular - A steady stream of projects encounter difficulties. The permit problems have caused delays in the past, although a minority of projects are affected.

Common or Systematic - Many projects are likely to encounter a permitting delay or problem of some type. A sizeable minority or a majority of projects are affected.

NOTE: No presumption is made that governmental authorities are responsible for permitting problems. The frequency measures indicate only the tendency of permit controversies to arise.

OSM mine plan review. The APD process is undergoing intensive review at this time, with new operating rules expected in late 1982 that will improve handling efficiency. The OSM mine plan is a lengthy and frequently difficult process which has caused delays in some mining operations. The effect of mine plan review times is clouded by the slack coal market which has stilled mining company interests in new mine openings. In any case, substantive revisions to the OSM regulations have been proposed and, if adopted, will also improve application and handling efficiency, as well as provide for numerous technical clarifications.

1.6 Cost of Project Delays

A methodology was developed for estimating the cost of project delays for energy firms. The technique allowed for consideration of three types of spending during delays:

1. Non-postponable direct expenditures - such as wages for field personnel, purchased supplies, equipment costs, rental charges, and any contracted items;
2. Overhead expenditures - such as for project supervision, corporate-level project management, and administrative (non-field) charges; and
3. Capital charges - such as for amortized equipment purchases, loan interest payments and implicit opportunity costs for use of company funds.

All three types of spending would occur during a delay of an unspecified type in a project schedule. (If a project delay proves to be lengthy, e.g., 3 months or more, then the rate of direct and indirect spending should decline.)

The capital charges, which proved to be most important, reflect the burden of invested (and therefore non-transferable)

project funds. The capital charge figures presented approximate the increased interest charges which would apply to a debt-financed project when a project delay means that loan payments must be deferred. An annual rate of 15% (monthly rate of 1.171%) was assumed for capital charges.

The delay cost estimation techniques were applied to cost estimates for individual oil and gas and coal mine projects which were consistent with the projects assumed in network development. The total estimated capital cost for the oil and gas project was \$13.85 million. The coal mine assumed is a 5-million-ton-per-year Western surface mine with a total capital cost of \$59.72 million.

The estimated costs of delay indicate that delay costs become quite large in the later stages of a project. The delay cost estimates, which are stated in terms of monthly delay charge rates, are shown in Table 1-10. The monthly delay charges for oil and gas are quite high during the stages of exploratory well drilling and development, at \$218,000 and \$197,000 per month. While the exploratory well is being drilled, heavy expenditures are incurred within a brief time period for drilling crews and production testing. ERCO estimated that 20 percent of the direct spending at this stage could not be immediately postponed, resulting in large delay costs. During development, the capital charge factor is of overriding concern.

For coal mining, the bulk of the capital investment is incurred during the development stage. Much of this spending is for large-scale mining and hauling equipment. As a result, potential delay costs rise sharply during the mine development and construction activities. A delay occurring late in the mine development phase is more serious to the company than a delay which occurs during the pre-development design work or while environmental studies are being conducted.

TABLE 1-10
PROJECT DELAY COST ESTIMATES
(\$000)

PROJECT STAGE	CUMULATIVE CAPITAL COSTS	MONTHLY DELAY COSTS			TOTAL
		DIRECT COSTS	OVER- HEAD COSTS	CAPITAL CHARGES ^a	
<u>OIL AND GAS PROJECT</u>					
Regional Appraisal	-		Not Estimated		
Detailed Reconnaissance and Data Interpretation	-		Not Estimated		
Investigation of Target Area and Land Acquisition	3,600	13.8	6.9	21.1	41.8
Permitting, Drilling, and Production Testing of Exploratory Well	8,600	117.6	29.4	71.4	218.4
Development	13,850	52.5	13.1	131.4	197.0

<u>COAL MINING PROJECT</u>					
Exploration	213	0.0	0.7	1.2	1.9
Lease Acquisition	6,313	NA	NA	NA	NA
Pre-Development	7,815	4.6	2.3	82.7	89.6
Mine Development and Facility Construction	59,720	225.7	56.4	345.4	677.5

Source: ERCO estimates.

^aCapital charges are applied to the cumulative capital investment of previous project stages plus one-half of the capital investment of the current project stage.

^bProject cost estimates are expressed in 1978 dollars.

1.7 Study Conclusions and Recommendations for Permit Streamlining

The analysis has provided a broad overview of the permitting systems and their impact on energy developers. The investigation allows the following conclusions to be drawn about the conduct of permit processes. Recommendations for improvements in permitting systems are also provided.

1.7.1 Conclusions and Recommendations for All Resource Areas

A number of conclusions and recommendations can be introduced at a general level and then separately considered in the content of each resource area. The permitting systems all evidence a degree of similarity and many of the problems discussed in this report are of a generic nature, that is, they influence all permitting or regulatory processes and not just those applying to specific types of resources. Thus the general conclusions and recommendations are set forth below.

Conclusions

1. The duration of project leadtimes is due largely to non-regulatory activities, although regulatory activities lengthen the leadtimes till further. Among the energy resource areas covered here, permitting activities lengthen the critical time path for projects by 3 months to 1 year on average, although greater impacts certainly occur. For the "representative" energy projects defined in the network models, the total project leadtimes varied from approximately 8 to 15 years. It may be concluded from the network models that elimination of all permitting and regulatory requirements would not dramatically shorten total project leadtimes.

2. Many agencies have recently taken steps to improve their administrative processes for permit review. Significant revisions are now being developed or have been instituted for (1) applications for Permit to Drill (MMS), (2) rights-of-way approvals (federal surface management agencies), and (3) geothermal energy project plan reviews. The Office of Surface Mining, through proposed rulemaking in June 1982, has also endeavored to give state regulatory agencies greater flexibility in their coal mining regulatory programs. In general, a substantial amount of procedural streamlining, which is internal to agencies or divisions, has occurred in the past two years or is underway at this time (September 1982).
3. Most of the permit approvals applicable to a given project are independent of one another and can be obtained concurrently. The majority of the separate approvals likely to apply are minor permits and do not involve lengthy reviews. Simplification or streamlining of these processes is not likely to affect project leadtimes. This conclusion was reached by consideration of the network diagrams.
4. The principal opportunity for permit streamlining is through the consolidation of major permitting authority in individual agencies. Duplication or overlap of environmental reviews occurs principally because agencies with comprehensive (or nearly comprehensive) review authority (e.g. OSM, MMS) exist along side agencies with specific environmental control responsibilities (e.g., EPA or authorized state agencies). Consolidation of permitting authority would improve the technical efficiency of permit reviews. This issue is discussed further immediately below.

Recommendations

1. Consolidation of permitting authority should be pursued although legal, administrative and political issues will restrict the scope for such changes. This avenue constitutes the primary area where permit streamlining could noticeably reduce project leadtimes and paperwork burdens for developers. Memorandums of Understanding between agencies would be a principal means of managing the necessary cooperation. However, the actual potential for such changes is limited. The constraining factors include the following:

- (a) Integration of two federal regulatory programs, each of which provides for transference of authorities to states, raises difficult questions of federal and state interaction;
 - (b) Federal agencies are unable to delegate their NEPA responsibilities for federal lands, thus incomplete transference of authority may occur.
 - (c) The present alignment of federal agencies represents a political status quo for competing interests. Changes to agency responsibilities, such as would modify the existing balance, would be difficult to implement. It may prove politically difficult to reach consensus agreement on significant changes in agency responsibilities.
2. Statutory or other strict review guidelines should be more widely used in federal permitting programs. Statutory guidelines are commonly employed in state agencies where they contribute to the expediency of operations. The deadlines also provide developers with greater certainty about the timeframe for regulatory action. At the federal level, selected environmental programs (NPDES and PSD) have review deadlines, but these are the exception. Other agencies (e.g., MMS) make use of internally-imposed deadlines in their programs.
3. More intensive management of inter-agency consultations during permit reviews should be made in order to reduce total review times. A frequent element of lengthy permit reviews is difficulty in obtaining responses or consultation from other agencies. This recommendation is related to number 2 above which provides for strict statutory or other guidelines for reviews. In this case, the imposition of deadlines after which agency approval is assumed could be utilized.

1.7.2 Conclusions and Recommendations for Oil and Gas Permitting Studies

The permitting processes applicable to oil and gas developments on federal lands were examined through delineation of federal and state permits and through utilization of

network analysis techniques. In this section, conclusions about the permit systems are presented. Recommendations about possible improvements in the permit systems are also given, immediately following the conclusions.

Conclusions

1. Regulatory activities have a modest impact on the total lead time for oil and gas projects. The permits most likely to be on the critical path are the Application for Permit to Drill (MMS) and rights-of-way requests (federal surface management agencies). These permits, which are usually obtained simultaneously, require an average of three months each for processing. The APD permit, however, is needed for each well drilled on federal lands in a project, and difficulties vis a vis rig scheduling, can arise.
2. Environmental and other permits (e.g., water appropriation) do not delay most projects, but are important in selected cases or in certain areas. Many projects have limited requirements for air emission, water discharge (beyond the reinjection or discharge controls of oil and gas regulatory commissions) or water appropriation permits. Examples of projects where these approvals become prominent are (1) tertiary oil recovery projects in Southern California (air permits); (2) sour gas processing facilities in various locales (air permits); (3) conventional oil and gas projects in areas where water purchases or other alternatives to water appropriation are not available. Numerous additional examples of projects with important environmental permitting requirements could be cited.
3. Given the mobility of production operations and the geographic spread of oil and gas resources, many firms appear to avoid federal lands. Many of the firms contacted expressed annoyance with the additional permit requirements (most notably the data requirements of the APD and rights-of-way permits) of operations on federal lands. State drilling permit processes are notably more simple and expeditious than the federal APD in all western states.
4. Although permitting requirements are less extensive for oil and gas than for other resource areas, permit scheduling problems frequently occur. Project activities and permitting are performed within a brief timeframe as imposed by the demands of scheduling for drilling

rigs. Drilling contractor services are expensive and tightly scheduled. If a developer has not obtained the requisite drilling or other permits, an immediate financial burden is imposed. Some of the firms contacted indicated that permitting responsibilities may not be fully observed in all cases by all firms.

5. Numerous minor permits and modifications are required of oil and gas developers by state regulatory agencies, but these permits present few difficulties. The routine permitting requirements imposed by state oil and gas commissions (or similar regulatory agencies) are uniformly straightforward and expeditious. Overall, permit requirements vary little in substance among states.

Recommendations

1. The current effort by the MMS to reform the APD process should be carried out. The APD process, with the length delays observed in recent years, has had a very notable and negative effect on the expediency of permitting on federal leases. A substantive reform proposal has been prepared by the Rocky Mountain Oil and Gas Association (RMOGA) to streamline the review process. These RMOGA suggestions, which provide for a more efficient interaction between the developer and government personnel, are being actively considered by the MMS.
2. Continued review of the rights-of-way permitting process by the federal agencies involved should be encouraged. Problems and delays in rights-of-way processing had been noted by BLM and other federal agencies with surface management responsibilities. In response, changes in handling procedures were made and the efficacy of the changes is now being monitored. The modifications provide for a briefer environmental review and for uniformity in review procedures across agencies.

1.7.3 Conclusions and Recommendations for Coal Mining Permit Systems

The permit and network analysis performed for coal mine regulatory processes was presented in Section Seven. The

federal and state permits were delineated and displayed in network diagrams. The networks depict the relationships among non-regulatory and regulatory activities for coal mine developments.

In this section, conclusions and recommendations about the permit systems are presented. The conclusions are listed first.

Conclusions

1. Regulatory activities require an estimated 30 months of the total 10-year lead time on coal mining projects. Removal of all regulations would, however, shorten the project lead time by 12 months. The result is due to the considerable overlap of regulatory activities with non-regulatory activities. The 30-month requirement for obtaining government approvals includes (1) 12 months for environmental studies, (2) a 3-month period for final preparation of the mine plan, and (3) 15 months for the Apparent Completeness Review and Technical Review of the mine plan. Other important regulatory activities, including review for other federal permits and preparation of the EIS, would be concurrent with these critical-path activities.
2. The review of the mine plan by the Office of Surface Mining (OSM) or by the state regulatory authority has proven to be a lengthy process but many significant modifications are still being made to improve the clarity and control of the regulatory system. For some large surface mines, several years have been required for approval. Long processing time is still expected in many states (e.g., Utah, Wyoming) because of the backlog of mine plans for review. However, the SMCRA program is still transitional in terms of (1) the continuing definition of the mining regulations, and (2) the transfer of authority from the federal government to state governments. With regard to the first point, the areas of greatest confusion involve hydrologic data requirements, fish and wildlife impact studies, and archaeological study requirements.

3. The role of state regulatory agencies in the mine plan reviews, including those for federal lands, has been expanding. Cooperative Agreements have been signed or will soon be signed by OSM with the regulatory agencies of the western coal mining states. The agreements allow the state agency to participate in the mine plan review for federal lands. Further proposed changes to the Federal Lands Program will allow state agencies to issue permits and provide all but the final environmental review of the mine plans. The latter responsibility must be retained by OSM under its NEPA responsibilities.
4. The expediency of key permit reviews for coal mine projects is frequently affected by the urgency of the mining company's application. Regulatory agencies can expedite the approval process in order to help a company meet its commitments. This factor has frequently been noted in the case of mine plan reviews. Companies which are seeking to begin operations soon can urge OSM (or state agencies) to move quickly. In contrast, many companies do not wish to proceed with the permit process when they have not successfully contracted their future coal production. This is currently occurring (Summer 1982) due to slack market demand. Such companies will be slow to respond to requests for more information (to support the mine plan review) made by OSM or the state regulatory agency.
5. Permitting delays for coal mining projects are particularly costly if they occur during the "development" stage of operations when the large capital and operating costs are being incurred. The cost analysis for coal mining clearly shows that delays are much more costly at the later stages immediately prior to actual mining. The capital charges accrued by all previous project spending are quite substantial at that point. At early project stages, large outlays have not yet been made for engineering, facility design, and capital equipment.
6. Difficulties and confusion with permit processes are likely to continue until the burden of paperwork upon coal mine operators is reduced. In addition to the obvious burdens placed upon coal mine companies, unfortunate side effects occur which imperil smooth functioning. In particular, mine company officials become unable to distinguish important data submissions from relatively unimportant data submissions. Company efforts tend, therefore, to be directed indiscriminately toward the completion of application requirements

rather than toward the seeking of genuine solutions to environmental issues. The requests for additional information made by regulatory agencies tend to encourage this attitude by appearing random and/or insignificant. In this vein, some company officials find it difficult to take permitting processes seriously.

7. Many permit programs appear to run smoothly, and have generated relatively little animosity from developers. Few complaints were received regarding MSHA permits, NPDES or other state water discharge permits, or sedimentation pond construction permits (state permits only). Future difficulties are anticipated by many companies concerning air emission and water appropriation permits, although even in these complex regulatory areas few problems have been encountered in the past.

Recommendations

1. Completion of a Memorandum of Understanding (MOU) between OSM and EPA for NPDES permit reviews would expedite this permit process. The mine plan provides for an extensive review of the mine site hydrology, planned discharges, sedimentation pond construction plans, and other factors relevant to the NPDES permit. The NPDES permits could be handled within the context of this review, thus providing for a simplification of regulatory matters facing coal mine companies. It should be noted, however, the completion of the MOU will involve resolution of significant legal and administrative issues concerning the transference of authority among a complex of federal and state agencies.
2. Additional expenditures by state and federal agencies to hire qualified personnel would improve mine plan review processes. The complex mine plan review requires experienced technical personnel. However, such personnel are frequently hired away from government agencies by mining companies in the area. The shortage of qualified personnel combined with personnel turnover contributes to the delays in mine plan handling.
3. As is frequently encouraged by regulatory agencies, coal mine companies should make contact with government personnel early in their project planning cycle. The incentives for early communication of project plans include (1) the greater likelihood that the environmental studies will meet the requirements of the regulatory agencies, (2) the early identification of serious environmental problems for an intended site,

such as would restrict or veto the mining operation, and (3) a related point, that unexpected issues will not arise late in the project, creating expensive delays. Many regulatory agencies encourage or require early meetings with mine developers at this time.

1.7.4 Summary of Geothermal and Oil Shale Permitting System

Taking a broad overview, the arrangement of regulatory responsibilities is similar for geothermal and oil shale resources on federal lands. In each case, the Minerals Management Service has a virtually comprehensive responsibility for the control of energy development and for the provision of environmental protection during such development. In addition, the full range of specific environmental permits applies to geothermal or oil shale projects.

In this section, conclusions and recommendations concerning permitting systems for geothermal and oil shale resources are discussed. Geothermal permitting systems are considered first.

1.7.4.1 Geothermal Permitting Systems

Conclusions

1. Modifications to the MMS Operating Procedures Have Improved Processing. The multiple MMS reviews were previously thought to require an excessive amount of data on environmental impacts. For reviews occurring early in a project, the environmental data were required before the developers could accurately assess the probable scope of their operations. However, the recent guidance provided to field offices provides for "phased environmental reviews," which efficiently limits the scope of early project reviews. This adjustment improves and rationalizes the review processes.

2. With the streamlining of federal procedures, geothermal developments on federal lands are not significantly more complicated than those on nonfederal lands from a regulatory point of view. Most of the developers contacted for this study were aware of the modifications in the MMS procedures and noted improvements in processing time. The other federal surface management agencies which cooperate with the MMS reviews have also expedited their procedures. Several developers commented that permit processes on nonfederal lands are now more complex and confusing. California, with the CEQA, has extensive environmental approval requirements, for example.
3. With the exception of California, western states have had little experience in permitting for geothermal developments, leading to a potential for delays in analysis, for jurisdictional disputes, or other problems. Also, the developers contacted commented on the lack of coordination in many states in permitting for energy projects. These factors may combine to leave government officials unsure of the appropriate type or level of review needed for alternative energy projects. In comparison, California has a well-charted process for regulatory review of energy projects.
4. The development of geothermal resources is subject to water appropriation processes in some states, leading to possible permitting delays. Utah, for example, requires an original water appropriation request to be filed for geothermal wells. In that case, a six-month review process is normally required. Water appropriation permits can often be lengthy processes due to the water scarcity in arid western regions. The potential for long delays for geothermal developers is limited, however, by the fact that the deep water resources are not likely to be exploited by other water users, and few disputes from competing users are likely to arise.
5. Recent activities in the geothermal area have focused on improving the processing time for lease requests by reducing the large backlogs at federal agencies. The Forest Service, in particular, has been tardy in its response to lease requests. Additional efforts have been made to educate the relevant federal personnel in the technology and environmental impacts of geothermal operations.

1.7.4.2 Oil Shale Permitting Systems

Conclusions

1. Permitting activities occupy an estimated three and one-half years of the critical path for oil shale projects, but elimination of all regulations would only reduce project lead times by one year. During many of the regulatory activities (such as performance of environmental studies) necessary engineering and design work is likely to be taking place. The exact scheduling and organization of regulatory and non-regulatory activities will vary by organization and circumstance, but considerable overlap of permitting and engineering work appears likely. (This conclusion assumes, however, that exceptional regulatory problems are not encountered.)
2. The procedures for review of Detailed Development Plans by the MMS have been set forth to encourage reviews within six months. By setting forth a timeline for reviews of the DDPs, the Minerals Management Services employs an approach similar to the use of statutory guidelines for major permit reviews. Because the DDPs are comprehensive project documents, requiring a full environmental review, a six-month timeline appears reasonable for agency performance.
3. Oil shale projects are of interest and concern to numerous regulatory and non-regulatory groups. The projects involve a greater variety of complex environmental issues than do the other resource areas. This fact, combined with the developmental stage of the technology, produces a confluence of public pressures and concern which affects and can complicate permit processes. In such situations, coordination of permit processes can be helpful by improving communication among regulatory agencies and with public interest groups.
4. Substantial uncertainties remain concerning the regulation and thus the permitting of oil shale projects. Among the potential issues are: (1) air emission limitations, restricting the industry as a whole, (2) groundwater pollution impacts due to in-situ operations, (3) disposal standards for spent shale under RCRA regulations, and (4) regulation of operations under the TSCA legislation. These uncertainties, although generally due to the substance of environmental regulation and not to the permitting process itself, add to the difficulty and risk of development perceived by oil shale companies.

5. The involvement of the regulatory agency (the MMS) in design of environmental study programs should reduce the potential for submission of inadequate environmental data. Currently, the MMS requires approval of the Baseline Data Collection Plan, thus initiating an involvement in the environmental studies attendant on the project. Communication may be maintained during the performance of environmental studies leading up to submission of the Detailed Development Plan. This arrangement is also informally used in environmental studies for coal mine projects, although patterns and levels of cooperation between the developer and the regulatory agency are more varied.

Recommendations

1. Overall coordination of permitting requirements is valuable for oil shale projects. Oil shale operations are large, highly visible, industrial operations which require the approval of numerous regulatory agencies. The project size, extent of land disturbance, and relative novelty of oil shale projects insure that permitting issues will not be routinely handled in the near future. As a result, permitting coordination through systems such as the Colorado Joint Review Process is appropriate. Such a system would allow for channeling of project data to regulatory agencies and for notifying developers of their permitting responsibilities. Since the Joint Review Process already exists in Colorado, the primary oil shale state, a useful mechanism is already in place for most developers.

This type of process is based on the assumption that developers will be willing and able to work openly with the regulatory authorities. Among the resources studied, oil shale firms appear most likely to accept such a public and visible regulatory process. The extremely long planning and construction lead time for a commercial oil shale facility presents, in any event, a long period of exposure to public scrutiny.

2. Although many factors must be considered, centralization of regulatory authority with the MMS would further streamline permitting activities. Under existing arrangements, the MMS is responsible for review of the Detailed Development Plans, which cover environmental impacts on all media. Permit reviews for water discharges, air emissions, spent shale disposal, and perhaps other outfalls, could be handled in conjunction with the DDP review. Transference of authority to MMS

from the one federal (EPA) and numerous state agencies (state agencies with delegations for the NPDES or PSD programs and so on) would, however, be an extremely complex undertaking. The topic of permit consolidation is discussed in the earlier section of general recommendations.

3. An effort should be made to clarify the regulatory issues facing oil shale developers. As mentioned above, several issues have yet to be resolved concerning regulation of oil shale projects. The major issues all involve pending rulemaking by divisions of the EPA and thus an effort within that agency would largely be sufficient for the questions to be covered. The effort should entail actual rulemaking to establish regulations, or preparation of a guidebook for permit writers in oil shale areas.

SECTION TWO

INTRODUCTION

The federal government is by far the largest landowner in the Western states. The holdings include the great wilderness areas of the Rocky Mountains, as well as vast desolate tracts of land of every variety. Also included in the federal property are rich reserves of energy resources. The magnitude of these reserves makes federal lands extremely important to the national energy picture.

Development of energy projects on federal lands is occurring in the context of systems of leasing and permitting which involve many areas of federal and state law. From some viewpoints, particularly those of industry, the regulatory processes which govern such projects are needlessly complex and seriously impede production. Numerous permit approvals are needed covering the concerns of environmental protection, orderly land use planning, public health and safety, wise energy exploitation and sundry community concerns.

In this study, the permitting requirements for energy projects on federal lands are examined in order to clarify their impact on new energy projects. The goals of the study are to enumerate all of the relevant permits for energy projects on federal lands and to prepare recommendations or conclusions for possible improvements in the regulatory operations. The outlook of the study, therefore, is comprehensive in that all regulations are considered. It is intended as an analysis of permitting "systems" as a whole.

With this general work scope in mind, some limitations on the study vista were necessary. The permits considered are those applicable at the federal level (for federal lands) and at the state level, with 8 states selected as being most interesting in terms of future energy development on federal lands. The eight states covered, in alphabetical order, are Alabama, Alaska, California, Colorado, Montana, New Mexico, Utah and Wyoming. Five of these states are in or near the Rocky Mountain area. The five states have in common large federal landholdings, major and recent energy development and probable large-scale future energy development. Alabama, Alaska and California have more specialized energy development patterns of interest to this study.

Four resource areas were studied: oil and gas, coal, geothermal and oil shale. Most research efforts, however, were directed at the first two, oil and gas and coal. These resources, because they are more routinely developed, provided the more interesting examples of the effects and problems of obtaining permit approvals. The projects considered in each resource area were limited to basic extraction operations without consideration of refining steps of power plant construction or other downstream activities.

In examining all, it proved useful to take the vantage point of a prospective developer, attempting to obtain permit approval for his project. The tasks of preparing applications and completing the approval processes were integrated into the context of normal project development. This effort was accomplished through use of project/permit network analyses which depict the logic and flow of "representative" or average energy projects. The network analysis allowed consideration of the delays or potential for delays

in project leadtimes attributable to regulatory actions. The project permit networks for oil and gas developers are provided in Section Six, followed by coal mining networks in Section Seven, and both geothermal and oil shale networks in Section Eight.

Other sections of the study present the permit data base and analytical sections. Section Three reviews the principal federal legislation from which permit regulations have been prepared. All relevant federal permits for energy projects are described and summarized in Section Four. The permits required in each of the 8 states studied are reviewed in Section Five. Both federal and state project/permit networks were developed for each of the resource areas in Section Six through Eight. The severity and cost of permitting delays to developers is examined in Section Nine, followed by the study conclusions and recommendations in Section Ten.

SECTION THREE

PREVIOUS STUDIES OF THE PERMITTING PROCESS AND OF FEDERAL LAND MANAGEMENT POLICIES

An extensive literature review was performed of the permitting process for energy development and of the federal land management system. The objectives of the work were to (1) collect background information and data on the regulatory procedures faced by energy firms, (2) review all available data on the nature of delays which have been caused by regulation, and (3) collect any procedural streamlining recommendations which have been made by previous researchers. Both computerized and conventional literature search methods were used.

Relatively few of the diverse studies collected were of major interest for this project. Many authors performed some level of analysis of regulatory issues and impacts, but few researchers have chosen to make procedurally oriented studies of federal or state permitting programs. Most studies of regulatory issues were performed at a general level without a need to analyze details of government/developer interactions. Also, most studies were directed at policy or academic interests and are not designed to be practical guides to permitting programs. Finally, the details of permitting processes are highly specific to the project and locale in question. Generalizations about permit difficulties cannot always be justified.

For those studies which do have a direct applicability for this research, brief synopses have been prepared. In most cases, these summaries were prepared only if a given

study offered conclusions or recommendations worth noting. Summaries were also prepared of eight studies which were exceptionally informative about permitting programs, or which were judged to have other notable features.

The entire project bibliography is presented in Appendix A. The synopses of approximately 20 individual reports are presented in Appendix B.

3.1 Major Conclusions of the Literature

A survey of the conclusions of the literature can be presented which indicates some of the problem areas in leasing and permit programs. The conclusions described should not be considered consensus opinions because few of the studies reviewed covered identical territory. Rather, the most relevant conclusions of a few select studies will be presented. The literature discussion has been divided into three sections, covering (1) permitting delays; (2) permitting costs; and (3) regulatory and permitting program analysis and criticism.

3.1.1 Permitting Delays

Three approaches have been commonly used in considering energy project delays caused by permit requirements. The first is an examination of the files of permitting agencies. This type of study relies on objective evidence of actual delay periods in order to identify problems of administrative policy. The second method is to examine case-study histories of major energy projects in order to view the

regulation-permit systems in operation. This approach is sometimes necessitated by the limited number of major projects initiated. A third and related approach is to study permit delays within the context of overall project planning and construction. A hypothetical planning process for an energy project may be generated, or summary data on project delays (without the detail of case-study histories) may be examined. The results of these different study methods, as represented by examples in the literature, are worth comparison.

The permit files of the Minerals Management Service (previously the U.S. Geological Survey) reviewed in two studies concerned with delays in oil and gas exploration performed by Everett Associates (1981) and by the General Accounting Office (U.S. GAO, 1981a; see Appendix A for full citations). Both studies noted lengthy delays in approval of applications to drill by developers. The primary reasons cited were (1) difficulties in obtaining archaeological clearances (2) delays in completion of environmental analysis, (3) inadequate information on the APD form designating the operator or owner, and (4) delays caused in obtaining BLM approval of APD. A sample of the review file data, illustrating the primary delays causes noted in the Everett Associates study, is provided in Table 3-1.

The GAO also examined the frequency of delays in the leasing of oil and gas lands. GA reviewed the leasing files covering five western states and found a high incidence of delays caused by federal agencies. The most prominent reasons for the delays were (1) slow completion of environmental reviews and (2) the deferral of leasing actions. The results of the GAO survey are shown in Table 3-2.

TABLE 3-1

REASONS CITED FOR DELAYS BEYOND
100 DAYS IN APD PROCESSING

REASON	DELAYS OVER 100 DAYS (RANK)	DELAY OCCURRENCES		
		PRIMARY REASON FOR DELAY	ONE OF MULTIPLE REASONS FOR DELAY	TOTAL NUMBER OF DELAY OCCURRENCES
Archaeological clearance	1	66	59	125
Environmental analysis	2	60	58	88
Designation of operator or agent	3	43	38	81
Slow BLM processing	4	57	22	79
Bonding	5	44	26	70
APD stipulation decisions	6	42	16	58
Heavy office workload	7	24	14	38
Surface Management Agency (USFS, Bur. of Rec.)	8	24	8	32
Special Use Permits	9	5	26	31
Surface owner agreement	10	23	5	28
Onsite inspection	11	22	1	23
Other ^a	12	13	5	18
Roadless area access	13	12	6	18
Weather	14	12	3	15
APD incomplete	15	11	3	14

^aIncludes delays with a frequency of less than four occurrences; examples: hydrogen sulfide, drilled in trespass, replacement well, location abandoned, drilling mud program.

Source: Everett Associates, Analysis of Delays in the Processing of Applications for Permits to Drill and Pre-Staking Clearance Applications, June 1981, p. 32.

Table 3-2
Primary Delays Experienced by Pending Oil and Gas Lease Applications
Sampled by GAO (Sample Size 1,448) (Note a)

	States					Total
	CO	MS	NV	NM	WY	
<u>Leases Considered To Have Not Experienced Delay</u>	115	70	116	106	166	573
<u>Leases Considered To Be Delayed:</u>	<u>134</u>	<u>324</u>	<u>132</u>	<u>194</u>	<u>84</u>	<u>868</u>
<u>Lease Delays Caused by Agencies:</u>						
Lease processing delays at Bureau (note b)	<u>18</u>	<u>172</u>	<u>86</u>	<u>159</u>	<u>18</u>	<u>453</u>
Environmental analysis:						
Bureau	11	71	20	0	12	114
Forest Service	8	12	2	1	16	39
Total environmental analyses	<u>19</u>	<u>83</u>	<u>22</u>	<u>1</u>	<u>28</u>	<u>153</u>
Deferral of leasing in study areas:						
Bureau	7	0	0	0	0	7
Forest Service	63	9	0	0	16	88
Total deferral of leasing in study areas	<u>70</u>	<u>9</u>	<u>0</u>	<u>0</u>	<u>16</u>	<u>95</u>
Title work:						
Bureau	0	0	1	0	0	1
Forest Service	0	7	0	0	0	7
Defense	4	36	0	0	0	40
NASA	0	1	0	0	0	1
Total title work	<u>4</u>	<u>44</u>	<u>1</u>	<u>0</u>	<u>0</u>	<u>49</u>
Other:						
Bureau	1	8	3	13	2	27
Survey	0	1	1	0	1	3
Defense	0	0	0	0	2	2
Water and Power Resources	1	0	0	0	1	2
Total other	<u>2</u>	<u>9</u>	<u>4</u>	<u>13</u>	<u>6</u>	<u>34</u>
Total leases delayed by agencies	<u>113</u>	<u>317</u>	<u>113</u>	<u>173</u>	<u>69</u>	<u>765</u>
<u>Lease Delays Not Caused by Agencies:</u>						
Suspended pending decision or study:						
Appeals or litigation	10	7	14	13	10	54
Miscellaneous	5	0	5	0	4	14
Total suspended pending decision or study	<u>15</u>	<u>7</u>	<u>19</u>	<u>13</u>	<u>14</u>	<u>65</u>
Applicant inaction	<u>6</u>	<u>0</u>	<u>0</u>	<u>8</u>	<u>2</u>	<u>16</u>
Total delays not caused by agencies	<u>21</u>	<u>7</u>	<u>19</u>	<u>21</u>	<u>16</u>	<u>81</u>

a/Seven lease application files could not be located.

b/Lease processing delays at Bureau include inaction, lack of followup, and mailing errors.

Source: U.S. General Accounting Office, *Actions Needed to Increase Federal Onshore Oil and Gas Exploration and Development*, February 11, 1981.

Few other studies add significantly to this data base on the efficiency of permitting or leasing programs. Thus the literature does not present a complete or near-complete picture of the sundry permit programs. Further investigations of this type will be conducted for this project in later contacts with government agencies.

Some additional data on delays are, however, available from several case-study type reports. Studies by API (1980), U.S. Congress, Congressional Research Service (Blodgett) and the U.S. Congress Office of Technology Assessment (1981) have all developed case-study examples. The studies did produce several examples of lengthy delays due to environmental regulations. These delays were often manifested in the process of completing environmental impact statements. Several long delays were due to uncertainties in the application of environmental regulations to specific projects or changes and shifts in regulatory judgments. The studies as a group present an impression of the permit process as it evolves when significant opposition to project development occurs.

The use of the case-study approach does not give much indication of the delays which will impact more commonplace projects involving energy exploration and production activities. Other studies focused on typical project delays for energy projects. One report, prepared by Policy, Planning and Evaluation (1981), utilized the approach of estimating representative delays which can be expected to occur based on knowledge of permit processes and energy project leadtimes. The study authors estimated that the normal planning process for a coal mine project is 79 months, covering initial exploration, project planning, equipment purchase and installation and so on. The

addition of environmental and coal mine permits required by federal agencies adds only 11 months to this time horizon, making the total project leadtime 90 months. The results of the study, which covered ten types of coal-related projects, are summarized in Table 3-3.

The PPE approach will often give a lower estimate of the regulatory impact on energy development because it considers the lengthy processes which already exist for initiating energy projects. Yet the approach does reflect the reality of complex engineering projects where delays can be caused by any number of factors. Another study which captured much of the inherent difficulty of project development was performed by Mark Messing (1978) for the Environmental Policy Institute. Mr. Messing concluded that for power plant construction, regulatory problems ran a poor third as a cause of delays to vendor-related delays (late equipment delivery, faulty installations, initial operating difficulties) and labor-related delays (construction strikes, labor shortages, low productivity). Mr. Messing's survey, which was based on reports to the Federal Power Commission between March 1973 and July 1977, is summarized by the results shown in Table 3-4.

To conclude, some studies have rightly pointed out that regulatory or permit-related problems are only one of several important factors causing delays in plant construction. However, it does not follow that amelioration of permitting delays is not worthy of attention. Regulatory delays are the only delays which policymakers can hope to affect through administrative changes and such delays can cause long project tie-ups. The other difficulties inherent in successfully completing a major energy project will remain in any case.

TABLE 3-3
SUMMARY OF REGULATORY IMPACTS
ON PROJECT LEADTIMES
(in months)

FACILITY	TOTAL PROJECT TIME ^a	ESTIMATED PROJECT TIME IF NO REGULATIONS EXIST	INCREASE IN PROJECT TIME DUE TO REGULATIONS	TOTAL DURATION OF ENVIRONMENTAL ACTIVITIES ON THE CRITICAL PATH
Surface Mine on Federal Lands	90	79	11	30
Surface Mine on Private Lands/ Private Coal	63	57	6	12
Underground Mine	69	54	15	30
Coal Preparation Plant ^b	--	--	--	--
Railroad Line	80	49	31	50
Coal-Fired Powerplant	99	74	25	31
Coal-Fired Industrial Facility	61	54	7	16
Coke Plant	63	42	21	21
Coal-Based Syn-fuel Plant ^c	58	52	6	8
Transmission Line	52	37	15	36

^aProject time equals the duration of the critical path.

^bCoal preparation plant included as part of underground mines.

^cThe typical synfuel project is a government funded project, the funding for which is approved in stages. That is, funds are usually appropriated first for developing a detailed conceptual design and a feasibility study, then for conducting environmental studies. These are followed by approval for detailed design and construction. So, the times given here are not representative of private commercial plants.

Source: Policy Planning and Evaluation, Impact of Government Regulations on the Leadtimes for Coal Facilities, 1981.

TABLE 3-4

CONTRIBUTING CAUSES OF DELAY IN BRINGING NEW
GENERATING STATIONS ON-LINE, 1967-1976

CONTRIBUTING CAUSES	NUMBER OF TIMES CITED
Vendor-related delays: (late equipment delivery, faulty installations, initial operating difficulties, factory strikes)	154
Labor-related delays: (construction strikes, labor shortages, low productivity)	142
Regulatory delays: (changes in requirements and delays in obtaining permits)	51
Management-related delays: (rescheduled plans, design changes, financial difficulties)	38
Miscellaneous delays: (legal challenges, adverse weather, unspecified delays)	34

Source: M. Messing, Reasons for Delay in Powerplant Licensing and Construction, Environmental Policy Institute, March 1978.

3.1.2 Regulatory/Permitting Program Analysis and Criticism

A few studies carried the analysis of project delays a step further by examining the regulatory and permitting programs themselves for flaws, or duplications of effort. The problems noted in the literature were most evident in the geothermal and coal leasing program.

One of the few studies which may be said to involve management analysis of administrative systems was completed by Wapora, Inc. for the Department of Energy (Beeland et al., 1978). The authors outlined the regulatory control of geothermal resource exploitation on federal lands from exploration to production. It was noted that there were eight distinct stages in the development process, each of which had its own environmental review procedures. While reviews are not required at each stage for a given project, the possibility of duplication was evident. Geothermal development was also discouraged by the environmental review burdens placed on initial exploration efforts, and by elements in the leasing program which appeared to penalize resource discovery by not allowing for preference right leasing.

A similar issue of duplicate environment reviews was noted by the GAO study of the Federal Coal Management Program (U.S. GAO, 1981c). The GAO reported that the transfer of authority from the Office of Surface Mining to the states had not occurred smoothly. As one result, both state and federal authorities are preparing nearly identical environmental reports in several cases of coal projects in the West.

Flaws in state and federal government interaction were also noted in a report published by the U.S. Regulatory Council (1981). The Council solicited complaints from coal mine operators about permitting burdens. A general observation was made that the state and federal interactions were poorly understood by operators and often appeared to be overlapping. Numerous complaints were also lodged about ambiguities and confusion in the interpretation of Mine Safety and Health Administration regulations.

Investigators also noted the general lack of self-imposed review deadlines for federal agencies (U.S. GAO, 1981a). Whereas some states have implemented permit assistance or streamlining measures, federal land managers have made only limited efforts to expedite their procedures. Memoranda of Understanding among BLM and other surface management agencies may allow for more rapid processing of lease applications and of post-lease approvals.

3.1.3 Costs of Permit Preparation

Numerous economic analyses of energy projects have occurred although the expenses of permit preparation or the costs of permit delays have rarely been separately quantified. An examination of permit costs therefore involves the careful use of those studies which give direct or indirect indications of permit expenses or other topics of interest.

One study which considered permitting costs directly was intended to evaluate the costs of SMCRA regulations for coal mine operators (Skelly and Loy, 1979). Pre- and post-SMCRA costs of permit and mine plan preparation were estimated based on an informal survey of mine operators before actual implementation of the OSM regulations. The cost estimates are shown in Table 3-5, but due to the operators lack of actual experience with SMCRA rules on the part of operators, the estimates should be viewed with skepticism. In any case, the wide range for the projected costs illustrates the considerable uncertainty about the rules. The maximum projected increase was estimated at over \$500,000.

An ICF study (1977) produced much more conservative, although no less preliminary, estimates of SMCRA compliance costs. The expenditures anticipated by ICF were mainly for test drilling and hydrologic assessments. The cost estimates, presented by states, are shown in Table 3-6.

For other cost studies, it was possible to measure premine planning costs against the total cost of coal production. The results of this effort are summarized in Table 3-7, with the study sources and the region of study indicated. Premine planning costs include mine design, permit and mine plan preparation costs, and reclamation planning. (However, the studies referenced should be examined for details of the estimation methodologies.) In nearly all cases, mine planning costs were less than 1 percent of the total cost of coal. In the Western states, premine costs were generally estimated at less than 0.5 percent of coal costs.

TABLE 3-5

INDUSTRY'S EXISTING AND PROJECTED
COMPLIANCE COSTS
(PRE- AND POST-SMCRA REGULATIONS)

REGION	<u>SURFACE MINES</u>		<u>UNDERGROUND MINES</u>	
	EXISTING	PROJECTED	EXISTING	PROJECTED
<u>Permit Preparation Cost per Mine (\$ x 1,000)</u>				
Central Appalachia	1-200	15-486	4-30	15-350
Northern and Southern Appalachia	3	N.A.	11-20	25-350
Midwest	0-25	13-595	0-50	4-100
West	28-159	60-353	1	10
<u>Mine Plan Preparation Cost per Mine (\$ x 1,000)</u>				
Central Appalachia	1-4	5-15	1-40	2-160
Northern and Southern Appalachia	3	N.A.	30-60	80-150
Midwest	0-35	2-70	0-5	1-100
West	2	4-5	1	20

Source: Skelly and Loy, Analysis of the Impact of Public Law 95-87 on Mining Performance, prepared for the Department of Energy, 1979.

TABLE 3-6

ESTIMATED INCREMENTAL PERMITTING COSTS,
BY STATE, DUE TO SMCRA REGULATIONS
(1978 \$ Per Mine)

STATES	TEST DRILLING ^a	HYDROLOGIC ASSESSMENT		CROSS SECTION MAPS	TOTAL INCREMENTAL PERMIT COST			
		SURFACE	SUB-SURFACE		EXISTING ^b		NEW	
					LARGE	<200 MT/Y ^c	LARGE	<200 MT/Y
Alabama	3,900	5,000	20,000	5,000	30,000	5,000	33,900	5,000
Alaska ^d	-	-	-	-	-	-	-	-
Arizona ^d	-	-	-	-	-	-	-	-
Arkansas	2,400	5,000	20,000	5,000	30,000	-	32,400	-
Colorado	-	-	-	-	-	-	-	-
Illinois	-	5,000	20,000	5,000	30,000	-	30,000	-
Indiana	25,900	5,000	20,000	5,000	30,000	-	55,900	-
Iowa	4,575	5,000	20,000	5,000	30,000	-	34,575	-
Kansas	3,525	5,000	20,000	5,000	30,000	-	33,525	-
Kentucky	3,450	5,000	20,000	5,000	30,000	5,000	33,450	5,000
(east)								
Kentucky	20,625	5,000	20,000	5,000	30,000	-	50,625	-
(west)								
Maryland	-	-	-	-	-	-	-	-
Missouri	9,400	5,000	20,000	5,000	30,000	-	39,400	-
Montana	-	-	-	-	-	-	-	-
New Mexico	55,400	-	-	-	-	-	55,400	-
North Dakota	-	5,000	-	-	5,000	-	5,000	-
Ohio	5,475	5,000	20,000	5,000	30,000	5,000	35,475	5,000
Oklahoma	-	-	-	-	-	-	-	-
Pennsylvania	-	-	-	-	-	-	-	-
Tennessee	3,525	5,000	20,000	5,000	30,000	5,000	33,525	5,000
Texas	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-
Virginia	3,750	-	20,000	5,000	25,000	5,000	28,750	5,000
Washington	75,900	5,000	20,000	-	25,000	-	100,900	-
West Virginia	-	5,000	20,000	5,000	30,000	5,000	30,000	5,000
(north)								
West Virginia	-	5,000	20,000	5,000	30,000	5,000	30,000	5,000
(south)								
Wyoming	-	-	-	-	-	-	-	-
Federal leases	-	-	-	-	-	-	-	-

^aDetermined as greater of 3 holes or 1 hole/320 acres, times overburden plus seam thickness (in Appalachia, western states would drill 200 ft below seam), times \$25 per foot drilled).

^bExisting mines not assumed to need additional test drilling.

^cSmall mine costs limited to cross section mapping; other costs assumed by regulatory authority.

^dIncremental costs shown for Alaska and Arizona assumed the same as for federal coal leases.

Source: ICF Inc., Draft Final Report, Energy and Economic Impacts of H.R. 13950 ("Surface Mining Control and Reclamation Act of 1976," 94th Congress), 1977.

TABLE 3-7

PREMINE PLANNING COSTS AS A PERCENTAGE
OF TOTAL COAL MINING COSTS

STUDY	REGION AND STATES	PLANNING COSTS AS PERCENTAGE OF TOTAL MINING COSTS
Skelly and Loy (1975)	I (IN,WV)	0.1 - 1.6
	II (PA,OH)	0.2 - 1.0
	III (OH,IL,IN)	0.2 - 0.8
	IV (WY,MT,ND)	0.6 - 0.8
Skelly and Loy (1979)	I (KY,TN,VA,WV)	0.6
	II (AL,MD,OH,PA)	0.1
	III (MIDWEST)	0.1
	IV (WEST)	0.1
Leathers (1980)	(WEST)	0.1 - 0.4

Source: See Appendix A for full report citations.

The costs of operating delays due to permitting difficulties have not been estimated by most researchers. The evidence of such delays remains largely anecdotal rather than quantitative (Jones and Beckner, 1974; Jones, 1976; Tobler, 1975; and Grandt, 1978).

SECTION FOUR

FEDERAL AGENCIES - RESPONSIBILITIES IN LEASING AND PERMITTING FOR ENERGY DEVELOPMENT ON FEDERAL LANDS

The management of U.S. lands involves a complex set of issues and organizations. Federal agencies control huge land areas, particularly in the Western states, and have considerable latitude to determine the extent and rate of development of such lands. In determining the future patterns of development, agency decision makers must consider the entire gamut of influences on land use policies. Among the competing interests are energy developers, nonfuel mineral companies, timberland interests, and agricultural concerns, as well as conservationists and environmentalists. Agency decisions impact the domestic energy production rate (and national energy independence), the environmental characteristics of Western states, and the aesthetic qualities of the American wilderness. Efforts to balance these interests have been central to legislation affecting land policies since the 1800's when competition and conflict for territories became evident.

In this section, the principles of federal land policies will be presented. These policies are founded upon more than 100 years of legislation governing the manner of land disposal and land use. The legislation, which is summarized in Section 4.1, directs the Secretary of the Interior (and other federal officials) to establish programs for leasing and/or managing federal lands. The

government offices and bureaus which conduct these land programs are described in Section 4.2 and the main leasing programs are outlined Section 4.3. Finally, the impact of federal regulations on energy development is considered with a listing of all federal permits which can apply to energy development.

4.1 Legislation Authorizing and Impacting Federal Permitting Activities

Federal land management and environmental control policies are based on a system of legislation developed over the past 100 years. Initial programs for control of mining and energy development on federal lands date back to the 1800's, with major program modifications occurring in the 1920's. Further lands policies are based on legislation passed since World War II, including federal land policy laws and leasing act amendments passed during the 1970's. Of course, environmental control policies are of a more recent vintage. The major environmental legislation, as well as most programs for preservation of fish and wildlife resources, were instituted since 1970.

Descriptions are provided below of the major and minor pieces of legislation which impact the federal permitting process. Often the connection between legislation and permits is an indirect one. Legislation spawns regulations, which become part of the United States Code. The regulations, and the authority provided therein to government agencies, then lead to permitting programs and other regulatory requirements. The effect of each piece of legislation on permitting activities is intermingled, through the process of codifying U.S. law, with that of many other laws, producing a complex of permitting

requirements. Nevertheless, it is generally possible, particularly for major legislation, to identify the resulting permit requirements.

Legislation is grouped into two categories, labeled first- and second-tier laws, according to the magnitude of its effect on federal lands policies and/or energy development. A listing of the legislation is provided in Tables 4-1 and 4-2. The first-tier (or major) legislation listed includes those laws which form the historic basis of land policy. The major environmental programs and the important Surface Mining Control and Reclamation Act are also included. Second-tier legislation, including some of the fish and wildlife protection programs, were passed for either more specialized purposes or for purposes not directly impacting energy development. These laws spawned permitting programs which generally have a smaller impact on energy programs. The separation of the first and second tiers of legislation is, of necessity, approximate and does not have formal significance.

A few laws which also affect permitting have not been noted in Tables 4-1 and 4-2. The need for permits extends to regulatory areas where no effects were intended upon federal land policy, environmental control, or energy development. For example, the Federal Aviation Administration requires permits for operation of a heliport, as may be installed near a coal mine or other major facility. This type of permit is included in the analysis of later chapters, but the statutory authority for such regulations has not been assessed.

TABLE 4-1

MAJOR LEGISLATION AFFECTING ACCESS TO
AND USE OF FEDERAL LANDS

<u>MINING AND/OR ENERGY LEGISLATION</u>	<u>ENVIRONMENTAL AND/OR GENERAL LEGISLATION</u>
Mining Laws of 1872	National Environmental Policy Act (1969)
Mineral Leasing Act of 1920	Clean Air Act (1970)
Acquired Lands Leasing Act (1947)	Federal Water Pollution Control Act of 1972
Multiple Use-Sustained Yield Act of 1960	Endangered Species Act (1973)
Geothermal Steam Act of 1970	Safe Drinking Water Act of 1974
Department of Energy Organization Act (1977)	Resource Conservation and Recovery Act of 1976
Federal Coal Leasing Amendments Act of 1976	
Federal Land Policy & Management Act of 1976	
Surface Mining Control and Reclamation Act of 1977	

TABLE 4-2

SECOND-TIER LEGISLATION AFFECTING ACCESS TO FEDERAL LANDS

MINING AND/OR ENERGY LEGISLATION	ENVIRONMENTAL AND/OR GENERAL LEGISLATION
Multiple Use Mining Act (1955)	Rivers and Harbors Act of 1899
Mining and Mineral Policy Act of 1970	Antiquities Act of 1906
Federal Mine Safety and Health Act of 1977	Wilderness Act of 1964
	Wild and Scenic Rivers Act (1968)
	Coastal Zone Management Act of 1972
	Archaeological and Historical Preservation Act of 1974
	National Forest Management Act of 1976
	Toxic Substances Control Act (1976)

4.1.1 First-Tier Legislation Summaries

4.1.1.1 Mining and/or Energy Legislation

Mining Laws of 1872

The Mining Law of 1872 is recognized as the first legislation to establish a system for disposal of federal energy and mineral lands. The law established the "claims" system for acquiring rights to valuable deposits on federal lands. All minerals (energy minerals or otherwise) were classified as locateable minerals and claims could be used for acquiring surface and subsurface rights to deposits on federal lands.

In practice, the Mining Law of 1872 led to an uncontrolled transfer of federal lands to private interests. Numerous public land tracts were thus being disposed of with little payment to the federal government and with no control over retention of supplies of strategic minerals and fuels. The situation encouraged tighter control of federal lands, as provided for by later legislation.

Mineral Leasing Act of 1920, P.L. 66-146. The Mineral Leasing Act of 1920 first established the leasing system for federal lands. Under this Act, the government would retain title to federal lands opened for development, but leases would be granted to individual land users. The law was passed as a means to slow the rapid sale of federal land occurring under the Mining Laws of 1872. That earlier legislation had established a "claims" or "location" system, under which land ownership was gained through a process of

resource discovery, appropriation, and development. The Mining Laws of 1872 allowed for relatively uncontrolled private exploitation of resources. In response, the leasing system was initiated to give the federal government control over land development.

The Mineral Leasing Act of 1920 remains the primary legislative authority for federal leasing. While the Federal Land Management and Policy Act (BLM Organic Act) gives the Interior Department overall land-use planning responsibility, the authority to lease lands was already established. Various later actions have amended the Mineral Leasing Act of 1920, including the Federal Coal Leasing Amendments Act, to further define the control of the federal government over land use.

Acquired Lands Leasing Act (1947), P.L. 80-347. The Act authorized the Department of Interior to lease lands which had been acquired by the federal government. The Act thus placed acquired lands on an equal footing with other federal lands for the purposes of resource exploitation.

The impact of the Acquired Lands Leasing Act was to expand the territory available to the federal government for land use planning and leasing. No particular permitting activities were developed due to this legislation.

Multiple Use - Sustained Yield Act of 1960. The Multiple Use-Sustained Yield Act of 1960 established broad land use principles to govern the policies of the National Forest Service. The same policies have come to govern BLM activities as stated in the Federal Land Management and Policy Act.

Under this Act, Congress stated a policy of establishing and administering national forests for the purposes of outdoor recreation; range and timberland control; and watershed, wildlife, and fish protection. The Secretary of Agriculture was authorized by the Act to develop and administer the renewable surface resources of the national forests for the multiple use and sustained yield of the several products and services obtained therefrom. In particular, "multiple use" refers to management of various surface resources of the forests so that they are utilized in combination, making for most judicious use of the land. "Sustained yield" refers to the maintenance in perpetuity of a high-level of annual or periodic output of forest resources without a loss of productivity.

This legislation encouraged the National Forest Service to adopt long-term plans for resource utilization on federal lands. In so doing, the law allows the surface management agency to resist or defer pressures for exploitative or single-use land development by allowing consideration of the varied uses (recreation, timber, grazing, etc.) which may be possible.

Geothermal Steam Act of 1970, P.L. 91-581. This Act authorized the Department of the Interior to grant leases of federal lands for geothermal energy development. Basic leasing terms established for geothermal lands are similar to those for oil and gas development. If a land tract is in a Known Geothermal Resource Area (KGRA), then competitive bidding for leases is required. If a land tract is outside a KGRA, noncompetitive leasing is acceptable. Other provisions of the Act establish conditions for royalty payments, lease terminations, and other actions.

As a result of the Geothermal Steam Act of 1970, federal leasing policy was extended to geothermal resource lands. The leasing authority for other resources was established by the Mineral Leasing Act of 1920. The Geothermal Steam Act was the first land-management statute passed after the National Environmental Policy Act (NEPA) legislation. The NEPA requirements were incorporated directly into the Act, and environmental review provisions have been included in the leasing procedures.

Department of Energy Organization Act (1977),
P.L. 95-91. The DOE Act transferred to the Department of Energy, from the Department of Interior, selected authorities vested by the Mineral Leasing Act of 1920, the Acquired Lands Leasing Act, and the Geothermal Steam Act of 1970 with regard to leasing land tracts for the purposes of energy development. The Department of Energy's responsibilities include:

1. The development of the economic terms and conditions for leasing.
2. The establishment of energy production goals for federal lands.
3. The issuance of regulations pertaining to fostering of competition for leases.
4. The implementation of alternative bidding systems.

The details and organizational impact of this transfer of authority has been a major issue for federal lands policy. In essence, the Department of the Interior retained most leasing authority, but the Department of Energy could act to encourage and regulate energy development. The alignment of authorities was further modified by the Reagan administration during 1982.

The Department of Energy Organization Act affects the administration of leasing policy, but does not translate into additional permitting requirements per se. The leasing process at the federal level is controlled by the Bureau of Land Management, and, after leasing, by various other regulatory agencies.

Federal Coal Leasing Amendments Act of 1976,
P.L. 94-377. The Act, which amended the Mineral Leasing Act of 1920, established a totally competitive coal leasing system to be implemented by the Department of the Interior. Criteria to be used in coal development by the Department of the Interior were redefined in order to provide much more stringent control of the leasing process. The Act directs the Department of the Interior to enforce diligent development of reserves to ensure that all recoverable reserves on a given lease tract will be mined within 40 years. The Interior Department must also approve of the mining method chosen to insure that maximum economic recovery is achieved. Additionally, each lease granted for coal mining must contain provisions requiring compliance with the Federal Water Pollution Control Act and the Clean Air Act during mining operations. Finally, the Act defines the process through which National Forest lands may be leased, with review procedures which may be exercised by Governors of the affected states.

The impact of the Federal Coal Leasing Amendments Act was to further define the Department of the Interior mission with regard to coal leasing. The provisions of Federal Coal leases were expanded to insure that national interests, such as those of maximum economic recovery and diligent development, were maintained. These changes were necessitated by

the slow coal production rates on many federal coal leases. Many of the leases had been obtained noncompetitively for speculative purposes.

Federal Land Policy and Management Act of 1976,
P.L. 94-579. The Federal Land Policy and Management Act (FLPMA) is now the principal basis for federal leasing authorities. Also known as the BLM Organic Act, the legislation recodifies and describes the mission of the Department of the Interior as the primary federal land use agency. Among the powers explicitly defined for the DOI are authorities for: (1) acquiring new federal land, (2) withdrawing federal lands from development, (3) classifying lands according to primary resources in order to control their use (e.g., designation of Wilderness lands), and (4) disposing of lands through sales, with general terms of the sales and of the revenue distribution defined in the Act. These powers are designated for the Department of the Interior within the context of a broad authority for national land use planning. The Secretary of the Interior was required by the Act to make an inventory of federal lands and to develop nationwide land use plans. In general, the Secretary has authority to sell, lease, and acquire land as may be consistent with the land use plans.

The BLM mission is further defined, in the Act, by the emphasis on multiple-use and sustained-yield objectives for federal land management. The same principles were defined for governing the National Forest Service activities in land management in the earlier Multiple Use-Sustained Yield Act of 1960. The principles of multiple-use and sustained-yield allow these federal agencies to balance demands for rapid development of lands by individual commodity interests with broad, long-term national interests.

The impact of the FLMPA was to establish clearly the premier position of the Department of the Interior, and particularly the Bureau of Land Management, in leasing of lands for mineral energy development. In authorizing broad land-use planning, the BLM is imbued with an explicit legislative basis for many activities that had been conducted through the years. The importance of the Act can be seen in a recent federal land action. The Federal Land Management and Policy Act, in conjunction with the Antiquities Act of 1906, was cited as authority by President Carter for withdrawal from development of 56 million acres of Alaskan lands pending completion of land-use plans and designations.

Surface Mining Control and Reclamation Act of 1977,
P.L. 95-87. The Surface Mining Control and Reclamation Act of 1977 established the Office of Surface Mining within the Department of the Interior and authorized it to promulgate and enforce regulations as needed to protect the environment from the effects of surface mining and the surface effects of underground mining. The major goals of the Act and the subsequent regulations are:¹

1. To set a national standard for a detailed control program for coal mining and reclamation.
2. To ban mining where land reclamation is not feasible.
3. To balance agricultural and coal resource uses of the land.
4. To allow public participation in decisions affecting their environment as it is affected by coal mining involvement.
5. To help achieve reclamation of previously mined and abandoned lands.

In short, the SMCRA legislation brings environmental regulation of coal mining under one statute, with the requirements of other environmental regulations, i.e. Clean Water Act, included by reference.

Major impacts of SMCRA have been felt by coal mine operators because of the extensive compliance requirements. The Office of Surface Mining is now the principal regulatory agency for coal mine operations once a lease tract has been acquired through BLM leasing procedures. The central aspect of the regulatory control is the requirement for submittal of detailed mining and reclamation plans, prior to the initiation of operation. This permit plan approval process represents the largest potential cost of regulation for mine operators.

4.1.1.2 Environmental and/or General Legislation

National Environmental Policy Act (1969), P.L. 91-190. The National Environmental Policy Act (NEPA) requires federal agencies to include environmental factors in decisionmaking through preparation of detailed environmental impact statements. The Act also established the Council on Environmental Quality which has published guidelines for the preparation of environmental impact statements. As currently invoked, NEPA requires that an EIS be prepared for any "major" federal action, and that the document cover the entire range of potential environmental impacts.

The impact of NEPA requirements has included increased visibility for environmental concerns, and a lengthened permitting procedure due to the time necessary to allow preparation and review of EIS documents. This impact has been felt in all major energy development activities on federal lands.

Clean Air Act (1970), P.L. 91-604. The Clean Air Act authorizes EPA to establish primary and secondary ambient air quality standards, emission standards for newly constructed industrial plants or stationary sources, and for hazardous air pollutants. The Prevention of Significant Deterioration Permits (PSD) which may be required of many energy facilities are authorized by the Clean Air Act.

The Clean Air Act has a major impact on energy development by limiting allowable emissions and requiring installation of the best available control technologies. Impacts are greatest among energy facilities in which some fuel processing occurs. Among the resource types considered in this study, oil shale properties and coal mines (particularly those located with preparation plants), are most strongly regulated under the Clean Air Act.

Federal Water Pollution Control Act of 1972, P.L. 92-500. The Federal Water Pollution Control Act of 1972 (FWPCA) authorizes the Environmental Protection Agency to prescribe regulations for the abatement and control of water pollution into navigable waters of the U.S. As a result of the Act, the National Pollutant Discharge Elimination System (NPDES) was established whereby any facility with a point source discharge must obtain a permit prior to operation. Also, Section 404 of the Act directs the Corps of Engineers to establish regulations controlling the disposal of dredged and fill material in navigable streams.

The FWPCA limitations on effluent discharges are a major concern for several of the resource areas covered in this study. The NPDES permits may be difficult to obtain for the energy extraction processes that have water resource implications, particularly oil shale and coal mine operations.

Endangered Species Act (1973), P.L. 93-205. The Act authorizes the Department of the Interior to determine which species are endangered and to promulgate regulations to insure the conservation of such species. The promulgation and enforcement activities under the Act have been performed by the Office of Endangered Species within the Fish and Wildlife Service.

The implementation of the Endangered Species Act has led to several notable delays or cancellations of development projects. In the event that development of a land tract would create a significant difficulty for rare wildlife, then the Office of Endangered Species (OES) can veto a potential BLM lease agreement. Until recently such a veto could not be overruled by BLM. However, amendments to the Act passed in 1979 created a procedure whereby a seven-member committee, including the Secretaries of Interior and Agriculture, could overrule an OES action. If a project has no impact on endangered species, then the BLM leasing process may continue with no incremental permitting required by OES.

Safe Drinking Water Act (1974), P.L. 93-523. The Safe Drinking Water Act authorizes EPA to set primary drinking water standards and to promulgate regulations as needed to protect drinking water sources. Included under the Safe Drinking Water Act is authority for control of Underground Injection operations.

The impact of the Safe Drinking Water Act on energy development is based on both the regulations for protection of drinking water supplies and on the Underground Injection Control (UIC) regulations. Mining operations are typically regulated to some degree in their rerouting of underground

streams and by the need to protect groundwater. Oil and gas and geothermal operations are also regulated by the UIC regulations with regard to reinjection of waste waters into underground reservoirs.

Resource Conservation and Recovery Act of 1976,
P.L. 94-580. The Resource Conservation and Recovery Act (RCRA) authorizes the Environmental Protection Agency to establish regulations for control of solid and hazardous waste disposal. The RCRA regulations have defined various standards for the location, design and operation of hazardous waste treatment, storage and disposal systems. General performance standards were defined in the Act for solid waste disposal. More specific regulations including some design requirements are still being developed by EPA for hazardous waste disposal systems.

The impact of RCRA on energy operations varies with the resource considered, and the specific regulatory treatment of the wastes. However, waste streams produced in oil and gas, oil shale and coal operations were statutorily exempted from control under RCRA, by the RCRA Reauthorization Bill passed in 1979, pending further study of potential hazards and impacts.

4.1.2 Second-Tier Legislation Summaries

4.1.2.1 Mining and/or Energy Legislation

Multiple Use Mining Act (1955). The Multiple Use Mining Act was passed in response to various abuses occurring under the claims system (General Mining Laws of 1872). In particular, many "miners" were conducting

logging operations on their claims without payment to the Forest Service. The Act authorized the Forest Service to manage the surface resources on national forest mining claims and to eliminate uses, including timber cutting, unrelated to mining.

The Act allows the Forest Service to balance claims of developers and preservationists in land management. In this regard, the Act is a precursor of later management policy statements, such as the Multiple Use-Sustained Yield Act of 1960.

Mining and Mineral Policy Act of 1970, P.L. 91-631.
The Act set forth various national policy guidelines and standards by which the federal government could pursue its resource objectives. The Act encouraged the orderly and economic development of domestic mineral resources. The Act also required the Secretary of the Interior to make annual reports to Congress on the state of the domestic mining industry.

Federal Mine Safety and Health Act (1977), P.L. 95-164.
The Act authorized the Department of Labor to establish the Mine Safety and Health Administration (MSHA). The Administration operates a program of mine safety governing coal, oil shale and mineral mining operations.

The MSHA regulations require coal mine operators to prepare a variety of plans covering various safety features of the mining operations. The plans must be approved before mining can begin. Oil shale mining is classified as a mineral mining operation and is subject to fewer, and less stringent, requirements.

4.1.2.2 Environmental and/or General Legislation

The Rivers and Harbors Act of 1899. The Rivers and Harbors Act authorizes the U.S. Army Corps of Engineers to license all construction activities in a navigable waterway. This responsibility is quite similar to the Section 404 permit requirements of the Corps, under the Clean Water Act, which control dredge and fill operations in navigable waters.

The permit requirement defined under the Rivers and Harbors Act of 1899 is generally relevant to construction of water diversion structures for industrial plants and pipeline crossings, as may be developed for selected energy projects. The permit application is virtually identical to that of the 404 permit program.

Antiquities Act of 1906. The Antiquities Act authorizes the President to declare public landmarks and to reserve parcels of land so as to protect items of historical value. The land parcels, which are limited to the smallest area compatible with care and management of the area to be protected, are thus withdrawn public lands.

The Antiquities Act was cited along with the Federal Land Policy and Management Act, by President Carter as authority for withdrawal of 56 million acres of Alaskan territory in 1978. Prior to this action, the Antiquities Act had a relatively minor impact on energy development, requiring only archaeological reviews and, in some cases, modifications in project plans.

Wilderness Act of 1964. The Wilderness Act authorized the Forest Service to make official designations of certain

areas of "primeval character and influence, without permanent improvements or human habitation," and which are at least five thousand acres in size, as Wilderness areas. Under the Act, 54 areas (9.1 million acres) were given Wilderness status immediately, and 34 areas were to be "reviewed" for possible Wilderness status. At present, 187 million acres have been set aside for wilderness review.

The Wilderness Act of 1964 raised the possibility of wilderness designations only for Forest Service lands. However, the Federal Land Policy and Management Act (1976) extended coverage of the Act to BLM lands. The Wilderness Act prohibits leasing of Wilderness lands beyond 1983. As a result, the scope for possible energy development is reduced to the extent that wilderness designations are made.

Wild and Scenic Rivers Act (1968). The Wild and Scenic Rivers Act authorizes the Department of the Interior to protect designated portions of selected river areas. Energy extraction activities are prohibited on the banks of or within one-quarter mile of the bank on designated rivers. Mining may also be prohibited as needed to maintain the character of a given locale.

Coastal Zone Management Act of 1972, P.L. 92-583. The Coastal Zone Management Act authorizes the Department of Commerce to assist states in the management of coastal resources and to act as a reviewer of state policies. In approving state coastal zone plans, the Secretary of Commerce is to verify that the plan provides adequate consideration of the national interest in facilities "which are necessary to meet requirements which are other than local in nature." In so doing, the Act establishes a need for federal consistency among the coastal zone

management plan. The Secretary is also authorized to mediate in disputes between states and leasees of Outer Continental Shelf areas. However, states have the option of vetoing OCS development.

The primary impact of the Act on energy activities is felt by offshore oil operations; few onshore projects are sited in coastal areas. Oil exploration and production activities must be reviewed by two agencies (Interior and Commerce) when a coastal zone area is used. However, as has been noted, state governments retain veto power over the development activities.

Archaeological and Historic Preservation Act of 1974, P.L. 93-291. The Archaeological and Historic Preservation Act authorizes protection of historic lands from federally approved construction. The Secretary of the Interior is authorized to undertake recovery, protection and preservation of relics on such lands. The Secretary is further instructed to use up to one percent of the allotted funds of a federal project for preservation purposes. However, any person harmed by delays in the use of private lands may be compensated by the Secretary.

The Act is authorization of the archaeological reviews performed by the National Parks Service and by the Interagency Archaeological Division. Such reviews may be necessary prior to initiation of energy development projects on federal lands.

National Forest Management Act of 1976, P.L. 94-588. The National Forest Management Act further extends the principles of multiple-use land planning to Forest Service lands. In particular, the extent of lumber harvesting was

required to be compatible with other uses of the land. The Act represents a strong mandate for multiple use timber management, watershed protection and reforestation accomplished by tying timber management into a comprehensive multiple-use planning system.

The direct impacts on energy development of this Act are minor. The extension of the land use planning mandate for the Forest Service, and provisions for public participation in the process, can indirectly complicate the pursuit of energy interests.

Toxic Substances Control Act (1976), P.L. 94-469.

The Toxic Substances Control Act (TSCA) authorizes the Environmental Protection Agency to regulate commerce and protect human health by requiring testing and by imposing necessary restrictions on certain substances which may cause health or environmental damages. The EPA is developing procedures for controlling and testing of new chemical substances and for delineating the hazards and proposing restrictions for existing chemicals.

The implementation of TSCA can potentially impact various aspects of energy technologies, particularly those involving new or unstudied chemical substances. Among the substances which could be regulated by TSCA are the products of oil shale retorting and oil drilling muds. If found to be dangerous, and regulated under TSCA, substances could be closely regulated, or suppressed, leading to unknown impacts for those energy activities.

4.2 Primary Federal Permitting Organizations

As a result of the legislation described in Section 4.1 above, a number of agencies or divisions within agencies have been established to carry out federal responsibilities. Five of these organizations, the U. S. Forest Service (Department of Agriculture), the Bureau of Land Management (Department of the Interior), the Minerals Management Service (Department of the Interior), the Office of Surface Mining (Department of the Interior), and the Environmental Protection Agency, administer the primary permits for energy development on federal lands. These five agencies are described in Sections 4.2.1 through 4.2.5 below.

4.2.1 Bureau of Land Management

The Bureau of Land Management (BLM) of the Department of the Interior has the authority to administer federal lands under the Federal Land Policy and Management Act of 1976 and the earlier Mineral Leasing Law of 1920. BLM is the sole authority for leasing of federal lands with its control extending to lands which are managed by other federal agencies. For example, BLM has the power to lease lands operated by the other principal surface management agencies: The National Forest Service and the U.S. Fish and Wildlife Service. In actual practice, however, the BLM seeks the approval of other surface management agencies if their lands are to be leased. All lands containing oil and gas, coal, oil shale, native asphalt, solid and semisolid bitumen, bituminous rock, or geothermal resources come under this authority.

With respect to permitting of developments on federal leases, BLM has authority to review permits as the surface management agency for those projects under its direct jurisdiction. Approximately 450 million acres, or 61 percent of all federal lands are under direct BLM control.

The Bureau of Land Management has regional offices in all states with large federal land holdings. Within the states, there are separate district BLM offices covering portions of the state. Each district office reviews permits pertaining to that district. A national service center in Denver, Colorado provides technical information and support to all of the regional and district offices. Figure 4-1 is an organization chart of the BLM.

4.2.2 United States Forest Service

The U.S. Forest Service (FS) of the Department of Agriculture has authority to administer National Forest Service Land under the Multiple Use-Sustained Yield Act of 1960. This act establishes broad land use management authority for administration of Forest Service lands to preserve the multiple purposes of outdoor recreation, range and timberland uses, and fish and wildlife protection.

The Forest Service has responsibilities for review of leases granted on Forest Service lands, and may request the inclusion of stipulations in the lease contracts. Typically, lease stipulations are used to limit or eliminate the surface disturbance which might be caused by development projects. Such stipulations are designed to maintain

Figure 4-1. Bureau of Land Management Organization Chart (September 1982).

the multiple-use goals of Forest Service land management policies. The Forest Service has a similar review role for USGS permits regulating energy development, if Forest Service lands are involved. Additionally, the Forest Service regulates surface use and access with special use land permits and right-of-way permits. Next to BLM, the Forest Service is the second largest federal landholder. Of the 737.4 million acres of federal land, 187.5 million acres, or 25.4 percent are on FS lands.

The Forest Service is a highly decentralized organization with most important land use decisions made at the local level by Forest Supervisors. The Forest Service organization is shown in Figure 4-2. There exist nine Forest Service regions, each headed by a regional forester. Within each region, forest supervisors are appointed, generally with one supervisor for each national forest. These forest supervisors serve as local administrators and have considerable autonomy for handling requests for access to or exploration of forest lands. Regional offices review the local land use decisions.

4.2.3 The Minerals Management Service

The Minerals Management Service (MMS) represents a large, new section within the Department of the Interior. The MMS was formerly, in approximate terms, the Conservation Division of the USGS prior to being split off in 1982. MMS authorities cover lands subject to surface management by either BLM and FS.

Among the responsibilities of MMS in the leasing program are:

Figure 4-2. Line and Staff Organization of the Forest Service.

Figure 4-3. Organization Chart for the Minerals Management Service.

1. Definition of land tract boundaries subject to leasing.
2. Review and approval of lease applications and applications for drilling or prospecting.
3. Estimation of land values and setting of minimum acceptable bids in competitive leasing.
4. Definition of known resource areas to identify which lands must be competitively leased.
5. Enforcement of compliance with lease terms.

With respect to the regulation of development on federal leases, MMS is the primary enforcement agency. This responsibility, however, is shared in the case of coal lands with the Office of Surface Mining. The MMS objectives in its review of energy project operations are to prevent the waste of resources, to prevent pollution, to minimize surface damage, and to ensure compliance with lease terms. Specific MMS permits are described in Section 4.4 below.

4.2.4 Office of Surface Mining

The Office of Surface Mining (OSM) of the Department of the Interior is the primary permitting body for coal mining operations on federal lands. OSM was created as a result of the Surface Mining and Reclamation Act (SMCRA) of 1977.

As stated above, the MMS (operations) and either BLM or FS (surface management) have some permitting responsibilities for energy resource development on federal lands. While

SMCRA gives OSM primary permitting responsibility for coal operations, MMS and either BLM or FS retain a review responsibility for SMCRA permits.

The Office of Surface Mining within the Department of the Interior runs the coal mine permitting program under SMCRA. An organization chart for OSM is shown in Figure 4-4. Individual permit applications are handled out of five DOI region offices located in Charleston, West Virginia; Knoxville, Tennessee; Kansas City, Missouri; Denver, Colorado; and Indianapolis, Indiana. The SMCRA legislation also encourages coal states to take over this coal permitting program.

4.2.5 Environmental Protection Agency

The U.S. Environmental Protection Agency (EPA) administers several programs requiring environmental data or permit preparation. These programs include the Clean Water Act, the Clean Air Act, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, and the Safe Drinking Water Act. The EPA also is responsible for reviewing environmental impact statements, prepared under the mandate of the National Environmental Protection Act, prepared for other federal agencies.

Permitting requirements under the above laws vary from resource to resource. Coal and oil shale development projects commonly require EIS submissions. Coal and oil shale projects can entail extensive Clean Air Act permitting. Projects of all types typically require water quality permits under the Clean Water Act (NPDES permits) or the Safe Drinking Water Act (UIC permits). Permit requirements under other legislation may be called for on a case-by-case basis.

Figure 4-4. Office of Surface Mining Organization Chart.

EPA's organization is shown in Figure 4-5. EPA's ten regional offices run its permitting programs. Furthermore, most of the major EPA programs allow the states to take control of their permitting if they develop an EPA-approved program.

4.3 Agency Responsibilities for Leasing Programs for Each Resource Area

The responsibilities of the land management bureaus within the Department of the Interior can be further defined in terms of the distinct leasing programs for each resource area. The Bureau of Land Management, while having the sole authority for disposing of federal lands, distinguishes among energy lands for the purpose of leasing. The federal coal management program, for example, operates separately from the oil and gas leasing program. The former ran into significant programmatic difficulties during the 1970's and was suspended from 1971 to 1979, while the latter has operated without interruption (although not without difficulties).

The four leasing programs of interest have evolved separate operating principles which reflect resource differences, varying legislative authorities, and distinct land management objectives. One area of differentiation is in the rules governing lease sales, such as those allowing competitive and noncompetitive lease sales. Other differences include the environmental review requirements for leasing, the nature of post-leasing activities, and the timing of lease sales vis-a-vis resource identification. The leasing of oil shale lands represents a special case because no further leasing is scheduled.

*Acting

Figure 4-5. United States Environmental Protection Agency Organization.

The conduct of the separable leasing programs affects both the rate of energy development and the complexity of permitting for energy projects on federal lands. For this reason, it is useful to briefly outline the main elements of each leasing process. The description will primarily cover both the pre-lease and the initial post-lease activities of federal agencies and energy developers. In the next section, the individual permits required for energy projects are described. The permits describe the post-lease responsibilities of agencies and developers.

After leasing, the Department of the Interior retains title to the federal lands and land management agencies are responsible for approving energy extraction operations. Information is provided below on the "central" permitting procedures designed to regulate such energy operations. These permit procedures are also conducted by offices or bureaus within the Department of the Interior and other agencies.

4.3.1 Oil and Gas Leasing

The Department of the Interior leases oil and gas lands with the BLM taking the lead role and MMS serving in important advisory capacities. Environmental factors are noted during leasing as well as prior to operations.

The Mineral Leasing Act of 1920, authorizes the Secretary of the Interior to dispose of oil and gas lands. The discretion granted is limited by five factors. First, lands in a known geological structure (KGS) must be leased competitively. Second, the royalty on oil and gas production on

federal lands is set by law at 12.5 percent. Third, the size of individual lease holdings is limited. Fourth, the Department of Energy has authority to establish diligence (of exploration and production) requirements, set production rates, and set terms for acquisition and disposition of royalties. Finally, by the Acquired Lands Act of 1947 the Secretary must obtain consent of the surface management agency (SMA) for disposal of acquired lands. The SMA is the agency which is the landholder of the tract in question. In practice, this policy of complying with recommendations of the SMA is followed on all public lands. These restrictions exist in similar forms in the other energy land leasing programs.

Leasing of particular oil and gas lands is performed through one of three channels. A brief description follows:

Competitive Method - Land location within a known geological structure, essentially land with proven production, must be leased through competitive bidding. Once a producing well is completed, the land around the well (generally about 1 square mile) is designated by the MMS as a KGS.

Noncompetitive Methods -

Simultaneous or lottery system - The majority of federal oil and gas lands are leased through this method. As leases expire or are terminated, they are scheduled for bimonthly drawings. Interested parties submit drawing cards and filing fees, and the winning entry is randomly selected.

Over-the-counter, or open filing - Land not previously leased or subject to the lottery is available to the first qualified applicant who submits an application and the first year's rental.

Beginning fiscal year 1980, there were more than 118,000 active oil and gas leases which cover over 100 million acres of federal land. Roughly 97 percent of the lands offered for leasing are outside a KGS and are leased noncompetitively.

In these pre-lease assignment activities, the responsibilities placed on the potential energy developer are quite modest. The developer must either submit a bid in a lease sale, participate in a lease lottery (or purchase lease rights from the successful entrant after the drawing) or apply for an oil and gas lease for "over-the-counter" lands. In deciding upon his role, a developer may first conduct exploration operations. A Notice of Intent - Oil and Gas Explorations Operations must be filed with the BLM district office. This notice allows limited exploration activities as needed for seismic measurements but does not allow core drilling. After lease acquisition, the developer must comply with MMS regulations.

4.3.1.1 Post Lease Responsibilities on Oil and Gas Lands

The MMS is the enforcement agency on oil and gas lands and developers must secure MMS approval before beginning operations. These approval processes represent some of the important permit obstacles for oil and gas firms.

The first submission by developers is needed prior to entry to leased lands. The items to be provided include a preliminary map showing the location of the proposed drilling site, a Preliminary Environmental Review (PER), and any necessary off-lease rights-of-way. This application, referred to as the "pre-staking clearance" is forwarded by the MMS to BLM, or other applicable surface management agency, for review vis-a-vis lease terms and stipulations. The lease stipulations are conditional lease provisions which may be imposed by surface management agencies in order to protect selected land characteristics.

The next submission is the Application to Drill (APD), and the accompanying Multipoint Surface Use and Operation Plan (MSUOP). The information to be provided in each submittal is specified in the Notice to Lessees No. 6, prepared by the MMS. The APD covers critical drilling information including proposed well locations, geological formation data and drilling techniques and depths. The Multipoint Surface Use and Operating Plan describes land characteristics and environmental data as needed to help the MMS consider land impacts.

The full process of obtaining pre-stake clearance and APD approval can involve the interaction of the MMS and of other federal agencies and includes provisions for EIS preparation in selected cases. The MMS must coordinate inputs from interested surface management agencies, perform an environmental assessment, consider the preparation of a full EIS and finally approve, approve with stipulations, or disapprove of the APD.

The actions required of the developer are concentrated at the beginning of the process with submittal of the APD and the MSUOP. Additional actions include obtaining off-lease right-of-way and state or local permits, and initiation of the needed archaeological reviews and land surveying. Further permits are mandated at the closure of operations or for significant changes in activities.

4.3.2 Coal Lands Leasing

As for other mineral resource lands, the original authority for leasing coal lands was provided by the Mineral Leasing Act of 1920. The Act provided for both competitive leasing and noncompetitive "preference right" leasing. However, the management of federal coal lands was marred by a lack of sustained development of resources, and coal production levels were considered unacceptably low. In response to this issue, the Secretary of the Interior suspended the issuance of new prospecting permits and the processing of preference right lease applications in 1971. The coal leasing program was held in abeyance until the passage in 1976 of the Federal Coal Leasing Amendments Act. This legislation repealed the provisions for preference right leasing, meaning that all coal lands are to be leased competitively, and authorized regulations for defining diligent development requirements for coal lease holders. The renewal of coal land leasing was eventually approved by the Secretary of the Interior in 1979, with leasing to start in 1981.

The Department of the Interior activities which are referred to as the federal coal management program include those actions needed to bring coal lands to readiness for

leasing. The program elements include land use planning, tract delineation, tract ranking and selection, and pre-lease sale and lease sale procedures. Land use planning activities are performed by either BLM or the Forest Service (that is, by the appropriate surface managing agency). The outcome of land use planning is the delineation of areas acceptable for further consideration for coal leasing. The lands are then judged according to their coal development potential, their environmental characteristics, and the probable value of competing land uses.

The results of the ranking and selection process, the proposed lease sale schedule, and the ranking criteria are published along with a regional lease sale environmental impact statement. These publications are followed by the submission of comments and public hearings. Consultation also occurs among BLM, the Governors of affected states, and other federal surface management agencies. The Governors must consent to issuance of the lease.

As is the case for other resource land programs, the MMS serves as the technical advisor to the program with responsibilities for tract delineation and estimation of reserves. After bidding, the MMS establishes the fair market value for the lease tract. After the lease sale, the MMS shares enforcement and permit approval authorities with the Office of Surface Mining of the Department of the Interior.

To the point of lease sale, prospective developers are active only in determining their interest in the coal lease sale. An Exploration License may be obtained from the appropriate BLM state office. This permit allows the

permittee to prospect on and explore specific federal lands to determine the existence, workability and commercial value of the specified deposits therein.

4.3.2.1 Post-Lease Responsibilities on Coal Lands

The major post-lease responsibilities were shifted from the MMS to the newly-created Office of Surface Mining by implementation of the Surface Mine Control and Reclamation Act. Under the current alignment, the MMS retains its functions for monitoring resource development and production. BLM and other surface management agencies have authority for selected land use reviews and consultations. OSM takes the lead responsibility for approving mining procedures.

The center of the permit process for coal lands is the mining plans to be submitted by the developer to OSM. The developer's submittal includes a full and detailed Mining and Operation Plan and complete information for the coal mining permit application. Legal information requirements include an identification of affected interests, evidence of compliance with non-SMCRA laws, rights on entry and operations, relationship of the proposed development to areas unsuitable for mining, and a variety of other non-technical datum. Environmental information must, according to the regulations, cover the mine plan and adjacent areas as well as the permit area. Information on area hydrology, geology, climatology, vegetation, fish and wildlife, and soils must be included with appropriate maps. Operations and reclamation plans must cover existing structures, new structures, air pollution control, post-mining land use, and special mining practices.

The SMCRA legislation also has provisions covering other coal mine permits. The permit application must list all other licenses and permits needed to conduct mining activities. OSM regulations also require that each regulatory program (i.e., federal or state programs) provide for the coordination of review and issuance of permits for surface mining and reclamation operations with all other federal or state permit processes applicable to the operator.

The central role of this permit application and of OSM's role in the review process can be judged by examining Figure 4-6, which characterizes the information transfers between OSM and other regulatory authorities. (Note: recent changes in OSM procedures may not be fully represented in the figure. More up-to-date information was not available.) OSM conducts its own review of the permit application and coordinates the review activities of other federal and state authorities. The MMS review covers technical aspects of production. The surface management agency reviews the proposed land use in terms of the impact on other land uses.

The OSM review is a lengthy process involving an environmental survey and technical review and coordination functions. The full OSM review and processing procedure is portrayed in Figure 4-7. The diagram refers to actions by the R.A., or regulatory authority. The R.A. is the Office of Surface Mining unless a state agency has assumed responsibility for the SMCRA program. Submittal of the permit application triggers five distinct activities by the R.A.: (1) initiation of coordination with other government entities, (2) review of past regulatory violations by applicant, (3) performance of the technical review, (4) examination of suitability of lands, and (5) issuance of public notice. Appeal processes have also been defined.

Figure 4-6. Procedures for Approval of a Permit Application on Federal Land.

Figure 4-7. OSM Permit Process.

Figure 4-7. (Continued).

Developers of coal lands may also face substantial state permitting hurdles in addition to the state or federally operated SMCRA program, as is evident by the state permit lists presented in Section Five. Nevertheless, the SMCRA program is acknowledged as the central permit requirement for coal mine operators. It should also be noted that the SMCRA-based regulations have been subject to extensive reviews and court challenges. Changes to this regulatory process, as well as problems in implementation, will be considered in later sections.

4.3.3 Geothermal Land Leasing

The geothermal leasing program was initiated by the Geothermal Steam Act of 1970 which extended DOI leasing authorities to geothermal lands. The leasing program is similar to that for oil and gas lands in the manner of land lease sales.

Geothermal lands may be leased either competitively or noncompetitively. Competitive leasing is required for land within a Known Geothermal Resource Area (KGRA). The KGRA concept is interpreted more broadly than is the KGS of oil and gas leasing, and large land tracts have been so designated. Noncompetitive processing involves issuing the lease to the first qualified applicant.

The responsibilities for geothermal lease sales are split between the BLM and MMS. The activities to be performed include tract delineation, preparation of environmental assessments, formulation of protective stipulations for lease tracts, and calculation of the minimum acceptable bid. If the lease sale is judged a major federal action, a full environmental impact statement must be prepared.

It has been asserted that the geothermal program incorporates a greater commitment to environmental protection than other programs. Requirements for partial (environmental assessment reports) or full environmental reports occur at each stage of pre- and post-lease activities. This facet of the geothermal program will be examined in later sections.

To participate in the geothermal leasing program, an energy developer may participate in bidding at competitive lease sales or apply for noncompetitive leases on undeveloped land. Prior to leasing, a developer may file a Notice of Intent for geothermal exploration operations with the BLM. The permit allows for limited geophysical operations including shallow well drilling.

4.3.3.1 Post-Lease Responsibilities for Geothermal Lands

The distribution of post-lease responsibilities for geothermal lands is similar to that for oil and gas (and oil shale) lands in that the MMS has primary enforcement responsibilities. Operating regulations, however, are based on geothermal-specific guidelines developed by USGS.

Developers of geothermal leases are subject to a series of plan-approval processes conducted by the MMS. The geothermal regulatory process is outlined in Figure 4-8. The developer must submit plans of operation, development and production to MMS. At each stage the current plan is subject to technical review, and environmental assessment, and perhaps environmental impact statements are prepared.

Figure 4-8. Existing Geothermal Regulatory Process, Principal Post-Lease Activities.

The conduct of geothermal operations is regulated by seven Geothermal Resources Orders (GRO) which have been prepared by MMS. The GRO's describe requirements for exploration, drilling, and well plugging, pipelines and surface production facilities and production and royalty payments. GRO #4 sets forth the general environmental protection requirements, which are quite extensive, for geothermal operators.

Surface management agencies maintain review rights by geothermal operations. The SMA's act to protect surface land characteristics or competing land uses in the vicinity of geothermal developments.

4.3.4 Oil Shale Leasing

The leasing of oil shale lands has the same legislative foundation as other leasing programs, but is uniquely impacted by the importance of a limited geographic resource base and the developmental state of the extraction technology. Again, the Mineral Leasing Act of 1920 authorizes the leasing program, with the Secretary of the Interior empowered to lease "any deposits of oil shale belonging to the United States and the surface of so much of the public lands containing such deposits, as may be required for the extraction and reduction of the leased minerals" As for other resources, the Secretary has broad authority to set lease terms.

Despite this authority, oil shale leasing has a short history owing partly to the withdrawal of such lands from leasing in 1930. At that time, DOI officials felt that the resource was not viable and did not wish to make land

sales for purely speculative purposes. Oil shale leasing was reborn in the 1970's with the initiation of the Federal Prototype Oil Shale Leasing Program. Under this new program, six land tracts were offered for sale in 1974, two each in Colorado, Utah, and Wyoming. Of these, four tracts were actually leased. Development of two of the Utah tracts has been postponed pending the resolution of legal disputes concerning land ownership. Only the two Colorado lease tracts, C-a and C-b, have been actively developed.

At present, no ongoing program exists for leasing additional oil shale lands. The fitful progress of the industry might suggest that further encouragements are needed in order to hasten developments. Permitting requirements for oil shale can also be particularly difficult due to substantive environmental uncertainties.

4.3.4.1 Post-Lease Responsibilities for Oil Shale Lands

The MMS has been the primary enforcement agency for the two instances of oil shale operations on federal lands under the Prototype Leasing Program. The role of other federal land management agencies is similar to that for other resource lands.

The MMS requires several distinct permit application and data collection efforts prior to allowing for full development. The first step is preparation by the developers of an Exploration and Baseline Data Plan, covering both a description of technical operations and the collection of baseline environmental data. Completion of this application

and review process can be quite time consuming. The second step involves preparation of a Detailed Development Plan (DDP) for submission to MMS. This plan covers actual plans for mining, operations, environmental monitoring and water management. The DDP review process includes public hearings and approvals must be signed by the Secretary of the Interior. A third step involves the submission of applications for various operational approvals covering specific elements within the scope of the DDP. The MMS has also developed permit formats for modifications or revisions to the DDP.

More than for other resource areas, oil shale developers may face major uncertainties in acquiring the key environmental permits from EPA or state governments. Both air and water pollution problems have been prominent in the oil shale developments to date.

4.4 Permits Required by the Federal Government

A survey of all federal permits was conducted. The survey was designed to provide a listing of each approval which could be required of an energy project, apart from the issuance of the federal land lease itself.

The results of the permit survey are displayed in Tables 4-3 through 4-6 (the tables appear at the end of this section) with the permits grouped according to media (multimedia, air, water, hazardous and solid waste) or operation and purpose (land use, cultural, utility, mine safety, other). The table format presents data on the permit, sponsoring agency, regulatory authority, permit purpose, applicability, and permit information requirements.

The same format is used in Section Five covering state permits. The definition of each table column is explained below:

Permit (name). The formal or informal name of a permit or the heading of the appropriate application form has been used to identify permit.

Sponsoring agency. The agency and, where appropriate, the agency office or bureau is identified in this column.

Regulatory Authority. The authorization for each permit process is identified by reference to the relevant article in the Code of Federal Regulations. Information on the legislative basis of each permit was not presented as being repetitious of the legislative discussion already provided.

Purpose. The rationale for most permits is fairly obvious, and is summarized, in general terms, in this column.

Applicability. The types of energy projects to which a given permit would apply was considered.

Information Requirements. A brief summary of the type of information to be provided by the applicant is summarized.

Some caveats concerning the study focus should be noted here. The projects considered for permitting were limited to exploration, development and production activities on federal lands in the resource areas of oil and gas, coal, geothermal and oil shale. The study emphasis did not go beyond basic extraction/production operations as this

limitation was judged to be appropriate for the study objectives. Power plants, coal preparation plants, transportation depots (for shipping fuel to its destination) and other facilities not directly part of the extraction operations were not considered. Also, in some cases the permits listed will not be required by federal offices because the relevant state government has assumed control of the program.

The permit survey illustrates the diversity and detail of federal permitting programs. Major regulatory measures have been instituted in the areas of environmental control, energy development regulation, and mine safety. Detailed permitting requirements also exist for control of access to various classes of federal lands and for modifications to such lands. Smaller permitting programs also cover the protection of cultural and historical values, the protection of wildlife and endangered species, and the regulation of airspace, communication channels and other public concerns.

In examining permits specific to energy development, several observations can be made. First, the Minerals-Management Service, in the conduct of its enforcement role over federal land leases, operates several major permitting programs. Several of the MMS permits for governing energy production were identified above in Section 4.3. These permits are grouped in the category of land use (energy development). Second, the issuance of a lease does not entitle the bearer to immediate access to federal lands. Controls are maintained on initial exploration or drilling operations in all cases.

TABLE 4-3

SUMMARY OF PERMITS REQUIRED BY THE FEDERAL GOVERNMENT

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
<u>Multi-Media</u>					
Environmental Impact Statement and Review (NEPA)	Lead Agency (Review by EPA, CEQ)	40 CFR Part 6	Consideration of environmental impacts	All major energy projects on federal lands	Full environmental report, discussion of alternative locations
<u>Air</u>					
Prevention of Significant Deterioration of Air Quality Permit	Environmental Protection Agency	40 CFR Part 51, 52	Regulate new emission sources	New emission sources in attainment areas	Description of design, emissions control equipment and 1 year of monitoring data
<u>Water</u>					
National Pollution Discharge Elimination System (NPDES) Permit	Environmental Protection Agency	40 CFR 125	Regulate surface water quality	Point source discharges to navigable waters	Description of location, quantity and characteristics of effluent
Spill Prevention Containment and Control Plans	Environmental Protection Agency	40 CFR 112	Prevention of uncontrolled oil releases	May apply to oil or shale operators with on-site storage	Description of storage, spill prevention and control plans
Underground Injection Well Operation Permit	Environmental Protection Agency	40 CFR Parts 122, 123 and 124	Prevention of aquifer contamination	Oil and gas projects	Description of injection plans, methods, water characteristics
Discharge of Dredge or Fill Material Permit	U.S. Army Corps of Engineers	33 CFR 323.1	To provide for environmental protection, and to monitor changes to U.S. waters	Applies to energy developments affecting water ways	Description of activity, location of dredging operation, proof of other permit approvals
Authorization for Disposal of Produced Water	Minerals Management Service	30 CFR 221.4 and 221.32	To prevent stream or aquifer damage	Oil and gas properties	Description and justification of disposal method

TABLE 4-3 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Land Use (Energy Development) (cont.)					
Application for Permit to Drill, Deepen, or Plug Back (Including Multi-point Surface Use Operating Plan)	Minerals Management Service	30 CFR 221	To provide for wise energy development and conservation	Oil and gas operations	Describe exploration, development, surface disturbance
Request for Pre-Stake Clearance	Minerals Management Service	30 CFR 221	To regulate entry to leased land	Oil and gas operations	Describe planned activities, agreement to lease lands
Notice of Completion of Oil and Gas Exploration	BLM	43 CFR 3045.2	To verify compliance with BLM terms	Oil and gas projects	Location and date of exploration
Approval of Transfer of Operating Rights in an Oil and Gas Lease	BLM	43 CFR 3106	To identify transfers of operating rights	May apply to purchase of operating rights from lottery winners to developers	Agreement to lease terms
Approval of Unitization (Oil and Gas)	Minerals Management Service	30 CFR Part 226	To allow for effective development of leased lands	Oil and gas projects	Geology of area, test well description
Approval of Communitization (Oil and Gas)	Minerals Management Service	43 CFR 3105.2	To identify and to allow combination of tracts	Oil and gas projects on adjoining tracts	Description of communitization, protection of all parties
Agreement for the Subsurface Storage of Gas	Minerals Management Service	30 CFR 221.4 and 221.32	To promote conservation of resources	May apply to oil and gas projects	Description of necessity of storage, ownership agreements
Coal Exploration License	BLM	43 CFR 3410	To identify exploration actions	For coal exploration	Description of exploration, cultural and owner clearances
Exploration Plan Approval	Minerals Management Service	30 CFR 211, 30 CFR 231	To protect lands and monitor activity under leases	Coal projects on leased lands	Description of lands, activities and anticipated disturbance

TABLE 4-3 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Land Use (Energy Development) (cont.)					
Mining and Reclamation Plan Approval or Disapproval	Office of Surface Mining	30 CFR 778	To minimize environmental impact of mining	All coal mining projects	Operation and reclamation plan, environmental data
Geothermal Exploration Operation - Notice of Intent	Minerals Management Service	30 CFR 270	To identify geothermal exploration	Geothermal exploration	Topographic map, cultural clearances
Plan of Utilization and Geothermal Utilization Permit	Minerals Management Service	30 CFR 270	To regulate geothermal activities and provide for wise development	Geothermal development	Description of area, full operating environmental protection plan
Geothermal Drilling Permit	Minerals Management Service	30 CFR 270	To regulate geothermal drilling	Geothermal exploration or production	Drilling program, potential hazard description
Plan of Exploration (Geothermal)	Minerals Management Service	30 CFR 270	To regulate geothermal exploration	Geothermal exploration	Operating and contingency plans
Approval of Plan of Baseline Data Collection (Geothermal)	Minerals Management Service	30 CFR 270	To regulate geothermal production and allow consideration of environmental factors	Geothermal production	Baseline data collection plan
Plan of Development (Geothermal)	Minerals Management Service	30 CFR 270	To regulate geothermal development and to protect federal lands	Geothermal development (well drilling and construction)	Operation, contingency plan, cultural clearances
Plan for Production (Geothermal)	Minerals Management Service	30 CFR 270	To regulate geothermal development and to protect federal lands	Geothermal production	Production and environmental monitoring plan
Plan of Injection or Disposal (Geothermal)	Minerals Management Service	30 CFR 270	To regulate injection of well effluent	Geothermal leases	Injection plan, full geotechnical description

TABLE 4-3 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
<u>Land Use (Energy Development) (cont.)</u>					
Approval of Unitization (Geothermal)	Minerals Management Service	30 CFR 271	To allow for maximum recovery of resource	Geothermal leases	Detailed geophysical plan and operating agreements
Exploration and Environmental Baseline Monitoring Plan Approval for Prototype Oil Shale Leasing Program	Minerals Management Service	30 CFR 221; 43 CFR 23.7	To regulate oil shale activities	Oil shale projects	Description of operations, full environmental characterization
Detailed Development Plan Approval for Prototype Oil Shale Leasing Program	Minerals Management Service	30 CFR 231 43 CFR 23.8	To regulate oil shale projects and provide for environmental protection	Oil shale projects	Detailed description of operation
Modifications to Detailed Development Plan (Oil Shale)	Minerals Management Service	30 CFR 231	To allow for and to monitor variations in the development plans	May apply to oil shale projects	Description of variants desired, effect of changes
Revision of Detailed Development Plan (Oil Shale)	Minerals Management Service	30 CFR 231	To provide procedure for revisions in the development plan	May apply to oil shale projects	Full description of revisions and environmental effects
Approval of Plan of Operations	BLM	43 CFR 3809	To regulate the manner of mining activities, provide for reclamation	Applies to mining activities	Topography, access routes and operation plan
Approval of Plan of Operations	FS	36 CFR 252	To regulate surface disturbances	Applies to any projects on FS lands	Operation plan, map
<u>Land Use (Access, Temporary or Special Uses)</u>					
Temporary Use Permit and Right-of-Way	BLM	43 CFR 2800	Regulation of land use	Any projects needing right-of-way	Project description and environmental protection plan
Special Land Use Permit	BLM	43 CFR 2800	Regulates land use, controls removal of sand	May apply to any construction project	Description of lands, project, and land modifications

TABLE 4-3 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
<u>Land Use (Access, Temporary or Special Uses) (cont.)</u>					
Oil and Natural Gas Pipeline Right-of-Way	BLM	43 CFR 2880	To regulate land use	Oil and gas projects requiring right-of-way	Description of pipeline, lands involved
Water Well or Water Impoundment Right-of-Way	BLM	43 CFR 2800	To regulate land use	Any project requiring water well drilling or water impoundment	Description of location and nature of activities
Rights-of-Way	Bureau of Indian Affairs	25 CFR 161	To regulate land use, protect land owners	Any project requiring rights-of-way through BIA lands	Land survey, description of projects and activities
Special Land Use Permit	Bureau of Reclamation	Not cited	To regulate land use	Any projects on Bureau lands requiring removal of sand, gravel	Description and purpose of activity
Special Land Use License or Easement	Bureau of Reclamation	Not cited	To monitor changes to Bureau lands	All projects on Bureau Lands	Description of purpose, lands, and improvement
Special Use Authorization	FS	36 CFR 251 and 252	Regulates occupancy and use of FS lands	All projects on FS lands	Description of lands and operations
Special Use Permit/Right-of-Way	Fish & Wildlife Service	50 CFR 29	To regulate use of F&WS lands	Projects using wildlife refuge lands	Map, description of purpose, environmental effects
Rights-of-Way Grants	National Park Service	36 CFR 14	To control access	Projects needing access across NPS lands	Map, description of activities, purpose
Right-of-Way, Pipeline or General Easement	U.S. Army Corps of Engineers	Not cited	To regulate access to Army and Air Force lands	May apply to any projects needing such access	Statement of function and purpose of easement; environmental impacts
Permit for Structures on Work in or Affecting Navigable Waters	U.S. Army Corps of Engineers	33 CFR 321, 325	To insure that all relevant factors including environment, fish	May apply to selected energy developments	Description and location of activity, other permit approvals
Permit for Dams and Dikes in Navigable Waters	U.S. Army Corps of Engineers	33 CFR 321, 325	To regulate construction over waterways	May apply to projects near navigable streams	Description of activity, of adjacent structures and other permits

TABLE 4-3 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
<u>Utility</u>					
Certificate of Public Convenience and Necessity for Construction and Operation of Rail Lines	Interstate Commerce Commission	49 CFR 1120.6, 1120.2	To regulate construction of public facilities	May apply to coal mining projects	Description of construction and operation, and of project financing
<u>Cultural and Historical</u>					
Antiquities Act Permit	DOI - Interagency Archaeology Division	36 CFR Part 1215	To protect archaeological and historic values	May apply to any energy project	Location, description of area affected; report of archeologist
Application for Permit to Conduct Archeological Explorations	Forest Service	43 CFR 3	To protect archeological and historic values	May apply to any energy project on Forest Service lands	Plan of exploration, agreement from repository agency
<u>Mine Safety</u>					
Approval for New Mine Opening or Reopening of Underground Mine	MSHA	30 CFR 75, 1721	To regulate safety measures	All underground coal mines	Seven distinct safety, operation and contingency plans
Notice of Commencement of Operations	MSHA	30 CFR 57.26, 55.26, Part 50	To monitor non-coal mining activities	Oil shale activities	Identification of operations
Legal Identity Report	MSHA	30 CFR 41	Notice is preparatory to regulation MSHA	Coal and oil shale mines	Ownership identification
Approval of New Surface Coal Mine	MSHA	30 CFR 77	To regulate safety measures	All surface coal mines	Four distinct safety plans
Training Plan for Miners	MSHA	30 CFR Part 48	To regulate training measures	All coal and oil shale operations	Description of training program

TABLE 4-3 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
<u>Other</u>					
Notice of Proposed Airspace Obstruction	Federal Aviation Administration	14 CFR 77	To monitor and regulate construc- tion affecting the air space	May apply to energy projects with tall construction requirements	Description and location of structure
Notice of Proposed Construction - Alteration of Airports	Federal Aviation Administration	14 CFR 157	To monitor and regulate changes to airports	May apply to large- scale energy projects	Purpose and type of change
Airport Lease	BLM	43 CFR 2911	Portion of leasing system	Any large-scale energy project requiring an airport	Complete description of airport plan
Radio Licenses - Land Transportation or Industrial Services	Federal Communications Commission	47 CFR 95, and 90	To regulate use of communication media	May apply to energy projects	Data on frequencies used, transmitters
Explosives User's Permit	Department of the Treasury, Bureau of Alcohol, Tobacco and Firearms	27 CFR 181	To monitor explo- sives handling and use	Applies to inter- state purchase or transportation of explosives	Purpose of use, type of material
Timber Sale Contracts	Forest Service	36 CFR, Parts 221 and 223	To account for timber cut during exploration or mining	May apply to any projects on FS lands	Submit operating plan and lease
Temporary or Permanent Exemption from FUA Prohibitions	Economic Regulatory Administration, DOE	100 CFR 500 <u>et seq.</u>	To restrict oil usage	May apply to combustion equip- ment needed for	Location, description of operations
Toxic Substances Control Act Pre- Manufacture Notice	Environmental Protection Agency	40 CFR, Part 720	To regulate distri- bution, use of potentially harmful chemicals	May apply to oil shale projects	Description of any new chemicals produced in processing, chemical formula, quantities use and distribution

TABLE 4-4
APPLICABILITY OF FEDERAL PERMITS
BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Environmental Impact Statement	O	O	O	X
<u>Air</u>				
Prevention of Significant Deterioration of Air Quality Permit	O		O	X
<u>Water</u>				
National Pollutant Discharge Elimination System (NPDES) Permit	X	X	X	X
Spill Prevention, Containment and Control Plans	O			O
Underground Injection Well Operation Permit	X		X	
Discharge of Dredge or Fill Material Permit	O	O	O	O
Authorization for Disposal of Produced Water	X			
<u>Solid/Hazardous Waste</u>				
Hazardous Waste Management Facility Permit				O
Solid Waste Management Facility Permit	O	O		X
<u>Fish and Wildlife</u>				
National Wildlife Refuge-Special Use Permit	O	O	O	O

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 4-4 (continued)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Endangered Species Permit	O	O	O	O
Threatened Species Permit	O	O	O	O
Migratory Bird Permits	O	O	O	O
Bald Eagle Permits	O	O	O	O
<u>Land Use (Energy Development)</u>				
Oil and Gas Exploration Operation - Notice of Intent	X			
Application for Permit to Drill, Deepen, or Plug Back (Including Multi-point Surface Use Operation Plan)	X			
Request for Pre-Stake Clearance	X			
Notice of Completion of Oil and Gas Exploration	X			
Sundry Notices and Reports on Wells	X			
Submittal of Modified MSUOP	X			
Approval of Transfer of Operating Rights in an Oil and Gas Lease	O			
Approval of Unitization (Oil and Gas)	O			
Approval of Communitization (Oil and Gas)	O			
Agreement for the Sub-surface Storage of Gas	O			

TABLE 4-4 (continued)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Coal Exploration License		X		
Exploration Plan Approval (Coal)		X		
Mining and Reclamation Plan Approval or Disapproval (Coal)		X		
Geothermal Exploration Operation - Notice of Intent			X	
Plan of Utilization and Geothermal Utilization Permit			X	
Geothermal Drilling Permit			X	
Plan of Exploration (Geothermal)			X	
Approval of Plan of Baseline Data Collection (Geothermal)			X	
Plan of Development (Geothermal)			X	
Plan for Production (Geothermal)			X	
Plan of Injection or Disposal (Geothermal)			X	
Approval of Unitization (Geothermal)			O	
Exploration and Environmental Baseline Monitoring Plan Appro- val for Prototype Oil Shale Leasing Program				X

TABLE 4-4 (continued)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Detailed Development Plan Approval for Prototype Oil Shale Leasing Program				X
Modifications to Detailed Development Plan (Oil Shale)				O
Revision of Detailed Development Plan (Oil Shale)				O
Approval of Plan of Operations (Mining, BLM)		O		O
Approval of Plan of Operations (FS)		O		O
<u>Land Use (Access, Temporary or Special Uses)</u>				
Temporary Use Permit and Right-of-Way (BLM)	O	O	O	O
Special Land Use Permit (BLM)	O	O	O	O
Oil and Natural Gas Pipeline Right-of-Way (BLM)	O			
Water Well or Water Impoundment Right-of- Way (BLM)	O	O	O	O
Rights-of-Way (BIA)	O	O	O	O
Special Land Use Permit (BuRec)	O	O	O	O
Special Land Use License or Easement (BuRec)	O	O	O	O

TABLE 4-4 (continued)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Special Use Authoriz- ation (FS)	0	0	0	0
Special Use Permit/ Right-of-Way (F&WS)	0	0	0	0
Rights-of-Way Grants (NPS)	0	0	0	0
Right-of-Way, Pipeline or General Easement (COE)	0	0	0	0
Permit for Structures on Work In Affecting Navigable Waters (COE)	0	0	0	0
Permit for Dams and Dikes in Navigable Waters (COE)	0	0	0	0
Bridge Permit (Coast Guard)	0	0	0	0
<u>Utility</u>				
Certificate of Public Convenience and Necessity for Construction and Operation of Rail Lines		0		
<u>Cultural and Historical</u>				
Antiquities Act Permit	0	0	0	0
Application for Permit to Conduct Archaeological Explorations (FS)	0	0	0	0
<u>Mine Safety</u>				
Approval for New Mine Opening or Reopening of Underground Mine		X		
Notice of Commencement of Operations				X
Legal Identity Report		X		X

TABLE 4-4 (continued)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Approval of New Surface Coal Mine		X		
Training Plan for Mines		X		X
<u>Other</u>				
Notice of Proposed Airspace Obstruction	O	O	O	O
Notice of Proposed Construction-Alteration of Airports	O	O	O	O
Airport Lease		O		O
Radio Licenses - Land Transportation or Industrial Services		O		O
Explosives User's Permit	O	O		O
Timber Sale Contracts	O	O	O	O
Temporary or Permanent Exemption from FUA Prohibitions	O	O	O	O
Toxic Substances Control Act, Premanufacture Notice				O

TABLE 4-5
SUMMARY OF TIME REQUIREMENTS FOR MAJOR FEDERAL PERMITS

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS RE-VIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD (Y OR N)	APPLICA-TION FEE	COMMENTS
Environmental Impact Statement and Review (NEPA)	Lead agency (agency taking significant action, i.e., issuing permit)	Full environmental report, discussion of alternative project locations	Not appli-cable	Not appli-cable	Yes	None; appli-cant may pay cost of document preparation	EPA reviews EIS's of other agencies
Prevention of Significant Deterioration of Air Quality Permit	Environmental Protection Agency	Description of design emissions control equipment	Not speci-fied	9 months (est.)	Yes	None	
National Pollutant Discharge Elimination System (NPDES) Operating Permit	Environment Protection Agency	Description of location, quantity and characteristics of effluent	30 days	6 months (est.)	Yes	None	Most states have been delegated NPDES permit authority
Underground Injection Well Operation Permit	Environmental Protection Agency	Description of injection plans, methods, water characteristics	—	—	—	None	Permits not currently being issued
Discharge of Dredge or Fill Material Permit	U.S. Army Corps of Engineers	Description and location of activ-ity, proof of other permit approvals	Not speci-fied	90-120 days (est.)	Yes	\$100	Most common of Corps permits
Mining and Reclamation Plan Approval or Disapproval	Office of Surface Mining	Operational reclama-tion plan, envi-ronmental data.	Not appli-cable	Not appli-cable	Yes	Not Applicable	All OSM permitting is at state level
Exploration/Environmental Baseline Moni-toring Plan Approval for Prototype Oil Shale Leasing Program	Minerals Management Service	Description of operations, full environmental characterization	Not speci-fied	1-3 months (est.)	No	None	
Detailed Devel-opment Plan Approval for Prototype Oil Shale Leasing Program	Minerals Management Service	Detailed descrip-tion of operations	Not speci-fied	6 months (est.)	Yes	None	Revisions and modifi-cations to DDP are listed as minor permits
Certificate of Public Conven-ience and Necessity for Construction and Operation of Rail Lines	Interstate Commerce Commission	Description of construction and operation, and of project financing	Adequacy review	9 - 12 months	Yes	\$700	A major permit if long extensions needed

TABLE 4-6
SUMMARY OF TIME REQUIREMENTS AND APPLICATION FEES FOR MINOR FEDERAL PERMITS

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS RE-VIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD (Y OR N)	APPLICA-TION FEE	COMMENTS
Spill Prevention Containment and Control Plans	Environmental Protection Agency	Spill prevention and control plans	Not appli-cable	Not appli-cable	No	None	Plan is not submitted to EPA but must be maintained
Authorization for Disposal of Produced Water	Minerals Management Service	Description and justification of disposal method	Not speci-fied	1-2 months (est.)	No	None	
National Wild-life Refuge Lands - Special Use Permit	Fish and Wildlife Service	Description of project purpose, location and dura-tion of activities	Not speci-fied	2-3 months (est.)	Yes, in some cases	Variable. Bonding also required	
Endangered Species Permit	Fish and Wildlife Service	Describe location and nature of activities	Not speci-fied	80 days (est.)	Yes	\$25	
Threatened Species Permit	Fish and Wildlife Service	Describe location and nature of activities	Not appli-cable	80 days (est.)	Yes	\$25	
Migratory Bird Permits	Fish and Wildlife Service	Describe location and nature of act-ivities, data on number and species of birds affected	Not speci-fied	30-40 days (est.)	No	None	
Bald Eagle Permit	Fish and Wildlife Service	Describe nature and location of activi-ties affecting eagle population	Not speci-fied	30-40 days (est.)	No	None	
Oil and Gas Exploration Operation No-tice of Intent	BLM	Description of exploration activities	Not appli-cable	Not appli-cable	No	No fee. Bonding is re-quired	No review is performed
Application for Permit to Drill, Deepen or Plug Back (Including Multi-Point Surface Use Operating Plan)	Minerals Management Service	Describe explora-tion, development, surface disturb-ance	Not speci-fied	30-120 days (est.)	No	None	Review times are highly variable by district
Request for Pre-Stake Clearance	Minerals Management Service	Describe planned activities, agree-ment to lease lands	Not speci-fied	15 days	No	None	
Notice of Completion of Oil and Gas Exploration	BLM	Location and date of exploration	Not appli-cable	Not appli-cable	No	None	No review is performed
Sundry Notices and Reports on Wells	Minerals Management Service	Data covering activity being reported	Not appli-cable	Not appli-cable	No	None	
Submittal of Modified MSUOP	Minerals Management Service	Data relevant to change in infor-mation of APD	Not appli-cable	Not appli-cable	No	None	

TABLE 4-6 (Cont.)

PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS RE-VIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD (Y OR N)	APPLICA-TION FEE	COMMENTS
Approval of Transfer of Operating Rights in an Oil and Gas Lease	BLM	Agreement to comply with lease terms	Not speci-fied	Not appli-cable	No	\$25	
Approval of Unitization (Oil and Gas)	Minerals Management Service	Geology of area, test, well description	Not speci-fied	2 months (est.)	No	None	
Approval of Communitization	Minerals Management Service	Description of communitization, protection of all parties	Not speci-fied	1 month (est.)	No	No	
Agreement for the Subsurface Storage of Gas	Minerals Management Service	Description of necessity of stor-age, ownership agreements	Not speci-fied	Not appli-cable	No	No	
Coal Exploration License	BLM	Description of exploration, cul-tural and owner clearances	Not speci-fied	6 months (est.)	No	\$250	Env. analysis required
Exploration Plan Approval	Minerals Management Service	Description of lands, anticipated disturbance, map	Not speci-fied	2-4 months (est.)	Yes	None	Env. analysis required. Comment period if new area.
Geothermal Exploration - Notice of Intent	Minerals Management Service	Topographic map, cultural clearances	Not speci-fied	30 days	No	Bonding required	
Plan of Exploration (Geothermal)	Minerals Management Service	Operating and contingency plans	Not speci-fied	2-4 months (est.)	No	None	Env. analysis required
Approval of Plan of Baseline Data Collection (Geothermal)	Minerals Management Service	Baseline data collection plan	Not speci-fied	45 days (est.)	No	None	
Plan of Injec-tion or Disposal	Minerals Management Service	Injection plan, full geotechnical description	Not speci-fied	3-6 months (est.)	Yes, in some cases	None	Comment period if new area
Plan of Utili-zation and Geothermal Utilization Permit	Minerals Management Service	Description of area, full operating and environmental plan	Not speci-fied	3 months (est.)	Yes	None	
Geothermal Drilling Permit	Minerals Management Service	Drilling Program, potential hazard description	Not speci-fied	2 weeks (est.)	No	None	
Plan of Development	Minerals Management Service	Operation, contin-gency plan, cultural clearances, map	Not speci-fied	4-6 months (est.)	Yes, in some cases	None	
Plan for Production	Minerals Management Service	Production and environmental monitoring plan	Not speci-fied	45 days (est.)	Yes	None	

TABLE 4-6 (Cont.)

PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD (Y OR N)	APPLICATION FEE	COMMENTS
Approval of Unitization (Geothermal)	Minerals Management Service	Detailed geophysical plan and operating agreements	Not specified	2-3 weeks (est.)	No	None	
Modifications to Detailed Development Plan	Minerals Management Service	Description of variants described, effect of changes	Not specified	4-6 months (est.)	Yes	None	Required for major changes to the DDP
Revision of Detailed Development Plan	Minerals Management Service	Full description of revisions and environmental effects	Not specified	Not applicable	1-2 months (est.)	None	Required for minor changes to the DDP
Approval of Plan of Operations	Forest Service	Operation plan, map	30 days	1-60 days (est.)	No	No	Applies to Forest Service Lands
Special Use Authorization	Forest Service	Description of lands and of operations	Not specified	3 months (est.)	Yes, in some cases	Based on activities	
Right-of-Way Permit	BLM	Project description and environmental protection plan	Not specified	2 months	Yes, in some cases	\$50/mile	Env. analysis required
Temporary Land Use Permit	BLM	Description of lands, project, and land modifications	Not specified	2-3 months (est.)	No	Variable	Applies to BLM lands
Oil and Natural Gas Pipeline Right-of-Way	BLM	Description of pipeline, lands involved	Not specified	2-3 months (est.)	Yes, in some cases	\$50/mile	
Rights-of-Way	Bureau of Indian Affairs	Land survey description of projects and activities	Not specified	2-6 months (est.)	No	No	Fees for land use, damages are involved
Special Land Use Permit	Bureau of Reclamation	Description of purpose, lands and activity	Not specified	1-3 months (est.)	No	Variable, based on review expenses, land costs	Applies to BuRec lands
Special Land Use License or Easement	Bureau of Reclamation	Description of purpose, lands and improvements	Not specified	1-3 months (est.)	No	Variable based on review, expenses, land costs	Applies to BuRec lands
Rights-of-Way Grants	National Park Service	Map, description of activities, purpose	Not specified	3 months (est.)	No	None	Env. analysis required; land use fees may be charged
Right-of-Way, Pipeline or General Easement	U.S. Army Corps of Engineers	Statement of function and purpose of easement; environmental impacts	Not specified	4-6 months (est.)	No	Not available	Rarely required permit

TABLE 4-6 (Cont.)

PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS RE-VIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD (Y OR N)	APPLICA-TION FEE	COMMENTS
Permit for Structures for Work in or Affecting Navigable Waters	U.S. Army Corps of Engineers	Description and location of activity, other permit approvals	Not speci-fied	90-120 days (est.)	Yes	\$100	Similar process to that for dredge material permit
Permit for Dams and Dikes in Navigable Waters	U.S. Army Corps of Engineers	Description of activity of adjacent struc-tures, proof of all permits	Not avail-able	Not avail-able	Yes	Not available	A rarely issued permit
Antiquities Act Permit	DOI - Inter-agency Archeology Division	Location, descrip-tion of area affected, report of archaeologist	Not speci-fied	8-10 weeks (est.)	No	None	
Permit to Conduct Archeological Explorations	Forest Service	Plan of exploration, agreement from repository agency	Not speci-fied	2-3 months (est.)	No	None	Applied for at local Forest Service offices
Approval for New Mine Opening or Reopening of Underground Mine	MSHA	Seven distinct safety, operation, and contingency plans	Not speci-fied	2 months (est.)	No	None	
Notice of Commencement of Operations	MSHA	Identification of operations	Not appli-cable	Not appli-cable	No	None	No review is performed
Legal Identity Report	MSHA	Ownership identification	Not appli-cable	Not appli-cable	No	None	Report entails informational submittal only
Approval for New Surface Coal Mine	MSHA	Training and emergency assistance plans	Not speci-fied	2 months (est.)	No	None	
Notice of Pro-posed Airspace Obstruction	Federal Aviation Administration	Description and location of structure	Not speci-fied	30-60 days (est.)	Yes, in some cases	None	
Notice of Proposed Construction - Alteration of Airports	Federal Aviation Administration	Purpose and type of change	Not speci-fied	90-120 days (est.)	No	None	
Airport Lease	BLM	Complete descrip-tion of airport plan	Not appli-cable	2-4 months (est.)	Yes, in some cases	\$10	
Radio Licenses - Land Transportation or Industrial Services	Federal Communications Commission	Data on frequencies used, transmitters	Not speci-fied	6-8 weeks (est.)	Yes, in some cases	None	

TABLE 4-6 (Cont.)

PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS RE-VIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD (Y OR N)	APPLICA-TION FEE	COMMENTS
Explosives User's Permit	Dept. of the Treasury, Bureau of Alcohol, Tobacco, and Firearms	Purpose of use, type of material	Not speci-fied	45 days (est.)	No	\$20	
Timber Sale Contracts	Forest Service	Submit operating plan and lease	Not appli-cable	Not appli-cable	Yes	Not appli-cable	Public notice if formal sales
Temporary or Permanent Exemption from FUA Prohibitions	Economic Regulatory Administration, DOE	Location, description of operation	Not speci-fied	4-6 months (est.)	Yes	None	EA or EIS required
Toxic Substances Control Act	Environmental Protection Agency	Descriptions of any new chemicals produced in processing, chemical formula, quantities, use and distribution	Not speci-fied	90 days	No	None	Review may be extended 90 days by EPA

REFERENCES FOR SECTION FOUR

1. Final Federal Surface Mining Regulations, McGraw-Hill's Quick and Easy Guide, Christopher R. Joyce, 1980.

SECTION FIVE

PERMITTING PROCESSES IN SELECTED STATES

As important as the federal government is to regulation of energy projects, a prospective energy developer is also likely to have numerous direct dealings with state officials in obtaining clearances for a new project. The federal government both allows states to assume federal programs and leaves states to regulate any additional items that they may wish to control. The importance of state controls extends to activities initiated on federal lands. Presidential Executive Orders signed and implemented since the 1960's have required projects on federal lands to comply with all state and local regulations which may apply.

In order to assess the difficulty of obtaining state clearances, a survey was performed of the permits required of energy developers in eight states. Data were collected on the purpose, authority and applicability of every permit identified. Permit processes were also examined in terms of the information required of applicants, and the time needed to obtain permit approvals. [Data on the time and expense needed by developers for submitting permit applications will be presented at a later time.] It is intended that the data assembled in this section will serve to supplement the federal regulation of new energy development projects on federal lands.

The states covered in this report were selected on the basis of their importance as energy-producing states and the significance of federal landholdings within these

territories. Six of the eight are located in the Far West, including California, Colorado, Montana, New Mexico, Utah and Wyoming. Alaska, with its huge federal land holdings, and Alabama were also included.

The state surveys are presented in Sections 5.2 through 5.9 in alphabetical order. Section 5.1 provides a description of the methodology used in the permit surveys.

5.1 Issues for the Scope and Definition of the Permit Survey

Data collected in the eight survey states are summarized in a series of tables below. A total of 32 tables, 4 for each state, were developed to provide concise information concerning the permits needed. The formats of each state survey discussion and of the tables used for each state are identical. Thus, only one discussion is needed of the approach used.

The state sections are brief descriptions of the main elements affecting the regulatory conduct in each state. First, a brief introduction is provided in which the most important state legislation is described. The extent to which a given state has assumed control of the major federal environmental programs is also covered. Next, an overview of the organization of the state government and of the functions of relevant state agencies is presented. A third and final section introduces the actual state permits which apply to energy development. Four tables, which are used to summarize permit requirements, are all referenced in this section.

The first of the four tables developed for each state provides a complete listing of all the permits required by state authorities. The table, entitled "Summary of Permits Required by the State of _____," gives each permit title and the sponsoring agency, regulatory authority, permit objective and applicability. A column is also used to describe briefly the information to be supplied by permit applicants.

This first table is designed to be a listing of all state permits which could apply to an energy project, with the exception that some basic business and operating permits are excluded. (Permits or notifications required by tax authorities or by state labor department for any new business or operation were not listed.) The permits were ordered according to the affected environmental media (air, water, solid and hazardous waste) and then by other regulatory issues (fish and wildlife, land use, transportation, and other).

In instances where the state has assumed control of federal programs, the relevant state-issued permit has been included. A large number of the permits would be required only in special circumstances or would not apply to all types of energy projects. For example, permit approvals for activities on state lands would obviously not be required for energy development on federal lands. However, many Western states have checkerboard patterns of land ownership with federal, state and private lands interspersed. State land approvals may be required for some federal land and thus these permits were included. In instances where the relevance of a permit may be in question, refer to the applicability column of the summary listing table for more information.

The second table for each state survey defines the applicability of the permits by resource area. Again, wide allowance is made for the possibility that a specific permit would be required for the different energy technologies. The largest number of permits generally apply to coal mining or oil shale operations, although simple permit totals could be misleading and totals of the required permits by resource area are not shown.

The third and fourth tables shown in each state survey define the estimated review times for each permit. The permits were roughly grouped into major and minor categories according to their typical importance in the overall regulatory process for energy projects. These tables provide preliminary data useful for later analyses of the time delays which may occur.

For each permit, data were assembled on the sponsoring agency and the permit form information requirements (both items were derived from the first summary listing table), the time needed by the government body to perform a completeness review and the actual permit review, the existence of a public comment period and of any permit application fees. A completeness review refers to the time allotted to or used by government agencies to verify that a permit application is complete prior to initiation of actual review procedures. The permit review time refers to actual agency processing of applications. Note that this review time does not include the completeness review period, if one is specified, but does include any public comment period held prior to actual permit issuance. The time which may be required in appeal processes has

also not been included. Data on application fees were assembled because such fees are one element, however minor, in the cost of seeking approvals of regulatory agencies.

The data entries for completeness reviews and for permit reviews represent either statutory time limitations imposed on the state agencies, or estimates of actual processing times. In the latter case, statutory deadlines were either not in effect or were not sufficiently strict to affect the agency functioning. Where estimated review times were presented, a range of times is normally provided, and the data entry is marked "(est.)".

The information for the state surveys was gathered from state permit assistance manuals and from state government personnel. Nearly all the states covered have prepared some materials to help guide the planners of new industrial developments. Also, state personnel were consistently helpful in describing permit requirements and in estimating typical review times. However, data from both manuals and from state personnel may not be completely accurate for two reasons. First, state personnel (including those who prepared the permit manuals) may tend to be optimistic about review times if only to avoid embarrassment about slow operating procedures. Few agencies collect information about their own processing and review times. Thus, the estimated review times were frequently based only on quick judgments of state personnel. Second, those personnel who were asked to estimate review periods may have tended to ignore the exceptional cases of long delays or regulatory snafus which may have applied to very few projects. Yet these exceptional cases may be of greater interest in this study than the more commonplace permits issued. For these

reasons, care should be used in accepting the review times shown as completely accurate. The issue is a small one for nearly all the minor permits shown because review times are short in any case, and application processes are simple. For the major permits, review times are being examined further in the analysis of total permit processing requirements and in the analysis of state-federal interactions.

5.2 Permitting Processes in Alabama

Alabama requires fewer permits than most other states, and state permitting processes appear to be relatively straightforward. State regulations are quite similar to federal regulations in most cases and permit review times appear to be relatively short. The permits required for energy development in Alabama are described in this section along with data on typical review times.

An element of Alabama's efforts to simplify permitting processes involves the rapid takeover of federal environmental programs. Alabama has applied for or received program responsibility for all of the major air and water programs, including the Underground Injection Control Program. The state has also petitioned (January 11, 1982) to assume the Surface Mining Control and Reclamation Act Program, and are closely following the Resource Conservation and Recovery Act program in order to prepare for an eventual state takeover. As a result of these actions, developers do not need to deal with both state and federal agencies in several major permit areas.

The Alabama state legislature has further considered the establishment of a "One-Stop" Permitting system under which various state permitting functions would be consolidated into a single department. However, no legislative action has been taken, and the regulatory authority is currently split among several commissions and departments.

Alabama resources include oil and gas reserves, and coal and oil shale deposits. No oil shale projects have been initiated in the state.

5.2.1 Responsibilities of Principal State Agencies

The state agencies with principal environmental permitting responsibility are concentrated in the Department of Public Health and, to a lesser extent, in the Department of Conservation and Natural Resources. The state organization is illustrated in Figure 5-1. The major environmental programs are administered under the Department of Public Health. The offices involved directly in energy project regulation, such as the State Oil and Gas Board, are within the Department of Conservation and Natural Resources. Another state agency of interest is the Alabama Development Office which assists in the distribution of permit information.

Alabama makes extensive use of the Commission form of organization in which a panel (consisting of five members in the Alabama case) supervises or otherwise directs the activities of a professional staff. The Commission of the Alabama Water Improvement Commission, for example, consists of five persons, appointed by the Governor and approved by the State Senate. This Commission delegates partial administrative authority to the Director of the Commission Staff, but reserves to itself various powers in the NPDES and UIC programs. The Commission type of organization for these agencies was established by the initial authorizing legislation for each program.

The activities of each of the agencies responsible for permits relevant to energy development is briefly set forth below.

Alabama Air Pollution Control Commission - Governs all of the air quality programs in effect in Alabama. The Commission has several district offices in the state.

Figure 5-1. Alabama State Government Organization (Some offices have not been shown in order to simplify the presentation).

Alabama Water Improvement Commission - Responsible for the NPDES program and has applied for authorization for the Underground Injection Control Program. However, the disposal wells commonly used by oil and gas operators are already regulated by the State Oil and Gas Board.

Division of Solid Waste and Vector Control - Regulates solid waste disposal in the state. Currently, the division takes no role in controlling activities of oil and gas operations or of coal mining. Mine tailings are exempted from control by the RCRA Reauthorization Bill.

State Oil and Gas Board - Regulates drilling activities for the general purpose of maintaining prudent development practices. A number of permits are issued by the Board governing various aspects of drilling activities.

Surface Mining Reclamation Commission - Regulates coal mining in Alabama. Under existing state regulations, various coal mine controls have been instituted. New procedures will soon be established as the Commission has petitioned the Office of Surface Mining for state take-over of the SMCRA program.

Public Service Commission - Regulates rail line extensions (as could be needed for coal mine developments) and pipeline operations when pipeline services are sold to the public.

Highways Department - Regulates intrusions to rights-of-way along the state highway system.

5.2.2 Permits Required by the State of Alabama

As mentioned earlier, Alabama has relatively simple and expeditious permitting procedures. The permits required by the State of Alabama are listed in various categories in Table 5-1 through 5-4. The format of these tables is identical to that of the other state analyses.

The summary listing of permits for Alabama, shown in Table 5-1, covers 22 permits. However, five of the permits are simple permit applications required by the State Oil and

Gas Board. Two additional permits, issued by the Alabama Air Pollution Control Commission, do not require applications per se. The Permit to Operate and the Temporary Permit to Operate are both based on the Permit to Construct application. No permits are required in the area of solid or hazardous waste management for energy development. Overall, the paperwork burden imposed by Alabama authorities appears relatively light.

The applicability of each permit to the state's resource types is shown in Table 5-2. A greater number of the permits apply to oil and gas drilling, although coal mine permitting is always more complex. Of course, no geothermal permitting is relevant to the state. The applicability of each permit is only crudely represented in this table. Several of the permits, particularly those for rail line extensions, for pipeline construction, and for routing of pipelines through highway rights-of-way, will rarely be needed for energy development.

Five major permits are required in Alabama, covering the air, water and surface mining areas, as shown in Table 5-3. The longest permit review time is currently required for Permits to Construct when PSD regulations are involved. The public notice requirements and the complexity of the technical issues may push the review time to the 180-day statutory limit. In simpler permitting cases, a 30- to 45-day review time has been estimated. The Surface Mining Permit is shown here to require a review period of a few months. This review period, which currently involves only the State of Alabama Mining Regulations, will increase substantially with the state take-over of the SMCRA program. Implementation of the full SMCRA program at the state level will cause an increase in review time to 6-18 months.

The most commonly used minor permits all have short review periods. The permits classified as minor are shown in Table 5-4. The State Oil and Gas Board is able to respond quickly to the various permit applications it receives, with review times of less than a week in some cases, or less than 3 weeks in others. Among the State Oil and Gas Board authorities is regulation of Class II underground injection wells (Application for Disposal Wells). This permit, which requires the most extensive description of the drilling area, takes several weeks to process. The estimation permit review times shown are approximate ranges based on conversations with personnel of the State Oil and Gas Board.

The minor permits with more substantial review times are all rarely needed by industrial developers. The stream diversion permit, which can be needed in coal mining, has been issued only a few times in the last 15 years. The other permits refer to utility-type permits for pipeline and rail line construction.

TABLE 5-1
SUMMARY OF PERMITS REQUIRED BY THE STATE OF ALABAMA

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Permit to Construct	Alabama Air Pollution Control Commission	<u>APCC Rules and Regulations, Ch. 16</u>	To control air emissions	Applies to any emission generating projects	Description of equipment and operations as necessary to predict emissions
Permit to Operate	Alabama Air Pollution Control Commission	<u>APCC Rules and Regulations, Ch. 16</u>	To control air emissions	Applies to any emission generating projects	Description of equipment and operations as necessary to predict emissions
Temporary Permit to Operate	Alabama Air Pollution Control Commission	<u>APCC Rules and Regulations, Ch. 16</u>	To add flexibility to permitting process	Applies to any facility requiring a Permit to Operate	No separate application
Temporary Emissions Approval	Alabama Air Pollution Control Commission	<u>APCC, Rules and Regulations, Ch. 16</u>	To identify temporary emission sources	Applies to gas flaring during well testing activities	Location of flaring, content of gas
National Pollution Discharge Elimination System (NPDES) Permit	Alabama Water Improvement Commission	<u>AWIC Regulations, Policies, and Procedures</u>	To regulate discharges to navigable waters	Any point-source discharge	Receiving water, location and chemical composition of discharge
Application for Disposal Well	State Oil and Gas Board or Alabama Water Improvement Commission	State Oil and Gas Board, Rules and Regulations	To regulate deep underground waste disposal	May apply to oil field operations (Class II wells)	Well logs and diagrams of disposal areas
Stream Division or Rerouting Permit	Alabama Water Improvement Commission	Alabama Water Pollution Control Statutes	To regulate stream diversion and control water pollution	May apply (rarely) to coal mining	Describe proposed changes, maps of areas
Special Agreement for Installation of Utilities on Highway Rights-of-Way	Highways, Bureau of Administration	NA	To regulate construction affecting highways	May apply to pipeline construction crossing state highways	Description of construction, drawings

TABLE 5-1 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Producer's Certificate of Compliance and Authorization to Transport Oil, Gas or Condensate from Lease	State Oil and Gas Board	State Oil and Gas Board Rules and Regulations, Part I	To regulate transportation of dangerous materials	Applies to oil and gas operations	Mode and destination for transport
Motor-Carrier's Permit	Public Service Commission	Code of Alabama, 37-3-13b	To regulate activities of private hauling companies	May apply to contracted trucking firms used in mining operations	Description of scope of trucking operations
Certificate of Public Necessity	Public Service Commission	NA	To regulate public transport companies	Applies to construction of common carrier oil or gas pipeline	Demonstration of need and description, location and tariffs for project
Certificate for Industrial Development	Public Service Commission	Code of Alabama, 10-5-3	To allow eminent domain proceedings for rights-of-way	May apply to any energy project	Description of project, demonstration of public need
Permit for Surface Mining Project	Alabama Surface Mining Reclamation Commission	NA	To control environmental effects of coal mining	All coal mining	Detailed mining and reclamation plans
License for surface mining	Alabama Surface Mining Reclamation Commission	NA	To regulate surface mining	Surface mining activities	Identification of company and of intended operations
Application for Permit to Drill, Deepen or Convert (Application to Re-Enter)	State Oil and Gas Board	State Oil and Gas Board, Rules and Regulations, Part I	To promote wise development and to protect state liability	To all oil and gas drilling	Method of drilling, tract diagram

TABLE 5-1 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Application for Permit to Drill Directionally	State Oil and Gas Board	State Oil and Gas Board, Rules and Regulations, Part I	To promote wise development	May apply to oil field operations	Description, depth of drilling, tract diagram
Notice of Intention to Chemically Treat or Fracture a Well	State Oil and Gas Board	State Oil and Gas Board, Rules and Regulations, Part I	To promote wise development	May apply to oil field operations	Well history, results of treatment, well logs
Letter of Concurrence	Historical Commission of Alabama	Not cited	To protect historical values	May apply to any project, but particularly to mining	Map, description of extent of disturbance, cultural assessments
Certification for Blasting	Alabama Surface Mining Reclamation Commission	Not cited	To maintain safety during blasting operations	Applies to mining projects	Proof of certification of relevant personnel
Permits to Drill Coal Degasification Wells	State Oil and Gas Board	State Oil and Gas Board, Rules and Regulations	To allow extraction of gas from mining area	Coal mining activities	Description of well operation, gas disposal plans
Rights-of-way for state lands	Department of Highways	NA	To monitor activities affecting state lands	To any project involving access to state lands	Description of proposed activity
Pollution abatement plan	Alabama Water Improvement Commission	NA	To prevent water pollution	To any project where water discharge may occur	Description of abatement plan

TABLE 5-2

APPLICABILITY OF ALABAMA PERMITS BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL ^a	OIL SHALE
Permit to Construct	O	X		X
Permit to Operate	O	X		X
Temporary Permit to Operate	O	X		X
Temporary Emission Approval	O			O
NPDES Permit	O	X		X
Application for Disposal Well	X			
Stream Diversion or Rerouting Permit		O		O
Special Agreement for Installation of Utilities in Rights-of-Way	O	O		O
Producer's Certificate for Authorization to Transport	X			
Motorcarrier's Permit		O		O
Certificate of Public Necessity	O			
Certificate for Industrial Development	O	O		O
Permit for Surface Mining Project		X		X
License for Surface Mining		X		X

^aNot applicable to Alabama.

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-2 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL ^a	OIL SHALE
Application for Permit to Drill	X			
Application for Permit to Drill Directionally	O			
Notice of Intention to Chemically Treat a Well	O			
Letter of Concurrence	O	O		O
Certification for Blasting		X		X
Permits to Drill Coal De- gasification Wells		O		
Rights-of-Way for State Lands	O	O		O
Pollution Abatement Plan	O	O		O

^aNot applicable to Alabama.

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-3

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF ALABAMA

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Permit to Construct	Alabama Air Pollution Control Commission	Description of equipment and operations as necessary to predict emissions	Not specified	30-180 days (est.)	Yes	None
Permit to Operate	Alabama Air Pollution Control Commission	Description of equipment and operations as necessary to predict emissions	Not applicable	Not applicable	No	None
5-18 National Pollution Discharge Elimination System (NPDES) Permit	Alabama Water Improvement Commission	Identification of receiving water, location and chemical composition of discharge	Not specified	60-90 days (est.)	Yes	None
Permit for Surface Mining Project	Alabama Surface Mining Reclamation Commission	Detailed mining and reclamation plans	45 days	60 days	Yes	\$1,000
License for Surface Mining	Alabama Surface Mining Reclamation Commission	Identification of company and of intended operations	Not specified	30-90 days (est.)	No	\$500

TABLE 5-4

SUMMARY OF TIME REQUIREMENTS FOR MINOR PERMITS, STATE OF ALABAMA

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Temporary Permit to Operate	Air Pollution Control Commission	Description of equipment and operations as necessary to predict emissions	Not specified	Not applicable	No	None	Automatically issued when operations are ready to begin
Application for Disposal Well	State Oil and Gas Board	Well logs and diagrams of disposal area	Not specified	1/2 to 3 weeks (est.)	No	\$250	Part of UIC regulations
Stream Diversion or Rerouting Permit	Alabama Water Improvement Commission	Describe proposed changes, maps of area	Not specified	30-60 days	Yes	None	No specific application form
Special Agreement for Installation of Utilities on Highway Rights-of-Way	Highways Department, Bureau of Administration	Description, drawings of construction	Not specified	1-2 months	No	None	Issued by district (county) offices
Producer's Certificate of Compliance and Authorization to Transport Oil, Gas or Condensate from Lease	State Oil and Gas Board	Mode and destination for transport, oil or gas test	Not specified	1/2 to 3 weeks (est.)	No	None	May apply to oil field operators
Motorcarrier's Permit	Public Service Commission	Description of operations, rates	Not specified	1 1/2 - 9 months	Yes	\$100	May apply to coal mine for hire trucking concerns
Certificate of Public Convenience and Necessity	Public Service Commission	Demonstration of need, description location and tariffs of project	Not specified	6-9 months	Yes	None	May (rarely) apply to oil field pipelines, or rail extensions
Certificate (For Industrial Development)	Public Service Commission	Petition for certificate, purpose, location, of project	Not specified	3-4 months	Yes	None	Allows exercise of eminent domain

TABLE 5-4 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Application for Permit to Drill, Deepen or Convert (Application to Re-Enter)	State Oil and Gas Board	Method of drilling, tract diagram	Not specified	1-5 days (est.)	No	\$250	Also need affidavit of ownership, organization chart and bond
Application for Permit to Drill Directionally	State Oil and Gas Board	Method of drilling, tract diagram	Not specified	1-5 days (est.)	No	\$250	Also need affidavit of ownership, organization chart and bond
Notice of Intention to Chemically Treat or Fracture a Well	State Oil and Gas Board	Well history, well logs, results of treatment submitted	Not applicable	Not applicable	No	None	Notification occurs after treatment
Temporary Emissions Approval (Gas Flaring)	Alabama Air Pollution Control Commission	Location of flaring, content of gas	Not applicable	5 days (est.)	No	None	Allows testing of gas wells
Letter of Concurrence	Historical Commission	Map, description of extent of disturbance	Not specified	2 weeks to month	No	None	State function is based on federal program
Certification for Blasting	Alabama Surface Mining Reclamation Commission	Proof of certification of relevant personnel	Not applicable	Not applicable	No	NA	Course completion may be necessary
Permits to Drill Coal Degasification Wells	State Oil and Gas Board	Description of well operation, gas disposal plans	Not specified	10 days	No	\$250	
Rights-of-way for state lands	Department of Highways	Description of proposed activity	Not specified	2 months	No	NA	
Pollution Abatement Plan	Alabama Water Improvement Commission	Description of abatement plan	Not specified	2-3 months	Yes	None	Pollution abatement plan review may duplicate other mining reviews

5.3 Permitting Processes in Alaska

While Alaska has instituted a formal procedure to expedite and coordinate permitting processes in the state, it is not clear that the procedure has been effective. The Environmental Procedures Coordination Act, enacted in 1977, is the statutory basis for a Master Application process in the state. This process defines approvals and permits that will be required for any large commercial project, serves as a trigger for a joint public hearing, and establishes a schedule for review and decision. However, participation is optional and may be terminated at any time. To date, only eight participants have filed Master Applications -- and most have discontinued participation upon identification of required permits and approvals. State officials attribute the low participation rate to developers' beliefs that the process will impose additional time and resource constraints.

The State of Alaska currently has not assumed jurisdiction of federal air quality, water quality, solid waste disposal or surface mining regulatory programs, but pursues its own permitting activities in each of these areas.

A dual permitting situation exists with respect to air quality control. The PSD and NSPS programs come under EPA purview. The state, however, requires a separate Air Quality Permit to operate. A somewhat similar situation exists in the area of water quality control. The state regulates effluent discharge through the issuance of a Wastewater Disposal Permit. If the discharge is major and requires an NPDES permit (EPA administered), the state will usually adopt the NPDES Permit as its own.

A permit is required to conduct solid waste disposal operations in the state. While regulations in this area are pre-RCRA, state authorities are currently drafting regulations that will enable an eventual takeover of the federal program.

Alaska has three of the energy resource areas being considered in this study. The state has oil and gas reserves, coal deposits and minor geothermal resources.

5.3.1 Responsibilities of Principal State Agencies

The Executive Branch of Alaska state government is organized according to a cabinet structure comprising 14 departments. Four of these departments play key roles in the regulation and permitting of energy resource development projects: Fish and Game, Environmental Conservation, Natural Resources, and Commercial and Economic Development. Figure 5-2 diagrammatically presents this organization. (The key state departments are within the dotted rectangle; relevant offices within each of these key departments are also shown.)

The functions of the relevant state agencies are defined below:

Fish and Game Department - Charged with the conservation, development and regulation of fish and game resources within the state. The department plays active and important roles both in the issuance of permits and in providing advice and technical support to offices in other State departments, particularly in the areas of solid waste and water quality regulation.

Department of Environmental Conservation - The central permitting authority in the state relevant to the

Figure 5-2. Organization of Alaska State Government (Some offices have not been shown in order to simplify the presentation).

development activities under consideration. The Department's responsibilities include: (1) the administration of the Master Application process through regional permit information centers, and (2) the establishment of programs, standards and regulations (and the issuance of permits) relating to solid waste disposal, and air and water pollution control and abatement. All water quality, air quality and solid waste disposal permits are issued by the Department. Additionally, regulations specific to oil spill prevention and cleanup are administered here.

Department of Natural Resources - Plays two roles that affect energy resource development. The Department regulates and issues permits for the appropriation of water. The Department also approves leases and grants easements on state lands - an activity which could have some bearing on the development of adjacent federal lands.

Department of Commerce and Economic Development - Encompasses two relevant regulatory bodies. One, the Oil and Gas Conservation Commission, issues permits required to drill oil or gas wells. The Public Utility Commission, also part of this department, issues the Certificate for Public Convenience and Necessity, an approval that will be necessary, in many areas, to construct or extend a pipeline.

A number of other state agencies play more minor roles. The Office of Coastal Management administers the Alaska Coastal Management Program. In this role it reviews applications for a number of state permits to assess the potential impact such activity might have on the coastal zone. The Department of Transportation and Public Facilities issues permits relating to encroachments on state highways. Finally, the Department of Revenue issues a mining permit for the purpose of taxation.

5.3.2 Permits Required by the State of Alaska

The absence of state authority for many environmental programs means that state agencies must interact regularly with federal offices on permit decisions. The coordination of the two levels of government can add to permit processing delays. The permits that may be required by any energy resource development project by the State of Alaska are summarized in Table 5-5. Twenty-nine permits were identified, representing a fairly conventional set of regulatory controls. The applicability of the permits to the energy resource areas is described in Table 5-6. Permitting for geothermal resources is least developed, due to their limited utilization in the state.

Five state permits were designated as major permits as shown in Table 5-7. The criteria for this designation include the probability that an energy resource development project would require the permit and the time needed for permit issuance. The length of time required to consider an application for the Air Quality Control Permit to Operate is dependent on EPA action in many cases. Where prevention of significant deterioration approval is needed, the state will not consider the application complete until EPA completes its technical review. This might result in a significant delay before review of the application commences.

Three major permits relate to water quality control. Of these, the Wastewater Disposal Permit is most important. In most cases, where EPA designates the discharger as minor (and thus not requiring an NPDES Permit), the state reviews a completed application and issues a permit in an estimated

30-90 days. When the discharger is considered major, EPA requires an NPDES Permit. The process for review and issuance of an NPDES Permit could take up to 200 days. Upon reissuance, the state usually adopts the NPDES Permit as the Wastewater Disposal Permit.

The last major permit, the Solid Waste Disposal Permit, may be considered applicable to most development activities as the state's definition of solid waste encompasses both drilling muds and coal mining wastes. Developers engaging in disposal activities themselves would require this permit. The time that elapses between initial application submission and final action can be as long as 120 days.

Minor state permits are listed in Table 5-8. Most of the minor permits have brief review times. However, state land permits could be required in select cases and these review periods are quite lengthy.

TABLE 5-5

SUMMARY OF PERMITS REQUIRED BY THE STATE OF ALASKA

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Air Quality Control Permit to Open Burn	Department of Environmental Conservation	18 AAC 50.030	To prevent, abate and control air pollution	Required to burn any material which gives off black smoke or odors; includes gas flaring and effluents generated while testing an oil or gas well	Description of burning operation
Air Quality Control Permit to Operate	Department of Environmental Conservation	18 AAC 50.300	To prevent, abate and control air pollution	Needed to construct a facility which emits air contaminants	Engineering facility plans, description of operations and ambient meteorological data
Plan Review for Sewerage Systems or Water and Wastewater Treatment Works	Department of Environmental Conservation	18 AAC 72.060	To prevent water pollution	Applies to wastewater discharge of any project	Engineering reports, plans, and specifications
Wastewater Disposal Permit	Department of Environmental Conservation	18 AAC 72	To prevent water pollution	Disposal of wastewater onto land or into waters	Description of operations, treatment procedures
Certificate of Reasonable Assurance	Department of Environmental Conservation	18 AAC 70.081-.085	To prevent water pollution	Activities requiring federal permit or license to discharge into navigable waters	Letter of request and attached Wastewater Disposal Permit Application
Surface Oiling Permit	Department of Environmental Conservation	18 AAC 75	To prevent water pollution	May apply to road maintenance during energy projects	Description of procedures
Oil Discharge Contingency Plan Approval	Oil Pollution Control, Department of Environmental Conservation	18 AAC 75.305 et. seq.	To assure that operators have the organization and equipment for containing and cleaning up an oil discharge	Oil storage facilities, tank vessels and barges	Components of the plan

TABLE 5-5 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Proof of Financial Responsibility	Oil Pollution Control, Department of Environmental Conservation	18 AAC 20.005 et. seq.	To assure that operators have sufficient financial resources to compensate for losses resulting from an oil discharge	Oil storage facilities, tank vessels and barges	Proof of sufficient financial assets
Water Rights Permit and Certificate of Appropriation	Division of Land and Water Management, Department of Natural Resources	11 AAC 72.050	To assure the beneficial use of waters of the state and to protect public health and safety	Appropriation of non-mineralized water	Location, use, and means of appropriation of water
Permit to Construct or Modify a Dam	Dam Safety and Construction Division of Land and Water Management, Department of Natural Resources	11 AAC 72.150-.200	To ensure public safety	May apply to larger dams in local mining operations	Dam specification and location
Water Well Authorization	Oil and Gas Conservation Commission, Department of Commerce and Economic Development	20 AAC 25.140	To prevent contamination of fresh water	Conversion of abandoned oil and gas wells to freshwater wells	Well specification and reason for use as a freshwater well
Solid Waste Disposal Permit	Department of Environmental Conservation	18 AAC 60	To protect public health and the environment	Disposal of solid waste or hazardous material (includes disposal of mine wastes)	Plans or specifications of facility and description of operations
Burning Permit	Division of Land and Water, Department of Natural Resources	11 AAC 92	Fire prevention	Burning any material in designated areas of the state during the fire season (May 1 through September 30)	Area and material to be burned
Anadromous Fish Protection Permit	Habitat Division, Department of Fish and Game	5 AAC 95.010	Protect and preserve anadromous fish in waters important to their spawning, rearing or migration	Required for any work in a listed anadromous fish river, lake or stream	Description of project, project site and measures taken to protect fish

TABLE 5-5 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Fishways for Obstructions to Fish Passage	Fisheries Rehabilitation, Enhancement and Development Division, Department of Fish and Game	AS.16.05.840	To guarantee the passage of fish in waters of the state	Construction of dam or other obstruction across stream frequented by salmon or other fish	Description of project, project site, and measures taken to assure proper passage of fish
Coastal Management Program Consistency Certification	Office of Coastal Management, Division of Policy Development and Planning, Office of the Governor	AS.46.40	Protection and wise development of coastal areas in the state	Any activity within a coastal zone or which could impact a coastal zone	No separate application; information taken from other permit and license applications (federal or state)
Critical Habitat Area Permit	Habitat Division, Department of Fish and Game	AS.16.20.220, 230, 260	To protect fish and wildlife within Critical Habitat Areas	May apply to activities on federal lands where state Critical Habitat Area lands are interspersed	Description of proposed activities and anticipated impact on fish and game
State Game Refuge Permit	Habitat Division, Department of Fish and Game	AS.16.20.010, 030, 060	To protect fish and wildlife within State Game Refuges	May apply to activities on federal lands where state Game Refuge lands are interspersed	Description of proposed activities and anticipated impact on fish and game
Permit to Drill or Deepen	Oil and Gas Conservation Commission, Department of Commerce and Economic Development	20 AAC 25.005	Efficient development of oil and gas resources, protect correlative rights, safety	Drilling or deepening any oil or gas well	Description of well operations
Application for Additional Recovery Approval	Oil and Gas Conservation Commission, Department of Commerce and Economic Development	20 AAC 25.400	Efficient development of oil and gas resources, protect correlative rights, safety	Operator proposing to use methods of recovery of oil or gas other than those methods used for primary recovery	Description of well operations

TABLE 5-5 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Mining License	Department of Revenue	AS 43.65.010-060	Taxation of business engaged in mining	Mining activities	Description of mining activity
Land Use Permit	Division of Minerals and Energy Management	11 AAC 96,62.140, 58.210	To protect the natural environment of state-owned lands	May apply to activities on federal lands where state lands are interspersed	Description of proposed activity
Lease Operations Approval	Division of Minerals and Energy Mgt., Dept. Natural Resources	11 AAC 82,83	Proper management of property leased by the state	May apply to activities on federal lands where state lands are interspersed	Description of operations
Coal Lease	Division of Minerals and Energy Mgt., Dept. Natural Resources	11 AAC 82	To provide for orderly development of coal resources owned by the state	May apply to activities on federal lands where state lands are interspersed	Statement of qualifications
Coal Prospecting Permit	Division of Minerals and Energy Mgt., Dept. Natural Resources	11 AAC 82,84, 76,88	Manage and encourage prospecting for mineral resources on state lands	May apply to activities on federal lands where state lands are interspersed	Legal description of area
Oil and Gas Lease	Division of Minerals and Energy Mgt., Dept. Natural Resources	11 AAC 82,83, 88	To provide for orderly development of petroleum resources owned by the state	May apply to activities on federal lands where state lands are interspersed	Statement of qualifications
State Park Noncompatible Use Permit	Division of Parks, Department of Natural Resources	11 AAC 18.010	To protect state parks lands	Applies in cases where access over state park lands is required. May also apply when state and federal lands are interspersed	Description of activity

TABLE 5-5 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Right-of-Way Easement	Division of Land and Water, Department of Natural Resources	11 AAC 58.200	Proper and efficient use of state resources	Construction of a road, trail, ditch, pipeline, telephone line or storage site (or similar activity) on state lands	Description of activity
Utility Permit for Encroachment within Highway Rights-of-Way	Department of Transportation and Public Facilities	17 AAC 15	To maintain a record of utilities in highway rights-of-way	Construction or placement of any utilities in highway rights-of-way	Plans, specifications and description of work
Encroachment Permit	Right-of-Way and Land Acquisition Agent, Department of Transportation and Public Facilities	17 AAC 10.010	To ensure that encroachments will not interfere with traffic and that public safety is maintained	Construction, alteration, or maintenance of an encroachment across or along a public highway or right-of-way	Description of encroachment (with map or diagram)
Driveway Permit	Department of Transportation and Public Facilities	17 AAC 10.020	To maintain highway standards and public safety	Construction of a driveway or road approach within state highway lands or a right-of-way	Description and plan of proposed driveway
Certificate of Public Convenience and Necessity	Public Utilities Commission, Department of Commerce and Economic Development	3 AAC 48	Utility regulation and protection of the public interest	May apply to the construction or extension of an oil or gas pipeline	Description of proposed pipeline or extension

TABLE 5-6

APPLICABILITY OF ALASKA PERMITS BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALES ^a
Air Quality Control Permit to Open Burn	O	O	O	
Air Quality Control Permit to Operate	O	X	X	
Plan Review for Sewerage Systems or Water and Wastewater Treatment Works	O	O	O	
Wastewater Disposal Permit	O	X	X	
Certificate of Reasonable Assurance	O	X	X	
Surface Oiling Permit	O	O	O	
Oil Discharge Contingency Plans	O			
Proof of Financial Responsibility	O			
Water Rights Permit	O	O	O	
Permit to Construct or Modify a Dam		O		
Water Well Authorization	O	O	O	
Solid Waste Disposal Permit	O	O	O	
Burning Permit	O	O	O	

^aDoes not apply to Alaska.

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-6 (CONT.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE ^a
Anadromous Fish Protection Permit	0	0	0	
Fishways for Obstructions to Fish Passage	0	0	0	
Critical Habitat Area Permit	0	0	0	
State Game Refuge Permit	0	0	0	
Coastal Management Program Certificate of Consistency	0	0	0	
Permit to Drill or Deepen	X			
Application for Additional Recovery Approval	0			
Mining License		0		
Land Use Permit	0	0	0	
Lease Operations Approval	0	0	0	
Coal Prospecting Permit		0		
Coal Lease		0		
Oil and Gas Lease	0			
State Park Non- Compatible Use Permit	0	0	0	

^aDoes not apply to Alaska.

X - Permit is applicable to most development activities of this resource.

0 - Permit applicability is dependent on site and project characteristics.

TABLE 5-6 (CONT.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALES ^a
Right-of-Way Easement	O	O	O	
Utility Permit for Encroachment Within Highway Rights-of-Way	O	O	O	
Encroachment Permit	O	O	O	
Driveway Permit	O	O	O	
Certificate of Public Convenience and Necessity	O			

^aDoes not apply to Alaska.

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-7

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF ALASKA

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	GOVERNMENT AGENCY			
			COMPLETE- NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICA- TION FEE
Air Quality Control Permit to Operate	Department of Environmental Conservation	Facility engineering plans and specifications, description of operations and ambient air and meteorological data	30-180 days	30 days	Yes	None
Plan Review for Sewerage System or Water and Wastewater Treatment Works	Department of Environmental Conservation	Engineering reports, plans and specifications	14 days (est.)	30 days (est.)	No	None
Wastewater Disposal Permit	Department of Environmental Conservation	Description of operations, treatment procedures and disposal site	Not specified	60-200 days (est.)	Yes	None
Certificate of Reasonable Assurance	Department of Environmental Conservation	Letter of request and attached Wastewater Disposal permit application or similar federal application	Not Specified	60-200 days (est.)	Yes	None
Solid Waste Disposal Permit	Department of Environmental Conservation	Plans and specification of facility and description of operations	30-60 days (est.)	60 days (est.)	Yes	None

TABLE 5-8

SUMMARY OF TIME REQUIREMENTS FOR MINOR PERMITS, STATE OF ALASKA

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Air Quality Control Permit to Open Burn	Department of Environmental Conservation	Description of burning operation	Not specified	5-30 days	No	None	
Surface Oiling Permit	Department of Environmental Conservation	Description of procedures	Not specified	5 days	No	None	
Oil Discharge Contingency Plan Approval	Oil Pollution Control, Department of Environmental Conservation	Components of oil discharge contingency plan	Not specified	1-65 days (est.)	No	None	
Proof of Financial Responsibility	Oil Pollution Control, Department of Environmental Conservation	Proof of sufficient financial assets	Not specified	7 days (est.)	No	None	
Water Rights Permit (and Certificate of Appropriation)	Division of Land and Water, Department of Natural Resources	Location, use and means of appropriation of water	Not specified	15-30 days (est.)	Yes	None	When appropriation commences a Certificate of Appropriation is issued
Permit to Construct or Modify a Dam	Dam Safety and Construction, Division of Land and Water, Department of Natural Resources	Dam specification and location	Not specified	3 months (est.)	No	Fee dependent on size of dam	
Water Well Authorization	Oil and Gas Conservation Commission, Dept. Commerce and Economic Development	Well specification and reasons for use as a freshwater well	NA	NA	No	None	
Burning Permit	Division of Land and Water, Dept. Natural Resources	Area and material to be burned and person in charge	Not specified	1 day	No	None	

TABLE 5-8 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Anadromous Fish Protection Permit	Habitat Division, Department of Fish and Game	Description of project, project site and measures to be taken to protect fish	Not specified	14 days (est.)	No	None	
Fishways for Obstruction to Fish Passage	Fisheries Rehabilitation, Enhancement and Development Div., Dept. of Fish and Game	Description of project, project site and measures taken to assure proper passage of fish	Not specified	30 days	No	None	
Alaska Coastal Management Program Consistency Certification	Office of Coastal Management, Division of Policy Development and Planning, Office of the Governor	No separate application. Information taken from other permit applications (federal and state)	Not specified	Not specified	Yes	None	
Critical Habitat Area Permit	Habitat Division, Department of Fish and Game	Description of proposed activities and anticipated impact on fish and game	Not specified	30 days	No	None	
State Game Refuge Permit	Habitat Division, Department of Fish and Game	Description of proposed activities and impact on fish and game	Not specified	30 days	No	None	
Permit to Drill or Deepen	Oil and Gas Conservation Commission, Department of Commerce and Economic Development	Description of well and operations	Not specified	7-14 days (est.)	Yes	\$100	
Application for Additional Recovery Approval	Oil and Gas Conservation Commission, Department of Commerce and Economic Development	Description of well and operations	Not specified	30-60 days (est.)	Yes	None	

TABLE 5-8 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Mining License	Fisheries and Mining Tax Unit, Department of Revenue	Description of mining activity	Not specified	14 days (est.)	No	None	
Land Use Permit	Division of Land and Water, Dept. Natural Resources	Description of proposed activity	Not specified	30-45 days (est.)	No	Bond (amount dependent on extent of activities)	
Lease Operations Approval	Division of Mineral and Energy Mgt., Dept. Natural Resources	Description of operations	Not specified	65-90 days (est.)	NA	None	
Coal Lease	Division of Minerals and Energy Mgt., Dept. Natural Resources	Statement of Qualifications	Not specified	Indefinite	Varies by lease		
Coal Prospecting Permit	Division of Minerals and Energy Mgt., Dept. Natural Resources	Legal description of area	Not specified	60-90 days (est.)	No	\$20	
Oil and Gas Lease	Division of Minerals and Energy Mgt., Dept. Natural Resources	Statement of Qualifications	Not specified	Up to 5 years	No	Varies by lease	
State Park Noncompatible Use Permit	Division of Parks, Dept. Natural Resources	Description of proposed activity	Not specified	1-5 months	Yes	None	
Right-of-Way Easement	Division of Land and Water, Dept. Natural Resources	Description of proposed activity	Not specified	90 days-1 year	\$10		
Utility Permit for Encroachment within Highway Rights-of-Way	Department of Transportation and Public Facilities	Plans, specifications, and description of work	Not specified	2 weeks (est.)	No	None	

TABLE 5-8 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Encroachment Permit	Right-of-Way and Land Acquisition Agent, Department of Transportation and Public Facilities	Description of encroachment (with map or diagram)	Not specified	2 weeks (est.)	No	None	
Driveway Permit	Department of Transportation and Public Facilities	Description and plan of driveway	Not specified	2 weeks (est.)	No	None	
Certificate of Public Convenience and Necessity	Public Utilities Commission, Department of Commerce and Economic Development	Regulate utilities, assurance that the public is served	Not specified	180 days (est.)	Yes	\$50 + investigation costs	

5.4 Permitting Processes in California

California has been fairly active in its efforts to regulate energy development activities and to limit environmental pollution. The states' environmental regulations are generally more stringent than the federal standards. At the same time, however, the state has not assumed complete authority for the environmental programs authorized by EPA. Among the air programs, California does not have authority to issue PSD permits. Also, California has only partial responsibility for operating the federal program for control of underground injection of wastewaters. Discussions are now being held to clarify responsibilities for this program among state and federal agencies.

The California legislature has significantly impacted the state permitting processes. Among the most important legislative actions was passage of the California Environmental Quality Act (CEQA) which requires public agencies to consider the possible environmental impacts of private, state, and federal projects. The CEQA impact on the permitting process is similar to that of the NEPA legislation on federal agencies. In particular, the CEQA requires that a lead agency be identified for preparing an Environmental Impact Report (EIR) for major projects. Applications for any of several major state permits can trigger the CEQA process.

The CEQA process also establishes formal requirements for state agency interaction and cooperation, including permit decision deadlines. If it is determined that a full Environmental Impact Report is required for a given project, the lead agency (usually a local planning agency) must prepare the EIR, circulate it to other interested agencies,

hold appropriate public hearings and decide to approve or disapprove the project. All of these actions must be completed within one year of receipt of a complete permit application. After the lead agency's decision is reached, all other responsible state agencies must decide on the project-specific permit applications within 180 days of either the lead agency's decision or receipt of a complete application, whichever is later. As a result, if the developer submits all other applications soon after the lead agency's decision, the total permit processing time should be a maximum of 18 months. By requiring this agency interaction, the CEQA process effectively limits the time delays involved in obtaining regulatory approvals.

The California legislature also passed the Permit Streamlining Act (may be referenced as Statutes of 1973, Chapter 1200 or as Assembly Bill 884) which added permit review deadlines, independently of the CEQA process, to many programs. Statutory deadlines for completion of permit reviews are, thus, quite common in California.

Energy development in California is restricted to two of the four energy resource areas being studied, namely the (1) oil and gas, and (2) geothermal resources. The state's principal oil fields are located at the southern end of the Central Valley in Kern County with much smaller oil fields being developed along the Southern California coast. Geothermal development is occurring in the Geysers area in Northern California, which includes portions of Sonoma, Lake Colusa, Mendocino, and Napa counties. Geothermal activity is also taking place in the Imperial Valley near the southern boundary of the state.

5.4.1 Responsibilities of Principal State Agencies

The executive branch of California government is dominated by four "superagencies," each of which is the umbrella agency for a wide range of state functions. The executive branch organization chart, which is shown in Figure 5-3, indicates the four large agencies of (1) Business, Transportation and Housing, (2) Resources, (3) State and Consumer Services, and (4) Health & Welfare. The state offices with the greatest roles in regulation of energy development are concentrated in the Resources Agency, with a few permitting offices distributed among other agencies and among the independent state commissions.

The particular agencies which are active in permitting for energy development are listed below. A short summary is provided of each agency's authority and role.

Air Pollution Control Districts - The Air Pollution Control Districts issue permits and monitor new and modified sources of pollution to enforce federal and state standards. The permitting authority is delegated to each district office.

Department of Conservation - Division of Oil and Gas - The Division of Oil and Gas controls and monitors activities relevant to oil and gas and geothermal resource extraction in the state. The division's responsibilities are primarily for wise development of state resources and for environmental control of drilling operations. Permits are issued through district offices for initiation or cessation of drilling activities.

Department of Fish and Game - This department controls and monitors activities affecting streams, lakes, channels or crossings. The Department is also involved if energy development occurs in wildlife habitats.

California Coastal Commission - The Commission operates as a land-use control agency for coastal areas. The Commission's authorization emphasizes protection of the

Figure 5—3. Organization of California State Government (Some government departments have been omitted in order to simplify the presentation).

coastal environment and resources, and maintenance of public access. Development permits, which are issued for industrial activities in coastal areas, have been issued for oil and gas operations.

CALTRANS (Department of Transportation) - CALTRANS is relevant to energy development only as far as changes or abutments to the state highway system are required. If access to the highway is needed, Encroachment Permits are issued by the agency.

Public Utilities Commission - The PUC monitors utility activities in the state. Certain energy development operations may be controlled by the agency; in particular, pipeline construction and extension of railroad lines. In such cases, PUC approvals (Certificate of Public Convenience and Necessity) may be needed.

Reclamation Board - The Reclamation Board controls any land modifications in the Central Valley which may affect floodways. Oil and gas wells may require encroachment permits if they are located near any flood control structures.

State Lands Commission - The Commission serves as the main land-use control agency for state lands in California. Permits are issued for stream or lake alterations, or for geothermal exploration on state lands.

State Water Resources Control Board - This state agency operates the NPDES permit system in California, through district water resources boards. Additional permit programs exist for groundwater discharges and for water appropriations.

5.4.2 Permits Required by the State of California

California has a relatively brief listing of permits because only two major resources, oil and gas and geothermal reserves, are found in the state. These energy sources are relatively nondisruptive of the environment when compared to major mining operations. The summary listing shown in Table 5-9 covers 24 distinct permits.

The applicability of these permits to the two resources is quite similar, as shown in Table 5-10. Both oil and gas developments and geothermal explorations must comply with a standard set of water pollution control and drilling regulations.

Eight permits were selected for the "major permit" category based on their usual importance to state energy developers. The major permits are listed in Table 5-11. The air pollution regulations are quite important to oil developers due to the predominant use of secondary recovery techniques, which require the use of steam generating equipment in the oil fields. Water pollution control is handled by the NPDES permit system or by a more broadly applicable Facility Permit/Waste Discharge program. The latter is an umbrella act which covers any major industrial discharges to ground or surface waters. Water appropriation permits can be quite controversial and the processing time in this case can be quite long. The average review time was estimated at 1 to 1-1/2 years. Hazardous waste permitting is also a difficult state issue which can affect oil field developments. The state uses a waste identification test which sometimes registers oil drilling muds and brines as hazardous wastes. On-site disposal of such wastes would require a Hazardous Waste Facility Permit. In practice, affected firms transport their wastes to existing waste facilities.

Minor permits, shown in Table 5-12, are those which will generally not cause long delays, particularly for California energy activities. It is possible for a minor permit to trigger the California Environmental Quality Act (CEQA) which may necessitate preparation of an Environmental Impact Report (EIR). However, for energy projects, the CEQA process would already be triggered by the major permits shown above. The minor permitting agencies would not be lead agencies in the environmental review process for energy projects.

TABLE 5-9

SUMMARY OF PERMITS REQUIRED BY THE STATE OF CALIFORNIA

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Authority to Construct	Air Pollution Control District	California Health and Safety Code Sect 39000-43834	Air Pollution Control	For construction of facility which emits pollutants	Details of process, control equipment and fuels
Permit to Operate	Air Pollution Control District	California Health and Safety Code Sect 39000-43834	Air Pollution Control	For operation of facility which emits pollutants	No separate application; review based on Authority to Construct Application
National Pollutant Discharge Elimination System Permit	California Regional Water Quality Control Board	C.A.C., Title 23, Ch. 3	Pollution Control in navigable waters	For all discharges to navigable waters	Facility description and location, quantity and type of discharge
Project Proposal (to inject water)	Department of Conservation, Division of Oil and Gas	C.A.C., Title 14	To protect groundwater quality and oil reservoir characteristics	For water injection for disposal or enhanced recovery	Location, drilling depth, condition of adjacent wells
Facility Permit/Waste Discharge	California Regional Water Quality Control Board	C.A.C., Title 23, Ch. 3	Pollution control in all waters	For all discharges of any type above minimum levels	Facility description and location, quantity and type of discharge
Permit to Appropriate Water	State Water Resources Control Board	C.A.C., Title 23, Ch. 3	Regulation of water use	For diversion of non-riparian waters	Source location, quantity and use of diverted water
Hazardous Waste Facility Permit	Department of Health Services	C.A.C., Title 22	Control Hazardous waste disposal	For construction of Class I or II-1 disposal sites	Detailed operation plan for facility
Solid Waste Facility Permit	State Solid Waste Management Board (or local agency)	C.A.C., Title 14	Control solid waste disposal	For construction of all disposal sites, except Class 1	Facility and description of location
Stream or Lake Alteration Agreement	Department of Fish and Game	California Fish and Game, Sections 1601 and 1603	Protect natural habitats	For activities occurring in streams, lakes, and riverbeds	Description of activities in stream bed
Dredging Permit	Department of Fish and Game	NA	Protect natural habitats	Applies to suction dredging	Description of proposed dredging, land ownership

TABLE 5-9 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Special Use Permit for State Park Lands	Department of Fish and Game	NA	Control use of state park lands	For projects impinging on state park lands	Description of proposed activities
Notice of Intention to Drill	Department of Conservation, Division of Oil and Gas	C.A.C., Title 14, Ch. 2., 660-734	Promote wise energy development and conservation	All new oil, gas and geothermal wells	Drilling plans
Geothermal Exploration or Prospecting Permit	State Lands Commission	C.A.C., Title 2, Div. 3	Maintain orderly exploration	May apply to exploration on federal lands, if state lands interspersed	Description of land and survey exploration methods
Encroachment Permit	The Reclamation Board	NA	Maintenance of flood control structures	For construction in floodways of Sacramento or San Joaquin valleys; applies to oilfields	Construction plans and topographic details
5-47 Coastal Development Permit	California Coastal Commission	C.A.C., Title 14, Section 1300	Control use of and protect public access to coastal lands	For industrial activities within 1,000 yards of ocean; may apply to shoreline oilfields	Construction plans and details of shoreline effects
Encroachment Permit	CALTRANS	State Highways Code, Section 660-734	Maintenance of state highway system	May apply to pipelines or access road developments near highways	Construction plans for highway area
Land Use Lease	State Lands Commission	C.A.C., Title 2 Div. 3	Control use of state lands	Applies to federal land development only if state lands are interspersed	Land characteristics and area zoning data
Certificate of Public Convenience and Necessity	Public Utility Commission	C.A.C., Title 20	Protect public interest in utility operations	May apply to oil-field pipelines, if used by multiple firms	Describe pipeline service, tariffs and potential users
Easements for State Forest Lands	Dept. of Forestry	Public Resources Code	Control actions affecting state forest lands	Limited applicability for oil and gas or geothermal activities	Intended land use, and location of use

TABLE 5-9 (CONT.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Temporary Use Permit	Department of Parks and Recreation	Public Resources Code, Sect. 5003-5012	Control actions affecting state parks	Limited applicability for energy operations in selected areas	Intended land use, and location of use
Approval of Plans for Activities Involving Dams and Reservoirs	Department of Water Resources, Division of Safety and Dams	NA	Assure safety of dams and reservoirs	For projects involving dams and reservoirs	Location, construction specifications, water flow and precipitation information
Timber Harvesting Permit	Department of Forestry	NA	To monitor timber harvesting on non-Federal lands	For projects where timber will be harvested from non-Federal lands	Description of site, amount and type of timber to be harvested
Timberland Conversion Permit	Department of Forestry	NA	To assure orderly use of timberland	For projects where timberland will be converted to other uses	Description of location, conversion plans
5-48 Notice of Intent and Certificate of Public Convenience and Necessity (Power Plant)	California Energy Commission and Public Utilities Commission	NA	To institute a thorough economic and environmental review of a projected power plant	For projects where the energy resource will be associated with a power plant	Design specifications, environmental and economic impact information, adherence to overall state energy plans

TABLE 5-10

APPLICABILITY OF CALIFORNIA PERMITS BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL ^a	GEO- THERMAL	OIL SHALES ^a
Authority to Construct	X		X	
Permit to Operate	X		X	
NPDES	O		X	
Facility Permit/Waste Discharge	O		X	
Project Proposal (for Water Injection)	X		X	
Permit to Appropriate Water	O		O	
Hazardous Waste Facility Permit	O			
Solid Waste Facility Permit	O		O	
Stream or Lake Alteration Agreement	O		O	
Land Use Lease	O		O	
Notice of Intention to Drill	X		X	
Geothermal Exploration Permit			O	
Encroachment Permit (Reclamation)	O		O	
Coastal Development Permit	O			

^aNot applicable to California

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-10 (CONT.)

RESOURCE AREA	OIL AND GAS	COAL ^a	GEO- THERMAL	OIL SHALES ^a
Encroachment Permit (CALTRANS)	O		O	
Certificate of Public Convenience	O			
Easements for State Forest Lands	O		O	
Temporary Use Permit	O		O	
Dredging Permit	O		O	
Special Use Permit for State Park Lands	O		O	
Approval of Plans for Ac- tivities Involving Dams and Reservoirs			O	
Timber Harvesting Permit	O		O	
Timberland Conversion Permit	O		O	
Notice of Interest and Certificate of Public Con- venience and Necessity (Power Plant)			X	

^aNot applicable to California

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-11

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF CALIFORNIA

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Authority to Construct	Air Pollution Control District	Details of process, control equipment and fuels	30 days	180 days	Yes	\$100-\$1,500 per unit
Permit to Operate	Air Pollution Control District	No separate application, review based on Authority to Construct Application	Not applicable	Not applicable	No	\$100-\$1,500 per unit
National Pollutant Discharge Elimination System (NPDES) Permit	California Regional Water Quality Control Board	Facility description and location, quantity and type of discharge	90 days (est.)	90 days (est.)	Yes	to \$1,000
Facility Permit/Waste Discharge	California Regional Water Quality Control Board	Facility description and location, quantity and type of discharge	90 days (est.)	90 days (est.)	Yes	to \$1,000
Permit to Appropriate Water	State Water Resources Control Board, Division of Water Rights	Source location, quantity and use of diverted water	Not specified	1 to 1-1/2 years (est.)	Yes	Formula based on diversion
Hazardous Waste Facility Permit	Dept. of Health Services	Detailed operation plan for facility	30 days	6 months (est.)	Yes	None
Solid Waste Facility Permit	Solid Waste Management Board (or local agency)	Facility description and location	5 days	120 days	Yes	\$100-\$500
Notice of Intent and Certificate of Public Convenience and Necessity (Power Plant)	California Energy Commission and Public Utilities Commission	Design specifications, environmental and economic impact information, adherence to overall state energy plans	Not specified	12-18 months	Yes	NA

TABLE 5-12

SUMMARY OF TIME REQUIREMENTS FOR MINOR PERMITS, STATE OF CALIFORNIA

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Project Proposal (to inject water)	Division of Oil and Gas	Location, drilling depth, condition of adjacent wells	Not specified	3-30 days (est.)	No	None	Separate NOI's needed for each well
Stream or Lake Alteration Agreement	Department of Fish and Game	Description of activities in stream bed	Not specified	30 days	No	None	Review time may be extended. EIR required in some cases
Notice of Intention to Drill	Department of Conservation, Division of Oil and Gas	Drilling plans	Not applicable	10 days	No	None	Also applies to geothermal wells and to water injection wells
Geothermal Exploration or Prospecting Permit	State Lands Commission	Description of land and survey exploration methods	Not specified	6 months	No	\$125+	
Encroachment Permit	The Reclamation Board	Construction plan and topographic details	30 days	2-3 months	Yes	None	Controversy lengthens process, but this is rare for oil and gas developers
Coastal Development Permit	California Coastal Commission	Construction plans and details of shoreline effects	5 days	47 days	Yes	\$25-\$2,500	Time limits can be waived by agreement
Encroachment Permit	CALTRANS	Construction plans for highway area	30 days	30 days	No	\$50-\$200	EIR, public comment in rare cases
Land Use Lease	State Lands Commission	Land characteristics and area zoning data	30 days	6 months (est.)	No	\$325 - \$525	Other expenses, rentals, increase fees. EIR may be needed

TABLE 5-12 (CONT.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Certificate of Public Convenience and Necessity	Public Utility Commission	Describe pipeline service, tariffs and potential uses	Not specified	2-8 months	Yes	\$500	
Easements for State Forest Lands	Dept. of Forestry	Intended land use and location of use	Not specified	2 months	No	\$300-\$600	Virtually all requests are for minor easements
Temporary Use Permit	Dept. of Parks & Recreation	Intended land use and location of use	Not specified	1-4 months	No	\$750	Park system covers 1 million acres
Dredging Permit	Dept. of Fish & Game	Description of proposal dredging, land ownership	Not specified	2 weeks	No	\$5-\$75	Suction dredging permits are seldom issued
Special Use Permit for State Park Lands	Dept. of Parks & Recreation	Maps showing applicant's property, affected state park lands	Not specified	12-20 weeks	No	\$350 or market value of land	
Approval of Plans for Activities Involving Dams and	Dept. of Water Resources, Division of Safety &	Location, construction specifications, water flow, and precipitation information	Not specified	Up to 6 months	Yes	\$100 minimum plus percentage of cost of dam	
Timber Harvesting Permit	Dept. of Forestry	Description of site, amount and type of timber to be harvested	5 days	15-30 days	Yes	None	
Timberland Conversion Permit	Dept. of Forestry	Description of location, conversion plans	Not specified	45-60 days	No	None or \$100, depending on location	

5.5 Permitting Processes in Colorado

Colorado is one of the Western state governments which has moved to simplify and clarify its permitting programs. The state has implemented a Joint Review Process (JRP) designed to expedite the permit procedures faced by energy and industrial development firms. This program is a voluntary, intergovernmental review process which coordinates federal, state and local regulatory reviews. A number of major energy firms have utilized the system.

In other regulatory areas, such as the takeover of federal programs, Colorado is not particularly advanced. Currently the state is responsible for the NPDES program, and it will assume the RCRA program in 1983. However, the EPA has not yet approved transfer of air programs to Colorado.

Within the state, local agencies have considerable powers for control of development, including projects such as energy and mineral resource extraction operations. The Colorado Land Use Act of 1974 authorizes local governments to adopt guidelines and regulations for mineral resource areas, historic or archaeological zones, or for natural hazard areas within their jurisdiction. Local governments also have authority for permitting under some of the main state environmental programs.

All of the energy resources covered in this study are found in Colorado. Of course, Colorado has had the most extensive development of oil shale projects in the nation.

5.5.1 Responsibilities of Principal State Agencies

Six major departments of the State of Colorado are involved in the permitting of energy and mineral resource development. These are:

1. Department of Health
2. Department of Natural Resources
3. Department of Regulatory Agencies
4. Department of Highways
5. Department of Labor and Education
6. Department of Higher Education

Each of these is composed of divisions which play an important role in the permitting process. Shown in Figure 5-4 are the pertinent departments and divisions. Synopses of responsibilities for each relevant division are presented below.

1. Department of Health

Air Pollution Control Division - Responsible for enforcing air emission limits on new or modified sources, and regulation of open burning of debris.

Water Quality Control Division - Responsible for ensuring all wastewater discharges comply with adopted water quality standards; regulating the design, location and construction of potable water supply plants; into underground waters; sewage treatment facility construction or expansion.

2. Department of Natural Resources

Mined Land Reclamation Division - Responsible for mining and reclamation activities.

Oil and Gas Conservation Commission - Responsible for regulating oil and gas extraction activities.

Figure 5—4. Organization of Colorado State Government (Some departments are not shown in order to simplify the presentation).

Division of Water Resources - Responsible for reviewing permits and plans for the construction of erosion control dams; approval of large reservoirs, and construction and relocation of wells outside designated basins.

Division of Wildlife - Responsible for the protection of fish and wildlife.

Division of Mines - Responsible for mining operations in the state including statistical information; diesel equipment in underground mines, certifying physical and mental competence of key individuals at mines and the use of explosives.

State Board of Land Commissioners - Responsible for the regulation of activities on state lands.

3. Department of Regulatory Analysis

Public Utilities Commission - Responsible for certifying common and contract carriers, and the "need" for major facilities constructed in the state.

4. Department of Highways

Division of Highways - Responsible for surveying on state and federal highways; controlling access to highway system; installation of pipelines, transmission lines within state highway right-of-way; oversize or overweight vehicles.

5. Department of Labor and Employment

Division of Labor - Responsible for approving plans for industrial bulk liquid petroleum gas storage facilities; sale, manufacture, use, purchase, storage, and transportation of explosives; and operation of boilers.

6. Department of Higher Education

State Historical Society - Responsible for production of cultural resources.

5.5.2 Permits Required by the State of Colorado

A comprehensive list of permits which may be required by Colorado state government agencies has been assembled. The results of the permit survey are described in this section.

An unusually lengthy testing of permits was found to be potentially applicable to energy developers in Colorado. The summary listing, shown in Table 5-13, includes 42 permits. Of these, the greatest number apply to coal mining and oil shale. The extensive regulation of these more disruptive technologies can be seen by the permit breakdown, according to resource area, provided in Table 5-14. As a reminder, it should be noted that all permits which may be required for a given project have been included. Up to one-third of the total of applicable permits may be eliminated for specific projects.

A subset of the permits, those which are most likely to have longer review times and greater application requirements, were judged to be "major" permits, and are shown in Table 5-15. This subset includes, in addition to major environmental permits, a number of state permits governing water appropriation and mining controls. The approvals judged to be major are also those for which the public notice requirements may lead to extended comment public hearing processes.

The minor permits are listed in Table 5-16. A variety of minor water permits are included, indicating one measure of the complex water control legislation in the state. A number of detailed mining permits are also shown.

TABLE 5-13

SUMMARY OF PERMITS REQUIRED BY THE STATE OF COLORADO

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Air Pollution Emission Permit	Air Pollution Control Division	5 CCR 1001-5 Reg. 3	Regulate emissions from new or modified sources	Applies to combustion, crushing, retorting, and other activities of energy projects	Description of process, control equipment, and anticipated emissions
Open Burning Permit	Air Pollution Control Division	5 CCR 1001-3 Reg. 1	To control all open burning	May apply to land clearing in energy projects	Quantity, type and location of debris burned
National Pollutant Discharge Elimination System (NPDES) Permit	Water Quality Control Division	5 CCR 1002-2	To control discharges to navigable waters	Any point source discharge into state waters	Location, quantity, and characteristics of discharges
Water Quality Certificate	Water Quality Control Division	Cr 5 25-8- 302(f)	To control water quality effects of dredge and fill operations	Any dredging in river beds or wetlands	Description of project and of dredging activities
Permits to Construct a Well and Appropriate Designated Groundwater (Conditional and Final)	Division of Water Resources	2 CCR 402-2	To control and protect water resources	For location of water wells	Legal information, local hydrological data, and water use rate
Application for Water Rights	District Water Court	CRS 1973, 37-92- 302 through 304	To adjudicate water rights	Any use or change of use of water	Source and use for which right is needed
Approval of Plans for Reservoir	Division of Water Resources	2 CCR 402-1	To provide for safe water use and conservation	For dam construction or modification	Geotechnical and hydrological reports

TABLE 5-13 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Permit to Construct/Relocate Exempt/Non-Exempt Well Outside Designated Basins	Division of Water Resources	2 CCR 402-2	To control use of tributary groundwater, protect existing water rights, and regulate drilling	For well construction or modification in areas controlled by Water Courts	Description of local hydrology, proposed use rate, and water rights
License for Water and Wastewater Treatment Operators	Water Quality Control Division	5 CCR 1003-2	To ensure adequate operation of water treatment equipment	For on-site water and wastewater treatment facilities	Experience in the field of water treatment
Site Approval of Sewage Collection and Treatment Facility	Water Quality Control Division	5 CCR 1003-1	To assure proper collection and treatment of sewage	May apply selectively to projects where sewage treatment is needed	Size and type of facility, location, ownership
Permit to Construct an Erosion Control Dam	Division of Water Resources	2 CCR 402-1	To regulate small dam construction on intermittent streams	May apply selectively to coal or oil shale operations	Description of topography, geology, and location of area
Permit for Bedrock Aquifer Well	Division of Water Resources	NA	To regulate use of non-tributary groundwater resources	May apply selectively to energy projects	Description of drilling and water use
Approval of Location and Construction of Water Works	Water Quality Control Division	5 CCR 1003-1	To regulate construction of water purification facilities	May apply selectively to energy projects where water treatment is needed	Design details for water treatment facility
Fish and Wildlife Collection Permit	Division of Wildlife	CCR 2.04.11	To control collection or testing of wildlife	May apply selectively to projects where baseline environmental data is needed	Description of mine site and copy of mine plan
Post Mining Review	Division of Wildlife	CCR 2.04.11	To assure adequacy of reclamation	Applies to coal mining activities; voluntary for other mining	Reclamation plan
Coal Mining and Reclamation Permit	Mined Land Reclamation Division	2 CCR 407-2 Rule 2	To regulate mining and reclamation activities	All mines which remove over 250 tons of coal per year	Baseline environmental data, operation and reclamation plan

TABLE 5-13 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Limited Impact Mining and Reclamation Permit	Mined Land Reclamation Division	2 CCR 407-1 Rule 3	To regulate mining and reclamation activities	Oil shale mining and reclamation on less than 10 acres or removing less than 70,000 tons of material per year	Mining and reclamation plans
Regular Mining and Reclamation Permit	Mined Land Reclamation Division	2 CCR 407-1 Rule 2	To regulate mining and reclamation activities	Oil shale mining and reclamation on more than 10 acres or removing more than 70,000 tons of material per year	Mining and reclamation plans
Special Mining and Reclamation Permit	Mined Land Reclamation Division	2 CCR 407-1 Rule 4	To regulate special mining activities	May apply to short duration projects or to oil shale projects	Mining and reclamation plans
Notice of Intent to Conduct Prospecting Operations	Mined Land Reclamation Division	2 CCR 407-1, Rule 5	To identify prospecting activities	Mineral prospecting	Location and method of prospecting
Notice of Intention to Explore	Mined Land Reclamation Division	2 CCR 407-2, Rule 4.21	To identify coal exploration activity	Coal exploration involving removal of more than 250 tons of coal	Description of exploration activities and reclamation plan
Exploration Permit	State Board of Land Commissioners	CRS 1973, 36-1-113 as amended	To regulate drilling and other exploration activities	Exploration for oil and gas and oil shale	Exploration and drilling plans
Coal Lease	State Board of Land Commissioners	CRS 1973, 36-1-113 as amended 36-1-139	To regulate coal mining on state lands	Applies to federal land developments if state and federal lands are interspersed	Land tract identification
Oil and Gas/Geothermal Lease	State Board of Land Commissioners	CRS 1973, 36-1-113, 115 as amended	To regulate oil, gas, geothermal development on state lands	Applies to federal land developments if state lands are interspersed	Land tract identification

TABLE 5-13 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Mining Leases and Permits	State Board of Land Commissioners	CRS 1973, 36-1-113, as amended	To regulate mining on state lands	Applies to oil shale developments if state and federal lands are interspersed	Land tract identification
Authorization of Unitization	State Board of Land Commissioners	CRS 1973, 36-1-113, 115, as amended	Permits oil and gas lessee to enter federal-type units for development	State mineral leases where developer does not own all necessary land	Approvals from state and USGS
Authorization of Communitization	State Board of Land Commissioners	CRS 1973, 36-1-113, 113 as amended	To communitize owners of energy rights to determine royalty payments	To all owners of oil and gas rights within one well space (160 acres oil, 40 acres gas)	Location of well, acreage of lease and acreage of other owners
Permit to Drill, Deepen, or Re-Enter and Operate an Oil and Gas Well/ Permit To Use an Earthen Pit	Oil and Gas Conservation Commission	2 CCR 404-1, (303, 315)	To regulate the location and conduct of oil and gas drilling	For oil and gas wells and for oilfield disposal areas	Operating plan and data on earthen pits
Permit to Drill, Deepen, or Re-Enter and Operate Geothermal Resources/ Permit To Use an Earthen Pit	Oil and Gas Conservation Commission	2 CCR 404-2	To regulate the location and conduct of geothermal drilling	For geothermal well and for disposal areas	Operating plan and data on disposal of liquid effluents
Rights-of-Way	State Board of Land Commissioners	CRS 1973, 36-1-136 as amended	To control uses of state lands	All public facilities including pipelines	Maps and legal description
Special Transport Permit	Department of Highways	2 CCR 601-4	For the movement of oversize or overweight vehicles on roads	May apply to energy and mineral developers	Data on routes, size and frequency of trips

TABLE 5-13 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Survey Permit	Department of Highways	CRS 1973, 42-4-701 highway system et. seq. as amended 42-4-910 as amended	To control access to highway system	May apply to energy and mineral developers	Location and time of work near or on highway
Access Permit	Department of Highways	2 CCR 601-1	To control access to highway system	May apply to energy and mineral developers	Location and type and volume of traffic created
Certificate of Public Convenience and Necessity	Public Utilities Commission	4 CCR 723-3,4	To represent the public interest in utility services	May apply to oilfield pipelines	Demonstration of need and description of the project
Underground and Utility Permit	Department of Highways	CRS 1973, 38-5-101	To regulate construction within a highway right-of-way	May apply to pipeline or project activities near highways	Description and location of activities
Cultural Resource Clearance	Colorado State Historical Society	CRS 1973, 24-80.1-101 through 108 and others	To protect cultural resources	All industrial activities	Detailed maps of project location
Hoistman Certificate	Division of Mines	2 CCR 403-1	To maintain worker safety	All mining activities; applies to lifts hoisted by workers	Doctor's examination of workers
Diesel Permit	Division of Mines	2 CCR 403-1	To regulate air quality in underground mines	All mining activities	Description of equipment uses
Application to Store, Use and Transport Explosives	Division of Mines	2 CCR 403-1, 403-2	To regulate use of explosives	May apply to energy projects	Quantity and use of explosives

TABLE 5-13 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Certification of Competency	Division of Mines	CRS 1973, 34-21-101 <u>et. seq.</u> , as amended	To maintain worker safety	All underground mining	Identity and experience of individual workers
Notice of Activity	Division of Mines	2 CCR 403-1, 403-2	To identify activities	Coal and oil shale operators employing less than 75 people	Notification of start-up
Certificate for Boilers	Division of Labor-Boiler Inspection Branch	CRS 1973, 9-4-101 <u>et. seq.</u> , as amended	To regulate boiler safety	Applies to boilers needed for energy projects	Notification of boiler start-up
Permit for Explosive Materials	Division of Labor-Public Safety Section	CRS 1973, 9-7-101 <u>et. seq.</u> , as amended	To regulate use of explosives	May apply to energy projects	Use of explosives, and description of previously-held permits

TABLE 5-14

APPLICABILITY OF COLORADO PERMITS BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Air Pollution Emission Permit	O	X	X	X
Open Burning Permit	X	O		O
Natural Pollutant Discharge Elimination System Permit	O	X	X	X
Water Quality Certificate		O	O	O
Permits to Construct a Well and Appropriate Designated Groundwater (Conditional and Final)	O	O	O	O
Application for Water Rights	O	O	O	O
Approval of Plans for Reservoir	O	O	O	O
Permit to Construct/ Relocate Exempt/Non-Exempt Well Outside Designated Basins	O	O	O	O
License for Water and Wastewater Treatment Operators	O	O	O	O
Site Approval of Sewage Collection and Treatment Facility	O	O	O	O
Permit to Construct an Erosion Control Dam		O		O
Permit for Bedrock Aquifer Well	O	O	O	O

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-14 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Approval of Location and Construction of Water Works		O	O	O
Fish and Wildlife Collection Permit		O	O	O
Post Mining Review		X		X
Coal Mining and Reclamation Review		X		
Limited Impact Mining and Reclamation Permit				X
Regular Mining and Reclamation Permit				X
Special Mining and Reclamation Permit				O
Notice of Intent to Conduct Prospecting Operations				X
Notice of Intention to Explore		X		
Exploration Permit	X			X
Coal Lease		O		
Oil and Gas/Geothermal Lease	O		O	
Mining Leases and Permits				O
Authorization of Unitization	O			
Authorization of Communitization	O		O	

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-14 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Permit to Drill, Deepen, or Re-Enter and Operate an Oil and Gas Well/Permit to Use an Earthen Pit	X			
Permit to Drill, Deepen, or Re-Enter and Operate Geothermal Resources/ Permit to Use an Earthen Pit			X	
Rights-of-Way	O	O	O	O
Special Transport Permit	O	O	O	O
Survey Permit	O	O	O	O
Access Permit	O	O	O	O
Certificate of Public Convenience and Necessity	O			
Underground and Utility Permit	O	O	O	O
Cultural Resource Clearance	X	X	X	X
Hoistman Certificate		X		X
Diesel Permit		X		X
Application to Store, Use and Transport Explosives	O	O	O	O
Certification of Competency		X		X
Notice of Activity		O		O
Certificate for Boilers	O	O	O	O
Permit for Explosive Material	O	O	O	O

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-15

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF COLORADO

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Air Pollution Emission Permit	Air Pollution Control Division	Description of process, control equipment, and anticipated emissions	20 days	120 days	Yes	\$40 plus \$40/hr for processing
National Pollutant Discharge Elimination System (NPDES) Permit	Water Quality Control Division	Location, quantity and characteristics of discharges	Not specified	180 days (est.)	Yes	None
Permits to Construct a Well and Appropriate Designated Groundwater (Conditional and Final)	Division of Water Resources	Legal information, local hydrological data and water use rate	Not specified	1 month to 2 years (est.)	Yes	NA
Application for Water Rights	District Water Court	Facts concerning source and use applied for	Not specified	5 months to 1 year	Yes	\$25
Approval of Plans for Reservoir	Division of Water Resources	Geotechnical and hydrological technical reports	Not specified	90 days (est.)	No	NA
Permit to Construct/Relocate Exempt/Non-Exempt Well Outside Designated Basins	Division of Water Resources	Description of local hydrology, proposed use rate and water rights	30 days	60 days	No	\$25 (to construct) \$10 (to relocate)
Coal Mining and Reclamation Permit	Mined Land Reclamation Division	Operation and reclamation plans	10 days	4-6 months	Yes	\$25 plus \$10/acre

TABLE 5-15 (Cont.)

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Limited Impact Mining and Reclamation Permit	Mined Land Reclamation Division	Mining and reclamation plans	10 days	40 days	Yes	\$25 plus \$10/acre
Regular Mining and Reclamation Permit	Mined Land Reclamation Division	Mining and reclamation plans	10 days	3-4 months	Yes	\$50 plus \$15/acre
Special Mining and Reclamation Permit	Mined Land Reclamation Division	Mining and reclamation plans	3 days	10 days	Yes	\$200 plus \$15/acre plus \$2500 bond
5-69 Notice of Intention to Explore	Mined Land Reclamation Division	Location and description of exploration and reclamation activities	Not specified	2 weeks-2 months	Yes	None

TABLE 5-16

SUMMARY OF TIME REQUIREMENTS FOR MINOR PERMITS, STATE OF COLORADO

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Open Burning Permit	Air Pollution Control Division	Quantity, type and location of debris burned	Not specified	1 week	No	None	Concurrence of local fire marshal may be needed
License for Water and Wastewater Treatment Operators	Water Quality Control Division	Experience in the field of water and wastewater treatment	NA	NA	NA	NA	
Site Approval of Sewage Collection and Treatment Facility	Water Quality Control Division	Size and type of facility, location, ownership	Not specified	30-90 days	No	NA	
5-70 Permit to Construct an Erosion Control Dam	Division of Water Resources	Topological and geological information	Not specified	1-2 weeks	No	\$1	
Permit for Bedrock Aquifer Well	Division of Water Resources	Description of drilling and water use	Not specified	NA	NA	NA	
Approval of Location and Construction of Water Works	Water Quality Control Division	Design details for water treatment facility	NA	NA	NA	NA	
Water Quality Certificate	Water Quality Control Division	Description of project and of dredging activities	Not specified	6-8 weeks	NA	NA	
Fish and Wildlife Collection Permit	Division of Wildlife	Location of mine and copy of mine plan	Not specified	20 days	No	None	
Notice of Intent to Conduct Prospecting Operations	Mined Land Reclamation Division	Location and method of prospecting	Not specified	Automatic approval	No	None	Approval of permit is automatic if completed properly

TABLE 5-16 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Exploration Permit	State Board of Land Commissioners	Exploration and drilling plans	Not specified	2 weeks	NA	None	
Coal Lease	State Board of Land Commissioners	Land tract identification	Not specified	6 weeks	No	Bond \$12.75/1st 160 acres \$1.50/160 acres thereafter	
Oil and Gas/ Geothermal Lease	State Board of Land Commissioners	Land tract identification	Not specified	6 - 12 weeks	No	Bond \$12.75/1st 160 acres \$1.50/160 acres thereafter	
5-71 Mining Leases and Permits	State Board of Land Commissioners	Land tract identification	Not specified	2 - 6 months	Yes	Bond \$12.75/1st 160 acres \$1.50/160 acres thereafter	
Authorization of Unitization	State Board of Land Commissioners	Approvals from state and USGS	Not specified	NA	NA	None	
Authorization of Communi- tization	State Board of Land Commissioners	Location of well, acreage of lease and acreage of other owners	Not specified	NA	NA	None	
Permit to Drill, Deepen or Re-Enter and Operate an Oil and Gas Well/ Permit to Use an Earthen Pit	Oil and Gas Conservation Commission	Operating plan and data on earthen pit	Not specified	3 - 30 days (est.)	No	Fee and bond de- pendent on activity	

TABLE 5-16 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Permit to Drill, Deepen or Re-Enter and Operate Geothermal Resources/ Permit to Use Earthen Pit	Oil and Gas Conservation Commission	Operating plan and date on disposal of liquid effluents	Not specified	30 days (est.)	No	Fee and bond dependent on activity	
Rights-of-Way	State Board of Land Commissioners	Maps and Legal description	1 week	2 - 4 months	Yes	\$75 + \$10 document fee	
Special Transport Permit	Department of Highways	Data on routes, size and frequency of trips	Not specified	1 week (est.)	No	\$5	
Survey Permit	Department of Highways	Location and time of work near or on highway system	Not specified	1 day	No	None	
Access Permit	Department of Highways	Location and type and volume of traffic	Not specified	45 days (est.)	No	None	
Certificate of Public Convenience and Necessity	Public Utilities Commission	Demonstration of need and project description	Not specified	3 - 4 months	Yes	None	
Underground and Utility Permit	Department of Highways	Description and location of activities	Not specified	10 days (est.)	No	None	
Cultural Resource Clearance	Colorado State Historical Society	Detailed maps of project location	Not specified	2 months	No	\$5/township for file search	

TABLE 5-16 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Hoistman Certificate	Division of Mines	Doctor's Examination of workers	Not specified	NA	No	None	
Diesel Permit	Division of Mines	Description of equipment used	Not specified	1 week	No	None	
Application to Store, Use and Transport Explosives	Division of Mines	Quantity and use of explosives	Not specified	1 - 3 weeks	No	None	
Certification of Competency	Division of Mines	Identity and experience of individual workers	Not specified	NA	No	None	
Notice of Activity	Division of Mines	Notification of start-up	Not specified	NA	No	None	Purpose of notice is to inform DOM to provide proper assistance
Certificate for Boilers	Division of Labor	Notification of boiler start-up	Not specified	2 weeks	No	\$15	
Permit for Explosive Materials	Division of Labor	Use of explosives and description of previously held permits	Not specified	3 - 5 days	No	\$10	
Post Mining Review	Division of Wildlife	Reclamation plan	Not specified	60 days	No	NA	

5.6 Permitting Processes in Montana

Montana is similar to other Western states in that major regulatory efforts have been made to control energy development activities. The state has developed its own environmental review requirements and facility siting processes.

Montana has adopted several pieces of legislation which significantly influence the permitting processes. The Montana Environmental Policy Act (MEPA) requires that state agencies prepare an Environmental Impact Report (EIR) for energy development activities with significant environmental impacts. Equally important is the Montana Major Facilities Siting Act. This law requires that certain kinds of generating, converting or transporting facilities obtain a Certificate of Environmental Compatibility and Public Need. This certificate is based on recommendations from the Department of Health and Environmental Sciences, the Department of Natural Resources and Conservation, and public hearings.

The state has assumed responsibility for all environmental programs with the exception of permitting for hazardous waste, Prevention of Significant Deterioration (PSD) and Underground Injection Control, which are controlled by the EPA. Permitting authority for the hazardous waste and PSD programs is in the process of being transferred to state agencies.

All four of the energy resource areas are found in Montana. Substantial development has occurred in the coal, oil, and gas areas while little has been done with geothermal and oil shale resources. Most of the state's developable resources are in the northern and eastern portions of the state.

5.6.1 Responsibilities of Principal State Agencies

The executive branch of the Montana government consists of 15 departments or boards which report to the Governor. Figure 5-5 depicts the agencies which are involved in the permitting process. The environmental bureaus are within the Department of Health and Environmental Sciences. Several energy-related divisions are within the Department of Natural Resources and Conservation.

The authority and role of agencies involved in the permitting of energy development activities are summarized below.

Department of Natural Resources and Conservation - Responsible for protecting Montana's quality of life by executing its laws relating to the state's land, water, forest, and energy resources; inclusive in this is the siting of major energy facilities, regulating drilling and recovery of oil and gas resources, and administering water rights.

Department of State Lands - Under the direction of the Board of Land Commissioners, the DSL is responsible for managing state lands and for administering Montana's mining statutes; inclusive in this is the leasing of state lands, regulating of all minerals (except oil and gas), and overseeing all mining reclamation activities.

Department of Health and Environmental Sciences - Responsible for controlling air pollution, water pollution, solid waste, and hazardous waste; also responsible for food and consumer safety and occupational health.

Department of Fish, Wildlife and Parks - Responsible for managing the state's wildlife, state recreation lands and other types of state parks; inclusive in this is coordination with the DSL's permitting process during the environmental review phase to ensure protection of lands.

Department of Highways - Responsible for regulating development activities affecting the state highway

Figure 5-5. Organization of Montana State Government (Some offices are not shown in order to simplify the presentation).

system; inclusive in this is controlling access to highways and right-of-ways.

State Historical Society - Responsible for ensuring the preservation of Montana's historical and cultural sites.

5.6.2 Permits Required by the State of Montana

A diverse group of permits was identified for Montana regulatory agencies. The permit survey is presented in this section.

Any of nearly 30 permits may be required for a given energy project in Montana. The summary listing of Montana permits is shown in Table 5-17. Montana has no unusual permit requirements; a normal complement of environmental permits and operating plan approvals must be complied with.

A majority of the Montana permits could apply to coal mine projects, as shown by the analysis of permit applicability in Table 5-18. As for other states, permits have been identified as applicable if there is a chance they could apply to various projects.

Among the major permits in Montana, review times appear to be fairly short in most cases. The major permit review times are given in Table 5-19. Exceptions however exist in the case of mine operating permits, which may require a year of review and processing, and in the case of the Certificate of Environmental Compatibility and Public Need. The latter is the major state environmental permit. Review times were

estimated to run to 22 months, including the time needed for the public comment period and public hearings.

The minor permit data for Montana are summarized in Table 5-20. Most of the review periods are brief with the exception of the legal proceedings which could occur for acquiring needed rights-of-way.

TABLE 5-17

SUMMARY OF PERMITS REQUIRED BY THE STATE OF MONTANA

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Air Pollutant Discharge Permit	Department of Health and Environmental Sciences (DHES) Air Quality Bureau	Administrative Rules of Montana (ARM), 16.8.1101 <u>et seq.</u> 16.2.14(1)-S1400	Control air pollution	For new facilities which emit pollutants	Details of process, control equipment, and fuels
Water Pollutant Discharge Permit (MPDES)	DHES; Water Quality Bureau	16.20.633 16.20.901 <u>et seq.</u>	Control water pollution	For all discharges into state waters and disposal systems	Source location, quantity, and type of discharge
3A Authorization	DHES; Water Quality Bureau	ARM, 16.20.633(3)	Control water pollution due to temporary activities	For short-term construction or hydraulic projects which may have short-term water quality impacts	Source location, project description, type of discharge, and mitigating measures
Water Use Permit	Department of Natural Resources and Conservation (DNRC); Water Rights Bureau	ARM, 36.12.101-105; 36.2.14J(1)	Control appropriation of water	For surface groundwater of diversions more than 100 gmp	Facility description, location, quantity, and type of use
Interim Water Use Permit	DNRC; Water Rights Bureau	ARM, 36.2.14J(1)-S1400 <u>et seq.</u> ; 36.2.8(1)-S800 <u>et seq.</u>	Control water use during test drilling	For exploratory geothermal well testing	Drilling plans and long-range plan
Solid Waste Disposal License	DHES; Water Rights Bureau	ARM, 36.2.14J(1)-S1400 <u>et seq.</u> ; 36.2.8(1)-S800 <u>et seq.</u>	Control solid waste disposal	For Class II and III solid wastes	Detailed operation plan for facility
Stream Alteration Approval	Department of Fish, Wildlife, and Parks (DFWP), Conservation District	NA	Protect natural habitats	For activities affecting streams	Description of activities affecting the stream
Geothermal Land Lease	Department of State Lands (DSL) Centralized Services Division	ARM, 26.3.401 <u>et seq.</u>	Control of state lands	May apply to activities on federal lands if there are interspersed state lands	Land characteristics and proposed activities

TABLE 5-17 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Coal Land Lease	DSL; Centralized Services Division	ARM, 26.3.301 <u>et seq.</u>	Control of state lands	May apply to activities on federal lands if there are interspersed state lands	Land characteristics and proposed activities
Oil and Gas Land Lease	DSL; Centralized Services Division	ARM, 26.3.205	Control of state lands	May apply to activities on federal lands if there are interspersed state lands	Land characteristics and proposed activities
Operating Permit (Coal)	DSL; Reclamation Division	ARM, 24.30.1302 26.4.301-912	Control mining activities and ensure reclamation	For all coal mine operations	Complete description of operations with certificate of insurance
Operating Permit (Oil Shale)	DSL; Reclamation Division	ARM, 26.4.107, 1101-1120	Control of mining activities and ensure reclamation	For oil shale operations	Reclamation plan mining plan, detailed map of the area, and surety bond
Mine Site Location Permit	DSL; Reclamation Division	ARM, 26.4.1101-1129	Control siting of mines to ensure preservation of lands	Commencement of facility construction prior to obtaining an Operating Permit for mining of coal	Reclamation plan and bond
Land Use Permit (Combines Floodplain Permit, Stream Alteration Permit, Lake Alteration Permit)	DNRC (administered on county level)	ARM, 36.214B(1)-S1400	Control development on floodplains and protect lakes and streams	For activities on floodplains or which impact lakes or streams	Location and description of activities
Permit for Geophysical Exploration	County Clerk and Recorder	ARM, 36.3.18(18)-S10620 <u>et seq.</u>	Control use of seismographs and explosives during exploration	Oil, gas, and geothermal exploration	Notice of intent and surety bond
Plan of Operations	DSL; Lands Division	ARM, 26.2.6(2)-S60120	Maintain orderly exploration	For geothermal exploration	Plan of operations and bond

TABLE 5-17 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Notice of Intent to Drill	DNRC; Oil and Gas Conservation Division	ARM, 36.22.601 <u>et seq.</u>	Control exploration and drilling	For oil and gas operations	Plan of operations and bond
Prospecting Permit	DSL; Reclamation Division	ARM, 26.4.1001-1015, 1101-1125	Control of prospecting activities	For coal prospecting on lands not included in a current operating permit	Description of activities, map, reclamation plan, and bond
Exploration Permit	DSL; Reclamation Division	ARM, 26.4.101 <u>et seq.</u>	Control of exploration activities	For oil shale exploration	Plan of activities, map of area, and bond
Slash Disposal Agreement	DSL; Forestry Division	ARM, 26.6.501-503	Control use of forest areas	For tree cutting activities	Fire hazard reduction agreements and bond
Land Easement	DSL	NA	Control development of state lands	Construction of pipelines and transmission lines	Extensive information on land required
Complaint for Condemnation	District Court	NA	Obtain easement by use of "eminent domain"	Facilities needing right-of-way over adjacent privately owned land	Project description, public use justification, and present ownership
Special Fuels Permit	Department of Revenue; Motor Fuels Division	ARM, 42.28.301,901	Control use of non-gasoline fuels on state highway	For operation of non-gasoline vehicles	Description of activities, bond and special fuels license
Encroachment/Approach Permit	Department of Highways (DOH)	ARM, 18.5.104 <u>et seq.</u> 18.7.101-108	Maintenance of state highway system	May apply to pipelines or access road developments near highways	Construction plans for highway areas
Right-of-Way Easement	DOH	ARM, 18.2.6A1(6)-S6080	Maintenance of state highway system	Construction of utility lines in highway rights-of-way	Notice of proposed right-of-way occupancy, plans, and location
Antiquity Site Permit	State Historical Society	NA	Preserve historic sites	For excavation on registered antiquity sites	Description of adverse impacts on site
Certificate of Environmental Compatibility and Public Need	DNRC; Facility Siting Division; DHES	ARM, 36.7.1201 <u>et seq.</u>	Ensure environmental compatibility	For major energy facilities	Long range plan with project description

TABLE 5-18

APPLICABILITY OF MONTANA PERMITS BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Air Pollutant Discharge Permit	O	X	X	X
Water Pollutant Discharge Permit	O	X	X	X
3A Authorization	O		O	
Water Use Permit	O	O	O	O
Interim Water Use Permit			X	
Solid Waste Disposal License	O	O	O	O
Stream Alteration Approval	O	O	O	O
Geothermal Land Lease			O	
Coal Land Lease		O		
Oil and Gas Land Lease	O			
Operating Permit (Coal)		X		
Operating Permit (Oil Shale)				X
Mine Site Location Permit		X		X
Land Use Permit	O	O	O	O
Permit for Geophysical Exploration	X		X	O

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-18 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Plan of Operations			X	
Notice of Intent to Drill	X		X	
Prospecting Permit		O		O
Exploration Permit				X
Slash Disposal Agreement	O	O	O	O
Land Easement	O	O	O	O
Complaint for Condemnation	O	O	O	O
Special Fuels Permit				O
Encroachment/ Approach Permit	O	O	O	O
Right-of-Way Easement	O	O	O	O
Antiquity Site Permit	O	O	O	O
Certificate of Environmental Compatibility and Public Need			O	O

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-19

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF MONTANA

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Air Pollutant Discharge Permit	DHES	Details of process, control equipment, and fuels	30 days	2-6 months (est.)	Yes	None
Water Pollutant Discharge Permit (MPDES)	DHES	Source, location, quantity, and type of discharge	Not specified	6 months	Yes	None
Water Use Permit	DNRC; Water Rights Bureau	Facility description, location, quantity, and type of use	30 days (est.)	180-270 days (est.)	Yes	Based on project size
Solid Waste Disposal License	DHES	Detailed operation plan for facility	Not specified	60 days (est.)	Yes	None
Operating Permit (Coal)	DSL; Reclamation Division	Complete description of operations with certificate of insurance	120 days	120-240 days	Yes	\$50
Operating Permit (Oil Shale)	DSL; Reclamation Division	Reclamation plan, mining plan, map of area, and surety bond	30 days	30 days to 1 year (est.)	Yes	\$25
Mine Site Location Permit	DSL; Reclamation Division	Reclamation plan and bond		1 year (est.)	No	\$50
Certificate of Environmental Compatibility and Public Need	DNRC; Facility Siting Division; DHES	Project description and long-range plan	90 days	22 months	Yes	Based on project size

TABLE 5-19

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF MONTANA

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Air Pollutant Discharge Permit	DHES	Details of process, control equipment, and fuels	30 days	2-6 months (est.)	Yes	None
Water Pollutant Discharge Permit (MPDES)	DHES	Source, location, quantity, and type of discharge	Not specified	6 months	Yes	None
Water Use Permit	DNRC; Water Rights Bureau	Facility description, location, quantity, and type of use	30 days (est.)	180-270 days (est.)	Yes	Based on project size
Solid Waste Disposal License	DHES	Detailed operation plan for facility	Not specified	60 days (est.)	Yes	None
Operating Permit (Coal)	DSL; Reclamation Division	Complete description of operations with certificate of insurance	120 days	120-240 days	Yes	\$50
Operating Permit (Oil Shale)	DSL; Reclamation Division	Reclamation plan, mining plan, map of area, and surety bond	30 days	30 days to 1 year (est.)	Yes	\$25
Mine Site Location Permit	DSL; Reclamation Division	Reclamation plan and bond		1 year (est.)	No	\$50
Certificate of Environmental Compatibility and Public Need	DNRC; Facility Siting Division; DHES	Project description and long-range plan	90 days	22 months	Yes	Based on project size

TABLE 5-20

SUMMARY OF TIME REQUIREMENTS FOR MINOR PERMITS, STATE OF MONTANA

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
3A Authorization	DHES; Water Quality Bureau	Source location, project description, type of discharge, and mitigating measures	Not specified	1-5 days (est.)	No	None	Review time typically very short
Interim Water Use Permit	DNRC; Water Rights Bureau	Drilling plans and long-range plans	Immediate	2-4 months	No	Based on formula	
Stream Alteration Approval	DFWP; Conservation District	Description of activities affecting the stream and preliminary plans	5 days	60 days	No	None	
Geothermal Land Lease	DSL; Centralized Services Division	Land characteristics and proposed activities	Not specified	6 months (est.)	Yes	\$10	
Coal Land Lease	DSL; Centralized Services Division	Land characteristics and proposed activities	Not specified	6 months (est.)	Yes	\$10	
Oil and Gas Land Lease	DSL; Centralized Services Division	Land characteristics and proposed activities	Not specified	1 month (est.)	Yes	\$10	
Land Use Permit	DNRC	Location and description of activities	Not specified	to 90 days (est.)	No	\$10	Administered on county level
Permit for Geophysical Exploration	County Clerk and Recorder	Notice of intent and surety bond	Not applicable	Not applicable	No	\$10	
Plan of Operations	DSL; Lands Division	Description of project, map of activities and bond	Not applicable	Not applicable	No	\$10	

5.7 Permitting Processes in New Mexico

Energy resource development within the state of New Mexico is licensed by state agencies with interests in the protection of the environment, the fair appropriation and beneficial use of water, human health and safety, and efficient development of extractive resources. Four specific areas where state regulation is particularly notable are water quality control, air quality control, water appropriation and land use permitting.

New Mexico does not have federally approved water or air pollution control programs. The state does, however, engage in permitting activities in each of these areas. The New Mexico Water Quality Act and the Air Quality Control Act form the legislative basis for such state regulations.

New Mexico has entered into an interim cooperative agreement with the federal Office of Surface Mining and regulates all coal mining in the state. The statutory basis for this regulation is the New Mexico Surface Mining Act.

New Mexico's resource base includes coal, oil, and gas, and geothermal energy sources. No oil shale deposits exist in the state.

5.7.1 Responsibilities of Principal State Agencies

In 1977 the New Mexico Legislature passed the Executive Reorganization Act, which provided the framework for the reorganization of the executive branch into 12 Cabinet-level departments. Three departments play principal roles in the promulgation and administration of regulations affecting

natural resource development in the state: the Natural Resources Department, Energy and Minerals Department, and Health and Environment Department. The state government organization is given in Figure 5-6.

New Mexico Natural Resources Department - Charged with providing and coordinating services necessary to protect the renewable resources of the State. (New Mexico's extractive resources come under the purview of the Energy and Minerals Department.)

The most relevant organ of the Natural Resources Department is the Water Rights Bureau of the Water Resources Division. This bureau issues permits for the appropriation of surface and ground water in the state - a potentially major requirement for many development activities. The bureau also administers other permits relating to well drilling, well hole plugging and mine dewatering.

A second relevant organ of the Natural Resources Department is the Game and Fish Department, a department which is relatively autonomous, having only administrative ties with Natural Resources. While the Game and Fish Department has no direct permitting authority it provides advisory support to other state agencies' energy resource development regulation.

New Mexico's Energy and Minerals Department - Major responsibilities in the regulation of energy resource development regulations that encompass the protection of correlative rights, health or safety concerns, protection of the environment and resource production methods.

The Mining and Minerals Division of the Energy Minerals Department administers a number of major permits that relate to coal resource development. Potential coal resource developers must have an exploration plan approved by the Surface Mining Bureau (for both surface and underground mining) of the Mining and Minerals Division. A Coal Surface Mining Permit, also issued by the Bureau, is requisite for production activities.

Figure 5-6. New Mexico State Government Organization (Some offices have not been shown in order to simplify the presentation).

The Oil Conservation Division, also within this department, is the primary regulator of oil and gas development within the state. The division oversees all such resource development activities on state lands, and has been delegated the authority to regulate the liquid and solid waste streams of oil and gas producers on all lands within the state.

Health and Environment Department - Primary responsibility for administering the state's environmental quality control programs. The division has, however, delegated water quality and solid and hazardous waste regulation of energy resource developers to the appropriate agencies within the Energy and Minerals Department. The division maintains its air quality regulatory authority.

5.7.2 Permits Required by the State of New Mexico

The permits required by New Mexico authorities have been compiled, and are displayed in the tabular formats developed for the state permit surveys.

The summary listing for New Mexico shows 25 permits, approximately one-half of which involve water-related issues. These permits are listed in Table 5-21. Many of the arid Western states, such as New Mexico, are obviously quite concerned with the control and protection of water resources. Non-water permitting in New Mexico is similar to that of most states with a complement of air, land use and mining permit requirements.

The applicability of the permits to each resource type is described in Table 5-22. The water permits can apply to a variety of energy extraction processes.

Ten of the New Mexico permits were judged to be major. The average estimated permit review times for these permits, along with basic descriptive information, is shown in Table 5-23. The principal air pollution and coal mining permits along with seven types of water permits are included in this group. Review times were estimated to be fairly short in most cases, with the exception of the coal surface mining permit. This permit, based on the New Mexico state regulations, can require 2 to 3 years for approval.

Among the water appropriation permits, review times are subject to considerable variability, but can be quite lengthy. Applications for several types of water permits frequently lead to lengthy disputes and court proceedings. Resolution of such disputes may require up to 2 years for settlement. Any resource development project with a substantial water requirement would probably be subject to a delay of a similar magnitude.

A number of minor permits, mostly involving water use and mining practices, are also administered by the state. These permits are listed in Table 5-24. Permit review times are generally short, although data on review times is not complete.

Solid and hazardous waste facility permits were not included for New Mexico because separate permits would not be issued to energy developers. Responsibility for regulation of waste disposal from energy activities is accorded to the agencies with primary regulatory control of those activities. Thus waste disposal from oil and gas operations is regulated by the Oil Conservation Division, and waste from coal mining activities by the Energy and Minerals Department.

TABLE 5-21

SUMMARY OF PERMITS REQUIRED BY THE STATE OF NEW MEXICO

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Air Quality Construction Permit	Air Quality Bureau, Environmental Improvement Division, Health and Environment Department	Air Quality Control Regulation 702, Permits	Air pollution control	Construction of modification of a source of air contaminants	Process description
Authorization to Inject	Oil Conservation Division, Energy and Minerals Department	Oil Conservation Division, Rules and Regulations (Oil and Gas)	To prevent water pollution and protect correlative rights	Injection of fluids by oil and gas producers	Well and process description, name of surface owner and nearby operators
Authority to Place Well in Injection-Geothermal Resources Area	Oil Conservation Division, Energy and Minerals Department	Oil Conservation Division, Rules and Regulations (Geothermal)	To prevent water pollution, assure efficient resource development and protect correlative rights	Injection of fluids into a geothermal reservoir or disposal of geothermal waters	Well and process description, name of surface owner and nearby operators
Effluent Discharge Plan Approval	Oil Conservation Division, Energy and Minerals Department	Water Quality Control Commission Regulations	Pollution control in underground water supplies	Oil, gas and geothermal resource developers discharging liquid wastes	Detailed description of effluent disposal process
Permit to Appropriate and Use Underground Waters	Water Resources Division, Natural Resources Department	Rules and Regulations governing drilling of wells, and appropriation and use of groundwater in New Mexico	To protect existing water rights and assure beneficial use of public water	Drilling of water wells	Description and location of well, use of the water, and the quantity of water appropriated

TABLE 5-21 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Permit to Appropriate and Use Surface Water	Water Resources Division, Natural Resources Department	Rules and Regulations governing the appropriation and use of surface waters of New Mexico	To protect existing water rights and assure beneficial use of public water	Construction of works for the appropriation and use of surface water	Description of works, location of point of diversion and quantity and period of water use
Certificate and License to Appropriate (groundwater)	Water Resources Division, Natural Resources Department	Rules and Regulations governing drilling of wells and appropriation and use of groundwater in New Mexico	To protect existing water rights and assure beneficial use of public water	Commencement of appropriation and use of ground water	"Final Inspection and Report" and "Proof of Completion of Well" submitted (description of well as it exists and actual use of water)
Certificate of Construction (Surface Water)	Water Resources Division, Natural Resources Department	Rules and Regulations governing the appropriation and use of the surface waters of New Mexico	To assure that works completed as specified in plans	Construction of works to appropriate surface	Submission of form "Proof of Completion of Works" (description of works as completed)
License to Appropriate (Surface Water)	Water Resources Division, Natural Resources Department	Rules and Regulations governing the appropriation and use of the surface waters of New Mexico	To assure that water is put to beneficial use and define the conditions and extent of use	Commencement of appropriation and use of surface water	Submission of form "Proof of Application of water Beneficial Use" (details the quantity and use of water appropriated)
Permit to Change Location of Well and Place or Purpose of Use of Underground Waters	Water Resources Division, Natural Resources Department	Rules and Regulations governing the drilling of wells and appropriation and use of groundwater in New Mexico	To protect existing water rights and assure beneficial use of public water	Applies when uses water originally appropriated for another purpose and/or at another location	Description of changes
Permit to Change Point of Diversion and Place and/or Purpose of Use of Surface Waters	Water Resources Division, Natural Resources Department	Rules and Regulations governing the drilling of wells and appropriation and use of groundwater in New Mexico	To protect existing water rights and assure beneficial use of public water	Applies when water originally appropriated for another purpose and/or at another location	Description of changes
Water Well Drillers License	Water Resources Division, Natural Resources Department	Rules and Regulations governing the drilling of wells and appropriation and use of groundwater in New Mexico	To regulate the drilling of water wells within underground water basins	Water well drilling within any of the underground water basins in New Mexico	Type of wells to be drilled, applicants qualifications and references

TABLE 5-21 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Mine Dewatering Permit	Water Resources Division, Natural Resources Department	<u>Rules and Regulations</u> governing the drilling of wells and appropriation and use of groundwater in New Mexico	To protect existing water rights while promoting development	Mine dewatering and water disposal (within the boundaries of a declared underground water basin)	Mine dewatering plan and assessment of impact on existing water rights
Water Supply Construction Permit	Water Supply Section, Environmental Improvement Division, Health and Environment Department	Regulations governing water supplies, Section 103	To prevent faulty construction of water supply facilities	Construction or modification of storage, treatment or production facilities	Plans and specifications prepared by professional engineer
Approval of Drill Hole Plugging	Water Resources Division, Natural Resources Department	<u>Rules and Regulations</u> governing the drilling of wells and the appropriation and use of groundwater in New Mexico	To assure that water encountered during drilling is confined to the aquifer in which it was encountered	Applies to mining activities encountering a water body or water-bearing strata	Location and depth of hole; method and material used to plug hole
Exploration Plan Approval	Mining and Minerals Division, Energy and Minerals Department	Coal Surface Mining Commission, Rule 80-1, Part 6	Environmentally sound exploration activities	Coal exploration activity	Description of mining and reclamation methods, method of compliance with environmental regulations
Coal Surface Mining Permit	Mining and Minerals Division, Energy and Minerals Department	Coal Surface Mining Commission, Rule 80-1	To protect the environment during mining activities	All surface and underground coal mining	Mining and reclamation plan, ecological information
Annual Mine Registration	State Mine Inspector	New Mexico Statutes Annotated 69-11-1 and 69-11-2	To inform Inspector of continuation of mining activities	All coal mines	Operation information

TABLE 5-21 (Cont.)

PERMIT	GOVERNMENT AGENCY	REGULATORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
State Trust Land Lease	State Land Office	<u>Rules and Regulations</u> concerning the sale, lease, and other dispositions of State Trust Land	Regulate leasing and protect natural resources	May apply to activities on federal lands if state lands are interspersed	Location of tract and proposed development activity
Utility Permit	Highway Department, District Office	New Mexico Statutes Annotated 55-7-19 and 55-2-7	Maintain quality of state highway	Activities enroaching on state highways	Description and locations of the activity
License to Operate a Pipeline	Corporation Commission, Pipelines Department	<u>Rules and Regulations</u> concerning the licensing and regulation of pipelines	Oil and gas pipeline safety	Applies to operators of oil and gas pipelines (inter- and intra-state)	Construction and operation specifications
5-195 Permit for Archaeological Survey and Excavation Easements	State Land Office	Regulations Pertaining to the Preservation and Maintenance of Registered Cultural Properties and Objects of Antiquity or General Scientific Interests	To preserve and maintain property and artifacts of significance	May apply to activities on federal land, if state lands are interspersed	Construction and operation specifications
Certificate of Compliance and Authority to Transport Oil and Gas	Oil Conservation Division, Energy and Minerals Department	Oil Conservation Division, Rules and Regulations (Oil and Gas)	To monitor oil and gas activities	To oil and gas operators	Proof of other permits obtained
Rights-of-Way for State Lands	State Land Office	<u>Rules and Regulations</u> concerning the sale, lease, and other disposition of state trust lands	To regulate access to and use of state trust lands	May apply to activities on federal lands if state lands are interspersed	Location and map of tract, proposed use
Groundwater Discharge Plan	Water Pollution Control Bureau, Health & Environment Dept.	Water Quality Control Commission regulations	To prevent water pollution	Applies to activities discharging contaminants to groundwater	Flow characteristics, location, sampling methods

TABLE 5-22

APPLICABILITY OF NEW MEXICO PERMITS BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALES ^a
Air Quality Construction Permit	X	X	X	
Authorization to Inject	X			
Authority to Place Well in Injection-Geothermal Resources Area			X	
Effluent Discharge Plan Approval	O		X	
Permit to Appropriate and Use Underground Waters of the State of New Mexico	O	O	O	
Permit to Appropriate and Use Surface Water	O	O	O	
Certificate and License to Appropriate (groundwater)	O	O	O	
Certificate of Construction	O	O	O	
License to Appropriate (surface water)	O	O	O	
Permit to Change Location of Well and Place or Purpose of Underground Waters	O	O	O	
Permit to Change Point of Diversion and Place and/or Purpose of Use of Surface Waters	O	O	O	

^aNot applicable in New Mexico.

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-22 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE ^a
Water Well Drillers License	O	O	O	
Mine Dewatering Permit		O		
Water Supply Construction Permit	O	O	O	
Approval of Drill Hole Plugging	O	O	O	
Exploration Plan Approval		X		
Coal Surface Mining Permit		X		
Annual Mine Registration		X		
State Trust Land Lease	O	O	O	
Utility Permit	O	O	O	
License to Operate a Pipeline	O			
Permit for Archaeological Survey and Exploration Easements	O	O	O	
Certificate of Compliance and Authority to Transport Oil and Gas	X			
Rights-of-Way for State Lands	O	O	O	
Groundwater Discharge Plan		X		

^aNot applicable in New Mexico.

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-23

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF NEW MEXICO

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Air Quality Construction Permit	Air Quality Bureau, Environmental Improvement Division, Health and Environment Department	Process description	15 days	30-120 days (est.)	Yes	None
Authorization to Inject	Oil Conservation Division, Energy and Minerals Department	Well and process description, name of surface owner and nearby operators	Not specified	15-60 days (est.)	Yes	None
5-98 Authorization to Place Well on Injection-Geothermal Resources Area	Oil Conservation Division, Energy and Minerals Department	Well and process description, name of surface owner and nearby operators	Not specified	15-60 days (est.)	Yes	None
Effluent Discharge Plan Approval	Oil Conservation Division, Energy and Minerals Department	Detailed description of effluent disposal process	30-60 days (est.)	60-120 days (est.)	Yes	None
Permit to Appropriate and Use Underground Waters	Water Resources Division, Natural Resources Department	Description and location of well, use of water and quantity appropriated	Not specified	2 months - 2 years (est.)	Yes	None
Groundwater Discharge Plan	Water Pollution Control Bureau, Health and Environment Dept.	Flow characteristics, location sampling methods	Not specified	60 days	Yes	None

TABLE 5-23 (CONT.)

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Permit to Appropriate and Use Surface Water	Water Resources Division, Natural Resources Department	Description of works, location of point of diversion, and quantity and period of water use	Not specified	2 months-2 years (est.)	Yes	\$5
Permit to Change Location of Well and Place or Purpose of Underground Water	Water Resources Division, Natural Resources Department	Description of changes	Not specified	2 months-2 years (est.)	Yes	\$5
5-69 Permit to Change Point of Diversion and Place and/or Purpose of Use of Surface Waters	Water Resources Division, Natural Resources Department	Description of changes	Not specified	2 months-2 years (est.)	Yes	\$10
Exploration Plan Approval	Mining and Minerals Division, Energy and Minerals Department	Description of mining and reclamation methods; method of compliance with environmental regulations	N/A	30-45 days (est.)	Yes	\$50-\$100
Coal Surface Mining Permit	Mining and Minerals Division, Energy and Minerals Department	Mining and Reclamation Plan, ecological information	6 months (est.)	6 months (est.)	Yes	NA

TABLE 5-24

SUMMARY OF TIME REQUIREMENTS FOR MINOR PERMITS, STATE OF NEW MEXICO

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Certificate and License to Appropriate (groundwater)	Water Resources Division, Natural Resources Department	"Final Inspection and Report" and "Proof of Completion of Well" submitted (Description of well as it exists and the actual use of the water)	Not specified	3 months (est.)	No	\$5	Forms must be submitted within predesignated time from issuance of Permit to Appropriate
Certificate of Construction (surface water)	Water Resources Division, Natural Resources Department	Submission of form "Proof of Completion of Works" (Description of works as completed)	Not specified	Not specified	No	\$5	Form must be submitted within predesignated time from issuance of Permit to Appropriate
License to Appropriate (surface water)	Water Resources Division, Natural Resources Department	Submission of form "Proof of Application of Water to Beneficial Use" (Quantity and use of water appropriated)	Not specified	3 months (est.)	No	\$5	Form must be submitted within predesignated time from issuance of Permit to Appropriate
Water Well Drillers License	Water Resources Division, Natural Resources Department	Type of wells to be drilled, applicant's qualifications and references	Not specified	1 week (est.)	No	\$20 + surety	License valid for 2 years bond of \$5,000
Mine Dewatering Permit	Water Resources Division, Natural Resources Department	Mine dewatering plan and assessment of impact on existing water rights	Not specified	45 days minimum (est.)	Yes	\$5	
Water Supply Construction Permit	Water Supply Section, Environmental Improvement Division, Health and Environment Department	Plans and specifications prepared by professional engineer licensed in New Mexico	Not specified	30 days (est.)	No	None	

TABLE 5-24 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Approval of Drill Hole Plugging	Water Resources Division, Natural Resources Department	Location and depth of hole; method and materials used to plug hole	Not specified	Not specified	No	None	
Annual Mine Registration	State Mine Inspector	Operation information	Not specified	Not specified	No	None	Submitted on or before February 15 of each year
State Trust Land Lease	State Land Office	Rules and Regulations concerning the sale, lease, and other disposition of State Trust Land	Not specified	1-6 months (est.)	No	Varies depending on size of lease	
Utility Permit	Highway Department	Description of activity	Not specified	15 days (est.)	No	None	
License to Operate a Pipeline	Pipelines Department, Corporation Commission	Construction and operation Specifications	Not specified	2-3 days (est.)	No	Varies (dependent on length of pipeline)	
Permit for Archaeological Survey and Excavation Easements	Historial Preservation Bureau, New Mexico State Planning Division	Project description and demonstrated qualifications	Not specified	2-3 weeks (est.)	No	\$10 plus an amount that varies dependent on the activity	
Certificate of Compliance and Authority to Transport Oil and Gas	Oil Conservation Division, Energy and Minerals Department	Proof of other permits obtained	Not specified	1 week	No	None	
Rights-of-Way for State Lands	State Land Office	Location and map of tract, proposed use	Not specified	15 days	No	\$10 (easement fee varies depending specific pipeline, road, etc.)	

5.8 Permitting Processes in the State of Utah

The state of Utah has become fairly progressive in terms of permit streamlining. The results of the permit survey in Utah are described in this section.

Utah currently has an informal Joint Review Process which can be utilized by any major industrial developer. The Utah system is similar in design to the Colorado Joint Review Process, although its structure has not been set by any legislative action. Instead, it is flexible review process which can be adapted to the needs of any particular project. At present, there are no projects utilizing the system (Summer 1982). If a developer requests use of the Joint Review Process, personnel from the key state agencies will be designated to provide assistance.

Utah has assumed or soon will assume control of all the federal environmental programs. Utah operates the PSD air pollution control program, and is actively pursuing control of the RCRA program. The state will soon begin to administer the National Pollution Discharge Elimination System (NPDES) water program.

The pursuit of environmental control in the state may be partly encouraged by the existence of major energy resource areas, including reserves of all the energy types covered in this study. The northeast portion of the state holds most of these resources; the exception is the geothermal fields in the southwestern portion of the state.

5.8.1 Responsibilities of Principal State Agencies

Within the Utah state government, nine major departments exist of which only two are involved in the permitting needs of resource development. As shown in Figure 5-7, the Department of Health has one division, Environmental Health, with some jurisdiction over energy resource development. The Department of Natural Resources has five divisions with relevant permitting authorities, including the state water control, oil and gas, and mining authorities. The divisions within the Department of Natural Resources are directed by management boards which often have final judgment on major permit actions.

Responsibility or goals of the divisions with permit jurisdiction over energy resource development are identified below.

1. Department of Health

Division of Environmental Health - Responsible for protecting the health and welfare of the public from harmful effects of pollution; protecting the economic welfare of Utah within bounds of environmental standards and regulations; and protecting the scenic beauty, natural attractions and recreation areas from adverse effects of pollution.

2 Department of Natural Resources

Division of Oil, Gas, and Mining - Responsible for the prevention of unnecessary drilling; protection of correlative rights; and the conservation of physical resources.

Division of Water Rights - Responsible for the distribution, adjudication, and development of water in Utah for the good of the public; and for honoring old water rights.

Figure 5-7. Organization of Utah State Government (Some offices have not been shown in order to simplify the presentation).

Division of State Lands - Responsible for administering surface and mineral leases and the exchange of lands with other governmental or private parties.

Division of Wildlife Resources - Responsible for the care and management of the wildlife resources of Utah, and for the generation of public awareness about wildlife issues.

Division of Parks and Recreation - Responsible for maintenance of a broad spectrum of park and recreational facilities.

5.8.2 Permits Required by the State of Utah

Utah has over 30 permits which may be required for oil and gas, oil shale, coal or geothermal developments. The summary listing of Utah permits is provided in Table 5-25. Permits unique to Utah include licenses for the sale of minerals from the Great Salt Lake and permits for any development which would impinge on the Provo-Jordon River Parkway and its drainages. The remaining permits are similar to those of the other states where energy development is taking place.

The applicability of permits by resource areas is shown in Table 5-26. Coal mining and oil shale operations are most carefully regulated, as would be expected.

Among the permits judged to be "major," water appropriation and coal mining approvals are likely to have the longest review periods, although even these reviews were estimated at 4-6 months. The major permits and their probable review times are shown in Table 5-27. For most major permits, statutory review deadlines have not been set or were not generally applicable.

The review periods and other data for minor permits are provided in Table 5-28. The minor permit review periods are typically brief, and the information requirements are relatively modest.

TABLE 5-25

SUMMARY OF PERMITS REQUIRED BY THE STATE OF UTAH

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Review and Approval of Air Pollution Sources	Division of Environmental Health	Utah Code Annotated (UCA) 26-24-9,13	Air pollution control	New or modified air pollution sources	Plans and specifications and other requisite air quality information
Open Burning Permit	Division of Environmental Health	UCA 26-24-5	Air pollution control	May apply to selected projects needing land clearance	Location, type and amount of wastes to be burned
Permit for Discharge of Wastewater into State Waters	Division of Environmental Health	UCA 73-14-5,10	Regulate discharges into state waters	Any treatment facility which would discharge waste materials into state waters	Plans and specifications (use Federal NPDES permit)
Underground Disposal of Water Associated with Oil and Gas Drilling	Division of Oil, Gas and Mining	UCA 40-6-1 <u>et seq.</u>	Regulate subsurface disposal of unfit water	Underground disposal of brackish water	Description of disposal activities and plat showing location of well
Certificate of Appropriation of Water	Division of Water Rights	UCA 73-3-1 through 29	Regulate water use	Right to use unappropriated water	Source, location, and quantity
Application for Change of Point of Diversion, Place, or Nature of Use of Water	Division of Water Rights	UCA 73-3-3	Protect water rights	Change of place or purpose of use	Source, location, and quantity
Certificate of Appropriation of Water for Geothermal Purposes	Division of Water Rights	UCA 73-3-1 through 29	Regulate water use	For use of water for geothermal purposes	Description of the general development

TABLE 5-25 (Cont.)

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Approval of Construction or Repair of a Dam or Impoundment	Division of Water Rights	UCA 73-5-5	Protect from possible hazards to life or property	Dams or impoundments for use of water	Plans and specifications
Well Drillers Permit	Division of Water Rights	UCA 73-3-14,25,26	Prevent drilling of unnecessary or improper wells	If wells are to be drilled by the developer	Demonstration of competence through a test
Approval of Disposal of Solid Waste	Division of Environment and Health	UCA 26-15-5(5)c	Protection of the environment	Land disposal of solid wastes	Plans and specifications
Approval of a Development Proposal Impinging on the Provo-Jordon River Parkway and its Drainages	Division of Parks and Recreation	UCA 65-10-1 through 7	Protect water, recreation and wildlife along the Provo-Jordon River	Any activities within 150 feet of the Provo-Jordon Parkway	Description of development
Certificate of Registration to Take Protected Wildlife	Division of Wildlife Resources	NA	Regulate the taking of protected wildlife	Disturbance of lands on which research projects or wildlife are located	Description of activities
Relocation or Alteration of Natural Stream	Division of Water Rights	UCA 73-3-29	Protect water rights and natural habitat	Activities occurring in streams and riverbeds	Description of activities, proposed changes, purpose, location and condition of stream
Notice of Intent to Divert a Canal, Reservoir, or Other Waterway Containing Protected Aquatic Wildlife	Division of Wildlife Resources	UCA 23-15-5	Protect aquatic wildlife	Activities occurring in specified waterways	Description of activities
Permit to Commence Coal Exploration	Division of Oil, Gas, and Mining	UCA 40-8-13 40-10-8	Protect surface or subsurface lands from substantial disturbance	Coal exploration and field data collection	Written notice of intent and performance standards

TABLE 5-25 (Cont.)

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Permit to Mine Coal	Division of Oil, Gas and Mining	UCA 40-10-MC 700 <u>et seq.</u>	Minimize impacts of surface coal mining	Surface coal mining and reclamation activities	Notice of intent and (possibly) environmental baseline studies
State Mineral Lease	Division of State Lands	UCA 65-1-18	Insure state lands are being used for beneficial purposes	Lease of state lands for mineral development	Location and type of resource
Notice of Intent to Mine	Division of Oil, Gas, and Mining	UCA 40-8-8, 13 18 and 21	Regulate mining activities	Mining operation and on-site processing	Location of mine, water systems affected, reclamation plan, and type of mining
Approval of a Temperature Gradient Well	Division of Water Rights	UCA 73-1-20	Regulate use and appropriation of water	Geothermal well drilling	Use of water and general description of operations
Plans of Operation for Geothermal Drilling	Division of Water Rights	UCA 73-1-20	Regulate use and appropriation of water	Geothermal well drilling	Source location, quantity and plan of operations
Use Permit on State Park Lands	Division of Parks and Recreation	UCA 73-11-7 (2)	Regulate the use of state park lands	May apply to activities on federal lands if there are state lands interspersed	Plan describing proposed use of land
Special Use Permit for State Lands	Division of State Lands	UCA 65-1-18	Regulate the use of state park lands	May apply to activities on federal lands if there are state lands interspersed	Description of activities
Notice of Intention to Drill	Division of Oil, Gas and Mining	UCA 40-6-5 (y) 40-6-9	Prevent drilling of unnecessary wells	Drilling any oil or gas well	Notice of intent to drill and location
Permit to Commence Non-Coal Exploration Activities	Division of Oil, Gas and Mining	UCA 40-8-4 (12)	Prevent drilling of unnecessary wells	Exploration activities	Letter of intent with location of exploration describing activities and reclamation plan

TABLE 5-25 (Cont.)

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Right-of-Way Across State Lands	Division of State Lands	UCA 65-2-1 <u>et seq</u>	May apply to activities on federal lands if there are interspersed state lands	Transmission of electricity, roads, telephone lines, etc. on, over or through state lands	Description of location and use
Easement Across State Wildlife Resource Lands	Division of Wildlife Resources	UCA 23-14-1,3 23-21,1,3	Regulate use of wildlife resource lands	May apply to activities on federal lands if there are interspersed state lands	Explanation of proposed uses
Utility Easement on State Park Lands	Division of Parks and Recreation	UCA 73-11-10.3	Regulate use of state park lands	Public utilities on state park lands	Map, legal description, activity and possible detriments to land
Permit to Explore, Excavate or Remove Archaeological or Paleontological Remains	Division of State Lands	UCA 63-11-2	Protect historically significant artifacts	Exploration or excavation of archaeological or paleontological deposits on state or federal lands	Description of activities
Application to Remove a Heritage Tree	Division of State Lands	UCA 63-11-47,58 59,60, and 61	Protect rare or vanishing species of trees	Activities which require removal of specified species of trees	Demonstrate the necessity of removal
Permit for Wastewater Disposal Systems	Division of Environment and Health	UCA 73-14-4	Prevent water pollution due to improper disposal of wastewater	Any energy development which includes worker housing	Plans and specifications for engineering review
Approval of Drinking Water System	Division of Environment and Health	UCA 26-15-5(5)	Assurance of potable water	Any energy development which includes worker housing	Plans and specifications, water source, yield, appropriation rights
Permit for Overweight Vehicles on State Roads	Highway Patrol	UCA 27-12-151,154,155	Highway safety	Any energy development utilizing oversize vehicles	Route, cargo, size, and ownership of vehicle

TABLE 5-26

APPLICABILITY OF UTAH PERMITS BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Review and Approval of Air Pollution Sources	O	X	X	X
Open Burning Permit	O	O	O	O
Permit for Discharge of Wastewater into State Waters	O	X	X	X
Underground Disposal of Water Associated with Oil and Gas Drilling	X			
Certificate of Appro- priation of Water	O	O	O	O
Application for Change of Point of Diversion, Place or Nature of Use of Water	O	O	O	O
Certificate of Appropriation of Water for Geothermal Purposes			X	
Approval of Construction or Repair of a Dam or Impoundment		O	O	O
Well Drillers Permit	O	O	O	O
Approval of Disposal of Solid Waste	O	O	O	O
Approval of a Development Proposal Impinging on the Provo-Jordon River Park- way and its Drainages	O	O	O	O

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-26 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Certificate of Registration to Take Protected Wildlife	O	O	O	O
Relocation or Alteration of Natural Stream	O	O	O	O
Notice of Intent to Divert a Canal, Reservoir, or Other Waterway Containing Protected Aquatic Wildlife	O	O	O	O
Permit to Commence Coal Exploration		X		
Permit to Mine Coal		X		
State Mineral Lease	O	O	O	O
Notice of Intention to Mine		X		X
Approval of Temperature Gradient Well			X	
Plans of Operation for Geothermal Drilling			X	
Use Permit on State Park Lands	O	O	O	O
Special Use Permit for State Lands	O	O	O	O
Notice of Intention to Drill	X		X	
Permit to Commence Non-Coal Exploration Activities	X		X	X

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-26 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Right-of-Way Across State Lands	0	0	0	0
Easement Across State Wildlife Resource Lands	0	0	0	0
Utility Easement on State Park Lands	0	0	0	0
Permit to Explore, Excavate or Remove Archeological or Paleontological Remains	0	0	0	0
Application to Remove a Heritage Tree	0	0	0	0
Permit for Overweight Vehicles	0	0	0	0
Approval of Drinking Water System	0	0	0	0
Permit for Wastewater Disposal System	0	0	0	0

X - Permit is applicable to most development activities of this resource.

0 - Permit applicability is dependent on site and project characteristics.

TABLE 5-27

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF UTAH

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE
Review and Approval of Air Pollution Sources	Division of Environmental Health	Plans and specifications and other requisite air quality information	Not specified	30-180 days	Yes	Based on emission quantity estimates
Permit for Discharge of Wastewater into State Waters	Division of Environmental Health	Plans and specifications	Not specified	1-2 months	No	NA
Certificate of Appropriation of Water	Division of Water Rights	Source, location, and quantity	Not specified	6-12 months	Yes	NA
Application for Change of Point of Diversion, Place, or Nature of Use of Water	Division of Water Rights	Source, location, and quantity	Not specified	4-6 months (est.)	Yes	NA
Certificate of Appropriation of Water for Geothermal Purposes	Division of Water Rights	General description of the development	Not specified	4-6 months (est.)	Yes	NA
Permit to Commence Coal Exploration	Division of Oil, Gas, and Mining	Notice of intent and compliance with performance standards	Not specified	2 weeks	Yes	None
Permit to Mine Coal	Division of Oil, Gas, and Mining	Notice of intent and possible environmental baseline studies	Not specified	To 1-1/2 years	Yes	\$5 and bonding
Approval of a Temperature Gradient Well	Division of Water Rights	Source, location, and quantity	Not applicable	1 month (est.)	Yes	NA
Plans of Operation for Geothermal Drilling	Division of Water Rights	Source, location, and quantity	Not applicable	4-6 months (est.)	Yes	NA

TABLE 5-28

SUMMARY OF TIME REQUIREMENTS AND APPLICATION FEES FOR MINOR PERMITS, STATE OF UTAH

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE- NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLI- CATION FEE	COMMENTS
Open Burning Permit	Division of Environmental Health	Location and type and amount of waste to be burned	NA	NA	No	NA	
Approval of Construction or Repair of a Dam or Impoundment	Division of Water Rights	Plans and specifications	Not specified	1 month	No	NA	
Well Drillers Permit	Division of Water Rights	Demonstrate competence through a test	NA	NA	No	\$500 bond	
Approval for Disposal of Solid Waste	Division of Environment and Health	Plans and specifications	NA	14 days	No	NA	
Approval of a Development Proposal Impinging on the Provo-Jordan River Parkway and its Drainage	Division of Parks and Recreation	Description of development	NA	NA	NA	NA	
Certificate of Registration to Take Protected	Division of Wildlife Resources	Description of activities	NA	30 days (est.)	No	NA	Permit is rarely required
Relocation or Alteration of Natural Stream	Division of Water Rights	Description of activities proposed changes, purpose, location, and condition of the stream	Not specified	NA	NA	None	

TABLE 5-28 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Notice of Intent to Divert a Canal, Reservoir or Other Waterway Containing Protected Aquatic Wildlife	Division of Wildlife Resources	Description of activities	Not specified	5 days	No	None	
State Mineral Lease	Division of State Lands	Location and type of resource	Not specified	2 weeks	No	None	
Notice of Intent to Mine	Division of Oil, Gas, and Mining	Location of mine, affected water systems, reclamation plan, and type of mining	Not specified	30 days	No	NA	
Use Permit on State Park Lands	Division of Parks and Recreation	Plan describing proposed use of land					
Special Use Permit for State Lands	Division of State Lands	Description of activities	Not specified	1 month	No	\$20	
Notice of Intention to Drill	Division of Oil, Gas and Mining	Location	Not specified	1 week	No	None	
Underground Disposal of Water Associated with Oil and Gas Drilling	Division of Oil, Gas, and Mining	Description of disposal activities, well location	Not specified	15 days	Yes	None	
Permit to Commence Non-Coal Exploration Activities	Division of Oil, Gas, and Mining	Letter of intent with location, description of activities and reclamation plan	Not specified	15 days	No	NA	

TABLE 5-28 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Right-of-Way Across State Lands	Division of State Lands	Description of location and use	Not specified	1-3 weeks	No	\$50	
Easement Across State Wildlife Resource Lands	Division of Wildlife Resources	Legal description of land and explanation of proposed uses	Not specified	6 weeks	No	NA	
Utility Easement on State Park Lands	Division of Parks and Recreation	Map, legal description, activity and possible detriments to the land	NA	NA	NA	NA	
Permit to Explore, Excavate or Remove Archaeological or Paleontological Remains	Division of State History	Description of activities	Not specified	NA	NA	NA	
Application to Remove a Heritage Tree	Division of Parks and Recreation	Demonstrate necessity of removal and information on trees in the area	Not specified	60 days	No	NA	Permit is rarely required
Permit for Wastewater Disposal Systems	Division of Environmental Health	Plans and specifications for engineering review	Not specified	30 days	No	No	

TABLE 5-28 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETENESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICATION FEE	COMMENTS
Approval of Drinking Water System	Division of Environmental Health	Plans and specifications, water source, yield, appropriation rights	Not specified	30 days	No	No	
Permit for Overweight Vehicles on State Roads	Highway Patrol	Route, cargo, size and ownership of vehicle	Not specified	1 day	No	Variable Fee	

5.9 Permitting Processes in Wyoming

In recent years, the number and size of energy development projects in the State of Wyoming has increased dramatically. In an effort to maintain control of the state's resources and to help ensure orderly and desirable growth patterns, the state regulatory agencies have actively participated in the permitting of major energy facilities. To this end, the Wyoming State Legislature has championed a number of key statutes, the most important of which is the Wyoming Environmental Quality Act of 1973, as amended. This statute has served as the driving force in the promulgation of state regulations which cover such issues as air pollution control, water pollution control, solid and hazardous waste management, land use and mineral extraction.

In addition to the development and conduct of a variety of state permitting programs, the Wyoming regulatory agencies are also responsible for implementing two federally mandated programs: the National Pollution Discharge Elimination Systems (NPDES) water pollution control program and the Prevention of Significant Deterioration (PSD) air quality program. Local or county permitting regulations are generally limited to zoning or land use ordinances.

To aid both regulatory agencies and permit applicants, a State Planning Coordinator's Office has been established in Wyoming. This office is responsible for the coordination of planning activities for all state departments, boards, commissions and agencies regarding development activities. In addition, the State Planning Coordinator's Office is responsible for reviewing environmental impact statements, memorandums of understanding, cooperative agreements between state agencies, and cooperative agreements between state and

federal agencies. It is through the actions of this agency that the state hopes to minimize many of the permitting complexities and duplications of effort.

All of the energy resources covered in this study are found in the state of Wyoming. With the exception of geothermal resources, specific permit requirements have been developed for each type of energy development. The following subsection presents a brief overview of the key regulatory agencies.

5.9.1 Responsibilities of Principal State Agencies

There are 11 state agencies which typically have jurisdictional review or permitting authority for major energy development projects. A few of these agencies serve in a review capacity only and, as such, do not issue permits or licenses. The primary functions of each of the 11 state regulatory agencies are summarized below.

Department of Environmental Quality (DEQ) - Air Quality Division - The Air Quality Division of the Wyoming DEQ is responsible for the permitting of new or modified facilities which may cause the emission of air contaminants. The Division of Air Quality must ensure source compliance with federal and state air pollution emission limits as well as ambient air quality standards. This agency is responsible for implementing the Federal PSD program.

Department of Environmental Quality (DEQ) - Water Quality Division - The Water Quality Division of the Wyoming DEQ is responsible for implementing the Federal NPDES permit program for surface water disposal, and the ground water pollution control program, and for overseeing the construction and operation of wastewater facilities.

Department of Environmental Quality (DEQ) - Land Quality Division - This agency's primary function is to ensure

Figure 5-8. Organization of Wyoming State Government (Some offices have not been shown in order to simplify the presentation).

that proper exploration, production (extraction) and reclamation procedures are followed during the mining of minerals, including coal.

Department of Environmental Quality (DEQ) - Solid Waste Management Division - The Solid Waste Management Division issues permits for the construction and operation of industrial and hazardous waste disposal facilities.

Wyoming Oil and Gas Conservation Commission - This agency is charged with the responsibility of ensuring that oil and gas exploration and production operations are carried out in an environmentally acceptable fashion. The principal concern in this type of energy resource development is protection of surface and ground water quality. This agency is also responsible for the engineering integrity of oil and gas development projects.

State Engineers Office - The State Engineers Office is primarily concerned with ground and surface water appropriation and disposal. This agency also has permitting jurisdiction over the construction and operation of reservoirs.

Office of Industrial Siting Administration - This agency was established to serve as the permitting body for major facilities relating to energy generating and conversion plants. The Industrial Siting Administration is charged with the responsibility of ensuring that social, economic and environmental impacts associated with the construction and operation of major industrial facilities are successfully mitigated.

Public Service Commission - The Public Service Commission requires that a Certificate of Public Convenience and Necessity be obtained prior to the construction and operation of large utility facilities such as electric generating facilities, electric transmission lines, coal gasification plants and oil and gas pipelines, regardless of size or cost. The Public Service Commission is responsible for the protection of public interests in utility operations.

Wyoming Highway Department - The Wyoming Highway Department is responsible for protecting state highway rights-of-way and road construction. The two types of permits typically issued are encroachment permits for approval to cross a highway with an underground pipeline or overhead transmission line and an approach permit

for approval to connect a facility access road to a state road or highway.

State Inspector of Mines - The State Inspector of Mines conducts site inspections at the commencement and discontinuance of all mining activities to ensure that the mining and reclamation plans are carried out properly. The State Inspector of Mines is also responsible for ensuring that certain key mining facility personnel are properly trained in safety procedures.

Wyoming Recreation Commission/State Historic Preservation Office (SHPO) - This agency is responsible for assessing the archaeological value of government lands prior to project approval. For areas of known archaeological interest, the SHPO is responsible for the protection of these cultural interests by approving effective mitigation programs.

State Board of Land Commissioners - The State Board of Land Commissioners has the authority to administer all leasing and sale of state lands in Wyoming.

Wyoming Game and Fish Commission - The Wyoming Game and Fish Commission works with the U.S. Fish and Wildlife Service in the administration of rare and endangered species. The state agency's role is one of an advisor to the federal agency. The Wyoming Game and Fish Commission generally is not responsible for issuing permits.

Wyoming Geological Survey - The Wyoming Geological Survey serves in an advisory position to its federal counterpart, the U.S. Geological Survey.

5.9.2 Permits Required by the State of Wyoming

The survey of permits in Wyoming indicates, as mentioned above, a high level of regulatory activity and an extensive listing of permits. The results of the survey are given in this section.

Table 5-29 summarizes 42 "major" and "minor" permits, notices or petitions that are typically required for major energy development projects. Of course, not all of these

permits would apply to a single facility or project. The agencies with the greatest number of separate permits or notices are the DEQ Land and Water Quality Divisions, the Oil and Gas Conservation Commission, and the State Engineers Office.

Table 5-30 presents a summary of permits applicable to each energy resource. From this table, it can be observed that geothermal resource development is the least impacted by permit requirements. The major reason for this is that the State of Wyoming has not promulgated any licensing requirements which apply specifically to geothermal energy development projects. The resources most severely impacted by regulatory requirements are coal and oil shale. Given the massive amount of land disturbance typically associated with mining operations, this finding is not unexpected.

Table 5-31 provides critical permit processing information for the 11 "major" permits impacting energy development in the State of Wyoming. Most of these permits require four to six months to process and possibly longer if additional information is required. In addition, almost all of these permits require a public comment period. These "major" permits address all areas of primary environmental concern: air pollution, water pollution, mined land reclamation, hazardous waste disposal and water appropriation. Given the extensive information requirements and review times associated with these permits, it is not difficult to understand how they dominate "critical-path" licensing strategies.

Finally, Table 5-32 presents a summary of permit processing requirements for the 28 "minor" permits, notices

and petitions frequently encountered during the licensing of major energy development facilities. Note however that for any given project, these "minor" licensing requirements have the potential to significantly impact the permit process. This can occur in instances of poor planning or where "localized" project resistance is encountered.

TABLE 5-29

SUMMARY OF PERMITS REQUIRED BY THE STATE OF WYOMING

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Permit to Construct or Modify (An Air Pollution Source)	Department of Environmental Quality - Air Quality Division	Wyoming Statutes of 1957 as Amended (WS) 35-11-106, 110, 112, 114, 202 Wyoming Environmental Quality Act	Air pollution control	Applies to the construction or modification of any facility which emits air pollutants	Air quality impact assessment, project description
Permit to Operate (An Air Pollution Source)	DEQ - Air Quality Division	WS 35-11-106, 110, 112, 114, 202	Air pollution control	Applies to the operation of any facility which emits air pollutants	Source emissions tests
Wastewater Discharge Permit (NPDES)	DEQ - Water Quality Division	WS 35-11-301, 302 35-502 <u>et seq.</u>	Protection of state surface waters	All discharges to navigable waters/ construction of sediment ponds, etc.	Facility location and description, quantity and type of discharge and description of receiving waters
Permit to Construct, Modify, or Operate a Wastewater Facility	DEQ - Water Quality Division	WS 35-11-301, 302	Protection of water resources	Wastewater treatment, storage and disposal facilities	Facility specifications, design, monitoring plan, and water quality
Groundwater Pollution Control Permit	DEQ - Water Quality Division	WS 35-11-301, 302	Control of subsurface wastewater disposal	Any subsurface disposal operation, including geothermal injection	Characteristics of discharged waste, disposal formation, well location, and construction details
Underground Disposal of Water Notice	Oil and Gas Conservation Commission	WS 30-5-101	Protection of water resources	Underground disposal of waste waters	Plat, disposal formation, casing description, water source, and injection rates
Permit to Drill Test Well	Office of the State Engineer	NA	Regulation of well drilling and water use	Any shallow observation or test well in geothermal development	Location of well, intended use
Permit to Drill Geothermal Production Well	Office of the State Engineer	NA	Regulation of well drilling and water use	Any well for production of geothermal resources	Plat showing location, construction specifications, flow rate, etc.

TABLE 5-29 (Cont.)

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Ground or Surface Water Appropriation	Office of the State Engineer	WS 41-121 through 147	Regulation of state water use	Use of state owned waters	Source location and quantity used
Temporary Use Permit (Water Application)	Office of the State Engineer	WS 41-121 through 147	Regulation of state water use	Use of state owned water for construction and other short-term (<2 yrs) projects	Source location and quantity used
Reservoir Construction and Use Permit	Office of the State Engineer	WS 41-121 through 147	Protection of water quality	Construction, operation of fresh and waste water reservoirs, run-off and sediment ponds	Facility design, location, water quality, and proposed use
Permit to Construct and Operate Sedimentation Ponds	Wyoming DEQ - Water Quality Division	NA	Protection of water quality	Governs sedimentation ponds used in coal mining operations	Facility design, location, water quality, and proposed use
Change in Use or Point of Diversion Petition	Office of the State Engineer	WS 41-121 through 147	Control the diversion of water resources	Changes in existing water appropriations	Petition which addresses existing and proposed use, reasons, and quantity
Industrial and Hazardous Waste Facility Construction and Operation Permit	Wyoming DEQ - Solid Waste Management Division	WS 35-502-42 through 35-502-44	Control of solid waste disposal	Construction, modification and operation of all solid waste disposal facilities	Geologic and soil analysis
Industrial and Hazardous Waste Facility Construction and Operation Permit	Wyoming DEQ - Solid Waste Management Division	WS 35-502-42 through 35-502-44	Control of solid waste disposal	Construction, modification and operation of all solid waste disposal facilities	Geologic and soil analysis
Dredge and Fill Permit	DEQ - Water Quality Division	WS 35-11-301,302	Protection of wetlands	Dredge and fill activities in wetland areas	Project description, waters impacted and stream diversions
Scientific Permit	Wyoming Game and Fish Dept.	WS 23-1-103 through 23-4-101	Regulation of activities affecting wildlife	May apply to any major project, especially mining	Description of nature and purpose of activity

TABLE 5-29 (Cont.)

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
License to Explore by Dozing	Department of Environmental Quality (DEQ) Land Quality Division	WS 35-11-414	Land quality protection	For mineral (i.e., oil shale) exploration projects employing surface dozing	Project location, description, time table, reclamation plan
License to Explore by Drilling	DEQ - Land Quality Division	WS 35-11-404	Land quality and groundwater protection	For mineral (i.e., oil shale) exploration projects employing drilling operations	Reclamation and drilling plan, location of wells
Coal Exploration License	DEQ - Land Quality Division	WS 35-11-414, WS 35-11-404	Land quality and groundwater protection	Coal exploration only (by drilling or dozing)	Exploration and reclamation plan location, equipment and environmental setting
Permit to Mine (or Amendment)/ Small Mining Permit	DEQ - Land Quality Division	WS 35-11-406	Land quality and groundwater protection	Coal surface and underground mining	Mining and reclamation plan, location, and project description
License to Mine	DEQ - Land Quality Division	WS 35-11-410	Land quality and groundwater protection	Coal surface and underground mining	Copy of Permit to Mine
In-situ Mining Permit	DEQ - Land Quality Division	WS 35-11-427	Land quality and groundwater protection	In-situ mining operations only	Project description, geologic and hydrologic information, reclamation plan and timetable
In-situ Research and Development License	DEQ - Land Quality Division	WS 35-11-431	Land quality and groundwater protection	Experimental in-situ mining operations	Project description, geologic and hydrologic information, reclamation plan and timetable
Notification of Opening or Closing a Mine	State Inspector of Mines	WS 30-3-416, 430 30-2-301, 30-2-314	To insure mining and reclamation plans are carried out properly	All coal and oil shale mines	Notification of start or termination of mining operations

TABLE 5-29 (Cont.)

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Permit to Drill or Deepen a Well, Stratigraphic Test, or Core Hole	Oil and Gas Conservation Commission	Wyoming Oil and Gas Act, WS 30-5-101 through WS 30-5-204	Protection of water resources, insure proper well spacing, check blowout prevention	Exploration, extraction, injection wells, and core holes	Surveyor's plat, description of casing program, drill plan, and well depth
Notice of Intention to Recomplete a Well	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Protection of water resources, insure proper operating procedures	Recompletion of oil and gas wells	Casing program and drill plan
Notice of Intention to Abandon or Plug a Well or Exploratory Hole	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Protection of water resources, insure proper operating procedures	Abandonment of oil, gas, seismic, injection, exploratory wells, and core holes	Reason for abandonment and plugging method employed
Notice of Multiple Zone Completion	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Insure proper operating procedures, protection of oil and gas reservoirs	Multiple zone oil and gas production into one well bore	Production method, owners within 1/2 mile, and well location plat
Notice of Intent to Employ Waterflooding or Other Recovery Methods	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Protection of oil and gas resources, insure proper operating procedures	Production operations involving the injection of extraneous forms of energy into a pool	Well location plat, description of operation, production pools, well logs, fluid injected and casing program
Notice of Intention to Change Plans	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Insure proper operating procedures	Changes in approved work plans	Detailed discussion of proposed changes
Notice of Change of Ownership	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Revise performance bonding arrangements	Changes of ownership as defined in regulations	Completion of Notice application
Permit to Use Vacuum Pumps	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Insure proper operating procedures	Oil and gas operations which employ vacuum pumps	Names of owners within 1/2 mile, and well location plat
Notice of Commencement or Discontinuance of Injection Operations	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Insure compliance with established operating procedures, to maintain records	All injection operations	Date of action and reasons

TABLE 5-29 (Cont.)

PERMIT	GOVERNMENT AGENCY	STATUTORY AUTHORITY	PERMIT OBJECTIVE	APPLICABILITY	INFORMATION REQUIREMENTS
Notice of Unitization	Oil and Gas Conservation Commission	WS 30-5-101 through WS 30-5-204	Insure compliance with established operating and reporting procedures	Cooperative development or operation of a field or pool	Copy of cooperative development agreement
Industrial Siting Permit	Industrial Siting Council	WS 35-12-101 through 35-12-121	Mitigation of social economic and environmental impacts of major industrial facilities	All major energy and industrial facilities	Facility description, timetable, environmental impact studies, site justification, costs, social and economic impacts
Land Use Lease	State Board of Land Commissioners	Section 41-121 through 147	Control right-of-way access and use of state lands	May apply to activities on federal lands when state lands are interspersed	NA
State Historic Preservation Office Review	Recreation Commission	WS 36-1-114, 36-4-106, 35-11-112, 401, 406	Assess archeological value of a project area	Any project on federal lands or using federal monies	Archeological site (or literature) survey
Certificate of Public Convenience and Necessity	Public Service Commission	WS 37-1-101, 102, 37-2-116, 117, 119, 120, 122, 205, 206, 207, 210, 211, 212, 37-3-114, 37-6-101 through 107	Protect public interest in utility operations	Major utility plants	Facility description, rates, financial data, site characteristics and land use
Encroachment Permit	State Highway Department	WS 24-6-103 through 105	Control of access to highway right-of-way	Powerlines, pipelines, exploration, production in highway right-of-way	Project description and location
Approach Permit	State Highway Department	WS 24-6-103 through 105	Control of construction of access roads to highways	Private requests for access roads to highways	Project description and location
Certificate of Competency	State Inspector of Mines	WS 30-3-307, 30-3-501	Certify key coal mining facility personnel for competence	Mine foreman, mine safety engineer, shot firers for underground mines	Certificate of approval from Coal Mine Examining Board

TABLE 5-30

APPLICABILITY OF WYOMING PERMITS BY RESOURCE AREA

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Permit to Construct or Modify (an Air Pollution Source)	O	X	X	X
Permit to Operate (an Air Pollution Source)	O	X	X	X
Wastewater Discharge (NPDES) Permit	O	X	X	X
Permit to Construct, Modify, or Operate a Wastewater Facility	O	O	O	O
Groundwater Pollution Control Permit	X	X	X	X
Underground Disposal of Water Notice	O		O	O
Ground or Surface Water Appropriation	O	X	X	X
Permit to Drill Test Well			X	
Permit to Drill Production Well			X	
Temporary Use Permit	O	O	X	O
Reservoir Construction and Use Permit	O	O	O	O

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-30 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Permit to Construct and Operate Sedimentation Ponds		X		X
Change in Use or Point of Diversion Petition	O	O	O	O
Industrial and Hazardous Waste Facility Construction and Operation Permit	O	X	O	X
Dredge and Fill Permit	O	O	O	O
Scientific Permit	O	O	O	O
License to Explore by Dozing				X
License to Explore by Drilling				X
Coal Exploration License		X		
Permit to Mine (or Amendment to Permit)/ Small Mining Permit		X		
License to Mine		X		
In-Situ Mining Permit				O
In-Situ Research and Development License				O
Notification of Opening or Closing a Mine		X		X
Permit to Drill or Deepen a Well, Stratigraphic Test or Core Hole	X		X	

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-30 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Notice of Intention to Recomplete a Well	O			
Notice of Intention to Abandon or Plug a Well or Exploratory Hole	O			
Notice of Multiple Zone Completion	O			
Notice of Intent to Employ Waterflooding or Other Recovery Methods	O			
Notice of Intention to Change Plans	O			
Notice of Change of Ownership	O			
Permit to Use Vacuum Pumps	O			
Notice of Commencement or Discontinuance of Injection Operations	O			
Notice of Unitization	O			
Industrial Siting Permit	O	X	O	X
Land Use Lease	O	O	O	O
State Historic Preser- vation Office Review	O	X	O	X
Certificate of Public Convenience and Necessity	O			
Encroachment Permit	O	O	O	O

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-30 (Cont.)

RESOURCE AREA	OIL AND GAS	COAL	GEO- THERMAL	OIL SHALE
Approach Permit	O	O	O	O
Certificate of Competency		X		X

X - Permit is applicable to most development activities of this resource.

O - Permit applicability is dependent on site and project characteristics.

TABLE 5-31

SUMMARY OF TIME REQUIREMENTS FOR MAJOR PERMITS, STATE OF WYOMING

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICA-TION FEE
Permit to Construct or Modify (An Air Pollution Source)	DEQ - Air Quality Division	Air quality impact assessment, project description	30 days	90 days (est.)	Yes	None
Permit to Operate (An Air Pollution Source)	DEQ - Air Quality Division	Source emissions test	Not applicable	Not applicable	No	None
Wastewater Discharge (NPDES) Permit	DEQ - Water Quality Division	Facility location and description, quantity, and/or type of discharge and description of receiving waters	1 week (est.)	90 days (est.)	Yes	None
Permit to Construct, Modify, or Operate a Wastewater Facility	DEQ - Water Quality Division	Facility specification, design, monitoring plan and water quality	Not specified	2-6 weeks (est.)	No	None
Ground or Surface Water Appropriation	Office of the State Engineer	Source location, quantity and use of water	Not specified	30-60 days (est.)	No	\$25
Industrial and Hazardous Waste Facility Construction and Operation Permit	DEQ - Solid Waste Management Division	Geologic, hydrologic and soil analysis, operating and reclamation procedures	Not specified	155 days (est.)	Yes	None
Permit to Mine (or Amendment)/ Small Mining Permit	DEQ - Land Quality Division	Mining and reclamation plan, project, location, and description	60 days	180-260 days	Yes	\$100 (\$200 for amendments plus \$100 per acre not to exceed \$2000

TABLE 5-31 (CONT.)

MAJOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLICA-TION FEE
In Situ Mining Permit	DEQ - Land Quality Division	Project description, geologic and hydrologic information, timetable, and reclamation plan	60 days	180-260 days (est.)	Yes	\$100 (\$200 for amend-ments) plus \$10 per acre not to exceed \$2000
Permit to Drill or Deepen a Well, Stratigraphic Test or Core Hole	Oil and Gas Conservation Division	Surveyor's plat, descrip-tion of casing program, drill plan, and well depth	Not specified	30 days (est.)	Yes	\$25 per well
Industrial Siting Permit	Industrial Siting Council	Facility description, time table, environmental impact studies, site justification, costs and socioeconomic impacts	Not specified	130-180 days (est.)	Yes	Variable; based on % on estimated construction costs; up to \$1 mil-lion
Permit to Drill Production Well	Office of the State Engineer	Plat showing location, construction specifi-cations, flow rate, etc.	Not Specified	60 days (est.)	Yes	\$25 per well

TABLE 5-32

SUMMARY OF TIME REQUIREMENTS FOR MINOR PERMITS, STATE OF WYOMING

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE- NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLI- CATION FEE	COMMENTS
Groundwater Pollution Control Permit	DEQ - Water Quality Division	Characteristics of discharge, disposal formation, well location, and construction details	Not specified	30-120 days (est.)	Yes	None	
Underground Disposal of Water Notice	Oil and Gas Conservation Commission	Plat, disposal formation, casing description, water source, and injec- tion rates	Not specified	15 days	Yes	None	
Temporary Use Permit (Water Appropriation)	Office of the State Engineer	Source location, quantity and use of water	Not specified	5 days (est.)	No	\$25	
Reservoir Construction and Use Permit	Office of the State Engineer	Facility design, location, water quality, proposed use	30 days	45 days (est.)	No	\$25	
Change in Use or Point of Diversion Petition	Office of the State Engineer	Existing water use, proposed water use and reason for petition	Not specified	180 days (est.)	Yes	\$4/first page; \$2/each addi- tional page	
Dredge and Fill Permit	DEQ - Water Quality Division	Project description, waters impacted, and stream diversions	Not specified	60 days	No	None	
Scientific Permit	Wyoming Game and Fish Dept	Description of nature and purpose of activity	Not specified	2 months	No	NA	
License to Explore by Dozing	DEQ - Land Quality Division	Project location, description, time- table, and recla- mation plan	Not specified	30 days	No	\$25	

TABLE 5-32 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE-NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLI-CATION FEE	COMMENTS
Permit to Construct and Operate a Sedimentation Pond	DEQ - Water Quality Division	Facility design, location, water quality and proposed use	Not specified	45 days	No	None	
License to Explore by Drilling	DEQ - Land Quality Division	Reclamation and drilling plan, and location of wells	Not applicable	Not applicable	No	None	
Coal Exploration License	DEQ - Land Quality Division	Exploration and reclamation plan, location, equipment, and environmental setting	Not applicable	Not applicable	No	None	
License to Mine	DEQ - Land Quality Division	Copy of Permit to Mine	Not applicable	Not applicable	No	\$25	
In-Situ Research and Development License	DEQ - Land Quality Division	Project description, geologic and hydrologic information, reclamation plan, and timetable	90 days (est.)	90 days (est.)	No	\$25	
Notification of Opening or Closing a Mine	State Inspector of Mines	Notification of mining commencement or mine closure	Not applicable	Not applicable	NA	None	
Notice of Intention to Recomplete a Well	Oil and Gas Conservation Commission	Casing and drill plan	Not specified	15 days	Yes	None	
Notice of Intention to Abandon or Plug a Well or Exploratory Hole	Oil and Gas Conservation Commission	Reason for abandonment and plugging method employed	Not specified	15 days	Yes	None	

TABLE 5-32 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE- NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLI- CATION FEE	COMMENTS
Notice of Multiple Zone Completion	Oil and Gas Conservation Commission	Production method, owners within 1/2 mile, and well location plat	Not specified	15 days	Yes	None	
Notice of Intent to Employ Waterflooding or Other Recovery Methods	Oil and Gas Conservation Commission	Well location plat, description of operation, production pools, well logs, fluid injected, and casing program	Not specified	15 days	Yes	None	
Notice of Intention to Change Plans	Oil and Gas Conservation Commission	Detailed discussion of proposed changes	Not specified	15 days	Yes	None	
Notice of Change of Ownership	Oil and Gas Conservation Commission	Completion of Notice application	Not specified	15 days	Yes	None	
Permit to Use Vacuum Pumps	Oil and Gas Conservation Commission	Names of owners within 1/2 mile, well location plan	Not specified	15 days	Yes	None	
Notice of Commencement or Discontinuance of Injection Operations	Oil and Gas Conservation Commission	Date of action and reasons	Not specified	15 days	No	None	
Permit to Drill Test Well	Office of the State Engineer	Location of well, intended use	Not specified	10 days	No	None	

TABLE 5-32 (Cont.)

MINOR PERMIT	GOVERNMENT AGENCY	INFORMATION REQUIREMENTS	COMPLETE- NESS REVIEW TIME	PERMIT REVIEW TIME	PUBLIC COMMENT PERIOD? (Y OR N)	APPLI- CATION FEE	COMMENTS
Notice of Unitization	Oil and Gas Conservation Commission	Copy of cooperative development agreement	Not specified	15 days (est.)	NA	None	A hearing before the commission is required
Land Use Lease	State Board of Land Commissioners	NA	NA	NA	NA	NA	
State Historic Preservation Office Review	Recreation Commission	Archeological site (or literature) survey	Not specified	2 weeks (est.)	No	Based on file search at \$20/hour (\$10 minimum)	
5-140 Certificate of Public Convenience and Necessity	Public Service Commission	Facility description, rates, financial data, site characteristics, and land use	Not specified	2 months - 1-1/2 yrs (est.)	Yes	None	
Encroachment Permit	State Highway Department	Project description and location	Not specified	3-4 weeks (est.)	No	None	
Approach Permit	State Highway Department	Project description and location	Not specified	3-4 weeks (est.)	No	None	
Certificate of Competency	State Inspector of Mines	Certificate of approval by Coal Mine Examining Board	Not applicable	Not applicable	NA	None	Certificate of Competency issued after presentation of certificate of approval by Coal Mine Examining Board

SECTION SIX

NETWORK PRESENTATIONS OF PERMITTING SYSTEMS: OIL AND GAS PROJECTS

The permit data base presented in Sections Four and Five, while providing a comprehensive listing of the applicable approvals, was further refined in order to better describe the regulatory processes of concern to energy developers. Information on the probable applicability of permits to specific types of basic energy projects was developed. The commonly required permits were then displayed in a network-type presentation in order to show the correspondence of regulatory requirements to actual project stages.

The network diagrams used to display the study results are derived from the management tool called "PERT" (Program Evaluation Review Techniques). The PERT system was originally developed in order to assist in the tracking of government research and development projects and allows for the effective presentation of project stages and project logic. Simple PERT diagrams were developed for portrayal of exploration and development stages for representative projects for each resource area. Permits for such projects were then added to the diagrams at the points at which they would be required. The principal output of the PERT tool is the definition of a critical time path for energy projects, which defines the minimum project length given the series of stages needed in the project. The effect of permits upon the critical path or the overall project lead times is one result of interest.

A brief description of the PERT networking systems is provided in the next section. Succeeding sections present the network diagrams for a representative oil and gas project. Similar network diagrams for coal, geothermal, and oil shale projects are developed in Section Seven and Eight of this report. Oil and gas project diagrams were developed for a generalized federal lands project, and then for each study state.

6.1 PERT-CPM Models

Use was made in this study of network modeling techniques such as are useful for displaying a sequence of activities. The network diagrams were designed to aid in the display of the permit required vis-a-vis energy project stages. By examining the relationship of permits and project stages it is possible to determine the types, nature, and severity of the delays which might be caused by the exercise of regulatory authority.

The network diagrams were adapted from the PERT-CPM methods developed in the late 1950's and which are now frequently used in management of large-scale, complex construction projects. The PERT-CPM (Program Evaluation and Review Techniques - Critical Path Method) is a planning technique which requires the consideration of (1) what tasks are to be completed; (2) the sequencing of tasks; (3) the time required for each task; and (4) the resources required for each task. In our case, the last item on resource estimation was not relevant and was not performed.

The project tasks are connected in a network which displays the time relationships for the project. The

network defines the precedence relationships of activities and events in the project. Also, a critical path through the network is identifiable. This path, which represents the minimum possible completion time for the project, given the time required by the sum of all tasks on the path, provides the means of measuring any possible delays through the network chain of activities.

A simple PERT-CPM network section is shown in Figure 6-1. The diagram illustrates several basic elements of network construction. First, the project tasks are defined and their relationship to each other is established. Tasks can be identified by their titles or by the beginning and end nodes of their branches of the network. In the figure, Task B (Nodes 2-3) and Task C (Nodes 2-4) must be completed before Task E (Nodes 4-6) can be initiated. Task D (Nodes 2-5), on the other hand, can be performed independently of all but Task A, but must be finished for project completion. The two dotted lines 3-4 and 5-6 are dummy activities which do not consume time or resources. These activities are included in order to maintain the logical sequence of events. They also allow for unique node identification for each activity.

On the diagram, a critical path of Tasks A, C, and E is identifiable given the time durations estimated. The durations (in months) are the first number given after each task title. The second number refers to the float time or leeway available for a task's completion. Thus, Task B, which requires 4 months, must be completed within 6 months (the time needed for Task C) in order to avoid delaying the entire project. The difference of 2 months is the float time. Instead, if Task B required 7 months, then it would be on the critical path. All critical path activities have

LEGEND

- Activity
- Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months,
Second Entry is Float Time.
Ex.—Activity Requires 10 Months
Float Time Allowance is 11 Months.
- (ND) Activity Time Is Not Determined or
Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine
Diagram. Letters Denote State Permits.

Figure 6—1. Example of the PERT-CPM Network Techniques.

zero float time, as any delay in completion is directly transferable to a delay in overall project completion. Activities with brief float times may come on the critical path if the activity duration is increased. Such a happenstance is possible for many permit programs.

Task D has a short duration time (2 months) although it has been drawn on a lengthy branch in the figure. The length of network segments in the figures is determined only by the need to define logical relationships and is of no other consequence.

In its full embodiment, the PERT-CPM technology is more complex and more powerful than the illustrations of it used here. In many applications of the PERT-CPM techniques, detailed networks with associated manpower utilization plans are prepared for major construction projects. The large numbers of discrete tasks and calculations to be manipulated in such networks have led to the development of specialized PERT-CPM computer software. Such systems recalculate the critical path and float times when changes to the networks are made.

For examining the role of permits in energy project development, relatively simple, manually produced networks proved to be adequate for the analysis and more cost-effective. For even the most complex energy projects, the number of applicable permits can be displayed graphically by hand, and continual recalculation of the critical path (as would be performed if a project was actually being tracked through PERT-CPM) were not necessary.

The principles of PERT-CPM have been followed wherever possible in order to maintain basic consistency with other PERT studies.

6.2 Oil and Gas Project Networks

Network diagrams of representative oil and gas projects were prepared in order to display the sequence of steps involved. Permits were then integrated into the logic of the diagrams in order to isolate their effect and potential for causing delays.

Oil and gas projects involve a lengthy process of geophysical investigation, mineral right and land acquisition, site preparation, drilling, prospect well testing, and, perhaps, eventual field development. Modeling of this process, which varies substantively by region, by company, and by field, is obviously a subjective process. Numerous choices must be made about the types of situations which are of interest, and about what constitutes representative or average industry practice. ERCO has used existing source materials (as described below) to define the basic project network. Staff analysts then directed most of their efforts to adding the permitting requirements of the federal and state governments to the basic network diagram of the projects.

The oil project defined is meant to be roughly representative of the activities undertaken by a medium-sized oil company engaged in a full range of exploration, drilling, and development activities. The project stages and the time frames defined were taken from another study of oilfield processes prepared by the U.S. Congress, Office of Technology Assessment, entitled The Management of Fuel and Nonfuel Minerals in Federal Lands (1977). In the OTA study, oil exploration specialists were contacted in order to define the project stages and the associated time requirements of typical small, medium, and large oil companies. Project

stages were defined with sufficient detail to allow their use in this study. Numerous contacts were made with industry personnel to verify the OTA results, and no notable inaccuracies or discrepancies were identified. The OTA study was judged to be easily the best source for the specialized type of project description needed in this study.

In adopting the OTA project definition, ERCO made only slight adjustments in order to better allow for the addition of permit processes into the diagrams. The OTA time estimates for project stages of medium-size companies were adopted directly, although one 3-month period was added to represent the estimated time needed to obtain a federal drilling permit (called APD or Application for Permit to Drill). The lengthening of the federal APD process from a few weeks to 3 months has occurred since the OTA study was published.¹

6.2.1 Oil and Gas Project Network

A simple, stripped-down version of the representative oil exploration project, as used in the networks, is shown in Figure 6-2. A series of eleven project stages which define the critical path (the straight line through the middle of the figure) are identified from initial exploration (regional appraisal) to production. The numbers in parentheses on the figure refer to the duration and float time, in months, for each stage. As is immediately evident, quite lengthy processes are prescribed for the initial and detailed exploration exercises. Representative times for site preparation, drilling, and development were also estimated. General information concerning the content of project stages is provided below.

LEGEND

— Activity

— Critical Path

(10, 11) First Entry is Activity Time in Months.
Second Entry is Float Time.
Ex.—Activity Requires 10 Months.
—Float Time Allowance is 11 Months.

ND Activity Times Cannot Be Determined.

Note: Code Numbers are taken from Federal Permit Diagrams. Letters Denote State Permits.

Figure 6-2. Simplified Oil and Gas Project Network for Use in Identifying State Permits.

Extensive details of the oil project or of the "typical" oil company involved have not been developed. For the immediate purposes of displaying permit systems, these details were not of interest. It was only necessary to define a project sufficiently so as to allow identification of the commonly-required permits for such projects. In actual fact, wide variations in every stage of the project would exist across projects and firms. An indication of the range of project and permit variations is provided in a separate section on the relative network characteristics of wildcatters and major oil companies provided below in Section Nine of this study.

The 11 project stages on the critical path are given below, with the actual tasks of each stage delineated in Table 6-1.

Regional Appraisal - This stage refers to the initial identification of areas with potential for successful drilling. Much of this task represents data collection and data purchase (as from previous investigators).

Detailed Reconnaissance and Data Interpretation - For the next step, continued data analyses will occur to the point of recommending land purchases. Exploration activities across federal lands, including some seismic testing, may occur during this period.

Decision to Purchase Mineral Rights - Management staff of major oil companies will generally choose from among a number of potential oil and gas plays.

TABLE 6-1

EXPLANATION OF PROJECT STAGES
IN OIL AND GAS PROJECT NETWORK

STAGES AND MAIN ACTIVITIES	LOCATION OF EFFORTS	ESTIMATED TIME REQUIREMENTS	COMMENTS
<u>Regional Appraisal</u>		6 mo	General level of analysis
a. Identification of area potential; management recommends entry.	Office		
b. Literature search	Office		
c. Accumulate pub- lished data, log files, etc.	Office		
d. Assemble regional reports, maps, cross-sections	Office		
e. Selected field trips	Field		
<u>Detailed Reconnaissance and Data Interpretation</u>		35 mo	Concludes with recommended land pur- chases
a. Exploration team assigned	Office		
b. Seismic operations	Field		
c. Field geology	Field		
d. Data purchase	Office		
e. Begin interpre- tation of data	Office		
f. Lab studies of samples, etc.	Lab		
g. Prospects iden- tified, mapped	Office		
h. Land purchases recommended	Office		

TABLE 6-1 (CONT.)

STAGES AND MAIN ACTIVITIES	LOCATION OF EFFORTS	ESTIMATED TIME REQUIREMENTS	COMMENTS
<u>Decision to Purchase Mineral Rights</u>	Office	3 mo	Management chooses preferred oil and gas play
<u>Detailed Surface Study of Target Area</u>		24 mo	Concludes with identification of drilling prospects
a. Begin land acquisition	Office & field		
b. Perform detailed seismic and geological work	Office & field		
c. Make final interpretation of data; montage preparation	Office		
d. Drilling proposal made to management	Office		
<u>Decision to Drill, Rig Schedules</u>	Office	2 mo	Drilling rigs are ordered for approximate drilling plan
<u>Federal Application for Permit to Drill Process</u>	Office & field	3 mo	Site inspections are held, coordinated by MMS
<u>Site Preparation</u>	Field	2 wk	Temporary roads and drilling pads are constructed

TABLE 6-1 (CONT.)

STAGES AND MAIN ACTIVITIES	LOCATION OF EFFORTS	ESTIMATED TIME REQUIREMENTS	COMMENTS
<u>Drilling (Drill Prospects, Run Bore- hole Survey, Do Production Testing)</u>	Field	3 mo	Evaluate prospect wells
<u>Decision to Further Explore/Develop the Field</u>	Office	1 wk	Management decides on actions, given drill- ing results
<u>Delineation and Develop- ment Well Drilling and Completion Activities</u>		20 mo	Additional drilling permits need- ed during development
a. Design needed facilities	Office		
b. Construct roads and prepare locations	Field		
c. Construct produc- tion facilities	Field		
d. Drilling to de- lineate and develop the field	Field		
e. Construction of flow lines	Field		
<u>Production</u>		Not specified	No estimate of repre- sentative field life was pre- pared
a. Contract for sale of production	Office		
b. Make pipeline connection	Field		
c. Unitization of the field if desired	Office		
d. Water injection operations, if desired	Field		
e. Tertiary recovery	Field		

Detailed Surface Study of Target Area - This stage covers the focused seismic and geologic work leading up to the drilling program to be presented to management. Land acquisitions of federal, state, and private (or fee) lands will be made to allow sufficient room for drilling and potential development.

Decision to Drill, Schedule Rigs - Drilling decisions will be made by management at this point. Orders for rigs may need to be made at this time depending upon the existing tightness of rig demand. Rig schedules are continually adjusted to reflect changes in drilling plans as well tests are run.

Federal Application for Permit to Drill Process - The drilling request upon the Application for Permit to Drill (APD) is highly specific, applying to a single well location on federal lands. Because drilling plans have been completed, the APD is placed upon the critical path for the exploration program. Companies frequently request more APD's than they use, partly to retain some flexibility in planning. Simultaneous with the APD process, rights-of-way for access to the federal lease are requested.

Site Preparation - Access roads to the drilling site must be adequate to bear heavy drilling rig equipment. A drill pad is also constructed. These land alterations must wait upon the APD approval.

Drilling - Drilling and production testing occurs at the prospect well or wells. Temporary production facilities are used to support the well operations.

Decision to Further Explore/Develop the Field - Drilling results will elicit management plans for further operations. Plans for delineation wells will be drawn based on the objectives of complete field development and high-level utilization of the drilling rigs on site.

Delineation and Development Well Drilling and Completion Activities - This project stage covers a range of activities determining the size of the oil field and then for the efficient exploitation of it. Successive drilling occurs, generally in a regular pattern around the first successful well, with drilling approvals required for each. Permanent facilities are brought in or constructed as justified by the level of production.

Production - Once the level of production is established, arrangements may be made for the sale of produced resources. Pipeline connections for transporting oil to the nearest refinery are made. At some time during production, other measures may be made to improve recovery such as (1) unitization to allow more efficient development of a field jointly owned by several companies; (2) institution of water injection operations to dispose of excess produced water and to help maintain reservoir pressure; and (3) movement to tertiary and secondary recovery processes.

In the network presentations of the 11 project stages, no variation in activity times by region (or state) were allowed. Systemmatic variations in some activities can be modeled by region. For example, the drilling activity time is a function of drilling depth which varies between the extremes of Southern California (shallow wells in Kern County) and Alabama (deep gas wells). While interesting, these variations affect little of the permitting activity.

Wide variations among oil and gas plays within a region or state are equally or more important and could not be reasonably modeled in this study. For simplicity, these types of variations were excluded. In the coal networks in Section Seven, some state variability among the networks was allowed.

6.2.2 Environmental Considerations for Oil and Gas Projects

Before introducing the state permit networks below, it is useful to summarize the environmental issues for oil and gas exploration and development. Such operations create less land disturbance than mining operations, of course, but important environmental issues are involved for air, water and waste management.

Air Pollution

Minor air pollution impacts are created at each stage of an oil and gas project. The construction and use of roads and drill pad sites adds to local particulate levels. The level of such particulates during development and production is sustained according to the level of traffic on the roads.

Most stationary equipment is associated with artificial lift equipment needed for hydrocarbon recovery at well sites. These pumps generally operate on electricity, although internal combustion engines are used when electricity is not available. Such engines are commonly operated off natural gas supplies. Engines are also needed for powering of the drilling rigs which are temporarily on-site.

Several pollutants are emitted from the facilities needed on-site, including carbon monoxide, hydrocarbons, nitrogen oxides, sulfur oxides and hydrogen sulfides. The emissions occur during oil-water separation, by venting of vapors from storage tanks, and by flaring of unwanted gas.

More significant emission problems occur with processing of sour gas (gas containing hydrogen sulfide). A sulfur recovery plant combined with a tail gas treatment unit are generally effective in removing sulfur emissions. Significant emissions also occur in steamflooding projects due to the requirements for large combustion engines on site. Hydrocarbon, particulates and sulfur oxide emissions must be controlled in this case.

Oil field facilities are subject to PSD reviews at the federal level only if emissions exceed 250 tons of pollutant per year. For most operations, emissions are not that large. State permitting stringency varies, with some states requesting firms permit any emission sources, and others requesting permits only for sources over a given size. California oil fields generally are subject to the most stringent controls, while also producing (in steam flood projects) the highest emission levels.

Water Pollution

The largest volume waste stream from an oil and gas operation is produced water that exists naturally in oil and gas reservoir. The water is brought to the surface with the oil and gas where it is typically removed by gravity separators. Once separated, the water may be reinjected into the oil formation to (1) help maintain pumping pressures and (2) to eliminate the need for surface discharges.

Where injection is not used, disposal occurs using brine evaporation pits. Such water is most frequently brackish or highly saline. If the water quality is quite high, however, release to surface streams or for particular agricultural uses is possible. Oil contamination of local waters is also possible due to spills during transportation, release of oily water, or blowouts during drilling.

Water pollution concerns are largely handled through MMS and state permits covering drilling and production operations. The APD process requires submittal of the 13-point surface use plan. Additional actions are permitted or monitored with regulations on disposal of produced water and sundry notices. Reinjection of water is regulated by state drilling authorities. In cases, where the produced water is of sufficient quality to meet the effluent guideline limitations for oil and gas operations, an NPDES permit may be obtained from EPAf or the state authorized agency.

Oil field wastes include drilling muds and formation cuttings which require some special handling. The drilling needs are a suspension of clay in water with specialty chemicals added to produce the desired characteristics of viscosity, fluid loss, corrosion, and other properties. Cuttings are small pieces of rock produced by the drill bit penetrating the geologic formation.

Reserve pits are normally used to store the needs and cuttings. Construction of the pits is regulated by state oil and gas boards or by the state water pollution authorities. In sensitive areas, an impervious liner for the pit might be required.

Once the well has been completed, and drilling equipment is moved off location, three major methods of waste handling are used (in order of prevalence):

1. Dewatering it wastes followed by backfilling the pit;
2. Landfarming the waste into the surrounding soil;
3. Vacuum truck removal of the pit contents with ultimate disposal in a state-approved disposal site.

The last method is used in the environmentally sensitive areas.

The effect on the environment of drilling mud disposal, as in buried reserve pits, is not yet fully understood. Some muds could be classified as a hazardous waste under the RCRA testing protocols depending on the chemicals and metals in the mud and the leaching tendency of such chemicals. Regulation of drilling wastes under RCRA has been postponed pending the completion of environmental studies. At present, state-imposed disposal regulations are applicable to the materials.

Water Use and Water Appropriation Permits

Drilling operations also require a water supply for use in circulation of drilling fluids. For the initial wildcat well, a water tank truck may be used to bring in water purchased off location.

Alternatively, the oil company may choose to drill a water well on the drilling pad for its water supply.

Typically a water well permit and/or a water appropriation permit would be required in such cases. The difficulty of obtaining needed water supplies varies considerably by region.

Wildlife Issues

Oil and gas operations may disrupt wildlife populations, such as if development is to occur in a habitat area. Impacts may be felt on big game, nongame animals, waterfowl or marine life in wetlands areas, or endangered or threatened species.

Concerns about adverse impacts on wildlife exist in numerous areas, although few operations are actually impeded. In Southern California, an endangered species of lizards exists in active oilfield areas, and some operations have been postponed or deferred. One avenue for implementing wildlife protection is the involvement of the Fish and Wildlife Service in the review of the Application for Permit to Drill submitted to the Minerals Management Service. State Wildlife permits might also apply.

6.2.3 Federal Permits for Oil and Gas Projects

Important federal permits and generic types of state permits can also be added to the representative oil and gas project network. These permits were shown in Figure 6-2 above, which was provided in presenting the basic network. A listing of the federal permits included in the figure is provided in Table 6-2. A more detailed network showing

Figure 6-3. Network Presentation of Representative Oil and Gas Projects on Federal Lands.

TABLE 6-2

FEDERAL PERMITS APPLICABLE TO
NETWORK ANALYSIS OF OIL AND GAS PROJECTS

ACTIVITY BRANCHES (FIG. 6-2)	COMMONLY REQUIRED PERMITS	TIME ALLOTTED	FLOAT TIME	COMMENT
2-2a	Notice of Intent to Explore/ Mineral Management Service (MMS)	1 day	Not applicable	Routine notification Separate notices required for each distinct explor- ation operation.
2b-2c	Notice of Completion of Exploration/MMS	1 day	Not applicable	Routine notification.
6-21 8-11	Pre-Staking Clearance (PSC) and Application for Permit to Drill (APD)/MMS	3 months	None	PSC and APD required for each well on federal lands.
8-10	Rights-of-Way/Bureau of Land Management or Forest Service	3 months	None	Rights-of-way issuance and APD generally granted simultaneously.
15-15a	Filing of Notice of Well Completion/MMS	1 day	Not applicable	Routine notification required by MMS after completion.
15-15b	Sundry Notices and Reports on Wells/MMS	1 day	Not applicable	Routine notification required by MMS for mod- ifications of operations

TABLE 6-2 (CONT.)

ACTIVITY BRANCHES (FIG. 6-2)	COMMONLY REQUIRED PERMITS	TIME ALLOTTED	FLOAT TIME	COMMENT
15-15c	Submittal of Modified Multi-Point Surface Use and Operating Plan (MSUOP)/MMS	1 day	Not applicable	Routine submittal to MMS, modifying MSUOP submitted with original APD.
15-18	Authorization for Disposal of Produced Waters/MMS	1 month	2 months	Operation must submit plan for water disposal.
20-21	NPDES and Other Federal Operating Permits/ Various Agencies	6 months	2 months	The NPDES review, taking 6 months, is the only federal environmental permit listed. PSD permits are not generally applicable.

6-22

Additional Permits of Potential Applicability

Prevention of Significant Deterioration of Air Quality Permit/Environmental Protection Agency (EPA)	Migratory Bird Permits/F&WS
Spill Prevention, Containment and Control Plans/EPA	Bald Eagle Permits/F&WS
Underground Injection Well Operation Permit/ EPA	Approval of Transfer of Operating Rights in an Oil and Gas Lease/Minerals Management Service (MMS)
Discharge of Dredge or Fill Material to U.S. Waters/ Army Corps of Engineers	Approval of Communitization/MMS
National Wildlife Refuge - Special Use Permit/Fish and Wildlife Service (F&WS)	Agreement for the Subsurface Storage of Gas/MMS
Endangered Species Permit/F&WS	Permit for Structures on or Work In Affecting Navigable Waters/COE
Threatened Species Permit/Fish and Wildlife Service (F&WS)	Permit for Dams and Dikes in Navigable Waters/COE

TABLE 6-2 (CONT.)

Bridge Permit/Coast Guard	Notice of Proposed Airspace Obstruction/ Federal Aviation Administration (FAA)
Antiquities Act Permit/Department of the Interior	Notice of Proposed Construction - Alteration of Airports/FAA
Application for Permit to Conduct Archaeological Explorations/Forest Service	Natural Gas Certificate of Public Convenience and Necessity/Department of Energy, Federal Energy Regulatory Commission
Timber Sale Contracts/Forest Service	
Temporary or Permanent Exemption from FUA Prohibitions/ Department of Energy	Permit for Bridges over Navigable Waters/ Department of Transportation

permitting processes within project stages is presented in Figure 6-3.

As mentioned previously, the federal Application for Permit to Drill (APD) process is the primary item of concern to oil and gas developers, as it is on the critical path and any delays in issuance will lead to an equivalent lengthening of the overall project. In conjunction with the APD, rights-of-way requests are processed by the federal surface management agency, either the BLM or Forest Service in most cases. The federal rights-of-way applications, which are commonly needed in order to obtain access to the drilling site, are often simultaneously handled and approved (or disapproved) by MMS and BLM, although the coordination of these permits varies by district. In the network, the APD and rights-of-way are shown to share the critical path, reflecting the close correspondence of the two processes.

Review time estimates for the APD and the rights-of-way of 3 months each were made for the network. The 3-month time period for the APD as used here includes a 15-day preliminary approval process called the Pre-Staking Clearance, which allows initial entry to the lease. Considerable data have been assembled on the recent review times of MMS district offices and these data are presented in Section Nine below which focuses on problems with the APD process.

Other points of federal government involvement in oil and gas operations are also shown in Figure 6-3. The lease acquisition process (Nodes 4-7) occurs in conjunction with an increasingly focused exploration effort. Repeated lease purchases may be made during this time and the figures presented for task duration and float in the figure represent

a much more involved process. Non-federal land acquisitions are also made at this time.

A variety of routine permit submittals are also made to the MMS. The exploration permits, once submitted, allow land entry and no explicit review is involved. Various notices of well completions, abandonments, or modifications are also submitted to the MMS, but these may be filed after the actions are taken. The Authorization for Disposal of Produced Water requires the operator to develop an approved plan for any excess water brought out of ground and takes approximately 1 month for approval. Temporary permission for disposal may be granted if oil field activities are constricted, and their development actions can proceed unimpeded.

For basic production activities, the major environmental permits are not required in most cases. Excess produced water is generally reinjected and a small minority of operators require NPDES permits. Air pollution (PSD) permits are not required generally unless steam generating equipment is brought in for tertiary recovery operations in an attainment area. The applicability of federal air permits is considered also in the state sections.

Furthermore, oil field wastes are not subject to the RCRA hazardous waste regulations, pending further study by EPA of their environmental effects. The federal Underground Injection Control program has not yet been implemented (as of May 1982) and, in any case, responsibility for oil and gas wells will be delegated to the oil and gas regulatory agencies in each state.

The design of the oil and gas network was complicated by the existence of numerous recurring permit activities.

The recurring permits in a successful oil and gas play include the APD's, rights-of-way, state permits (those needed on a per well basis) and various notifications required by the Minerals Management Service. The overall process can be thought of as an inverted pyramid. As successful wells are drilled, and drilling plans are expanded, a widening set of approvals and development activities becomes required. The eventual width and height of the inverted pyramid depends on the extent of the field and the successful drilling within it.

The type and difficulty of permitting accompanying the field development is also dependent upon the extent of the field and the drilling activities. Minor oil fields, such as those with a short life or modest production, may not encompass major approval processes. In such a case, limited production facilities would be adequate and permanent land alterations would be avoided. For a large find, full-scale production systems, off-lease pipelines and other activities would increase the complexity of the permits needed. Environmental permits may then become a major planning concern.

The total length of the critical path for the oil and as project shown is 98.5 months to reach production. Of this only 3 months for the initial APD approval (and concurrent rights-of-way processing) is due solely to regulatory activities. Environmental permits are requested during the design of production facilities and are shown in the network as having brief, 2-month, float times. These permits could be on the critical path in some cases.

6.2.4 Simplified Oil and Gas Project Network

The oil and gas network shown above included too many branches to allow for simple presentation of the state permits also. Thus, the simplified oil and gas project network (shown in Figure 6-2) was utilized for displaying permits for each of the eight states covered. (These diagrams appear in Sections 6.2.4 through 6.2.11 below.) The activity "Obtain State Operating Permits" (20-22) is replaced in the state diagrams by any number of applicable permits.

Separation of federal and state permits suggested a potential problem for the analysis. In cases where the two levels of government interact, separation of the permit requirements may obscure a potential source of delay. This potential was eliminated by including the federal permits in cases where a similar review occurs. The most obvious such cases occur in states which do not operate the principal federal environmental programs. For Utah, for example, which is not authorized to conduct the NPDES program, both state and federal water permits are included in the Utah network.

6.2.4.1 Background Data for State Sections

By way of orientation, basic statistics about the oil and gas industries in each state were assembled. The data provide background concerning the levels of production and the extent of drilling operations in each state. References to the tables are made in the sections below in briefly introducing each state network.

TABLE 6-3

OIL AND GAS WELL DATA AND PRODUCTION IN THE STUDY STATES (1980)

	OIL		NATURAL GAS			
	WELLS DRILLED	BBL CRUDE OIL AND CONDENSATE (000/DAY)	WELLS DRILLED	MARKETED PRODUCTION (MMCF/DAY)	DRY HOLES	TOTAL WELLS
Alabama	29	61	63	103 ^a	104	196
Alaska	122	1,617	4	618	17	143
California	2,050	975	87	722	329	2,466
Colorado	298	81	537	509	497	1,332
Montana	211	81	195	148	404	810
New Mexico	702	206	1,074	3,128	255	2,031
Utah	69	68	92	222	117	278
Wyoming	577	345	230	1,046	515	1,322
Eight-State Total	4,058	3,434	2,282	6,496	2,238	8,578
U.S. Total	28,553	8,597	15,225	55,191	18,233	62,011
% of U.S. Total in Study States	14	40	15	12	12	14

Source: Well data, Joint Association Survey on Drilling Costs, 1980; production data, Oil and Gas Journal, January 25, 1982.

^aAlabama daily production was estimated based on annual production figures in Twentieth Century Petroleum Statistics, 1978, DeGolyer and McNaughton, using 1977 data.

TABLE 6-4

STATE DATA ON WELL DEPTHS AND COSTS (1980)

	TOTAL WELLS	TOTAL FOOTAGE	AVERAGE FOOTAGE/ WELL	TOTAL COST	AVERAGE COST/ WELL ^a	AVERAGE COST/FT
Alabama	196	1,243,438	6,344	\$125,419,837	\$640,000	\$100.9
Alaska ^b	142	1,478,797	10,414	548,416,763	3,862,000	370.8
California ^b	2,355	7,227,421	3,069	621,766,001	203,000	86.0
Colorado	1,332	7,030,587	5,278	329,957,569	248,000	46.9
Montana	810	3,497,914	4,318	244,059,241	301,000	69.8
New Mexico	2,031	11,878,563	5,849	809,742,138	399,000	68.2
Utah	278	1,662,433	5,980	261,775,850	942,000	157.5
Wyoming	1,322	10,381,016	7,853	1,080,938,799	818,000	104.1

Source: Joint Association Survey on Drilling Costs - 1980.

^aTo nearest thousand.

^bIncluded onshore wells only.

The first compilation presents data on the levels of production and the number of wells drilled in each state. These data, presented in Table 6-3, cover each of the eight states, an eight-state total, and a U.S. total in each column. The highest oil production occurred in Alaska, with California second. New Mexico and Wyoming led in gas production.

The differing nature of oil operations in the eight states can be glimpsed from the data in the Joint Association Survey (a survey performed by a combination of industry trade associations) on drilling costs. Data on the footage and cost of wells are provided in Table 6-4. Simple arithmetic allows derivation of figures on average footage per well, average cost per well, and average cost per foot. Well costs are roughly correspondent with well depths. Thus, California, with its numerous shallow wells, has an average well cost of only \$203,000. The deeper wells of Alabama, Utah, and Wyoming are three to five times as high in average cost. Alaskan operators, with an average well depth of over 10,000 feet, spend \$3.8 million per well. The cost per foot data also show the difficulty of Alaskan conditions. Alaskan wells cost \$370.8/ft as compared to the rough U.S. average of \$100/ft.

6.2.5 Alabama Oil and Gas Projects

Alabama is the smallest producer of both oil and gas among the eight states examined in this report. Activities for gas production are more common with approximately twice as many successful gas wells as oil wells being drilled. However, gas production amounted to 103 million cubic feet per day, which equals only 3 percent of the total for New Mexico, the largest gas producer covered in this study. Production is derived principally from several small oil and gas fields in the southwestern portion of the state.

Oil and gas producers must file a series of permit applications, but state permits are rarely critical-path items in Alabama. The Alabama state permit network is shown in Figure 6-4, with the individual permits described in Table 6-5. Three of the branches shown cover permits required by the Alabama State Oil and Gas Board for the activities of drilling, deep-well disposal, and other field operations. One of these permits, the Producer's Certification to Transport Oil and Gas, is used to verify compliance with other state drilling permits on a given lease prior to removal of produced oil.

State air pollution permits may be required for gas processing plants placed on-site in the gas-producing fields. "Sour" gas, that is, gas containing H_2S , must be cleaned before it can be added to a gas pipeline. Sulfur recovery equipment in the field is regulated by the Alabama Air Pollution Control Commission. A Permit to Construct is first issued prior to placement of the processing unit. A Permit to Operate is issued automatically if facility tests verify emission levels. The Temporary Permit to Operate allows the facility owner to utilize his equipment prior to testing.

NPDES permits are required for surface discharges, although reinjection of wastewater appears more common. Wastewater disposal well applications are processed within 3 weeks of application. If an NPDES permit is required, the lengthier review process puts only a 2-month float in the network shown, leaving a possibility that the permit will occasionally become part of the critical path. Also, operators expressed some uncertainty about the division of authority between the Alabama Water Improvement Commission (which handles the NPDES) and the State Oil and Gas Board (which regulates reinjection of waste/waters into an oil-bearing formation), suggesting potential for confusion and delays. However, if delays do occur for water pollution permits, they are the exception because of the predominance of injection methods.

Few Alabama operators have experience with MMS permits because federal landholdings in the state are not extensive. In terms of state permits, no consistent problems are evident for onshore drilling activities. Lengthy delays were noted by operators for offshore drilling and for activities in wetlands when the U.S. Army Corps of Engineers has regulatory powers. The delays estimated for COE permits were 4-6 months.²

Nine distinct state permits or permit types in all were identified in Alabama with most representing short approval processes. The most important environmental permits were not seen as representing difficult regulatory obstacles by the oil and gas developers contacted. Only occasional delays were noted for other permit processes.

Figure 6—4. Alabama Permits Displayed on Simplified Oil and Gas Network.

TABLE 6-5

STATE OF ALABAMA PERMITS APPLICABLE TO
OIL AND GAS NETWORK ANALYSIS

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Application for Permit to Drill/State Oil and Gas Board	1 week	2-3/4 months	Routine state drilling approval. May be replaced by Application for Permit to Drill Directionally.
Right-of-Way for State Lands/ Various Agencies	2 months	1 month	May be required for access to state lands.
NPDES Permit/Alabama Water Improvement Commission	6 months	2 months	Full 6 months allowed for review are very rarely needed in Alabama.
Application for Disposal Well/State Oil and Gas Board	2 weeks; recurring permit	Not applicable	Required for waste water injection.
Permit to Construct (Air Emissions Permit)/ Alabama Air Pollution Control Commission (AAPCC)	2 months	6 months	Required if gas clean-up plant is needed in the field.
Temporary Permit to Operate/ AAPCC	Not applicable	Not applicable	Governs first months of operation prior to per- formance of facility tests.
Permit to Operate (Air Emissions Permit)/AAPCC	Not applicable	Not applicable	Issued on completion of facility tests.

TABLE 6-5 (Continued)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Temporary Emissions Permit/ AAPCC	1 week; re- curring permit	Not defined	Required for flaring of waste gas.
Producer's Certification for Authorization to Transport Oil, Gas, or Condensate from Lease, other Reports/ State Oil and Gas Board	1 week; re- curring permit	Not defined	Certification is used to verify compliance with all drilling regulations.
<u>Additional Permits of Possible Applicability</u>			
Special Agreement for Installation of Utilities in Rights-of-Way		Highways, Bureau of Administration	
Certification of Public Necessity and Convenience		Public Service Commission	
Application for Permit to Drill Directionally		State Oil and Gas Board	
Notice of Intention to Chemically Treat or Fracture a Well		State Oil and Gas Board	
Letter of Concurrence		Historical Commission of Alabama	
Certificate for Industrial Development		Public Service Commission	
Pollution Abatement Plan		Alabama Water Improvement Commission	

6.2.6 Alaska Oil and Gas Projects

Oil and gas operations are closely controlled by Alaskan authorities, and regulatory restraints and permitting requirements for the state are quite strict. Also, the difficulty of operating in the frigid weather conditions of the state's oil fields has a major effect on the overall length of oil projects.

Alaskan oil operations are characterized by large volume oil production from relatively few wells. The state's oil production in 1980 was 1.6 million barrels/day, which was easily highest among the eight states and over 60 percent greater than California production. During 1980, only 143 wells (fewest among the eight states) were drilled. Of these, only 17 were dry holes, partly indicating the care which must be taken in drilling operations in the state. Most development is occurring on the Alaskan North Slope in the tundra areas.

Alaskan authorities regulate oil production from all environmental standpoints. The network diagram for Alaska is shown in Figure 6-5, with the permit listing in Table 6-6. State permits cover air pollution, wastewater disposal, and solid waste disposal. Most states only regulate solid waste disposal sites in the oil fields through the oil and gas commission and not with separate environmental approvals. Also, the Alaskan open burning regulations apply to gas flaring during oil operations, and thus flaring of waste gas (gas is flared frequently when no local market for the gas is available) is controlled at each well.

The activity times for some permits are fairly long, i.e., to 6 months. These long review times are due to the

absence of state authority for administering the federal environmental programs. For example, if an NPDES permit is required for an installation, the state Wastewater Discharge Permit will not be issued until the NPDES is approved, which requires up to 6 months.

The Alaskan permits were displayed on the same simplified network diagram used for other states. "Typical" Alaskan oil and gas projects are longer than those on the continental United States. Information prepared by the Alaska Oil and Gas Association indicated project leadtimes of 10 years or more for onshore production. The critical path for Alaska, therefore, would stretch from 98.5 months (as shown here) to 120 months or more.³ (All state permit networks were based on identical diagrams for simplicity.)

Complaints concerning the efficiency of permit processes in Alaska have been made by the Alaskan Oil and Gas Association.⁴ Delays were noted for (1) NPDES processes, (2) air quality permits, and (3) regulatory processes for offshore platforms. According to AOGA, a main reason for delays in permit issuance has been the division of authority between state and federal governments, resulting in excessive permit handling and review by state agencies. Difficulties with these permit programs for the industry in general are discussed below in Section Nine.

Federal permits, in particular rights-of way approvals, are also relatively difficult to obtain for Alaskan operations. For a drilling site in the Northern tundra, the movement of heavy vehicles may damage the top layers of the permafrost barrier. Cracks in the surface layers may allow for erosion and excessive land disturbance. To prevent such occurrences, BLM may require a right-of-way approval for

activities which, if occurring in the lower 48 states, would be automatically allowed as "casual use" (activities not causing permanent land disturbances).

In all, 13 state approvals were identified in Alaska. Additional permits would be required for offshore activities or for projects with unusual characteristics. In general, both the physical nature of the operations and the manner and extent of regulatory coverage make Alaskan projects difficult undertakings.

Figure 6—5. Alaska Permits Displayed on Simplified Oil and Gas Network.

TABLE 6-6

STATE OF ALASKA PERMITS APPLICABLE TO OIL AND GAS NETWORK ANALYSIS

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permit to Drill/Dept. of Commerce and Econ. Dev./ Oil and Gas Conservation Commission	2 weeks	2-1/2 months	Routine state drilling approval.
Surface Oiling Permit/ Dept. of Environment Conservation	1 week	2-3/4 months	Required for oiling of roads, as may be done in lease area.
Rights-of-Way and Easements for State Lands/Various Agencies	2 months	1 months	Occasionally significant delays could occur in sensitive areas.
Air Quality Control Permits to Open Burn/DEC	1 month	2 months	Covers flaring of gas during production testing.
Solid Waste Disposal Permit/ DEC	4 months	4 months	Permit required for drilling mud disposal.
Plan Review for Wastewater Treatment Works/DEC	2 months	6 months	Applies to any wastewater discharges.
Water Well Authorization/ DCED, Oil and Gas Conser- vation Commission	1 month	6 months	Routine drilling approval.

TABLE 6-6 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Water Rights Permit (and Certificate of Appropriation)/ Dept. of Natural Resources, Div. of Land and Water	1 month	6 months	Water rights are not a major permit in Alaska.
Wastewater Disposal Permit/ DEC	6 months	2 months	If discharges are planned, approval requires previous issuance of NPDES by EPA.
Certificate of Reasonable Assurance/DEC	6 months	2 months	Certificate issuance is tied to wastewater discharge approval.
Air Quality Control Permit to Operate/DEC	6 months	2 months	Required for all emission generators.
Operating Notices/Oil and Gas Conservation Commission	Not applicable	Not determined	Notifications are routinely handled
Application for Additional Recovery Approval/OCED, Oil and Gas Conservation Commission	2 months	Not determined	Approval needed for selected oil field operations

Additional Permits of Possible Applicability

Alaska Coastal Management Program/Certificate of Consistency

Office of the Governor

Certificate of Public Convenience and Necessity

Public Utilities Commission

TABLE 6-6 (CONT.)

Anadromous Fish Protection Permit	Department of Fish and Game
Fishways for Obstructions to Fish Passage	Department of Fish and Game
State Game Refuge Permit	Department of Fish and Game
State Park Noncompatible Use Permit	Department of Fish and Game
Oil Discharge Contingency Plan	DEC, Oil Pollution Control Division
Proof of Financial Responsibility	DEC, Oil Pollution Control Division
Land Use Permit	Division of Minerals and Energy Management
Oil and Gas Lease	DRN, Division of Minerals and Energy Management
Burning Permit	Department of Natural Resources
Critical Habitat Area Permit	Department of Fish and Game
Lease Operation Approval	Department of Natural Resources

6.2.7 California Oil and Gas Projects

California, one of the major oil-producing states in the United States, has the most highly visible permitting requirements of all the study states. The thermal recovery processes, widely used for development of California oil fields, use large oil-fired steam generating equipment which must be approved by the district offices of the California Air Resources Board and, in some cases, by EPA. As will be discussed below, these air quality programs dominate the California permitting issues.

Drilling activities in California are concentrated in development projects in established oil fields. According to Table 6-3 above, 1980 drilling in California resulted in 2050 oil wells and 87 gas wells, but only 329 dry holes, indicating this development emphasis through the high success rate. Oil production was just below 1 million barrels of crude oil per day, second to Alaska among the states being reviewed. Over 50 percent of this production was derived in thermal recovery processes employed to extract the heavy low-viscosity oil found in the Kern County oil fields of the southern San Joaquin Valley.

The California network is shown in Figure 6-6, with Table 6-7 providing a list of the permits included. State notifications for permits to drill and for water injection can be quickly approved, as they are in most states. In the case of water injection projects, the operator files, with the Division of Oil and Gas, a Project Proposal (for water injection) which describes the intended activities. Separate drilling permits are then required for each water well. Occasionally, if fresh water is produced by an oil well, an NPDES permit may be issued to allow surface discharges of water.

Of more concern than the drilling permits, however, are the air pollution permits required in the state. Air pollution regulations are the main regulatory obstacle for secondary recovery operations. The degree to which the necessary permits are on the critical path depends largely upon the pattern and timing of oil field development.

In the network shown, it has been assumed that the oil field in question goes through two stages of production: (1) primary production and eventually, depleting primary production, during which pressures in the reservoir decline, and (2) secondary production, during which steam generators are used to improve production rates. The steam is used to heat the oil to allow recovery of an additional portion of the reservoir which primary production techniques cannot capture.

The timing of the switchover from primary to secondary production depends on the size of the reservoir and many other factors. Oil companies may sustain primary recovery systems until depleting production necessitates the investment in steam recovery systems. The company may then continue with its declining production wells while planning for and obtaining permits for new facilities.

Air pollution permits (both an Authority to Construct and an Authority to Operate) must be obtained for each stage of production. These permits are noted in the California permit network shown. The relationship of the air quality permits to the critical path depends upon the oil company's ability to forecast its production requirements and its equipment needs. Because of the variability in the length of the primary production stage, the critical path after primary production was not modeled. However, oil company

representatives have indicated that project delays can occur due to air permitting difficulties. At times, the Kern County Air Quality Control District, which encompasses the heavy oil reserve areas, has become overwhelmed with permit applications for steam generating equipment. This situation has occurred immediately prior to what the oil companies considered adverse changes in the regulations. Firms were encouraged to rush to submit all conceivable future permit applications. As a result, processing was slowed.

For operations in attainment areas, PSD permits must be obtained from the EPA office in San Francisco, further complicating the application/review process. Most Kern County oil fields require PSD permits for new installations. Overall, the California approval process may require from 4 to 9 months, with the longer review representing the PSD process.⁵

The oil companies contacted appear to expect long leadtimes for their secondary recovery installations, largely as a result of air pollution permits. Such leadtimes may indicate that the permit process is on the critical path although, as noted above, the critical path was not modeled after the primary production stage because of the reservoir-specific nature of the production pattern. Suffice it to say that air quality permits are potential sources of delay for oil field operators.

California oil company representatives have also complained of APD processing delays due to endangered species questions. Some operators have been restrained by the concerns that the blunt-nosed leopard lizard, which is unique to California's San Joaquin Valley, may be disturbed by oil field activities. During the APD preparation and

review, wildlife surveys are conducted in order to discover any possible lizard habitats. In some cases where habitats were found, the drilling permits were held up by more than 1 year.⁶

In all, eight permit types were identified among California processes as applying to most state oil operations. The air permits and the federal APD difficulties were the main concerns of the oil firms contacted. Other approvals could be quickly obtained or, because requirements are well understood, do not present problems for most operators.

LEGEND

- Activity
- - - - - Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months, Second Entry is Float Time.
Ex.—Activity Requires 10 Months
Float Time Allowance is 11 Months.
- (ND) Activity Time Is Not Determined or Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine Diagram. Letters Denote State Permits.

Figure 6—6. California Permits Displayed on Simplified Oil and Gas Network.

TABLE 6-7

STATE OF CALIFORNIA PERMITS APPLICABLE
TO OIL AND GAS NETWORK ANALYSIS

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Authority to Construct (Air Emission Source)/ California Air Quality Control Board	6 months	2 months	Needed for operation of steam generators in ter- tiary recovery.
Authority to Operate (Air Emission Source)/ California Air Quality Control Board	No review time required	Not applicable	Granted if construction is according to permit speci- fications.
Notice of Intention to Drill (including Water Wells)/ Division of Oil and Gas	10 days; recurring permit	2-1/2 months	Required for each new oil well or water injection well.
NPDES Permit/ California Water Resources Board	6 months	3 months	Waste water injection is the preferred method of disposal.
Project Proposal (for Water Injection)/ Division of Oil and Gas	1 month	3 months	Needed for water disposal or for waterflooding.
Rights-of-Way and Easements/ State Lands Commission; CALTRANS	2 months	1 month	State lands and facilities may be impinged upon during development, requiring state rights-of-way
Sundry Notices/Division of Oil and Gas	Not applicable	Not applicable	Sundry notices are submit- ted after action is completed

TABLE 6-7

Additional Permits of Possible Applicability

Permit to Appropriate Water	State Water Resources Control Board
Stream or Lake Alteration Agreement	Department of Fish and Game
Certificate of Public Convenience and Necessity	Public Utilities Commission
Coastal Development Permit	California Coastal Commission
Hazardous Waste Facility Permit	Department of Health
Land Use Lease	State Lands Commission
Encroachment Permit	Reclamation Board
Solid Waste Facility Permit	Solid Waste Management Board
Facility Permit, Waste Discharge	Regional Water Quality Board
Easements for State Forest Lands	Department of Forestry
Temporary Use Permit	Department of Parks and Recreation

6.2.8 Colorado Oil and Gas Projects

Colorado, like other Rocky Mountain states, is the site of significant oil exploration operations. To date, the surge in activity has not notably lengthened the state's permitting processes, with the possible exception of the water well drilling permits sometimes required in field development.

Colorado has a number of small oil fields scattered throughout the northern half of the state, and a major gas field in the southwestern corner of the state. Production in 1980 was approximately 81,000 barrels of crude oil per day, and 509 million cubic feet of natural gas per day. Each of these figures equals approximately 1 percent of the U.S. totals. Nevertheless the drilling activity, particularly in the Overthrust Belt, is fairly heavy, with 1,332 new wells drilled in 1980.

Although Colorado has numerous energy-related permits, relatively few apply to oil and gas operations. The state's permit network is shown in Figure 5-7, with the applicable permits listed in Table 5-8. The Oil and Gas Conservation Commission issues the standard permits to drill and also regulates reinjection or surface disposal of produced water and drilling wastes. Processing times are typically short.

The Colorado State Historical Society issues Cultural Resource Clearances which provide for preservation of archaeological values. This agency is typical of a number of historical preservation agencies in western states which review operations on federal lands. In most instances, the agency will notify any federal land lessee of potential historical values, and will require an inventory of the lease prior to land disturbance.

Several oil and gas operators noted the difficulties in Colorado of obtaining approvals for drilling water wells. Permitting for water wells in Colorado is differentiated by geographic area (e.g., East Slope vs. West Slope of the Rocky Mountain Range) and by hydrologic designation (e.g., bedrock aquifers and designated or non-designated groundwater basins). Permits for water well construction and appropriation generally take from 3 to 4 months, although in some areas up to 7 months are needed. The slow processing has been caused by the large volume of applications being received by the Colorado Division of Water Resources. Oil and gas developers, as a result of these approval delays, may seek several options for water supply such as (1) water rights purchases from private individuals, (2) water acquisition from the river sources, and (3) water well construction on the drilling pad. Permitting and purchase negotiations for all three may proceed simultaneously. As a result, the water well permits can generally be kept off the critical path. In the network diagram, water well permits are a non-critical item shown occurring during field development.

Other Colorado permits are briefly noteworthy. The state requires air pollution permits for any fossil fuel fired generators in the field, and for gas processing or gas flaring operations. Firms which can use electrical motors in the field and which have minor sulfur emissions (i.e., produce sweet gas) do not require the air pollution permit. For water pollution, reinjection of wastewater is most common. Few NPDES applications are made by oil and gas operators in Colorado (as is true in most states). These permits generally are not on the critical path for operators.

Ten distinct permits in all were identified as applying to most Colorado oil projects. With the possible exception of water appropriation permits in some areas, permitting issues have little delay potential for operators.

Figure 6-7. Colorado Permits Displayed on Simplified Oil and Gas Network.

TABLE 6-8

STATE OF COLORADO PERMITS APPLICABLE TO OIL AND GAS NETWORK ANALYSIS

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Exploration Permit/State Board of Land Commissioners	2 weeks	Not determined	Needed if exploration activities also cover state land.
Cultural Resource Clearance/ Colorado State Historical Society	2 months	3 months	Required prior to activities of federal lands.
Special Transport Permit/ Department of Highways	1 week	4 months	Regulates movement of oversize vehicles such as drilling rigs.
Permit to Drill/Oil and Gas Conservation Commission	1 month	2 months	Routine state drilling approval.
Rights-of-Way and Easements for State Lands/State Board of Land Commissioners and Department of Highways	3 months	None	If state lands are interspersed with federal lease, access permits may be needed.
Permit for Water Well in Bedrock Aquifer, Designated Groundwater Basin or Other Area/Department of Natural Resources, Division of Water Resources	7 months	1 month	If water well is needed, lengthy process may ensue. Depending on area, review takes 3-7 months.

TABLE 6-8 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
NPDES Permit/Department of Health, Water Quality Control Division	6 months	2 months	Few NPDES permits processed for oil and gas.
or Injection Well Reports/Oil and Gas Conservation Commission	1 week	2 months	Reporting of Injection activity is quickly processed.
Air Pollution Emission Permit/DOH, Air Pollution Emission Permit	6 months	2 months	Fossil-fired equipment and gas processing requirements permits.
Sundry Notices and Reports/Oil and Gas Conservation Commission	Not applicable	Not applicable	Minor notices for reporting of oil field activities.

Additional Permits of Possible Applicability

Open Burning Permit

Air Pollution Control

License for Water and Wastewater Treatment Operators

Water Quality Control Division

Application to Store, Use and Transport Explosives

Division of Mines

Permit for Explosive Materials

Division of Labor-Public Safety Section

Certificate of Public Convenience and Necessity

Public Utilities Commission

Oil and Gas Lease

State Board of Land Commissions

TABLE 6-8 (CONT.)

Authorization of Unitization	State Board of Land Commissioners
Authorization of Communitization	State Board of Land Commissioners
Certificate for Boilers	Division of Labor
Application for Water Rights	District Water Court
Approval of Plans for a Reservoir	Division of Water Resources
Site Approval of Sewage Collection and Treatment Facility	Water Quality Control Division
Permit to Construct an Erosion Control Dam	Division of Water Resources

6.2.9 Montana Oil and Gas Projects

Montana's regulatory controls have not placed unusual restrictions on oil and gas developers. Permitting activities in the state involve the common drilling approvals, such as the state permits to drill and air or water emission permits.

Montana's oil production level is modest, representing approximately 1 percent of the U.S. total, and gas production is equal to only one third of 1 percent. However, exploratory drilling activity is fairly high. Of 800 wells drilled in the state in 1980, one-half were dry holes suggesting a large volume of wildcat activities. This ratio of dry holes to oil wells drilled was highest among the eight states covered.

The permitting network for Montana is not complex. The network is shown in Figure 6-8, and the permits shown are also listed in Table 6-9. The permit for Geophysical Exploration is actually a license for conducting seismic operations in the state, and one permit could be applied to a number of exploration actions. Because the permit is a license rather than an activity-specific permit, no duration time or float period has been attached to the network branch. The state drilling permits and state rights-of-way are similar to those for the other states covered and quick approvals are most common.

The major environmental permits apply selectively to oil and gas operators. For air quality, all emission sources producing 25 tons/yr or more of a given pollutant are required to obtain a state permit. This minimum cut-off captures the larger gas processing (gas clean-up) plants, selected permanent installations of diesel engines for

processing or compression of gas and oil, and gas flaring operations. A few installations in Montana may also require PSD permits (issued by Montana), and the state regulatory agency is currently surveying operators to gauge the extent of air emissions.⁷ Should they be needed, PSD permits could delay or restrict some Montana operations.

Water discharge or injection wells are obtainable as needed. Injection is most common among operators. For water supplies needed during drilling, purchases of water supplies are most commonly made. Occasionally water wells are drilled (requiring appropriation permits) if other sources are not available.

Eight permit types in all were identified for Montana. No permit programs represent unusual difficulties for developers.

LEGEND

- Activity
- - - - - Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months, Second Entry is Float Time.
Ex.—Activity Requires 10 Months
Float Time Allowance is 11 Months.
- (ND) Activity Time Is Not Determined or Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine Diagram. Letters Denote State Permits.

Figure 6-8. Montana Permits Displayed on Simplified Oil and Gas Network.

TABLE 6-9

STATE OF MONTANA PERMITS APPLICABLE TO OIL AND GAS PROJECT NETWORK

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permit for Geophysical Exploration/County Clerk and Recorder	Not determined	Not determined	A license must be obtained prior to seismic operations.
Notice of Intent to Drill/ Department of Natural Resources and Conservation; Oil and Gas Conservation Division	1 week	2-3/4 months	State approval requires previous MMS approval; same form used for water injection wells.
Rights-of-Way and Easements for State Lands/Department of State Lands or Department of Highways	2 months	1 month	Several minor permits may be needed for access or special uses of state land during development.
Water Use Permit/ DNRC, Water Rights Bureau	6 months	2 months	Occasionally, the water ap- propriation process may be initiated by operators.
Water Pollutant Discharge Permit/DHES, Water Quality Bureau	6 months	2 months	Some firms, due to lack of options, require discharge permits.
or NOI to Drill (Injection Wells)/DNRC, Oil and Gas Conservation Division	1 week	2 months	Injection of wastewater is common.
Air Pollutant Discharge Permits/DHES, Air Quality Bureau	6 months	2 months	Required for large pro- cessing or gas flaring operations.

TABLE 6-9 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Operating Notices/Oil and Gas Conservation Commission	Not applicable	Not applicable	Operating notices are routinely handled, submitted after the event covered.
<u>Additional Permits of Possible Applicability</u>			
3A Authorization (Short-term water quality impacts)		DHES, Water Quality Bureau	
Solid Waste Disposal License		DHES, Water Rights Bureau	
Stream Alteration Approval		Department of Fish, Wildlife, and Parks	
Oil and Gas Land Lease		Department of State Lands (DSL)	
Land Use Permit		DNRC	
Slash Disposal Agreement (Tree cutting)		DSL, Forestry Division	
Complaint for Condemnation		District Court	
Antiquity Site Permit		State Historical Society	

6.2.10 New Mexico Oil and Gas Projects

New Mexico's permitting systems for oil and gas projects reflect the careful guarding of the state's water resources, but otherwise have no special elements. The permit systems overall are similar to those of most other states covered.

New Mexico has modest oil resources (2 percent of the total U.S. crude oil production) and more significant natural gas production (6 percent of total production). The major oil fields are in the southeastern and northwestern corners of the state. The northwest area also includes the major natural gas production area.

New Mexico is the only state which does not require a state drilling permit for activities on federal lands. The absence of the normal state permit can be noted for the New Mexico network provided in Figure 6-9, and in the permit listing in Table 6-10. The New Mexico Oil Conservation Division receives a copy of the federal APD package but issues no drilling permits itself. The New Mexico Historical Preservation Bureau monitors land alterations on federal leases and will issue an archaeology permit prior to or as part of the federal APD process. Otherwise, the Oil Conservation Division requires a fairly standard set of well reports covering abandonments, transport of product, and well modifications.

Water injection permits are differentiated by whether productive or non-productive oilfield zones are used. Reinjection is especially common in New Mexico because no surface disposal of muds and brines is allowed. The Effluent Discharge Plan covers the overall disposal system proposed by the operator.

Air quality regulations require permitting of sources emitting 25 tons/yr or more of a given pollutant. Large gas processing plants and selected permanent field installations exceed this minimum emission level and must be permitted.

Seven permits were identified among New Mexico state regulations as generally applying to oil and gas operators. The companies contacted reported consistent difficulties only with the necessary federal APD approval process. The APD issue is covered in Section Nine of this study.

LEGEND

— Activity

— Critical Path

(10, 11) First Entry is Activity Time in Months.
Second Entry is Float Time.
Ex.—Activity Requires 10 Months.
—Float Time Allowance is 11 Months.

ND Activity Times Cannot Be Determined.

Note: Code Numbers are taken from Federal Permit Diagrams. Letters Denote State Permits.

Figure 6—9. New Mexico Permits Displayed on Simplified Oil and Gas Network.

TABLE 6-10

STATE OF NEW MEXICO PERMITS APPLICABLE TO OIL AND GAS NETWORK ANALYSIS

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permit for Archaeological Survey and Excavation Easements/ Historical Preservation Bureau, New Mexico State Planning Division	1 month	4 months	State issued permit is needed for federal lands activities
Rights-of-Way and Easements for State Lands/State Land Office	1 month	2 months	May be needed for access to federal lease.
Certificates of Compliance and Authority to Transport Oil and Gas/Oil Conservation Division, Energy and Minerals Department	1 week each	Not determined	Verification of compliance with state regulations.
Operating Notices/Oil Conservation Division, Energy and Minerals Department	Not stated	Not applicable	Includes various notices reporting on oil field activities.
Authorization to Inject/ Oil Conservation Division Energy and Minerals Department	Not stated (1/2-2 months for each)	Not determined	Permit needed for each water disposal well.
Effluent Discharge Plan Approval/Oil Conservation Division, Energy and Minerals Department	6 months	2 months	Approval of discharge plan required.

TABLE 6-10 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Air Quality Construction Permit	5 months	3 months	May be needed for gas flaring, or gas processing plants exceeding minimum emissions levels.
<u>Additional Permits of Possible Applicability</u>			
Permit to Appropriate and Use the Underground Waters of the State of New Mexico			Natural Resources Department (NRD), Water Resources Division
Permit to Appropriate and Use Surface Water			NRD, Water Resources Division
Certificate and License to Appropriate (Groundwater)			NRD, Water Resources Division
License to Appropriate (Surface water)			NRD, Water Resources Division
Permit to Change Location of Well and Place or Purpose of Underground Waters			NRD, Water Resources Division
Water Well Drillers License			NRD, Water Resources Division
Water Supply Construction Permit			Health and Environment Department (HED), Water Supply Section
Approval of Drill Hole Plugging			NRD, Water Resources Division
State Trust Land Lease			State Land Office
License to Operate a Pipeline			Corporations Commission
Utility Permit			Highway Department

6.2.11 Utah Oil and Gas Projects

Like most of the other states, Utah presents no major permitting difficulties to oil and gas operators. Serious delays are not common from among the routine set of drilling and production-related permits.

Among the Rocky Mountain states covered (Colorado, Montana, New Mexico, Wyoming, Utah), Utah has the lowest oil production and second lowest gas production level (Montana is lowest). The extent of well drilling activities is much lower than for any of the other Western states, with only 278 new wells in 1980 as compared to 1300 for Wyoming and Colorado and 800 for Montana. Thus, Utah sees a relatively modest level of activity, which is concentrated in the northeast corner of the state near the Colorado border.

The Utah agencies require a set of permits similar to other states. The permit network is shown in Figure 6-10, with the permit listing provided in Table 6-11. Permits are issued by the Division of Oil, Gas and Mining for well drilling and for injection of produced water. Rights-of-way across state lands may be required, as they frequently are in most states, because of the interspersed nature of state and federal lands.

For air quality, all pollutant-emitting sources must be permitted. Thus, various diesel engines and power-generating equipment in the field (if electrical lines cannot be tapped) would require permits. PSD permits (the PSD program is operated by Utah) could also be required, although very few applications have been made in recent years by oil field operators.

The state issues permits for underground and for surface disposal of wastewater. If surface disposal is used, a federal NPDES is still required because Utah does not handle that program.

In all, nine state permits were identified as applicable for many Utah projects. The coverage of the permits is quite similar to that of other states and no special problems were noted.

LEGEND

- Activity
- - - Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months, Second Entry is Float Time.
Ex.—Activity Requires 10 Months Float Time Allowance is 11 Months.
- (ND) Activity Time Is Not Determined or Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine Diagram. Letters Denote State Permits.

Figure 6-10. Utah Permits Displayed on Simplified Oil and Gas Network.

TABLE 6-11

STATE OF UTAH PERMITS APPLICABLE TO OIL AND GAS PROJECT NETWORK

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permit to Commence Non-Coal Exploration Activities	1 month	Not determined	A brief approval process is required for activities including surveying and taking of core samples.
Permit to Explore, Excavate or Remove Archaeological or Paleontological Remains/ Division of State Lands	1 month	4 months	Archaeological survey required prior to drilling.
Notice of Intention to Drill/ Division of Oil, Gas and Mining	1 week	2-3/4 months	Routine state drilling permit.
Rights-of-Way and Easements Across State Lands/Division of State Lands and Division of Wildlife Resources	2 months	1 month	May be needed for access to federal lease.
Well Drillers Permit/ Division of Water Rights	1 month	1 month	A license required for personnel drilling water wells.
Application for Change in Point of Dispersion, Place, or Nature or Use of Water/ Division of Water Rights	6 months	6 months	A possible, albeit lengthy method of water acquisition. Other water purchase methods may be used.
NPDES Permit/EPA, Denver Office	6 months	2 months	Utah does not run NPDES pro- gram. If discharging, fed- eral permit is needed also.

TABLE 6-11 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permit for Discharge of Wastewater into State Water/Division of Environmental Health	2 months	6 months	Needed prior to con- struction of equipment, if discharging to surface water.
Underground Disposal of Water Associated with Oil and Gas Drilling/ Division of Oil, Gas and Mining	2 weeks	6 months	Permit needed for injection operations.
Review and Approval of Air Pollution Sources	5 months	3 months	All emitting equipment must be permitted.
Operating Notices of Division of Oil, Gas and Mining	Not stated	Not applicable	Sundry notices and reports on oil field operations.

Additional Permits of Possible Applicability

Open Burning Permit	Division of Environmental Health (DEH)
Certificate of Appropriation of Water	Division of Water Rights
Approval of Disposal of Solid Waste	DEH
Approval of a Development Proposal Impinging on the Provo-Jordon River	Division of Parks and Recreation

TABLE 6-11 (CONT.)

Certificate of Registration to Take Protected Wildlife	Division of Wildlife Resources (DWR)
Relocation or Alteration of Natural Stream	Division of Water Rights
Notice of Intent to Divert a Canal, Reservoir, or Other Waterway Containing Protected Aquatic Wildlife	DWR
State Mineral Lease	Division of State Lands (DSL)
Use Permit for State Park Lands	Division of Parks and Recreation (DPR)
Special Use Permit for State Lands	DSL
Application to Remove a Heritage Tree	DSL
Permit for Overweight Vehicles	Highway Patrol
Approval of Drinking Water System	Division of Environmental Health
Permit for Wastewater Disposal System	Division of Environmental Health

6.2.12 Wyoming Oil and Gas Projects

Wyoming state agencies appear to handle oil- and gas-related permits with considerable dispatch, as some approvals take only a few days. No exceptional permitting requirements exist in the state.

Wyoming is the largest oil producer among the Rocky Mountain states with average daily production in 1980 of 345,000 barrels of crude oil per day (equal to 4 percent of domestic production). Gas production equals approximately 2 percent of national production. Drilling activities have been operating at a high level with over 1300 wells drilled in 1980.

The state authorities require a standard set of drilling and environmental and land use permits for oil and gas operations. The Wyoming permit network is provided in Figure 6-11, with the permit listing in Table 6-10. Prior to drilling, a drilling approval must be received from the Wyoming Oil and Gas Conservation Commission. State land rights-of-way may also be needed in some cases because of the interspersed nature of state and federal lands.

Environmental permits, as in the other states, will not generally be critical-path items. The permit with the longest time requirement is the groundwater pollution control permit needed for permanent disposal activities. However, this permit does not frequently delay oil field operations. More commonly, temporary on-site disposal ponds are used for handling excess water. Approval of pond construction is commonly received in under 2 months from the Department of Environmental Quality, Water Quality Division.

In all nine Wyoming permits were identified as applying to most projects. The coverage of the permits is quite similar to that of other states and no special problems were identified.

—————	Activity
- - - - -	Dummy Activity
—————	Critical Path
(10, 11)	First Entry is Activity Time in Months, Second Entry is Float Time. Ex.—Activity Requires 10 Months Float Time Allowance is 11 Months.
(ND)	Activity Time is Not Determined or Cannot Be Meaningfully Stated.

Figure 6–11. Wyoming Permits Displayed on Simplified Oil and Gas Network.

TABLE 6-12

STATE OF WYOMING PERMITS APPLICABLE TO OIL AND GAS PROJECT NETWORK

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permit to Drill/Oil and Gas Conservation Commission	1 week	2-3/4 months	Routine state drilling approval.
State Rights-of-Way or Easements/Various Agencies	2 months	1 month	Approvals are needed for activities affecting state lands and highways.
Underground Disposal of Water Notice/Oil and Gas Conservation Commission	Not stated	Not determined	Recurring permit covering injection operations.
Other Operating Notices to Oil and Gas Conservation Commission	Not stated	Not applicable	Various notices and approvals for reporting activities.
Permit to Construct Air Pollution Source/Department of Environmental Quality, Air Quality Division	4 months	4 months	Required for some pumping stations or gas processing plants.
Groundwater Pollution Control, (Wastewater Discharge) or Pond Construction Permit/DEQ, Water Quality Division	6 months	2 months	The three options for wastewater disposal are all evaluated by DEQ. Pond disposal is most common.

TABLE 6-12 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Ground or Surface Water Appropriation/Office of State Engineer	3 months	5 months	May be needed for water source during drilling.
Permit to Construct a Wastewater Facility/DEQ, Water Quality Division	5 months	4 months	Occasionally applies to oil and gas operators if discharging wastewater.
Permit to Operate Air Pollution Source/DEQ, Air Quality Division	Not stated	Not applicable	Approval occurs after source emission tests are completed.
<u>Additional Permits of Possible Applicability</u>			
Temporary Use Permit (Water)		Office of the State Engineer	
Change in Use or Point of Diversion Petition		Office of the State Engineer	
Industrial and Hazardous Waste Facility Construction and Operation Permit		Department of Environmental Quality (DEQ), Solid Waste Management Division	
Dredge and Fill Permit		DEQ, Water Quality Division	
Scientific Permit		DEQ, Land Quality Division	
Industrial Siting Permit		Industrial Siting Council	
Land Use Lease		State Board of Land Commissions	
State Historic Preservation Office Review		State Historic Preservation Office	

TABLE 6-12 (CONT.)

Certificate of Public Convenience and
Necessity

Public Service Commission

Water Disposal Permit

Office of the State Engineer

Reservoir, Construction and Use Permit

Office of the State Engineer

6.3 Summary of Federal-State Oil and Gas Networks

The federal and state networks illustrate the role of regulation in oil and gas projects. As an overriding conclusion, the effect of permitting on the length of time required for oil and gas development in most areas is small. Only two federal processes - the Application for Permit to Drill (APD) and the rights-of-way processes - are on the project critical path. Only these permits actually lengthen the critical path in most cases.

A summary of the permit statistics for the federal and state networks is provided in Table 6-13. The number of permit types included in the networks as well as the total number of permits of possible applicability were tallied. These figures give an indication of the potentially high number of approval processes which might be involved for a new project. The greatest number of permits applies to Alaskan operations, due to the state's additional requirements for protection of sensitive areas.

In Table 6-13, the phrase "Permit Type" is used to allow a convenient grouping of similar permits. In the federal case, for example, fourteen distinct rights-of-way or special land use permits may be included as one permit type: rights-of-way approvals. The number of permit types required is nine for the federal government and between eight and fifteen for states (column 1 in Table 6-13).

For federal lands, both the federal and state permits would apply in most cases. Looking only for the moment at the permits in the networks (commonly required permits), the federal permits may be combined with each state total to give a better indication of the full extent of permitting

requirements. In the case of Alabama, for example, 9 federal and 10 state permits or permit types would typically apply, for a total of 19 approvals (ignoring for the moment the minor issue of double-counting certain permits). The combined federal-state totals derived this way vary from 17 (New Mexico) to 24 for Alaska. These totals are shown in column 2 of Table 6-13.

Another statistic of interest is the number of state permits of potential applicability. This illustrates the potential number of approval processes a developer might face. Referring to column 3 in Table 6-13, as many as 43 approvals may be required.

TABLE 6-13

PERMIT TOTALS FOR OIL AND GAS PROJECTS ON FEDERAL LANDS

	PERMIT TYPES INCLUDED IN NETWORK	COMBINED FEDERAL & STATE PERMITS	ALL FEDERAL OR STATE PERMITS OF POTENTIAL APPLICABILITY
Federal	9	--	43
Alabama	10	19	16
Alaska	15	24	28
California	8	17	21
Colorado	11	20	25
Montana	9	18	16
New Mexico	8	17	19
Utah	12	21	25
Wyoming	11	20	21

Source: ERCO estimates.

Of the nine major federal permits required, only some subset of those would be required on non-federal lands. The need to acquire all of the federal permits puts federal land operations at an obvious disadvantage. Oil companies have expressed preferences not to explore on federal lands because of the additional permit requirements. This preference may not be important in many Western states because of the high proportion of federal lands.

Again viewing the permit totals, it should be noted that few of the approvals for oil and gas projects represent major regulatory processes. Many permits refer only to routine clearances and notices which must be submitted to the Minerals Management Service or to state oil and gas regulatory bodies. Of this group of permits, most require only notification of activities (Notice of Well Completion, Sundry Notices on Operations) and do not involve a review period.

The permit totals are useful for comparison of the federal and state regulatory activities but do not represent the actual number of approvals for any given project. Three cautionary points in interpreting the data should be noted. First, the term permit "type", as noted above, implicitly combines several approvals into a single category. Second, individual permits are required numerous times for a given process. Most notably, the federal APD will be required for each well drilled. Third, large numbers of what may be called "special-circumstance" permits add variation to the potential permit processes an operator must face. These permits are not typically required but could become critically important to a given project.

It might be noted here that the complexity of activities during exploration and field development confuses the

identification of a critical path. Numerous activities, such as development drilling, facility construction, and road improvement, are taking place at roughly the same time. Difficulties with certain permits, for example an APD for a given site, may not deter drilling and continued development on another site in the same field.

A more subjective look at regulatory processes is provided in Table 6-14 where major permits, whether or not they occupy the critical path, are listed. A judgment was made of the relative difficulty of permitting at the federal level and for each state. The most difficult areas, federal, Alaska, and California, were so judged because of the greater likelihood of project delays due to permitting. The environmental sensitivity of the permafrost area in Alaska, and the air emission requirements of heavy oil recovery in California, are the key factors behind this judgment. Other states showed little differentiation in permit processes. Water appropriation issues are of slightly more concern in Colorado than elsewhere. In the other five states, major delays due to state permitting requirements were rare.

TABLE 6-14

SUMMARY OF PERMIT ISSUES FOR OIL AND GAS PROJECTS

RELATIVE DIFFICULTY OF FEDERAL OR STATE PROCESSES ^a		NOTABLE PERMIT PROCESSES	SPECIAL OPERATING ISSUES
Federal	1	Application for Permit to Drill; Rights-of-Way	1. Delays in APD, rights-of-way approvals
Alabama	3	Permit for Work in Navigable Water	1. Wetland drilling, involving COE permits, may be delayed
Alaska	1	State and federal water permit ap- provals; Solid waste permit for reserve pits	1. Sensitive permafrost environ- ment 2. Lack of state authority for environmental programs 3. State permit for all reserve pits
California	1	Air pollution permits	1. Permitting of steam generators for thermal recovery 2. Endangered species issues in federal APD process
Colorado	2	Water well permits	1. In some areas, delays in water well approvals
Montana	3	None	None
New Mexico	3	Effluent discharge plan	1. Some discharges restricted for aquifer or surface water protection
Utah	3	Air pollution permits	1. All pollution sources must be permitted
Wyoming	3	None	1. None

Source: ERCO estimates.

^aState processes were rated according to the following scale: 1 - Relatively difficult; lengthy delays due to permit or regulatory problems have occurred; 2 - average; selected processes are lengthy but few problems noted; 3 - relatively easy; no consistently lengthy processes noted.

NOTES TO SECTION SIX

1. For more data on the APD process, refer to Section Nine below. The lengthening of the APD review occurred after additional environmental responsibilities were placed in the Minerals Management Service.
2. Personal communication between John Eyraud of ERCO and Norman Porterfield of Getty Oil Co., New Orleans, March 17, 1982, and with Ken Edgerton of Exxon, March 16, 1982.
3. U.S. Arctic Oil and Gas, National Petroleum Council, December 1981.
4. AOOA, Alaska Regulatory Reform Program, Alaska Oil & Gas Association, 1980.
5. Personal communication between John Eyraud of ERCO and Clifton Calderwood of the Kern County Air Pollution Control District, Bakersfield, California, December 20, 1982.
6. Personal communication between John Eyraud of ERCO and Brett Braden of the Santa Fe Oil Company, March 15, 1982.
7. Personal communication between John Eyraud of ERCO and Harry Keel, Department of Health, Billings, Montana, May 11, 1982.

SECTION SEVEN

NETWORK PRESENTATIONS OF PERMITTING SYSTEMS: COAL MINING PROJECTS

Coal mining operations in the United States are subject to a relatively new and complex system of control as authorized by the Surface Mining Control and Reclamation Act of 1977. The SMCRA program, as run by the Office of Surface Mining of the Department of the Interior, provides for environmental protection and land reclamation during and after the mining activities. All major environmental legislation also controls the location and manner of coal mining operations.

In this section, the regulatory control of coal mining projects was modeled using the PERT networks introduced previously in Section Six. As for oil and gas operations, the purpose of the network analysis was to define and measure the effects of government regulations on project leadtimes, and to identify any bottlenecks or exceptional difficulties imposed on energy developers.

7.1 Sources for Coal Mine Project Network Preparation

For the coal project networks, use was made of previous work on coal project planning horizons. The basic network design used here is derived from the study Impact of Government Regulations on Leadtimes of Coal Facilities, prepared by Policy Planning and Evaluation, Inc., of McLean, Virginia. For that work, a coal project network for a representative Western surface mining facility was developed. Major permit processes were then included in the project network. As the

study title indicates, the purpose of the report was to measure the lengthening of project leadtimes caused by regulatory processes. For more information about the PPE study, the reader may refer to the discussion of project delay findings in the literature in Section Three or to the report synopses in Appendix A.

The final network design used by ERCO in this study incorporates several modifications to the PPE design.¹ The changes include the addition of an exploration activity, in order to make the network more consistent with the scope of the oil and gas network and several changes in interpretation of the actual regulatory requirements. The time periods set forth for describing exploration activities are derived from the same source material used in the oil and gas section (Office of Technology Assessment, Management of Fuel and Non-Fuel Resources in Federal Lands - Current Status and Issues, Appendix C: Survey of Mineral Industry on Techniques, Parties, Costs, Acreages, and Times for Exploration, Development and Production of Various Mineral Occurrence Types in the Onshore United States).

Other network modifications were made based on ERCO research into the permit processes themselves. Because of the permitting focus of the study, sections of the PPE study were expanded upon considerably to provide more detail on the regulatory processes.

A fundamental problem in the network design, particularly for the estimation of time required for specific activities, is to define the "representative" facility to be depicted. For the coal network, a large surface mine in a Western state was chosen as the network basis. The production capacity for the representative open-pit mine is set at

between 2 and 5 million tons per year, using dragline mining techniques. If an underground mine is considered (Colorado, Utah and Alabama among the states covered have underground mines), the basic outline of regulatory and non-regulatory activities would remain the same. Specific activities would be adjusted, however. Similar changes would be needed if the "representative" mine under consideration was larger or smaller than the case here.

7.2 The Basic Coal Mine Project Network

A coal project network presents the sequence of activities which coal developers must carry out. The coverage of the network is similar to that for oil and gas in that all major activities from exploration to production are noted.

The coal mine network is presented in Figure 7-1, and covers both project activities and major permit processes. More will be said about the federal and state permits in the subsequent sections.

The network can be divided into seven major stages, each of which includes several elements. The stages are (1) exploration and land and mineral rights acquisition, (2) collection of environmental baseline data and other data, (3) market development and mine design, (4) permitting, (5) final design, plan preparation and procurement of equipment, (6) mine facility construction and equipment erection, and (7) production.

A description of the project stages and their elements is given below. The numbers in parentheses refer to the node endpoints for each activity in Figure 7-1.

LEGEND

- Activity
- - - - - Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months, Second Entry is Float Time.
Ex.—Activity Requires 10 Months
Float Time Allowance is 11 Months.
- (ND) Activity Time is Not Determined or Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine Diagram. Letters Denote State Permits.

Figure 7-1. Network Presentation of Representative Coal Projects on Federal Lands.

I. Exploration and Land Acquisition - The early stages of coal mine operations bear some similarity to oil and gas or any mineral extraction operation. Exploration work progresses from regional to more focused land area examinations. The objective of the work is to obtain an accurate, three-dimensional model of the prospective mine reflecting seam depth, thickness, continuity pitch, and also to determine the nature of the overburden and of any potential ground and surface water problems.

General and Detailed Exploration (1-4). The exploration activities include identification of prospective land areas for purchase. Detailed mapping and examination of purchase prospects occurs during this task. Exploration permits would be obtained as needed.

Decision to Acquire Resource (5-6). This activity is included in order to identify the management decision to proceed with certain land purchases based on the evaluation of prospects during exploration.

Federal Lease Acquisition (6-7). A three-month process of bidding and lease acquisition is posited for the federal coal mine project. Bid evaluation and negotiations are presumed to occur at this stage. Actual lease acquisitions, because they occur at the discretion of the government, are not actually under the control of the mining company. Longer lease acquisition processes are, thus, quite likely.

Decision to Develop Mine (7-8). After lease acquisition, the coal mining company will further consider the decision to initiate permitting and proceed with resource development. The decision will be based on market projections, and investment return forecasts, i.e., an overall project evaluation.

II. Collection of Environmental Data and Other Information - Preparation of the mine plan and other permit applications requires the compilation of environmental, legal, and administrative information. Additional data gathering through detailed drilling.

Environmental Studies (8-8a through 8q). Seven distinct studies are required for the preparation of the mine plan. Four of the studies - hydrology, meteorology, wildlife, and vegetation - require a year of analysis in most cases. Measurement of the seasonal variation in these baseline environmental characteristics is the reason for the lengthy study period.

Legal and Administrative Information (8-8h). The mine plan must also include data on land and mineral ownership, water rights, and other information concerning the operators compliance with mining regulations at other existing mines.

Detailed Drilling (8-9). Drilling occurs frequently in order to collect additional data on the delineation of the resource. The data are needed to better assess the resource, for preparation of operating and reclamation plans, and for collection of environmental data.

III. Market Development and Mine Design - A series of non-regulatory activities occur concurrently with the environmental studies. Marketing is an ongoing effort which shapes a coal company's development plans. Basic design studies are also necessary for assessing the project's desirability.

Market Development (5-14). For the large Western mine, the marketing process for a major coal mine should culminate in final contracts agreements for sale of the produced coal. The lack of such a sale, or good prospects for a sale, frequently delays commitments of major funds to coal mine projects. In fact, the state of the coal market and the success at selling the potential mine output is the major determinant of the speed with which a company pursues all subsequent project tasks.

Preliminary Design and Cost Estimation (9-11). The mine facility design affects all of the main permitting activities as it determines the scale and type of environmental effects which may occur. The design is also

the basis for mine cost estimation, and for the equipment lists to be included in the mine plan. Also, the cost estimate becomes the basis for the bond requirement applied to the company. Also, equipment lists must be included in the mine plan submitted to OSM.

IV. Permitting - Consideration of regulatory matters should be initiated early in the planning process to aid in the design and for the avoidance of downstream difficulties. Depending on the coal company's expectations of permitting difficulties, all other activities may be halted until the necessary approvals are received or are no longer in doubt. However, most companies proceed with preparations (if sales of their coal are contracted) concurrently with permitting processes.

NPDES Permit (13-16). Water pollution permits are required for surface water discharge resulting from mining operations. Control measures, such as sedimentation ponds, are commonly employed to reduce effluent loadings prior to release to area streams. If no discharge is planned, no NPDES permit is needed.

Fish and Wildlife Service Permits (13-17). Mining activities may disrupt certain natural habitats. Permits issued by the Fish and Wildlife Service are designed to control and mitigate such potential disturbances to rare bird or endangered species areas.

MSHA Safety Plan Approvals (13,19). All types of mining activities must submit a series of plans governing the safety systems for worker protection. A brief review process is generally involved. Seven distinct safety plans covering ventilation, fire-fighting systems, personnel training, roof control (underground) and so on.

Miscellaneous Federal Permits, FCC, ATF (13-19). Minor federal permits govern specific activities which are associated with coal mines. The Federal Communications Commission licenses industrial radio operations such as are used at mine sites. The Alcohol, Tobacco and Firearms Division of the Treasury Department regulates the handling and use of explosives.

State Operating Approvals (13-20). Numerous state operating approvals are required of coal mine developers. Most of these approvals may be obtained simultaneously with federal permits from the various state agencies.

Preparation of Mine Plan for OSM Review (12-21). The environmental studies, legal data and engineering and reclamation plans are elements in the mine plan prepared for OSM or the state regulatory agency. The mine plan may be as large as several volumes to incorporate all the relevant details.

OSM Apparent Completeness Review (21-25). The OSM or the regulatory authority may request additional information from the mining company and may require that portions of the environmental or engineering work be redone. This branch of the network covers activities performed by both the regulatory agency and the coal company.

OSM Technical Review (25-30). Once the application is deemed complete, the actual review of mine plan by OSM and/or the state regulatory authority occurs. This review is central to the regulatory process, and is the most important permit approval.

Determination of Significant Impacts (21-24). Early in the planning of review process, OSM decides whether a given mine project will create major environmental impacts. The determination governs the type of environmental documentation to be prepared.

Environmental Assessment (EA) or (If Needed) Environmental Impact Statement (EIS) Preparation - If the Determination of Significant Impacts is negative, then an EA, which is a general environmental review of the project, is made. If there will be significant impacts, a full EIS is prepared. The OSM has estimated that 15 percent of all mining projects will require EIS preparation. The public comment and analytical requirements of the EIS cause the preparation to require approximately 1 year.

V. Final Design, Plan Preparation, and Equipment Procurement - The passage of time and planning adjustments made in the permitting process may cause revisions in the design of facilities or in operating plans. In any case,

plans are reviewed. In any case, plans are reviewed and finalized prior to the initiation of commitments for equipment purchases and mine construction scheduling.

Management Approval to Proceed (14,22). The coal company management will make a decision to proceed prior to making equipment purchases, which involve major capital outlays. The timing of this decision will typically precede the receipt of permit approvals.

Detailed Mining Plan (20-35). The mining plan describes the location and depth of the excavations to be made. Additional details of the plan are developed as needed to govern actual operations.

Detailed Plant and Facility Design (26-32). Onsite facility plans and final plant designs will be prepared at this stage. The items included in the plan are crushing equipment (if needed), conveyor systems, storage silos, buildings, and other infrastructure for the operation.

Procure Overburden Stripping Equipment (22-27). The mine plan includes a description of the type of equipment to be used. Purchase commitments for the equipment are made after the company management has decided to proceed. Overburden stripping equipment removes the soil and rock layers above the coal seam. In large Western surface mines, draglines with bucket capacities of 50 cubic yards or more are commonly used. Equipment shipments are initiated approximately 12 to 15 months after order, according to the equipment market conditions in May 1982². In periods of greater equipment demand, the leadtime needed for purchase of the large draglines could increase.

Procure Mining Equipment (22, 28). The selection of mining equipment is included in the mine plan. In this task, the choice of equipment is reviewed and purchase commitments are made. Again, long leadtimes are needed for delivery, although generally not as long as for draglines.

Procure Construction Equipment (22-32). Construction equipment, much of which is less specialized than the mining equipment, is ordered at the same time as other purchases are being made. Trucks, digging implements, and other items are included in this category.

Detailed Overburden Stripping Plan (22 -34) The efficient removal of overburden is based on careful planning of the sequence of operation. The stripping plan is prepared prior to development of the pit.

VI. Mine Facility Construction and Equipment Erection -

Once the equipment shipments are received and major permit applications are approved, construction may begin. In actual practice, some permit approvals are not needed until the beginning of operations, but others must be in hand prior to the initiation of land disturbances or any discharges (water) or emissions (air).

The facilities to be constructed include access roads on site operations, buildings and housing, coal conveyors and handling machinery, load-out facilities, coal storage silos, coal crushing plants and ancillary facilities.

Construction of Plant and Facilities (32-35).

A lengthy process is involved in construction of the facilities. The chain of coal recovery and handling mechanisms must be put in place before production begins. Housing and ancillary facilities are also needed.

Construct Railway (32-33). A railway spur leading from the mine mouth to the main rail line may be needed for expediting coal delivery. If the length of the rail span is short (a few miles) or if the coal company performs its own hauling operation over the line, ICC approval is not required. For long rail linkups, ICC approval and separate EIS processes could be required. Other transport systems may require separate permit approvals.

Erection of Overburden Equipment (33-34). Erection of equipment for overburden removal is a discrete activity of considerable length (15 months). The overburden stripping equipment draglines are shipped in stages and assembled on-site. Erection may begin with receipt of the early shipments, but lasts for the entire shipping cycle (approximately 4-6 months) and then for approximately 10 additional months.³

Pit Development (34-35). This activity encompasses overburden removal (with special topsoil handling to allow replacement during reclamation) and exposure of the coal deposits. Actual mining of the resource may then begin.

Erection of the Mining Equipment (25-35). Mining equipment is not used until pit development has occurred sufficiently to allow production. Erection of the equipment is, in itself, a lengthy process the completion of which should coincide with the completion of the other facilities on site.

VII. Production - Commencement of Minerals (35-36) -
Mining and further pit development occurs while production levels reach the desired level. In the meantime, commercial production is generally occurring.

7.3 Environmental Concerns from Coal Mine Operations

In addition to the environmental protection provided by the SMCRA program, coal mine operators must be cognizant of the other federal environmental programs. The problems and issues raised by mining operations in the context of permits issued by EPA and other agencies are briefly reviewed below.

Air Quality and PSD Construction Review - Coal mines generate large quantities of fugitive dust emissions which may cause local particulate levels to exceed acceptable standards. Truck traffic on unpaved mine roads is the greatest source of fugitive dust, although crushing operations and other handling processes add to the total particulate levels. Coal preparation plants, which raise additional air quality issues, were not covered in this study.

The federal or state PSD program regulates incremental air pollution from new industrial projects in attainment areas. Most Western coal mines are in remote areas with good baseline air quality and are thus in attainment areas, as defined in the Clean Air Act (attainment areas are those whose air quality is better than the National Ambient Air Quality Standards). However, facilities such as coal mines that major sources only because of fugitive emissions are exempted from the PSD program. Only those states which have authority for implementation of the PSD program and which do not exempt coal mines (or fugitive dust emissions) may issue these air quality permits. The effective particulate limitations are set forth in State Implementation Plans. Monitoring requirements and permit review periods also vary by state. An activity branch for PSD permits has not been included in the federal network diagram because of the federal exclusion of coal mines. Air permits are included in state permit networks.

To date, air quality restrictions have not limited coal operations in the West. In the Powder River Basin of Montana and Wyoming, emissions are nearing the national ambient air quality levels and state officials are concerned about further mine expansions. If the air quality standards are exceeded, reevaluation of permits for existing operations may be made and additional control measures stipulated. However, agreements between state and mine officials concerning the matter could occur without production levels being affected.⁴

Aside from particulates, coal mining does not create other major emissions. Further air quality issues are raised, however, in the case of mine-mouth power plant construction or for coal-based synfuel projects. Sulfur

dioxide and nitrogen oxide emission levels may violate local standards in such cases, leading to a potentially broader air quality controversy. These possibilities are not fully considered in this study in the interests of focusing on the mining operations themselves.

Water Quality and NPDES Permits - Effluent discharge permits required under the Clean Water Act are applicable to point source discharges from coal mines. The principal concern is increased sediment loads in streams due to erosion of the mine site and reclamation areas. EPA accepts sedimentation ponds as the "best technology currently available" to prevent water pollution when used in conjunction with other sediment control measures on drainages below land disturbance areas. Also, OSM regulations require sediment control measures which provide for better control than the discharge limitations of EPA regulations.

NPDES permits have not represented unusual problems for coal mine operators. The permits apply only to surface discharges, and do not cover groundwater pollution, nonpoint source pollution, and seepage in streams from groundwater sources. The OSM regulations, however, cover these additional possibilities.

Although sedimentation ponds do not constitute complex permitting problems, numerous permits may be involved. Separate construction permits are required in most states for the ponds themselves. Also, pond construction is regulated in the OSM mine plan, with all ponds covered at once, or separately as they are constructed. For an NPDES permit, multiple discharges can be covered under a single permit. As the discharge points change during mining, the permit can be quickly revised as needed. In summary,

numerous permits may be associated with sedimentation ponds at the mine site. The number of permits required will increase less than proportionately with the number of ponds.

Water Use and Water Appropriation Permits - The effect of mining on groundwater supplies is a major concern. Competition for limited water supplies is evident, particularly in sections of Utah, Wyoming, Colorado, and New Mexico. Underground mines tend to intercept groundwater streams, resulting in a lowering of water levels and depletion of area wells. Water is also needed in the mining operations for dust control and for irrigation of reclaimed lands. Resolution of these issues is a major uncertainty for future mining in selected areas.

Solids Handling (Topsoil and Spoil) - Surface mining activities are constrained by the need to protect topsoil resources and to suitably dispose of solid overburden materials. In developing the pit, topsoil is removed separately and stored in stockpiles or placed on other reclamation areas. Overburden, which is the rock strata above the coal seam or between seams, is removed and disposed of in various fashions depending on the type of mine. In open pit mines, the overburden or "spoil" material is immediately dumped in the mined out area of the pit.

Topsoil handling is important to the eventual revegetation plans for the mine. The SMCRA regulations specify that all mined or regraded areas be covered with topsoil or such soil as best provides for vegetation. Spoils, because they may contain high levels of harmful elements or metals, may constitute a hazard to surface and groundwater supplies if

if not properly handled. The SMCRA regulations encourage replacement of spoils in order for the reclaimed surface to resemble the original contour of the land.

To date, few mines have faced severe restriction due to the handling requirements for solid matter. For one mine in the Green River-Hams Fork region, spoil handling problems caused a reduction in the mine area. In that case, the plan for disposal of spoils out of pit, due to the pattern of mining, was found to violate regulatory standards, and the mine plan was revised. Restrictions of this type for other mines with similar geologic settings (most likely to be found in the Green River-Hams Fork region) are possible.⁵

Most state solid waste agencies do not regulate spoil disposal. Some agencies do issue permits for ancillary waste facilities such as for disposal of cafeteria waste at the site. However, the principal review of topsoil and spoil handling procedures is included in the mine plan review.

Wildlife Permits - The U.S. Fish and Wildlife Service enforces the wildlife laws providing for protection of critical habitats. The important laws are the Bald Eagle Protection Act, the Endangered Species Act, and the Migratory Bird Treaty Act. The FWS regulations stipulate avoidance of nesting areas and critical habitats, and adoption of mitigation measures. The permitting process, under normal non-controversial circumstances, is quite brief. In instances where wildlife conflicts have occurred, measures have been adopted to allow continued mine production. Many mines have eagle nests located on them, and FWS has allowed the moving of nests in selected instances. To date, endangered species have not been found in areas of active mining.

Nevertheless, some constraints on operations have occurred. Several mine plans in Southern Wyoming have been adjusted for protection of eagle and other bird areas. Sites of several proposed mines, again in Southern Wyoming, coincide with critical winter habitats of antelope and deer. Surface mines in northwest Colorado also conflict with migration areas. It has not yet been determined what modifications to specific mine plans or sites may be needed.⁶

7.4 Federal Permits on the Coal Mine Project Network

The coal project network shown above (Figure 7-1) includes the federal permits which must be obtained by coal mine operators. A listing of the permits included in the network (and of permits which could be required in some cases) is provided in Table 7-1. The duration times and float times associated with the permits is also provided. For the time being, only one activity branch is set aside to denote state operating permits which might be applicable. Among the federal programs represented, many can be taken over by state governments. Whether or not a given state runs the environmental programs is discussed in the sections below. The state permits themselves are also displayed in those sections.

As is evident in Figure 7-1, regulatory processes are important to the critical path of a coal mining project on federal lands. After the lease is acquired, the critical path of the project incorporates the following items: (1) a 12-month period for environmental studies, (2) a second 12-month period for preparation of the OSM application and for passage through the completeness review, and then (3) a 6-month OSM mine plan review with a concurrent EIS preparation

TABLE 7-1

FEDERAL PERMITS APPLICABLE TO COAL MINING
PROJECT NETWORK

ACTIVITY BRANCHES FIG. (7-1)	COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
1-2	Coal Exploration License/ Bureau of Land Management	6 months	None	Allows land entry and drilling on federal lands.
1-3	Approval of Exploration Plan/Minerals Management Service	3 months	3 months	One element in system of control of mineral re- sources.
13-15	Rights-of-Way Permits/ Various Federal Agencies	3 months	15 months	Permits may be needed for off- lease road con- struction. Rights- of-way of a short length are assumed here.
13-16	NPDES Permit/Environmental Protection Agency	6 months	12 months	Multiple discharge points covered under one permit.
13-17	Wildlife Permits/Fish & Wildlife Service	3 months	15 months	Includes permits for activities affecting endangered and threatened species and bald eagles.

TABLE 7-1 (CONT.)

7-18	ACTIVITY BRANCHES FIG. (7-1)	COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
	13-18	Safety Plan Approvals/ Mine Safety and Health Administration	2 months	16 months	Covers a variety of separate safety plans concerning mine construction and operation.
	13-19	Misc. Federal Permits/ Federal Communications Commission and the Alcohol, Tobacco and Firearms Div., Treasury Dept.	4 months	14 months	Covers permits for radio systems and explosives use.
	25-30	Mine Plan Review/Office of Surface Mining	6 months	None	The principal mining permit.
	24-29	Environmental Assessment or the Environmental Impact Statement/Office of Surface Mining	12 months	None	The extent of the environmental review depends upon the serious- ness of expected impacts.

TABLE 7-1 (CONT.)

ACTIVITY BRANCHES FIG. (7-1)	COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
<u>Additional Permits of Potential Applicability</u>				
Discharge of Dredge or Fill Material Permit			U.S. Army Corps of Engineers	
Solid Waste Management Facility Permit			Environmental Protection Agency	
Bridge Permit			U.S. Coast Guard	
Certificate of Public Convenience and Necessity for Construction and Operation of Rail Lines			Interstate Commerce Commission	
Notice of Proposed Airspace Obstruction			Federal Aviation Administration (FAA)	
Notice of Proposed Construction Alteration of Airports			Federal Aviation Administration (FAA)	
Airport Lease			BLM	
Permit for Structures on or Work in Affecting Navigable Waters			U.S. Army Corps of Engineers	
Permit for Dams and Dikes in Navigable Waters			U.S. Army Corps of Engineers	
Antiquities Act Permit			Department of the Interior	
Application for Permit to Conduct Archaeological Explorations			Forest Service	
Timber Sale Contracts			Forest Service	
Temporary or Permanent Exemption from FUA Prohibitions			Department of Energy	

period. An additional 3-month period for acquisition of rights-of-way across neighboring federal lands is also provided. These regulatory activities total 33 months out of the total 110 months. (The lease acquisition process is not considered here as a federal permit process.) In the simplest terms, the entire top half of the network diagram is devoted to regulatory activities and the bottom half to the actual mine development process.

Removal of all government regulations and permits would reduce the leadtime necessary, although not by the full 33 months. The revised critical path would run through the activities of detailed drilling (8-9), preliminary design and cost estimation (9-11), management approval to proceed (14,22), procurement of construction equipment (22,32), to construction of the rail spur. The total path in that case would be 88 months, a reduction of 19 months in the critical path.

7.5 State Coal Mine Project Networks

7.5.1 Background Information for the State Sections

For reference purposes, basic data on coal production levels by state and by type of mine have been collected. This data, shown in Table 7-2, may be used as an aid in examining the sections below describing coal project networks in each state.

Overall, the eight study states represent 41 percent of the strip mining production (1981) and 11 percent of the underground mining for a total representation of 27 percent of U.S. production. The Western states, of course, use

TABLE 7-2
COAL PRODUCTION LEVELS BY STATE (1981)

	PRODUCTION LEVELS (000 TONS)			RANK AMONG ALL STATES
	STRIP	DEEP	TOTAL	
Alabama	16,772	9,435	26,207	11
Alaska	771	--	771	23
California	--	--	--	--
Colorado	12,545	6,755	19,300	12
Montana	34,204	--	34,204	7
New Mexico	17,393	954	18,347	13
Utah	--	15,000	15,000	15
Wyoming	102,128	1,872	104,000	3
Eight-State Total	183,813	34,016	217,829	--
U.S. Total	453,057	319,768	802,825	--
Eight-State Total as % of U.S. Total	41%	11%	27%	--

Source: Joseph F. Wilkinson, "1982, Another Year of Increased Sales," Coal Age, February 1982, p. 63.

predominately strip mining techniques, accounting for the higher production level in that category. The largest coal-producing state included in the study is Wyoming, which is the third highest producer in the country behind Kentucky and West Virginia.

Strip mining operations were used as the basis for the project network because, as Table 7-2 indicates, this technique is most widely used in the Western states where federal land ownership is so extensive. Eastern underground mining operations are located on private lands in most cases. Only Utah and Colorado among the Western states have large underground mines.

Also included for reference purposes is Figure 7-2 showing the location of the large Western coal fields. The large deposit areas generally cross state borders; thus, mines of the Powder River basin may be located in either Montana or Wyoming.

7.5.1.1 Implementation of the SMCRA Program in the States

The authority for conduct of the SMCRA program is being transferred to those states with significant levels of mining activities. The future role for the Office of Surface Mining, as it is envisioned within the Department of the Interior, is to be a limited one. Most mining operations would be permitted by OSM-approved state regulatory authorities. OSM's role would include (1) provision of oversight functions for approved state programs, (2) performance of mine plan review functions for all other states, and (3) maintenance of review functions for mining operations on federal lands.

Area of Coal Reserves

Generalized Location of Strippable Reserves

Major Areas of Metallurgical Coal

Numbers Show Locations of Major Coal Fields with Leased Federal Coal.

1. Colstrip	9. Rock Springs	17. Wasatch Plateau
2. Decker	10. Kemmerer	18. Emery
3. Buffalo	11. Yampa	19. Alton
4. Powder River	12. North Park	20. Kaiparowits Plateau
5. Gillette	13. Danforth Hills	21. Fruitland
6. Glenrock	14. Somerset	22. Bisti
7. Hanna	15. Book Cliffs (CO)	23. Star Lake
8. Little Snake River	16. Book Cliffs (UT)	24. Carbondale Coal Basin

SOURCE: Base Map: National Academy of Sciences, *Rehabilitation Potential of Western Coal Lands*, Cambridge, Mass.: Ballinger Press, 1974.

Figure 7-2. Major Coal Regions With Leased Federal Coal, and Generalized Locations of Strippable Coal Deposits.

As OSM moves closer to this limited role, regional OSM offices are being closed or reduced in force in favor of small state OSM offices.

The SMCRA program, as originally defined, provided for the rapid passage of program authority to the coal mining states. Under SMCRA, an interim program was established to govern mining activities while states prepared their own legislative and administrative structures for regulation. Under the interim program, OSM reviewed all new mine plans and also passed judgment on the adequacy of state submissions for program takeover.

Once a state's regulatory program is judged adequate, it receives approval (or conditional approval if some minor deficiencies remain) for operation of the permanent program. At this point, the state becomes the regulatory authority for mining operations in the state. All existing mine operators are required to submit mine plans to the state regulatory authority within 60 days of state primacy.

Operation of the permanent program does not, however, give the state agency authority over mining on federal lands. An additional procedure in the form of a Cooperative Agreement with OSM must be reached to explicitly describe the division of authorities over federal lands. The Cooperative Agreement can only be requested and negotiated once the state is conducting the permanent program. The document specifies which portions of a federal mine plan review will be conducted by the state or by OSM.

The status of each of the eight states on the transfer of authority from OSM varies, from those which have not initiated the process to those which have completed it. The

progress of each in obtaining state primacy (approval of the permanent program) and Cooperative Agreements is shown in Table 7-3. Two states have not received primacy; of these one state, California, has no plans to prepare an application for OSM due to the almost complete absence of coal mining operations in the state. Alaska is preparing its program although additional state legislation must be passed before the state program can be authorized.

The other six states are operating the permanent program, but only two states, Montana and Wyoming, have completed the Cooperative Agreements with OSM for regulation of federal coal lands. The other states - Colorado, New Mexico, and Utah - are expected to reach Cooperative Agreements during 1982.

In general, OSM wishes to rely extensively on state agencies for the mine plan review, but is restricted in the extent to which the review functions can be delegated. The Secretary of the Interior is required by the SMCRA legislation to pass final judgment on mining activities on federal lands, based on independent analysis by the Office of Surface Mining. Thus, OSM must assess the state's analysis of the mine plan and perform a degree of independent analysis, prior to a decision of approval or disapproval. Also, OSM cannot delegate authority for the National Environmental Policy Act (NEPA) review of the project. A final decision as to the adequacy of the environmental analysis must be made by OSM. Note that these restraints apply even in states which have been granted primacy for the SMCRA program operation.

TABLE 7-3

STATUS OF THE EIGHT STUDY STATES ON THE
TRANSFER OF SMCRA PROGRAM AUTHORITY

STATE	STATUS ON PROGRAM TAKEOVER		STATUS ON COOPERATIVE AGREEMENTS	
	INTERIM OR PERMANENT	APPROVAL DATE	AGREEMENT STATUS	AGREEMENT DATE
Alabama	Permanent	May 1982	Not requested	None
Alaska	Interim	Submitted application summer 1982	Not eligible	None
Calif- ornia	Interim	No plans to submit application	Not eligible	None
Colorado	Permanent	December 1980	Requested	Agreement expected Sept. 1982
Montana	Permanent	April 1980	Completed	February 1981
New Mexico	Permanent	December 1980	Requested	Agreement expected Sept. 1982
Utah	Permanent	January 1981	Requested	Agreement expected by Dec- ember 1982
Wyoming	Permanent	November 1980	Completed	November 1980

Note: Table compilation is correct as of August 1982.

The delineation of state OSM authority over federal lands can be described by considering the review procedures themselves. The first step is to provide the Apparent Completeness Review (ACP), and this is performed jointly by the state agency and by OSM, which also receives copies of the company mine plan. (The format of the ACP varies by state, but all approved programs cover this requirement.) By this stage, the regulatory agencies will have decided whether an Environmental Assessment (a general review) or an Environmental Impact Statement (EIS) is needed. In the majority of cases, only an Environmental Assessment is needed. Also, a Technical Assessment is prepared covering the suitability and acceptability of the mining and reclamation activities. The Technical Assessment is the more complete review document as it provides for an entire mine plan review but does not fully consider environmental impacts.

Generally, the state agency prepares the Technical Assessment, and from this and the mine plan itself, OSM prepares the Environmental Assessment. In this fashion, the state performs the bulk of the actual review, but the environmental review authority is maintained by OSM.

The only exception to this pattern of delegation occurs for Montana which performs, essentially, the entire Technical and Environmental Assessment (TEA) document. OSM gives only a brief independent analysis, and gives final approval to the environmental studies. The exceptional delegation to Montana is based on the existence of the Montana Environmental Policy Act (MEPA), which is a state-NEPA law. Montana's requirements, in going so far as to provide the necessary environmental analyses, allow OSM to rely heavily upon the state agencies.

7.5.1.2 Simplified Coal Mine Network for Use in State Sections

A simplified coal mine project network was developed in order to display the requisite state permits. The simplified diagram, shown in Figure 7-3, presents only the critical path of the complete project network shown above in Figure 7-1. The distillation of the complete network was necessary to allow presentation of the state permits without development of overly complex diagrams. The node numbers in the simplified network are derived from the complete project network.

Use of the simplified network could disrupt the consistency and logic of the overall networking process. However, the state permits do not cause major shifts in the critical path of the network. In any case, this fact allowed the use of the simplified network.

Another potential problem with the use of the simplified network is that it fails to reflect the variations in mine types and sizes among the states. In particular, smaller sizes than that used in developing the network are predominant in Alabama, Colorado, and Utah. Generally, larger mines occur in Montana and Wyoming. The mine size differences are notable for the late stages of the network such as during the erection of overburden equipment, the pit development, and the time period needed to reach full production. In the last case, the difference between small and very large mines is on the order of 1 to 3.

To correct for size factors, the last stages of the simplified network were allowed to vary by state. The average range of mine sizes and the network activity times for each state are given in Table 7-4. The activity times thus adjusted remain rough approximations of actual mine developments.

7-30

LEGEND

———— Activity
 - - - - - Dummy Activity
———— Critical Path

(10, 11) First Entry is Activity Time in Months,
 Second Entry is Float Time.
 Ex.—Activity Requires 10 Months
 Float Time Allowance is 11 Months.

(ND) Activity Time Is Not Determined or
 Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine
 Diagram. Letters Denote State Permits.

Figure 7—3. Simplified Coal Project Network.

TABLE 7-4

TYPICAL MINE SIZES AND MINE DEVELOPMENT TIMES, BY STATE

		TIME ALLOTTED TO NETWORK ACTIVITIES (MONTHS)			
	PREDOMINANT SIZE RANGE (MM TONS/YR)	CONSTRUC- TION OF RAIL SPUR	ERECTION OF OVERBURDEN EQUIPMENT	PIT DEVELOPMENT	START OF MINING TO FULL PRODUCTION
Ala.	Less than 2	7	9	6	12
Colo.	Less than 2	7	9	6	12
Mont.	Over 5	7	15	12	36
N. Mex.	2-5	7	15	12	24
Utah	Less than 2	7	9	6	12
Wyo.	Over 2	7	15	12	36 ^a

Note: California and Alaska are not shown because of lack of data. The lower activity times were used for the coal project networks in these states.

Source: ERCO estimates.

^aThe lower value of 24 months would be more appropriate for Wyoming mines outside of the Powder River Basin.

7.5.2 Alabama Coal Mine Network

Alabama is the third largest coal-producing state among the eight states covered in this study, and the eleventh largest in the nation (coal production information is taken from Table 7-2 above). Coal production in 1981 amounted to 26 million tons, of which approximately two-thirds was from strip-mining and one-third from underground mines. The coal deposits are found in the north central and northeast portions of the state, and are a continuation of the Appalachian coal region.

Alabama received authority from OSM for conducting the permanent SMCRA program in May 1982. The state had applied for the program twice, with the second submission being made in January 1982. The Alabama Surface Mining Commission has not yet requested a cooperative agreement with OSM for management of federal lands, but was preparing an application in late summer of 1982.

In displaying the coal network for projects in Alabama, the previous interim program has been depicted. The duration of network activities, which has been quite short, is expected to increase with the recent state takeover of the permanent program. The coal project network for Alabama is shown in Figure 7-4, with data on the state permits in the network listed in Table 7-5. The total permit review process for the mining permit is estimated at four months, including the completeness review. State officials reported that many reviews are completed within a few weeks.⁷ The Alabama review time is so brief because under the non-OSM-approved program, only basic descriptive data on the project are assessed.

With primacy in the SMCRA program, a substantially longer review time is expected, in order to provide for environmental reviews and for on-site inspections. Total permit review times may remain below those of other states, however, because of the relatively small size of coal mines in Alabama and due to the state's commitment to rapid permit reviews, based on discussions with state officials.

Other state permits are estimated to require less time than the Alabama mining permit. The state-issued NPDES permit and air pollution permits are not critical path activities for coal mine operators. A 6-month time allotment is given for the air quality permit under the possibility that a PSD review would be required by the Alabama Air Pollution Control Commission. In other cases, air pollution permits are generally issued within 90 days of application.

An unusual characteristic of Alabama mines is the drilling of gas wells for removal of methane gas from mining areas. The wells serve the two purposes of (1) allowing for capture of usable methane gas in the mine area, and (2) enhancing the safety of underground mining by removing explosive gases. These wells are quickly permitted through the State Oil and Gas Board.

The total length of the critical path for Alabama is estimated at 86 months. With the relatively small mine sizes in Alabama, the federal coal network was reduced, as was described above (see Section 7.5.1.2). State permit processes are brief, as compared to other states. For coal mines on federal lands, the OSM portion of the mine plan review is likely to remain the major regulatory activity on the critical path.

Figure 7-4. Alabama Permits Displayed on Simplified Coal Project Network.

TABLE 7-5

STATE OF ALABAMA PERMITS
APPLICABLE TO THE COAL PROJECT NETWORK

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
License for Surface Mining Operations/ Alabama Surface Mining Reclamation Commission	3 months	12 months	License allows company to operate in Alabama
Rights-of-Way and Easements for State Lands/ Various Agencies	1 month	2 months	Access across state lands may be needed to facilitate development
Permit for Surface Mining Project/ Alabama Surface Mining Reclama- tion Commission	4 months	11 months	Current Alabama program is much more simple than OSM program
Permit to Construct/ Alabama Air Pollution Control Commission	6 months	12 months	Required because of fugitive dust emissions
NPDES Permit/ Alabama Water Improvement Commission (AWIC)	3 months	15 months	Application is included in Pollution Abatement Plan submitted to AWIC

TABLE 7-5 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Pollution Abatement Plan/AWIC	3 months	15 months	Responsibility for plan is being transferred to ASMRC
Certification for Blasting/ASMRC	1 month	8 months	Use of explosives must be directed by licensed blasting personnel
Temporary and Permanent Permit to Operate/AAPCC	1 month	8 months	Temporary permit, which is automatically issued, applies until facility tests are made
Permits to Drill Coal Degasification Wells/State Oil and Gas Board	1 month	8 months	Wells for removal and capture of gas from mine area must be permitted
<u>Additional Permits of Potential Applicability</u>			
Stream Diversion or Rerouting Permit		AWIC	
Motorcarriers' Permit		Public Service Commission	
Special Agreement for Installation of Utilities in Rights-of-Way			
Certificate for Industrial Development		Public Service Commission	
Letter of Concurrence		Historical Commission of Alabama	

7.5.3 Alaska Coal Mine Network

Alaska has limited coal production, and has not yet implemented the SMCRA program. However, officials in the Alaska Department of National Resources are preparing the program for state takeover. The current schedule calls for submission of the program application to OSM by July 1, 1982. The Alaska legislature must also pass the implementing bills necessary to authorize such a program prior to the state takeover.

Currently, only one coal mine is operating in Alaska. That mine, owned by Usibelli Coal Mines Inc., is located predominantly on state lands and has been operating since the early 1900's. The state government's interest in implementation of the SMCRA program is based partly upon potential future development of coal mining in the state.

The SMCRA program regulations as they apply to the Usibelli Mine are enforced by personnel quartered in the OSM technical center in Caspar, Wyoming. New mine plans for Alaskan operations would be reviewed by the OSM Regional Technical Center in Denver, Colorado with a simultaneous review by the Caspar office.

The permits required in Alaska for a coal mining project are displayed in Figure 7-5, with further detail on state permits included in Table 7-6. With the limited development, there exists no state-specific data on the review of new mine plans. The critical time path shown is that for states with the smaller-sized mines as described earlier. The Alaska permitting situation is complicated somewhat by the probable need to obtain both federal and state permits for air and water pollution issues.

The state's primary water pollution permit must be approved prior to issuance of the federal NPDES permit by the EPA Region X office in Seattle, Washington.

The Mining License included in the network is not a major permit, but refers only to a general business license required by the state Department of Revenue for eventual taxation purposes. The solid waste permit is needed for disposal of mine spoil. In other Western states, these wastes are covered in the reclamation plan submitted to OSM-authorized regulatory authority. Alaska mines may also require critical habitat protection permits in some areas of operation.

The total critical path for Alaska mines is estimated at 86 months. Alaskan permitting, in general, is distinguished by the absence of EPA-authorized programs, most notably for water pollution control. Also, wildlife concerns in Alaska are more prominent than in most states.

Figure 7-5. Alaska Permits Displayed on Simplified Coal Project Network.

TABLE 7-6

STATE OF ALASKA PERMITS
APPLICABLE TO THE COAL PROJECT NETWORK

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Coal Prospecting Permit/Division of Minerals and Energy Management, Dept. of Natural Resources (DNR)	3 months	Not determined	Permit needed to commence detailed area examinations
Rights-of-Way and Easements for State Lands/ Various agencies	3 months	None	Approvals for access across state lands may be required
Alaska Certificates of Reasonable Assurance/Dept of Environmental Conservation (DEC)	6 months	12 months	Completion of federal NPDES permits requires certificate issuance
Air Quality Permit to Operate/DEC	6 months	12 months	Alaska permit does not cover PSD reviews
Water Rights Permit and Certification of Appropriation/ Div. of Land and Water Management, DNR	1 month	17 months	Certificate is issued after start of operations

TABLE 7-6 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permits to Construct a Dam/ Dam Safety Construction Div., DNR	3 months	15 months	Separate permits required for each sedimentation pond
Solid Waste Disposal Permit/ DEC	4 months	14 months	Required for both mine waste disposal and for incidental wastes
Critical Habitat Area Permit/ Habitat Div., Dept. of Fish and Game	1 month	17 months	Required in selected areas of the state
Mining License/ Dept. of Revenue	1 month	17 months	A notification for taxation authorities in Alaska
Plan Review for Sewerage Systems/DEC	2 months	16 months	Required for on-site sewage treatment systems

TABLE 7-6 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
<u>Additional Permits of Potential Applicability</u>			
Air Quality Control Permit to Open Burn		DEC	
Surface Oiling Permit		DEC	
Burning Permit		Division of Land and Water, DNR	
Anadromous Fish Protection Permit		Habitat Div., Dept. of Fish and Game (DFG)	
Fishways for Obstructions to Fish Passage		Fisheries Rehabilitation, Enhancement, and Development Div., PPG	
State Game Refuge Permit		Habitat Div., DFG	
Coastal Management Program Certificate of Consistency		Office of the Governor	
Land Use Permit		Div. of Minerals and Energy Management	
Lease Operations Approval		Div. of Minerals and Energy Management, DNR	
Coal Lease		Div. of Minerals and Energy Management, DNR	
State Park Non-Compatible Use Permit		Div. of Parks, DNR	
Wastewater Disposal Permit		Dept. of Environmental Conservation	
Water Well Authorization		Oil and Gas Conservation Commission	

7.5.4 California Coal Mine Network

A permit network for coal projects in California was not prepared due to the low level of coal production in the state. Most listings of coal outputs do not include California. Contacts were made with state officials in order to determine the approximate levels of production, and the probable outlines of regulatory activity.⁸

A small quantity of lignite production occurs in California as a byproduct of clay mining operations. More significant mines have not been developed because of the limited resource quantities, and because California coal is less economical to extract than other Western coals. In the past, mining operations solely for coal production have existed in California. Total production levels for the state were then less than 100,000 tons per year during these operations in the 1970's.

Should a new coal mine operator attempt to begin construction in the state, regulatory processes would involve a blend of federal and local regulation. California will not initiate steps to take over the SMCRA program, unless substantial interest in coal mining develops.⁹ Thus, the OSM must perform a mine plan review for any new operations. However, the state legislature did pass the California Surface Mining and Reclamation Act, predating the federal SMCRA legislation, to protect against surface disturbances by any mining activity. The program is administered by county or, in some cases, city governments under the guidance of the State Mining and Geology Board.

Other state permits applying to coal mine projects would include water quality, air quality and other issues.

California also has passed the California Environmental Quality Act (CEQA) which serves as a state NEPA program. Were mining to develop in the state, the CEQA would represent an important permit process.

7.5.5 Colorado Coal Mine Network

Over half of Colorado's coal mines involve some federal lands and many mine areas are located predominantly on federal lands. Thus federal coal accounts for a major portion of the state's annual production in FY81 of 19.3 million tons. The state ranked 12th in the United States (and third among Rocky Mountain States) in total coal production.

Colorado has four major coal producing districts. The Green River region (which extends north into Wyoming) and the Uinta region (which extends west into Utah) are the larger producing areas, and the areas with most of Colorado's federal coal leases. The other mining areas are the Raton Mesa region and the San Juan River region.

Colorado received authority for the permanent SMCRA program in December 1980. However, the Cooperative Agreement for management of federal lands has not yet been completed. Currently, mine plan reviews involving federal land are performed by both OSM (regional office in Denver) and the Colorado Mined Land Reclamation Division. This status may change soon, however, as completion of the necessary agreement is expected to be completed by June 1982.¹⁰

Colorado's SMCRA program is notable for having unusually brief review deadlines. Unlike most states, the principal mine plan review is not necessarily longer than other permit processes. The time frames for permit processes are displayed in Figure 7-6 and Table 7-7. The Colorado Mined Land Reclamation Division (MLRD) limits the plan review to 190 days, covering the four sections of the review. A 10-day completeness review of each application is made to insure that each section of the application is addressed. At the end of this

step, a letter is sent to the applicant. If the application is complete, the letter date establishes the submittal date. Next, a 60-day Preliminary Adequacy Review is made to determine if additional environmental data are needed. More information is always requested at this point. During a second 60-day period, the MLRD must decide to accept or request modifications or reject the application. An additional 60-day extension is allowed under Colorado regulations, bringing the total time frame to 190 days. Interestingly, should more data be requested of the applicant during the Preliminary Adequacy Review, this does not stop the review "clock" started at the submittal date. Other portions of the review continue while more data are awaited.

The short Colorado process contrasts with the more lengthy federal review. Under OSM Proposed Rules for federal lands, the federal review need not be completed within the state deadlines.¹¹ The normal (15-month) OSM review has been included in the network. However, OSM personnel attempt to comply with state guidelines where applicable. Nevertheless, if an EIS is required, the NEPA process requirements would make compliance with Colorado's time frame extremely difficult for OSM. The OSM proposed rules will allow the state to proceed and issue its permit, but that no mining shall begin until the federal review is complete.

The water appropriation process in Colorado can be lengthy depending largely upon the location of the desired well. If water is needed for irrigation of reclaimed areas, or for dust control of surface mines, the necessary permits could require up to 7 months or more to obtain.

Colorado also requires several permits concerning the physical fitness and competency of mine workers, the use of explosives, and the use of diesel engines. These permits may be obtained during mine construction and are unlikely to be on the critical path.

A mine owner wishing to begin operations as soon as possible would be advised to make all major applications while preparing the SMCRA mine plan because any of several state permits could create delays.

The total critical path estimated for Colorado mines is again 86 months. The same critical path was estimated for other states with the smaller-sized mines. With the 190-day mine plan review, other permits may be on the critical path for mine operators. Similar 6-month review processes are common for the NPDES permit and the Colorado Air Pollution Emission Permit (estimated at 5 months in most cases). Also, water appropriation and water well drilling permits may require a 7-month review in Colorado. Issuance of these permits is required prior to approval of the coal mining permit by MLRD, although conditional mine plans approvals (pending completion of other permit steps) are possible. A mine owner wishing to begin operations as soon as possible would be advised to make all major applications while preparing the SMCRA mine plan because any of several state permits could lengthen the project leadtime.

Figure 7-6. Colorado Permits Displayed on Simplified Coal Project Network.

TABLE 7-7

STATE OF COLORADO PERMITS RELEVANT
TO THE COAL PROJECT NETWORK

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Notice of Intention to Ex- plore/Mined Land Reclama- tion Division (MLRD)	2 months	Not determined	Required for removal of over- burden and sample gathering.
Notice of Activity/Division of Mines, Dept. of Natural Resources (DNR)	Not applicable	Not applicable	Notification triggers assistance from Division of Mines.
Rights-of-Way and Easements for State Lands/Various Agencies	2 months	1 month	May include road construc- tion or activities on state land or near state highways.
Cultural Resource Clearance/ Colorado State Historical Society	2 months	6 months	Required for activities on federal lease lands.
Air Pollution Emission Per- mit/Air Pollution Control Division/Dept. of Health (DOH)	5 months	13 months	Initial approval needed to begin construction. Final approval granted after start-up.
NPDES Permits/Water Quality Control Division, DOH	6 months	12 months	Covers discharges from sedimentation ponds.
Coal Mining and Reclama- tion Review/MLRD	4 months	9 months	State has unusually brief review deadlines. Would represent critical path permit but for longer federal process.

TABLE 7-7 (CONT.)

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Approval of Plans for Reservoir/Division of Water Resources, DNR	3 months	15 months	Required for construction of sedimentation ponds for runoff.
Special Transport Permit/ Dept. of Highways	1 month	12 months	Required for movement of oversize vehicles.
Permits for Water Wells in Bedrock Aquifer, Designated Basin or Other Area/Div. of Water Resources, DNR	7 months	11 months	May be required for dust control, irrigation in surface mining.
License for Water and Waste- water Treatment Operators/ Water Quality Control Div., DOH	Not applicable	Not applicable	License applies to individuals operating treatment equipment
Site Approval of Sewage Treatment Facility/Water Quality Control Div., DOH	2 months	16 months	Site approval is needed for sewage systems serving 20 people or more.
Application to Store or Use Explosives/Division of Mines, DNR	1 month	15 months	May be required if blasting occurs.
Hoistman Certificate/ Division of Mines, DNR	Not applicable	Not applicable	A physical exam is required for individuals operating lifting equipment in the mine.
Certificate of Competency/ Division of Mines, DNR	Not applicable	Not applicable	Competency exams are required for individual mine employees.

TABLE 7-7 (CONT.)

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Diesel Permit/Division of Mines, DNR	1 month	15 months	Required for air quality control in underground mines.
<u>Additional Permits of Potential Applicability</u>			
Open Burning Permit		Air Pollution Control Division	
Water Quality Certificate		Water Quality Control Division	
Permit to Construct an Erosion Control Dam		Division of Water Resources	
Approval of Location and Construction of Water Works		Water Quality Control Div.	
Application for Water Rights		District Water Court	
Post Mining Review		Division of Wildlife	
Fish and Wildlife Collection Permit		Division of Wildlife	
Coal Lease		State Board of Land Commissioners	
Certificate for Boilers		Boiler Inspection Branch, Division of Labor	
Permit for Explosive Materials		Public Safety Branch, Division of Labor	

TABLE 7-7 (CONT.)

Additional Permits of Potential Applicability (Cont.)

Permit to Change Point of Diversion and Place and/or Purpose of Use of Surface Water/Water resources Division	NRD
Water Well Drillers Licensed Water Resources Division	NRD
Approval of Drill Hole Plugging, Water Resources Division	NRD
Utility Permit	Highway Department
License to Appropriate (Surface Water)/ Water Resources Division	NRD
Annual Mine Registration	State Mine Inspector
State Trust Land Lease	State Land Office

7.5.6 Montana Coal Mine Network

Montana territory includes portions of two important coal producing areas: the Powder River Region (which extends into Wyoming) and the Fort Union region (shared with North Dakota). Most mines in these regions incorporate some federal lands, and thus federal mines account for 80 percent of the states' production. In 1981, Montana's total coal production was 34 million tons, second to Wyoming among the eight states covered. All of Montana's production comes from strip mines.

The extensive coal mining industry in the state has encouraged the development of the mining regulatory processes. Montana was the first state to receive authority from OSM for operation of the SMCRA program. Conditional approval for the program was received in April 1980. The state has also completed a Cooperative Agreement for regulation of federal mines. Furthermore, Montana has a state-NEPA law (the Montana Environmental Policy Act) which requires an EIS to be prepared for major projects. The existence of this legislation has encouraged OSM to allow Montana to perform almost the entire environmental review of mining projects. The Secretary of the Interior cannot fully delegate NEPA authority to a state, however, and thus OSM must give final approval of the mine plan prior to issuance by the state.

The time period anticipated for permit processes in Montana is shown in Figure 7-7, with a summary listing of the relevant permits in Table 7-8. The Department of State Lands issues Operating Permits to prospective coal mine operators. An initial 120-day period is provided in the permitting process for a completeness review, with successive 120-day periods for technical reviews. However,

successive 120-day periods for technical reviews. However, because the review "clocks" are restarted with each request to the operator for additional information, review periods are not notably different than those, at the federal level, based on the limited data and evolving operating history of the program to date. The overall time period required for the iterative completeness reviews and technical reviews has been estimated at 1 1/2 years. Simultaneously with the technical review of the mine plan, the Montana DSL prepares the EIS if necessary.

Water use permits have not created major controversies for coal companies in the state. Obtaining water appropriation permits has taken from 6-9 months (an estimate of 8 months was used in the figure) in the past. Nevertheless, some companies apply for such permits well in advance of actual needs in order to establish a priority claim to the water. Appropriation permits are issued only after all prior water claims are resolved and if water supplies are determined to be adequate.

Montana has authority for operation of the major environmental programs. Issuance of the mine plan approval is conditional upon receipt of these permits as noted in the figure. Montana may require PSD construction reviews prior to issuance of air pollution permits. The state-issued NPDES permit (MPDES) is also required.

The critical path for Montana mines is estimated at 122 months due to the large size of the state's mines. The lengthening of the path does not affect permitting most of which must be completed prior to any land disturbance. The lengthiest state permit processes are those for the Operating Permit followed by Water Use permits. In general the mine plan review is most likely to be the focus of concern for mining companies.

Figure 7-7. Montana Permits Displayed on Simplified Coal Project Network.

TABLE 7-8

STATE OF MONTANA PERMITS APPLICABLE
TO COAL PROJECT NETWORK ANALYSIS

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Prospecting Permit/Reclama- tion Division, Dept. of State Lands (DSL)	2 months	Not determined	Allows land entry and drilling by coal companies.
Rights-of-Way and Easements for State Lands/various agencies	2 months	1 month	The interspersation of state with federal lands may necessitate additional rights-of-way.
Operating Permit and Preparation of EIS/ Reclamation Division, DSL	15 months	None	The DSL process provides for mine plan review and preparation for EIS. OSM approval is needed if federal lands involved. The Montana Mine Site Location Permit is covered by the Operating Plan approval.
Air Pollutant Discharge Permit/Air Quality Bureau, Dept. of Health and Environmental Sciences (DHES)	5 months	13 months	The principal air pollution issue is control of fugitive emissions.
MPDES Permit (Water)/ Water Quality Bureau (DHES)	6 months	12 months	Montana NPDES Permit

TABLE 7-8 (CONT.)

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Water Use Permit/Water Rights Bureau, Dept. of Natural Resources and Conservation (DNRC)	8 months	10 months	Water issues, while important, have not caused exceptional permitting delays.
Solid Waste Disposal License/Water Rights Bureau, DHES	2 months	16 months	Mining wastes are covered by operating permit. Solid waste license covers only common industrial rubbish (e.g., cafeteria wastes).
Stream Alteration Approvals/ Conservation District, Dept. of Fish, Wildlife and Parks	3 months	15 months	May be needed during re- routing of streams or for water appropriation.
<u>Additional Permits of Potential Applicability</u>			
Coal Land Lease		Centralized Services Division, DSL	
Land Use Permit		DNRC	
Antiquity Site Permit		State Historical Society	
Slash Disposal Agreement		Forestry Division, DSL	
Complaint for Condemnation		District Court	
Mine Site Location Permit		Reclamation Division, DSL	

7.5.7 New Mexico Coal Mine Network

Most of New Mexico's coal deposits are located in the San Juan River basin in the northwest corner of the state. This area includes several active mines, and has large future development potential. Production in the state amounted to 18 million tons in 1981, of which over 90 percent was strip mined. Federal lease lands in New Mexico have been estimated to contain 447 million tons of recoverable coal. Development in the state in recent years has been slowed by: (1) weak demand for coal; (2) difficulties in bringing rail service to the San Juan basin, and (3) complex land ownership patterns, which complicate land acquisition tasks and create land use conflicts. The coal deposits coincide with Indian lands in portions of the San Juan basin.¹³

New Mexico has received authority for operation of the OSM mine regulation program. However, like several other Rocky Mountain states, the Cooperative Agreement for regulation of mines on federal lands has not yet been completed. The agreement is expected to be signed during the summer of 1982.

The state's regulations do not specify deadlines for mine plan reviews. Estimated review times are shown in the network in Figure 7-8, and in the permit summary table in Table 7-9. Recent experience, although limited, indicates that application completeness reviews typically require approximately 8 months, including some allowance for additional data gathering, as is usually required, by the applicant. The technical analysis may then be delayed by the need to obtain OSM mine plan approvals.¹⁴

The difficulty in obtaining water appropriation permits is highly location-specific, as may be expected. Several coal mine operators have recently received such permits, although these appropriations have involved either minor aquifers or the operators held prior water rights. Such existing rights must predate the establishment of state control over the resource. No major aquifer permits have been issued for coal mining, and some applications have been pending for several years. Clearance of such approvals must await processing of earlier appropriation applications and eventual determinations that no other users will be adversely affected.

Once such a permit is granted, the user then constructs such water works or water wells as may be needed. The Certificate and License to Appropriate Water is issued upon verification that the appropriation is within the guidelines originally permitted. Most other state permits cover various aspects of water supply and water discharge operations. Such permit processes may be interrelated for certain mine operations, as where more than one type of permit may be required.

New Mexico does not yet issue the PSD permit, although a partial delegation of PSD authority was granted to the State. As a result, most of the PSD review is performed by the state agency.

The critical path for New Mexico mines is estimated at 110 months, reflecting the medium to large size of the state's mines (2 to 5 million tons per year). The greatest permitting concerns for developers are likely to be the mine plan review and the state engineer permits, with both processes involving water appropriation issues. Delays due to water use are possible, and could prove lengthy.

Figure 7-8. New Mexico Permits Displayed on Simplified Coal Project Network.

TABLE 7-9

STATE OF NEW MEXICO PERMITS RELEVANT
TO COAL PROJECT NETWORK

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Exploration Plan Approval/ Mining and Minerals Division, Energy and Minerals Dept. (EMD)	2 months	Not determined	Permit applies specifically to coal operations, required prior to on-site exploration.
Additional Rights-of-Way and Easements for State Lands/Various agencies	2 months	1 month	Interspersion of state- federal lands requires state clearances
Permits for Archaeological Survey/State Land Office	1 month	7 months	State permit required for federal lands
Coal Surface Mining Permit/ Mining and Minerals Div., EMD	15 months	None	New Mexico Cooperative Agree- ment has not been completed
Air Quality Construction Permit/Environmental Im- provement Division, Health and Environment Dept (HED)	4 months	14 months	Required for fugitive dust emission control
Permit to Appropriate and Use Underground Water/ Water Resources Division, Natural Resources Dept. (NRD)	4 months	6 months	May be on critical path and involve lengthy delays in some cases.

TABLE 7-9 (CONT.)

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Certificate and License to Appropriate (Groundwater)/ Water Resources Div., NRD	3 months	19 months	Issued after water use begins.
Water Supply Construction Permit/Water Supply Section, HED	1 month	9 months	Applies to water supply or treatment facilities.
Groundwater Discharge Plan Approval/Water Quality Control Bureau, HED	6 months	9 months	Needed for discharge to ground waters
Mine Dewatering Permit/ Water Resources Division, NRD	6 months	9 months	Operation must not damage existing water rights.
<u>Additional Permits of Potential Applicability</u>			
Permit to Appropriate and Use Surface Water/ Water Resources Division,			NRD
Permit to Change Location of Well and Place or Purpose of Underground Waters/Water Resources Division			NRD
Certificate of Construction (Surface Water)/ Water Resources Division			NRD

7.5.8 Utah Coal Mine Network

Utah has two major coal regions: the Uinta region in East-Central Utah, and the Southwestern field near the Arizona border of the state. Federal land ownership in these regions is extensive due to the retention of federal control over the mountainous terrain and upland plateaus. State and private land sections are located in the flatlands or the valley floors. The USGS has estimated that 82 percent of the state's coal deposits occur on federal lands.¹⁵ In 1981 production, Utah produced approximately 15 million tons of coal, of which approximately 66 percent was federal coal and 88 percent was from federal mines (mines with some federal lands). This production level was slightly below that of Colorado and New Mexico.

Utah has had conditional approval for operation of the SMCRA regulatory program since January 21, 1981. OSM has stipulated that certain changes be made in state regulations governing minor program issues. Since program takeover, four new mine plans and numerous revised plans have been reviewed with appropriate actions taken. Utah has not completed a Cooperative Agreement with OSM for the regulation of federal lands.

The state permits are displayed on the simplified coal project network in Figure 7-9, with additional permit data provided in Table 7-10. At the present time, the mine plan review process is fairly lengthy. On the figure, a review time of 15 months was estimated to coincide with the OSM reviews based on historical review times. However, longer review times will apply to new mines because the state has approximately 25 mine plans or plan revisions pending at the current time.¹⁶

Most of the state's coal mines require water from the Colorado River, which, however, is fully appropriated. As a result, most coal companies choose to purchase existing water rights or to purchase shares in companies which hold water rights.¹⁷ Typically, the coal company purchases shares of an agricultural company with existing water rights. This purchase represents a private transaction and does not involve state government. The agricultural interest (or other holder of water rights) would then submit an Application for Change of Point of Diversion for their water rights to the State Engineer, Division of Water Rights. In the review process the State Engineer verifies that the coal company's water use is correct, given the number of shares purchased (percentage of the rights-holder company purchased; the water rights actually remain with the original company and are not purchased directly in this case), and that other water users are not adversely affected. The permit process for these change applications generally requires 4-6 months as compared to a year for direct appropriations. Also, direct water appropriations are not always feasible, as previously mentioned, in the Utah coal areas.

The other state permits are not generally difficult to acquire. Both state and federal wastewater disposal permits are required, as Utah has not assumed the NPDES permit responsibility. The state does have authority for operation of the PSD program.

A potentially lengthy approval process for stream alteration agreements has been noted. This permit is generally required if a stream alteration is made to facilitate water appropriation actions.

The mine plan reviews cover wildlife issues which, in some of the mountainous Utah coal regions, may be notable. However, with the underground operations contemplated, surface mining effects on wildlife are significantly reduced. The primary wildlife issue in the state is the coincidence of the mineable Wasatch Plateau in central Utah with big game habitats.

The length of the critical path for Utah mines is estimated at 86 months. The state's mines are smaller than those of the Northern Great Plains (Montana and Wyoming) as would be expected for underground mines. The review of the mine plan by the Division of Oil, Gas and Mining is the major permit with other approvals all showing lengthy float times.

Figure 7-9. Utah Permits Displayed on Simplified Coal Project Network.

TABLE 7-10

STATE OF UTAH PERMITS RELEVANT
TO COAL PROJECT NETWORK

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permit to Commence Coal Exploration/Division of Oil, Gas and Mining, Dept. of Natural Resources (DNR)	1 month	Not determined	Required for field gathering of sampling from Utah lands.
Rights-of-Way and easements for state lands/various agencies	2 months	1 month	Interspersion of state and federal lands may necessitate additional rights-of-way.
Permit to Excavate Archaeological Remains/ Division of State Lands	1 month	7 months	Required for collection of data needed for mine plan application.
Permit to Mine Coal/ Division of Oil, Gas and Mining, DNR	15 months	None	Utah has conditional approval for the SMCRA program.
Notice of Intention to Mine/Division of Oil, Gas and Mining, DNR	1 month	17 months	An informational notice.
Review and Approval of Air Pollution Sources/Div. of Environmental Health, Dept. of Health (DOH)	6 months	12 months	Covers the PSD permit requirement, if applicable.

TABLE 7-10 (CONT.)

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Permit for Discharge of Wastewater/Div. of Environ- mental Health, DOH	2 months	16 months	Federal NPDES permit also required.
Application for Change of Point of Diversion, Place or Nature of Use of Water/ Div. of Water Rights, DNR	6 months	12 months	Most coal firms purchase existing water rights and Application for Change is then needed.
Approval of Construction or Repair of a Dam or Im- poundment/Div. of Water Rights, DOH	3 months	17 months	Needed prior to construction of sedimentation pond.
Approval of Disposal of Solid Waste/Div. of En- vironmental Health, DOH	2 months	16 months	Required for ancillary facility (e.g. cafeteria rubbish disposal). Mine spoils disposal covered in Permit to Mine Coal.
Stream Alteration Approval/Div. of Water Rights, DOH	12 months	6 months	May be needed if water appropriation is also involved.
Sewage System Approval/ Div. of Water Rights, DOH	2 months	16 months	Exact nature of permit depends on size of system

TABLE 7-10 (CONT.)

Additional Permits of Potential Applicability

Open Burning Permit	Division of Environmental Health
Certificate of Appropriation of Groundwater	Division of Water Rights
Certificate of Registration to Take Protected Wildlife	Div. of Wildlife Resources
Notice of Intent to Divert a Canal, Reservoir, or Other Waterway Containing Protected Aquatic Wildlife	Div. of Wildlife Resources
Use Permit on State Park Lands	Div. of Parks and Recreation
Permit for Overweight Vehicle	Highway Patrol
Well Drillers Permit	Division of Water Rights
Approval of a Development Proposal Impinging on the Provo-Jordan River Parkway and its Drainage	Div. of Parkways and Recreation
State Mineral Lease	Division of State Lands
Application to Remove a Heritage Tree	Division of State Lands
Approval of Drinking Water System	Division of Environmental Health

7.5.9 Wyoming Coal Mine Network

Wyoming is by far the largest coal-producing state in the West, and is the third largest producer in the country. Wyoming's 1981 production totaled 104 million tons, which is three times the production of Montana, the next largest Western coal producer. Wyoming's major coal regions are the Powder River basin (northeast portion of the state), the Green River region (south central portion), and the Hams Fork region (near the western border). Nearly all Wyoming mines use strip mining techniques.

Appropriately, Wyoming has one of the more established mine regulation programs. The state primary authorization was received in November 1980 and Wyoming is one of the two states in this study (with Montana) to have completed the Cooperative Agreement with the federal government.

The state has placed fairly brief timeframes on its regulatory program, as operated by the Wyoming Department of Environmental Quality. The state regulations require DEQ to respond within 60 days of mine plan submission as to the completeness of the application. Once complete, federal agencies and OSM have 50 days to submit comments to the DEQ. The state review deadline is 150 days after a complete submission. In the network shown in Figure 7-10 (with the permit listing in Table 7-11), a 9-month review period was used for the state portion of the review. A 9-month period would allow for two completeness review periods (assuming that the first submission is incomplete and not considering the company's time to respond) and for a 150-day review for a total of 270 days.

In addition to the SMCRA program, Wyoming operates an important Industrial Siting Permit process. The Wyoming Industrial Siting Council (ISC) assesses the overall desirability of large facilities in the state. The ISC authority applies to any projects with a total investment of \$88 million. (This minimum investment was originally set at \$50 million by law with a provision for adjustment of the level according to an inflation index.) In looking at the overall project desirability, the ISC attempts to avoid any duplication of mine plan reviews.

Water appropriation permits for coal mining, in Wyoming, unlike other Western states, are generally not controversial. Most of the mine operations have occurred in sufficiently remote areas that few competing uses are evident. These permits are not likely to be on the critical path.¹⁸

To date, most coal mines have fallen beneath this minimum investment level and have received a Certificate of Insufficient Jurisdiction from ISC. New mines may not be so exempted, however, presenting the possibility of an additional level of project review.

For large new coal mines, the ISC would examine the environmental characteristics of the operation (relying upon the DEQ, Land Quality Division for technical analysis), assess the socioeconomic elements of the project, and analyze the transportation network to be utilized.

As for the other environmental permits, they must be obtained prior to issuance of the Permit to Mine. This relationship is shown in the figure by the channeling of other permitting activities into the "Permit to Mine" activity and the addition of node 30a to maintain the logic relationships. The ISC permit, if applicable, must also be obtained prior to issuance of the Permit to Mine.

The critical path for Wyoming mines is estimated at 122 months reflecting the large size of mines in the state portion of the Powder River Basin. As for all other states, the mine plan review process is the central permit approval process. Other approvals are typical of those in most states.

Figure 7-10. Wyoming Permits Displayed on Simplified Coal Project Network.

TABLE 7-11

STATE OF WYOMING PERMITS APPLICABLE
TO THE COAL PROJECT NETWORK

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Coal Exploration License/ Land Quality Div., Dept. of Environmental Quality (DES)	Not applicable	Not applicable	The license is not project specific and may be obtained anytime.
Rights-of-Way and Easements for State Lands/Various agencies	2 months	1 month	If federal and state lands are interspersed, state access permits will be needed.
State Historic Preservation Office Review/Recreation Commission	2 weeks	7 months	Required in some areas for protection of historic or archaeologic values.
Permit to Mine/Land Quality Division, DEQ	9 months	6 months	Wyoming mine reviews will tend to be faster than federal reviews.
Permit to Construct (Air Quality)/Air Quality Div., DEQ	6 months	12 months	Covers PSD reviews.
Wastewater Discharge Permit/ Water Quality Division, DEQ	5 months	12 months	Required for discharges from sedimentation ponds or other discharges.
Permit to Appropriate Groundwater/Office of the State Engineer	3 months	15 months	Most Wyoming coal companies appropriate groundwater. Separate permit needed for each well.

TABLE 7-11 (CONT.)

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Industrial Waste Facility Permit/Solid Waste Manage- ment Div., DEQ	5 months	13 months	Needed only for ancillary facilities at site. Mine spoil disposal is covered by the Permit to Mine.
Reservoir Construction and Use Permits/Office of the State Engineer	3 months	15 months	Required for construction of sedimentation ponds.
Wyoming Industrial Siting Permit/Industrial Siting Council	6 months	12 months	ISC reviews overall project desirability including socio- economic impacts.
Permit to Construct a Waste- water Treatment Facility/ Water Quality Division, DEQ	2 months	16 months	Required for sewage treat- ment facilities.
Notification of Opening of Mine/State Inspection of Mines	Not applicable	Not applicable	No review process is involved.
Permit to Construct and Operate a Sedimentation Pond/Water Quality Div., DEQ	2 months	10 months	Several ponds and the asso- ciated permits may be needed for a given mining operation.
Scientific Permit/Wyoming Game and Fish Dept.	2 months	10 months	Permit is sometimes obtained by mining companies in wild- life preservation activities.
Permit to Operate/Air Quality Div., DEQ	1 month	11 months	Must be obtained within 90 days of project start-up.

TABLE 7-11 (CONT.)

COMMONLY REQUIRED PERMITS/ AGENCY	TIME ALLOTTED	FLOAT TIME	COMMENT
Certificate of Competency/ State Inspector of Mines	Not applicable	Not applicable	Competency of key mine per- sonnel must be determined prior to mining.
<u>Additional Permits of Potential Applicability</u>			
Groundwater Pollution Control Permit Water Quality Division		DEQ	
Temporary Use Permit		Office of the State Engineer	
Land Use Lease		State Board of Land Commissioners	
Water Disposal Permit		Office of the State Engineer	
License to Mine/Land Quality Division		DEQ	
Change in Use or Point of Diversion Petition		Office of the State Engineer	
Dredge and Fill Permit/Water Quality Division		DEQ	

7.7 Summary Analysis of Coal Mine Project/ Permit Networks

The networks presented in Section Seven provide a means of organizing and displaying information about coal mine projects and the associated permits. The permit data is summarized in this section.

In general, the state permit networks for coal mines are very similar. The state permit networks were all based on simplified networks showing the critical path of the federal network (Figure 7-1). None of the state permits modify the critical path of the federal network, which shows the OSM mine plan review as the dominant regulatory action. This conclusion is modified only by the complication of combined federal-state mine plan reviews. In some cases a state permit process could then be on the critical path.

In simplest terms, the SMCRA program has focused attention on a single major permit. All other permits (1) have shorter review times, and (2) will tend to be secondary or even superfluous in comparison to the mine plan review. The comprehensive environmental coverage of the SMCRA program allows it to be the forum for the full range of potential issues such as air quality, water quality, aesthetic or noise values, wildlife protection, land reclamation and others.

In some cases, other permits may become critical and cause delays in a project or represent the most difficult approval process. Among the permits which have this capability are the water appropriation permits, air quality permits, and federal rights-of-way (or land-use permits), particularly if land ownership is at issue. In such cases, it is frequently the regulatory issue itself which requires

a long time for resolution. For example, for water appropriation permits in New Mexico's San Juan River basin, the water shortage is the issue and not the permit handling procedures of the state engineer's office.

The prominence of the mine plan review does not imply that only OSM procedures should be examined. All of the states with active mining industries have or will have primacy for the SMCRA program. The mine plan reviews are increasingly being handled at the state level with OSM involved only as necessary to fulfill its legal obligations. The recently (June 9, 1982) proposed rules of OSM formalize this trend. Thus the state mining permit is the most visible individual permit, with OSM shifting to an approval role. The OSM role will be limited to approval of environmental studies as required under their NEPA responsibility. Mining must wait upon the OSM clearance, however, so the route of the critical path in each state will depend on whether state or federal reviewers are slower. In the networks developed it was assumed that the federal government will require more review time than the state agency. The assumption may not prove correct in the future.

The critical paths for all states are thus similar, with parallel tracks representing the joint federal and state reviews of federal mine plans. Eventual patterns of review time will depend on the nature of mining in each state and the state's commitment to provision of expeditious reviews. A summary of the critical paths for the 7 state networks (California is excluded) is provided in Table 7-11. The length of the critical paths vary from 86 months for the states with relatively small mines to 122 months for the large surface mines of Montana and Wyoming. The variation in critical paths as modeled is entirely due to differences

TABLE 7-11

COMPARISON OF COAL MINE LEADTIMES BY STATE
(months)

STATE	AVERAGE MINE SIZE CLASS	LENGTH OF CRITICAL PATH	LENGTH OF REGULATORY ACTIVITIES ON PATH ^a	LENGTH OF PATH WITHOUT REGULATION	LEADTIME DUE SOLELY TO REGULATION
Alabama	Small	86	33	74	12
Alaska	Small	86	33	74	12
Colorado	Small	86	33	74	12
Montana	Large	122	33	110	12
New Mexico	Medium	110	33	98	12
Utah	Small	86	33	74	12
Wyoming	Large	122	33	110	12

^aThe length of the OSM review varies with mine size, although the data available is too limited to allow state-by-state comparison. For more information on OSM review times, refer to section 9.2 below.

Source: ERCO estimates.

in the expected development times among mines. The influences of regulatory times, under the network assumptions, is exactly identical in all cases. As the table shows, 33 months of the critical path represent activities necessary due to regulatory requirements, although if all regulations were eliminated, only 12 months of the total leadtimes would be eliminated. That is, all but one year of the regulatory activities overlap with other mine development functions and thus do not lengthen the overall project leadtime.

The assumption that regulatory influences are identical in all states was needed because of the lack of sufficient data to distinguish states. However, 2 factors are certain to vary across states. First, the states have developed differing internal processing guidelines or requirements with Colorado having the briefest deadline of 6 months. Although OSM aproval still is needed prior to mining, the state operations will influence the federal reviews. The OSM has attempted, for example, to comply with the Colorado deadlines.

Second, mine review times vary with mine size. The states which were assigned shorter lead times will generally have shorter mine plan reviews. The limited available data on this point is examined in Section 9.2 below.

The characteristics of the mining and associated permit process in each state were also summarized in Table 7-12. Again, there is relatively little to distinguish the permits applicable in each state. The states covered are separated more by differences in emphasis or degree than by major regulatory variations. Comments received from industry personnel verify that state processes are quite similar.

TABLE 7-12

OVERVIEW OF STATE PERMIT PROCESSES FOR COAL MINING

STATE	STATUS OF SMCRA PROGRAM	CHARACTER OF MINING ACTIVITIES	MINE PLAN REVIEW PROCESSES	OTHER NOTABLE STATE CHARACTERISTICS
Alabama	Permanent	Has surface and underground mining	AL is committed to brief reviews	Other permit processes are generally expeditious
Alaska	Interim	Limited coal mining to date	Has permit assistance mechanisms in place	AK has important environmental and wildlife permits
California	Interim	Very small coal reserves	SMCRA Program is not being developed	CA has established state NEPA program
Colorado	Permanent	Has surface and underground mining	Has instituted program with brief review deadlines	Any of several state permit processes could be as lengthy as the mine plan review in state.
Montana	Permanent	Has large surface mines, most include federal lands	MT performs nearly entire review of federal mine plans	MT has state NEPA. State requires PSD review
New Mexico	Permanent	Has large surface mines	Only one mine review, of non-federal mine, has been completed: 8 months were required	Water appropriation permits are difficult in some areas

TABLE 7-12

(Cont'd)

STATE	STATUS OF SMCRA PROGRAM	CHARACTER OF MINING ACTIVITIES	MINE PLAN REVIEW PROCESSES	OTHER NOTABLE STATE CHARACTERISTICS
Utah	Permanent	Has underground mining operations	UT mine reviews do not have exceptional review schedule	Developers have avoided water appropriation difficulties. Underground mines cause less surface disturbance.
Wyoming	Permanent	Has large surface mining operations; most include federal lands	Has instituted program with relatively brief review times	Industrial siting permit may apply to large mines. Water appropriation has been relatively easy.

NOTES TO SECTION SEVEN

1. J. Russell Boulding, Coal Mine Permitting - Meeting the Mandate of the Federal Surface Mining Regulations, 1980.
2. ERCO estimate based on telephone discussions with manufacturers of large dragline equipment, i.e., Bucyrus-Erie Corp., South Milwaukee, Wisc., and Marion Power Shovel Div., Dresser Industries, Inc., Marion, Ohio, May 1982.
3. ERCO estimates. See Note 2.
4. Office of Technology Assessment, An Assessment of Development and Production Potential of Federal Coal Leases, Dec. 1981, p. 287.
5. See Note 4, pp. 312-313.
6. See Note 4, p. 309.
7. ERCO estimate based on telephone communications between John Eyraud of ERCO and John Cranor of Alabama Surface Mining Reclamation Commission, April 12, 1982 and with Jim Culpepper, Office of Surface Mining, Knoxville, Tenn., April 12, 1982.
8. Telephone communications between John Eyraud of ERCO and Doug Sprague, Executive Officer of the State Mining and Geology Board, April 20, 1982.
9. See Note 7.
10. Telephone communication between John Eyraud of ERCO and Sandy Enrich of the Colorado Mined Land Reclamation Division.
11. Telephone communication between John Eyraud of ERCO and Frank Anderson of Office of Surface Mining, Washington, D.C., June 2, 1982.
12. ERCO estimate based on telephone communication between John Eyraud of ERCO and Ralph Dryer of the Montana Department of State Lands, April 8, 1982.
13. See Note 4.
14. ERCO estimate based on telephone communication between John Eyraud of ERCO and Jack Reynolds of the Mining and Minerals Division, New Mexico Energy and Minerals Dept., April 13, 1982.

15. See Note 4.
16. Telephone communication between John Eyraud of ERCO and Ron Daniels, Director of Mining Section, Division of Oil, Gas and Mining, Utah Department of Natural Resources, April 14, 1982.
17. Telephone communication between John Eyraud of ERCO and Bob Morgan, Division of Water Rights, Utah State Engineers Office, April 16, 1982.
18. ERCO appraisal based on telephone communication between John Eyraud of ERCO and Mike Penz of the Wyoming Office of the State Engineer, April 23, 1982.

SECTION EIGHT

NETWORK PRESENTATIONS OF PERMITTING SYSTEMS: GEOTHERMAL AND OIL SHALE SYSTEMS

The influence of regulatory programs has been widely noted in the development of alternative energy resources, as well as for the conventional energy projects discussed thus far. Permitting and regulatory issues, for instance, have been said to seriously restrain alternative energy resources by requiring excessive environmental studies and by creating high levels of uncertainty for energy companies. In this section, the permitting requirements faced by two important types of alternative energy, geothermal and oil shale resources, will be considered. Project/permit networks were prepared to cover regulatory approvals needed at the federal level and in selected states. This analysis provides useful background on the functioning of the relevant permitting programs.

8.1 Geothermal Project Network Presentation

The geothermal network was based on the available literature on project histories and on judgments of activity times made by industry and government personnel in the course of their communications with ERCO personnel. The limited operating history of individual geothermal projects was considered in the network definition. However, no individual project was used on the primary basis for the network. Instead, data obtained from the literature and through contacts to persons knowledgeable in the field were generalized and used as the basis for the networks.

In the basic network analysis, the scheduling of geothermal drilling and resource characterization activities was guided by the text, Analysis of Requirements for Accelerating the Development of Geothermal Energy Resources in California, by Jet Propulsion Laboratory, Pasadena, Calif., 1977. Contacts with executives of Republic Geothermal, Inc. and Magma Power Corp. also provided very useful information.¹ Other information on permit review requirements was supplied by personnel of the Minerals Management Service (MMS), the Bureau of Land Management (BLM), and the Forest Service (FS).²

Geothermal facilities differ from conventional energy sources in that the resource must be utilized on the site. The location, permitting, and construction of a power plant multiplies the complexity of the overall project. For this study, power plant permitting issues have not been considered. The general activity of power plant construction is included in the network only in general terms in order to relate its development to that of the geothermal resource. This omission, while making the discussion not fully reflective of geothermal project issues, keeps the study focus on resource extraction issues. The extent of drilling and resource development in the network diagram is estimated to be adequate for a 200-MWe power plant to be located on the site.³

The geothermal project/permit network is shown in Figure 8-1. As for the other resources, only federal permits are shown in the first project/permit network, with the state permits considered separately below. The federal permits are the only regulatory requirements which occupy the critical path for geothermal projects on federal lands.

The critical path for the geothermal network was estimated at 90 months (7.5 years). Of the total, 9 months are attributed to regulatory activities, including 6 months for simultaneous reviews of the Plan of Development and Plan of Injection by the MMS. These reviews occur with the lease application request. (In this case, a non-competitive lease sale is assumed, which consumes 3 months in handling time. A competitive lease sale requires 9 months.) Other notable MMS reviews occur for each of the four other plans covering Exploration (1 month), Baseline Data Collection (2 months), Utilization (12 months), and Production (6 months). The Plan of Utilization and Plan of Production reviews involve intensive environmental studies.

The major activities on the geothermal network are spelled out below.

Preparation for Exploration - Initial identification of lands where geothermal resources may be located which justify further exploration. This task may be performed by literature search and analysis followed by preliminary non-disruptive surface evaluation. The exploration plan prepared at this time includes a description of more extensive surface exploration and exploratory well drilling (temperature-gradient wells and stratigraphic wells), if any, proposed for the area.

Plan of Exploration Review - MMS review includes reference to the overall land management plan for the area to discover if major obstacles to development exist. An on-site inspection of the acreage covered by the plan is part of the review.

APD Approval - Once the Plan of Exploration is approved, an Application for Permit to Drill is submitted. This

LEGEND

- Activity
- - - - - Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months,
Second Entry is Float Time.
Ex.—Activity Requires 10 Months
Float Time Allowance is 11 Months.
- (ND) Activity Time Is Not Determined or
Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine Diagram. Letters Denote State Permits.

Figure 8-1. Network Presentation of Representative Geothermal Projects on Federal Lands.

states specifically where wells or other surficial disturbance will take place. If no drilling is contemplated, a Notice of Intent to conduct surface exploration is filed. An APD is required for each well drilled.

For the geothermal network, the APD process was estimated to require only 1 month as opposed to the average of 3 months in the case of oil and gas drilling. In the geothermal case, the MMS has knowledge of the developer's plans and of the probable environmental impacts of drilling prior to submission of the APD.

Preliminary Surface Exploration - The exploratory phase will include examination of surficial geology and measurement of other resource properties such as gravity, magnetism, microseismicity, resistivity, conductivity change, etc. Temperature-gradient wells, if drilled at this stage, give heat flow values and thermal gradient curves. Stratigraphic holes provide information about subsurface geology. Few of either of these types of wells are drilled at this stage in a non-competitive leasing situation. The discovery of geothermal resources at this point could cause the MMS to require competitive leasing for the land tract.

Plan of Development Review - The plan of development outlines the methods of extraction for the geothermal resource (number and placement of wells, access roads, pipelines, etc.) and the proposed final utilization of the energy produced (power plant, greenhouse, etc.). The review is coordinated with the lease application

concurrently before either the BLM or FS. The environmental review covers the disturbance that will be caused by the exploratory and development well drilling. The environmental review performed is of a general nature, designed only to identify serious impacts.

Exploratory Well Drilling - If only surface evaluation of the area's geology was done during the pre-lease phase (the most common situation), shallow (500 ft deep) temperature-gradient wells and stratigraphic holes will be drilled. Using the information obtained from the drilling of the shallow wells, locations for deep exploratory wells can be selected. These wells will give data on temperature, porosity, permeability, etc., as needed for future project planning.

Reservoir Characterization and Development Well Drilling - Development wells are drilled to perform extended flow and reinjection tests in order to evaluate the location and extent of the resource. Reservoir characterization utilizes all the information from the wells drilled and frequently involves modeling to estimate the size and longevity of the geothermal reservoir. During this phase additional wells are drilled as needed to confirm the potential of the resource in order to define the ultimate use pattern more precisely.

Plan of Baseline Data Collection Review - A Plan of Baseline Data Collection is submitted to assure that all necessary information will be collected on the geology and hydrology of the area, and on the air quality, flora, and fauna on a seasonal basis. The data collection will be carried out for at least a year before production begins.

The baseline data are not used in the environmental reviews of the Plan of Utilization or Plan of Production. They are collected for the purpose of designing a suitable monitoring program to be instituted once production begins, so that changes to the operating locale will be apparent to operators and government agencies.

Plan of Utilization Review - The Plan of Utilization covers the placement of the final production and injection wells and associated well sites, access roads, pipelines, etc. It includes plans for the utilization of the geothermal energy: power plant district heating, greenhouse, irrigation, etc. It is a complex document specifying the design for the ultimate use. The environmental review at this stage is designed to evaluate the overall impact of the project if it goes to the production phase, including air and water effluent and waste disposal parameters. An Environmental Assessment (EA) is first required. This document may show that a complete Environmental Impact Statement (EIS) is needed for the project. An EIS is most likely if the geothermal resource will be used in conjunction with a power plant. The EIS will be prepared during the Plan of Utilization Review.

Drilling of Production Wells - Access roads to the site must be prepared to accommodate the heavy drilling equipment. The well sites must be prepared before drilling can begin. Each drill site will usually contain more than one well. The production and injection wells will be drilled concurrently with the power plant construction.

Plan of Production Review - The Plan of Production will describe the location and operating conditions (flow rates, pressure, etc.) of production and injection wells together with the monitoring program set up to assure that no significant environmental changes occur. Specific designs for the power plant or other energy user will be reviewed at this time. A permit to begin production will be issued once construction is complete and the project has been certified as having been constructed according to the previously approved production plan.

Production - When the construction and reviews are complete and the permit to begin production is issued, the geothermal wells may begin pumping the geothermal fluid (steam or hot water) to the power plant or other user. Returned fluids will be disposed of either on the surface in impoundments or by underground injection. Monitoring will proceed to record any changes in geology, air or water quality, etc. Reports will be made to the proper authorities regularly and changes in the pumping and injection rates made if necessary.

8.1.1 Federal Permits Required for Geothermal Projects

As is evident from the discussion thus far, geothermal developments are closely monitored by the Minerals Management Service. Other reviews of major environmental permits are also applicable.

The geothermal network designates the principal permits for the resource. The permits designated in the network are listed in Table 8-1 with the issuing agency identified.

TABLE 8-1

FEDERAL PERMITS IN THE GEOTHERMAL NETWORK

COMMONLY REQUIRED PERMITS/AGENCY	REVIEW TIME	FLOAT TIME	COMMENT
Plan of Exploration Review/ MMS	1 month	None	First, general pre-lease review by MMS.
APD Approval/MMS	1 month	None	Shorter review for geothermal than for oil and gas APD's; must be repeated for each well.
Plan of Development Review/ MMS	6 months	None	Review is coordinated with the lease application.
Plan of Injection Review/ MMS	6 months	None	Review is coordinated with the lease application.
Rights-of-Way Approval/ Various Agencies	3 months	3 months	Requests are coordinated with lease application.
NPDES Permit/Environmental Protection Agency (EPA)	6 months	12 months	Needed if surface discharges are required.
Prevention of Significant Deterioration (PSD) of Air Quality Permit/EPA	9 months	9 months	May be needed for larger projects in attainment areas.
Plan of Baseline Data Collecton Review/MMS	2 months	16 months	Data provides background for monitoring during production.

TABLE 8-1 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	REVIEW TIME	FLOAT TIME	COMMENT
Plan of Utilization Review/MMS	12 months	18 months	An EIS could be required as part of review.
Plan of Production Review/MMS	6 months	18 months	Permit verifies previous approvals and allows production.
<u>Additional Federal Permits of Potential Applicability</u>			
Underground Injection Well Operation Permit/EPA		Endangered Species Permit/FWS	
National Wildlife Refuge-Special Use Permit/FWS		Threatened Species Permit/FWS	
Migratory Bird Permits/FWS		Bald Eagle Permits/FWS	
Approval of Unitization/MMS		Permit for Structures on or Work in or Affecting Navigable Waters/COE	
Discharge of Dredge or Fill Material Permit/Corps of Engineers (COE)		Bridge Permit/Coast Guard	
Permit for Dams and Dikes in Navigable Waters/COE		Application for Permit to Conduct Archaeological Explorations/FS	
Antiquities Act Permit/Department of the Interior		Notice of Proposed Construction Alteration of Airports/FAA	
Notice of Proposed Airspace Obstruction/Federal Aviation Administration (FAA)		Temporary or Permanent Exemption from FUA Prohibitions/Department of Energy	
Timber Sale Contracts/FS			

Additional federal permits which could apply to geothermal projects are enumerated in the second half of the table. These additional permits were not included in the network because they are not generally applicable.

The table includes the six plan approvals required by the MMS. These permits represent a comprehensive administrative review of the project activities. In the past, the MMS review system came under criticism as involving an unnecessary degree of environmental review. In particular, it was charged that the early environmental reviews were based upon unfounded speculation about the course of the project. For example, geothermal developers needed to prepare environmental documents for power plant construction before it could be known that the resource was viable for that use.⁴

In light of such criticism and other influences, the MMS, BLM, and Forest Service have agreed to reduce the extent of the environmental reviews in the early project stages. (The BLM and Forest Service may be involved in pre-lease and post-lease environmental review and approval process. The MMS is the lead agency after leasing for the environmental reviews.) These issues are dealt with directly in a BLM Instruction Memorandum to field officials of November 5, 1981.⁵ In that memorandum it is stated that the "pre-lease [environmental] review should be concise and general, relying primarily on relevant information in existing land use plans, existing resource inventories, or other environmental source documents." The purpose of the pre-lease review is to determine the compatibility of geothermal activities with the lands to be leased. In this determination, "lands should rarely be found to be incompatible with geothermal activities" considering "(1) the small percentage of a leased area likely to be developed, (2) the

flexibility for siting operations, (3) the degree of environmental controls available, and (4) the high value of developable geothermal energy resources"

Post-lease reviews likewise are not to include speculation about future project developments. The "environmental reviews should primarily assess the specific activity proposed and the impacts of the activity . . . they should . . . be limited to the levels of detail necessary to make an informed decision on the immediate proposal. Future activities should be anticipated and briefly considered, but it is not necessary to address them in detail."⁶

In addition to the reviews directed by the MMS, the Environmental Protection Agency and other federal agencies issue permits relevant to geothermal activities. The other environmental permits required, and the pollution issues involved, are described below.

Air Quality and PSD Construction Review

Since geothermal resources are commonly located in remote areas which are in attainment for air quality, development of a large geothermal field will generally require PSD review. A PSD permit is required if a development emits or has the potential to emit 250 tons/yr of any pollutant. Small direct users of geothermal energy (for space heating, greenhouses, etc.) will not be subject to PSD review. Larger geothermal fields supplying power plants or industrial users will trigger the PSD process. In this case the geothermal well field would be considered a separate source from whatever facility was using the resource.

An air quality permit application would need to be made before the drilling of the first deep well and would cover the construction of access roads and well pads as well as the drilling,

testing, and possible bleeding of deep exploratory and development wells. The pollutants of concern would be H₂S, SO₂, and particulates.

In certain geothermal areas, H₂S is present and the field would have the potential to emit more than the 250 tons/year allowed. In addition, certain states (among them California), have state ambient H₂S standards which the facility could not exceed. Blowout prevention equipment and H₂S alarm systems are required for drilling operations. Newly designed systems should have no problem meeting H₂S limitations and in satisfying California Air Pollution Control Districts that the conditions will be met.

Small amounts of SO₂ may occur in those cases when H₂ is present. The amounts will not be of concern or require permitting. Particulates are present primarily during construction, not operation. Control measures such as road watering and dust control can be taken to keep particulates within acceptable limits. Other hazardous air pollutants occur at such low levels as to cause no health problems.

Water Quality and NPDES Permits

Where a geothermal fluid is to be discharged into a waterway or a holding pond, an NPDES permit will be needed. The parameters of concern will be the temperature of the disposed fluid, the total dissolved solids, the pH (frequently acidic), and the presence of hazardous amounts of sodium, fluorine, boron, arsenic, and mercury.

In the cases where the geothermal fluids will be injected underground, no NPDES permit is needed. The injection wells (placement, drilling, operation, and monitoring) will be regulated by the MMS under the Plan of Injection.

Solids Handling

Permits will have to be obtained for proper disposal of solid wastes generated during drilling operations (spoil, drilling muds, refuse from construction, etc.) None of these materials will be considered hazardous under RCRA and disposal in an on-site sanitary landfill should be satisfactory.

Wildlife Permits

The U.S. Fish and Wildlife Service enforces the wildlife laws providing for the protection of critical habitats. Its expertise is utilized during the environmental assessment of any geothermal project. Their recommendations may require certain areas to be left undisturbed, certain activities to be prohibited for parts of the year, and/or reclamation procedures to be undertaken after land disturbance. Since geothermal development generally uses only a small percentage of the acreage leased, adjustment of the Plan of Development and Plan of Utilization may be sufficient to gain Fish and Wildlife approval.

8.1.2 State Permits Required for Geothermal Projects

The permits required in two states for geothermal projects were reviewed for this study. The states covered were California, which has seen the greatest level of development to date, and Utah, which is roughly typical of the Rocky Mountain States in the extent of its geothermal resources.

The permits potentially applicable to geothermal projects in California are listed in Table 8-2. The listing is intended to be comprehensive in that all permits which could be applied are

TABLE 8-2

LISTING OF CALIFORNIA PERMITS OF POTENTIAL
APPLICABILITY FOR GEOTHERMAL PROJECTS

PERMIT	AGENCY
<u>Exploration</u>	
Geothermal Exploration Permit	State Lands Commission
<u>Leasing</u>	
State Land Lease	State Lands Commission
<u>Drilling/Injection Plans</u>	
Project Proposal	Dept. of Conservation, Division of Oil and Gas
Notice of Intention to Drill	Dept. of Conservation, Division of Oil and Gas
<u>Air Quality</u>	
Authority to Construct	Air Quality Control District
Authority to Operate	Air Quality Control District
<u>Water Quality</u>	
NPDES	Regional Water Quality Control Board
Facility Permit/Waste Discharge	Regional Water Quality Control Board
Permit to Appropriate Water	Dept. of Water Resources
<u>Wildlife Protection</u>	
Permit for Stream or Lake Alteration	Dept. of Fish & Game
Dredging Permit	Dept. of Fish & Game

TABLE 8-2 (CONT.)

PERMIT	AGENCY
<u>Solid Waste</u>	
Solid Waste Facility Permit	Solid Waste Management Board
<u>Rights-of-Way</u>	
Easements for State Forest Lands	Dept. of Forestry
Special Use Permit for State Park Lands	Dept. of Parks and Recreation
Encroachment Permit	CALTRANS
<u>Dams, Reservoirs and Bridges</u>	
Approval of Plans for Activities Involving Dams and Reservoirs	Dept. of Water Resources, Division of Safety and Dams
<u>Other</u>	
Timber Harvesting Permit	Dept. of Forestry
Timberland Conversion Permit	Dept. of Forestry
Certificate of Public Convenience and Necessity	Public Utility Commission
Notice of Intent and Certificate of Public Convenience and Necessity (Power Plant)	California Energy Commission & Public Utilities Commission

included. The permits include the conventional air and water pollution permits as well as permits required for well drilling and injection operations. A majority of the permits listed are special situation permits which would apply to few projects.

The California Environmental Quality Act (CEQA) could require preparation of an EIS if major impacts are anticipated. The CEQA review could be triggered by major state permits required for the project. In the case of federal land developments, the EIS requirement would likely be initiated by the MMS. If initiated at the state level, the county would generally be the lead agency for the EIS study.

Geothermal operators contacted by ERCO indicated few problems with the permit procedures. California air quality standards include H₂S limits which had formerly been difficult to meet for geothermal projects. However, improved control techniques have solved this problem. Water discharge (NPDES) permits are time-consuming, with 3-6 months for review, but pose no other difficulties.

One area of occasional concern has involved Department of Fish and Game permits in California. The permits involved (Stream or Lake Alteration Agreements or Dredging Permits), if needed, can require 6 months to 1 year for processing. These permits could occupy the critical path for projects, particularly in cases where the wildlife issues are not identified early in a project.

A similar listing of permits for geothermal projects was prepared covering Utah state government. The listing, which is provided in Table 8-3, includes 28 permits. Again, the listing is intended to be comprehensive and cover every eventuality.

TABLE 8-3

LISTING OF UTAH PERMITS OF POTENTIAL
APPLICABILITY FOR GEOTHERMAL PROJECTS

PERMIT	AGENCY
<u>Exploration/Prospecting</u>	
Permit to Commence Non-Coal Exploration Activities	Division of Oil, Gas and Mining
<u>Leasing</u>	
State Mineral Lease	Division of State Lands
<u>Drilling/Injection Plans</u>	
Well Drillers Permit	Division of Water Rights
<u>Air Quality</u>	
Review and Approval of Air Pollution Sources	Division of Environmental Health
Open Burning Permit	Division of Environmental Health
<u>Water Quality</u>	
Permit for Discharge of Waste- water into State Waters	Division of Environmental Health
Approval of Development Proposal Impinging on the Provo-Jordon River Parkway and Its Drainages	Division of Environmental Health
Permit for Wastewater Disposal System	Division of Environmental Health
<u>Water Supply</u>	
Certificate of Appropriation of Water	Division of Water Rights

TABLE 8-3 (CONT.)

PERMIT	AGENCY
Application for Change of Point of Dispersion, Place or Nature of Use of Water	Division of Water Rights
Certificate of Appropriation of Water for Geothermal Purposes	Division of Water Rights
Approval of Drinking Water System	Division of Environmental Health
<u>Solid Waste</u>	
Approval of Disposal of Solid Waste	Division of Environmental Health
<u>Wildlife</u>	
Certificate of Registration to Take Protected Wildlife	Division of Wildlife Resources
Relocation or Alteration of Natural Stream	Division of Water Rights
Notice of Intent to Divert a Canal, Reservoir, or Other Waterway Containing Protected Aquatic Wildlife	Division of Wildlife Resources
<u>Dams, Reservoirs</u>	
Approval of Construction or Repair of a Dam or Impoundment	Division of Water Rights
<u>Archaeological/Historical Values</u>	
Permit to Explore, Excavate, or Remove Archaeological or Paleontological Remains	Division of State Lands
Application to Remove a Heritage Tree	Division of State Lands

TABLE 8-3 (CONT.)

PERMIT	AGENCY
<u>Rights-of-Way, Special Use Permits</u>	
Use Permit on State Park Lands	Division of Parks and Recreation
Special Use Permit for State Lands	Division of State Lands
Rights-of-Way Across State Lands	Division of State Lands
Easement Across State Wildlife Resources Lands	Division of Wildlife Resources
Utility Easement on State Park Lands	Division of Parks and Recreation
<u>Other</u>	
Permit for Overweight Vehicles	Highway Patrol

Among the major permits in Utah is the Certificate for Appropriation of Water for Geothermal Purposes. The Utah water law gives the state jurisdiction over all surface and underground waters. Thus each geothermal project requires completion of the permit procedures of the Division of Water Rights. The water appropriation process in Utah requires approximately 6 months to complete. However, complicated appropriation requests may lead to court cases and possible project delays.

The frequency of delays due to water appropriation is limited, however. Development of a geothermal resource involves the utilization of new, previously unclaimed supplies of water. The Certificate of Appropriation will generally be issued without controversy. In selected cases, contamination of an aquifer, or lowering of the water table, may be suspected, and the water claim settlement process would be lengthened.

Other state permits are not usually time-consuming. The state water discharge permit does not fill the NPDES program requirements, so the federal discharge permit must also be obtained if needed. A number of special situation permits are also included in the permit listing.

8.2 Oil Shale Project Network Presentation

The oil shale network was designed using data from the actual projects which have been initiated and from projections of future developments. As for the case of geothermal projects, the network modeling of a new, alternative energy system requires considerable judgment and extrapolation from limited operating experience.

The histories of oil shale projects were reviewed in order to obtain information on how companies organize and schedule their projects. All projects are briefly covered in a compilation prepared by the Minerals Management Service titled Oil Shale Development in The Piceance Basin and the Uinta Basin (March 1982). Such data provide an indication of the time required for certain projects' stages. However, none of the projects have reached the commercial production stage, a fact which affects the analysis in several ways. First, because there has been no actual experience with the later commercialization stages, projected company schedules have been used as the basis for the ERCO network. Second, the lack of a mature industry suggests that future lead times may not be as lengthy as those for the prototype plants. Data from the project histories were judged in light of this. Similarly, personnel of the MMS reported that the critical permit reviews (covering the Detailed Development Plan) could be more quickly processed in the future than has been the case to date.

For the network model, the history of the Cathedral Bluffs project on a federal lease tract in Colorado was followed most closely. Other project schedules were used for verification of certain stages. The Cathedral Bluffs project was useful for three reasons: (1) It occupies one of the four federal tracts in Colorado and Utah that were leased under the Federal Prototype Oil Shale program; (2) The project has been actively developed for several years (although a worsening economic picture caused the project to be shut down in December 1981); and (3) The modified in-situ technique planned for Cathedral Bluffs is a leading candidate technology for oil shale production.

The companies involved, Occidental Oil Shale, Inc., and Tenneco Shale Oil Co., planned to use a modified in-situ technique to separate the kerogen (an organic substance from which the shale oil is derived) from the shale rock while underground. In this process, underground explosions would be used to generate heat and thus free the kerogen from the shale. The kerogen would be collected in caverns and then pumped to the surface for processing. Other mined rock would be brought to the surface for above-ground retorting (AGR). The term "retorting" refers to the process of separating the kerogen material from the shale rock.

The network thus developed is shown in Figure 8-2, with the federally required permits shown. Separate listings of the permits applicable in Colorado and Utah (the two states with notable oil shale developments) are shown later below. The oil shale network follows the same pattern of the other networks, beginning with pre-lease activities and ending with full-scale production.

The main stages of the project run from exploration through the stages of leasing, environmental study, engineering and design, permitting, and construction. Among permitting activities, the MMS review and approval of the Detailed Development Plan is of major importance. However, numerous other federally mandated permits are also required, as will be discussed. The main project stages are spelled out below.

Exploration - The length of exploration activities can vary widely. The existence of oil shale deposits in the Piceance Basin has been known since early in the century. In terms of an individual project, the exploration task might be better described as representing the review of

LEGEND

- Activity
- - - Dummy Activity
- Critical Path
- (10, 11) First Entry is Activity Time in Months, Second Entry is Float Time.
Ex.—Activity Requires 10 Months
Float Time Allowance is 11 Months.
- (ND) Activity Time Is Not Determined or Cannot Be Meaningfully Stated.

Note : Code Numbers are from the Federal Coal Mine Diagram. Letters Denote State Permits.

Figure 8-2. Network Presentation of Representative Oil Shale Project on Federal Lands.

existing information and field studies in preparation of a bid for a lease tract.

Lease Acquisition - Four tracts in Colorado and Utah were leased under the prototype leasing program in 1974. Additional leases will be available under a permanent leasing program should it be initiated by the Department of the Interior.

Preparation and Approval of Baseline Data Collection Program - The MMS reviews the methodology for the environmental studies to be performed by the developer. The ensuing study period consumes up to 2 years. The involvement of the MMS at this stage is unique to oil shale projects and reflects a pattern of close regulatory agency involvement in the projects initiated thus far.

Mining and Development Plans and Environmental Studies - Actual development efforts have involved intensive engineering efforts for design of prototype facilities. Baseline environmental studies would also be initiated as soon as the decision to proceed with development is made.

Detailed Development Plan Review - The Detailed Development Plan (DDP) must be submitted for compliance with MMS regulations for resource extractions operations on federal land. The DDP plays a similar function to the OSM Mine Plan review in being an all-encompassing description of the project and its environmental effects. However, other substantial permit and mine plan reviews are also applied to oil shale operators.

Continued Engineering and Design Work, Submittal of Modified DDP's - Oil shale companies have continually revised and reevaluated their projects as planning and

construction have proceeded. The revisions are submitted to the MMS in modified DDP's which are put through a review process similar to that for the original DDP's. Future review time requirements of 6 months are projected.

Site Preparation - Prior to construction, groundwork is performed to allow laying of foundations and moving of heavy equipment. The site preparation covers grading, road construction, and fencing.

Construction of the (1) Ventilation/Escape Shaft, (2) Production Shaft, and (3) Service Shaft - The modified in-situ process of the Cathedral Bluffs project requires the construction of three shafts for performance of production operations. For each shaft, a head frame is constructed over the cavity for use in equipping the shaft and hoisting materials. The head frames range from 150 to 320 ft above ground level.⁸ Once in place, the head frames are outfitted and then the various shafts are sunk into the oil shale resource areas. The shafts will be sunk to depths of 2000 feet at the Cathedral Bluffs site.

Construction of Surface Process Facilities - With the modified in-situ process, 20-25 percent of the shale rock is mined and hauled to the surface for above-ground retorting (AGR). Surface process facilities must be constructed for the handling and processing of the shale, as well as for disposal of waste shale rock.

Underground Development Work, Retorting, and Mining Preparations - After the shafts have been sunk, horizontal development in the resource area occurs in preparation for mining and retorting. In a modified in-situ operation, a

portion of the shale is mined to provide an area for collection of kerogen. Vertical areas of shale are rubblized and then retorted to produce the kerogen.

Production: Phase I (Pilot Plant), II (Commercial-Sized), and III (Larger Commercial-Sized) - A staged production pattern is anticipated for several oil shale projects and has been utilized here in the network. The time requirements are based on company production schedules. However, the timing of phases is highly variable and is reliant upon the continuity of favorable economic conditions for the projects, a condition which is not now being held.

Upgrading of Permits for Commercial-Scale Operations - In some cases, permitting may be performed in stages replicating the pattern of production. One advantages to this approach is apparent. First, permitting authorities need only to pass judgment on a more modest process (pilot plant) for which fairly complete information is available rather than for a very large plant with some design uncertainties. This approach has been used for air pollution permits in Colorado.⁹ The developer company must, however, be willing to proceed with the additional uncertainty of the remaining downstream permit approvals.

8.2.1 Federal Permits Applicable to Oil Shale Projects

The permitting requirements for oil shale are the most extensive of any of the resources covered, with potential for difficulties with all media: air, water, and solid waste. The comprehensive requirements of the Detailed Development Plan add another layer to the already specialized permitting requirements.

The permits (and permit types) which are included in the network are listed in Table 8-4. The listing includes a number of substantive items including the PSD review, NPDES, the solid waste disposal approvals, and the DDP review. These processes are substantive in that compliance for an oil shale project could be in question, and because uncertainty about a given process could complicate the regulatory processes and slow the review.

The key environmental issues for oil shale projects are described below.

Air Emissions and PSD Permits

Air emissions arise from several points in oil shale facilities. SO₂ emissions have been the major concern, although NO_x, particulates, and volatile organic pollutants are also emitted. The major sources of SO₂ are from fuel consumed for process operations, including retorting and product upgrading, and from gas clean-up systems.

PSD issues have been of concern for the industry because of the potential limiting effect of the applicable increments of pollution on industry size. The Piceance Basin in Colorado is a Class II air quality attainment area, meaning that there are limitations on the new emissions which will be allowed. The limitation is below (more strict than) the ambient air quality standards. SO₂ emissions from oil shale development may use the entire allowable increments, creating an upper limit on industry growth which is not related to the resource base itself.

TABLE 8-4

FEDERAL PERMITS RELEVANT TO OIL SHALE PROJECT NETWORK

COMMONLY REQUIRED PERMITS/AGENCY	TIME REQUIRED	FLOAT TIME	COMMENT
BLM Exploration License/ BLM	6 months	None	Allows federal land entry, drilling, seismic activi- ties.
Baseline Data Collection Plan Approval/MMS	3 months	None	Document guides an exten- sive environmental study.
Detailed Development Plan Review/MMS	6 months	None	The DDP is a comprehensive project document.
Prevention of Significant Deterioration Review/EPA	9 months	6 months	Air quality issues may restrain development in Colorado.
NPDES Permit/EPA	6 months	9 months	The NPDES permit is not required if zero discharge is achieved.
MSHA Permits/Mine Safety and Health Administration	2 months	13 months	Covers the review of all necessary safety plans for mine operation.
Fish and Wildlife Service Permits/FWS	2 months	13 months	Covers any approvals necessary for activities affecting endangered species or wildlife habitats.

TABLE 8-4 (CONT.)

COMMONLY REQUIRED PERMITS/AGENCY	TIME REQUIRED	FLOAT TIME	COMMENT
Misc. Federal Permits/Federal Communications Commission and the Alcohol, Tobacco and Fire-arms Division, Treasury Dept.	4 months	11 months	Covers permits for radio systems and explosives.
Rights-of-Way/Various Agencies	3 months	12 months	Refers to any clearances needed from federal land-holders in the area.
<u>Additional Permits of Potential Applicability</u>			
Spill Prevention Containment and Control Plans/EPA			Discharge of Dredge or Fill Material Permit/Corps of Engineers (COE)
Hazardous Waste Management Facility Permit/EPA			Permit for Dams and Dikes in Navigable Waters/COE
Antiquities Act Permit/Dept. of the Interior			Application for Permit to Conduct Archaeological Explorations/FS
Notice of Proposed Airspace Obstruction/FAA			Notice of Proposed Construction or Alteration of Airports/FAA
Airport Lease/BLM			Timber Sale Contracts/FS
Temporary or Permanent Exemption from FUA Prohibitions/DOE			Toxic Substances Control Act, Pre-manufacture Notice/EPA

Water Discharges and NPDES Permits

The modified in-situ process, with additional above-ground retorting, will include several discharge points. Although some of the produced water will be recyclable, NPDES permits will still be required for dischargers.

The underground retort produces two condensate streams. The retort produces water vapor which condenses and percolates through the rock layers. Other vapor leaves the retort in the vapor phase and is condensed in the above-ground processing. This vapor will contain ammonia (NH_3) and hydrogen sulfide (H_2S).

The major water stream, however, appears to be mine drainage water. The volume of such water could vary widely. Certain existing operations have encountered significantly more underground water than they had anticipated.¹⁰ The quality of mine drainage water has been calculated to be quite high although some treatment will be required prior to discharge for the modified in-situ projects.

In some cases, zero discharge is planned for the projects. This arrangement is possible if excess water can be entirely recycled for process needs, dust control, and so on.

Solid Waste Disposal Permit

Shale oil projects produce large quantities of spent shale for disposal. Circumvention of the disposal problems is one of the key advantages of in-situ processes, which leave the spent shale underground.

However, with the modified in-situ process, 20-25 percent of the shale resource is mined for above-ground retorting. The spent shale produced may be backfilled, which is relatively expensive, or disposed of in solid waste disposal sites. The latter require careful design to prevent groundwater leaching problems and to provide for land reclamation. Regulations governing the disposal of spent shale are part of the Resource Conservation and Recovery Act program.

Water Use and Water Appropriation Permits

Water appropriation rights could constitute a major issue for the oil shale industry, although several decades may pass before water limits the industry's growth. This issue is briefly discussed here, although appropriation permits are handled at the state level.

Most potential oil shale developers have already acquired water rights. These rights were obtained either through requests through state water appropriation systems (permits issued by the State Engineer), or through purchase of irrigation water rights from agricultural interests. The extent of the developers' water rights can be judged through examination of Table 8-5, in which the conditional water rights held by companies in 1968 (many years before most projects were initiated on site) are shown. These holdings represent the status of holdings 6 years before the Prototype Federal Leases were sold in 1974. The companies also held conditional water rights (rights which could be exercised when water was available) to over 1 million acre-ft/yr of direct flow diversions from the Colorado and White rivers and their tributaries. Also substantial groundwater rights are held by developers. Water supplies of this order will

be sufficient to support near- and medium-term industry development.

TABLE 8-5

STORAGE RIGHTS OF OIL SHALE DEVELOPMENT
COMPANIES (ACRE-FT)

DEVELOPER	STORAGE RIGHTS
Exxon	122,000
Mobil	66,000
Getty Oil	53,000
Sinclair	51,500
Tosco	34,600
Total	327,100

Source: U.S. Congress, Office of Technology Assessment, An Assessment of Oil Shale Technologies, June 1980.

For new projects, water appropriation permits could also be requested from the state authorities. However, such a right, when granted, would be a junior (new) right and possibly subject to interruption in periods of water shortages. In contrast, by purchasing irrigation rights, more senior claims to the area's water would be established. Other strategies for ensuring supply include purchasing surplus water from federal reservoirs in the area.

Status of Permitting for Oil Shale Projects

Permitting issues to date have revolved around uncertainties concerning the environmental effects of development, and the applicability of certain regulations. Certain issues remain to be resolved.

The permits obtained for five oil shale projects are summarized in Table 8-6. The federal tracts require an EIS and DDP approval, whereas all tracts require PSD and NPDES permits and the regular (Colorado) mining permit. For the projects shown, all the major approvals that have been requested have been approved. However, all but one of the PSD permits and both NPDES permits cover only pilot phase plant operations. Thus, permits for commercial-scale operations remain to be tackled.

Developers also must await the promulgation of other regulations which will impact their operations. The areas of uncertainty include:

1. Permit requirements and chemical testing requirements for toxic substances regulated under the Toxic Substances Control Act.
2. Disposal standards to be required for oil shale waste disposal under the RCRA program.
3. Land reclamation standards to be applied to oil shale operating areas.

These regulations, while they might not seriously impede the overall project development, would add significant costs to an oil shale project.

8.2.2 Permits Required by Colorado and Utah for Oil Shale Projects

The number and variety of permits required for oil shale projects increases markedly when state permits are considered. The coverage of state permits in Colorado and Utah was examined in order to complete the oil shale permit analysis.

TABLE 8-6

STATUS OF ENVIRONMENTAL PERMITS
FOR FIVE OIL SHALE PROJECTS

PROJECT	TYPE OF TRACT	EIS	DDP APPROVAL	PSD PERMIT	REQUIRED MINING PERMIT	NPDES PERMIT
Rio Blanco	Federal (C-a)	Final pro- grammatic EIS issued	Yes ^a	Yes, for 1,000 bbl/d	Yes	Yes, 1st phase
Cathedral Bluffs	Federal (C-b)	Final pro- grammatic EIS issued	Yes ^a	Yes, for 5,000 bbl/d	Yes	Yes, 1st phase
Long Ridge (Union Oil)	Private	Not appli- cable	Not appli- cable	Yes, for 9,000 bbl/d	Yes	Not re- quired ^b
Colony	Private	Not appli- cable	Not appli- cable	Yes, for 46,000 bbl/d	Not applied	Not re- quired ^b
Superior	Private/ federal	Not appli- cable	Not appli- cable	Not applied	Not applied	Not applied

Source: An Assessment of Oil Shale Technologies. Office of Technology Assess-
ment, June 1980, p. 345.

^aLitigation pending after approval of modified DDP.

^bNo surface discharges planned.

In Colorado, thirty-six permits were identified which could apply to an oil shale project. These are listed in Table 8-7, with the administering agency also identified. Most of the permits are minor, and would not involve delay-creating potential or large expenditures of resources for the application procedures. The major Colorado permits include the following:

Air Pollutant Emission Permit - Some firms could have difficulty meaning state SO₂ standards for their oil shale processing plants.

NPDES Permit - The state issues the NPDES permit, replacing EPA responsibility for this approval.

Certification of Solid Waste Disposal Site - Solid waste management control standards are evolving for the industry.

Application for Water Rights (Or Other Water Appropriation Procedures) - As mentioned above, many firms have acquired the necessary water rights for their projects. Newcomers to the industry may face lengthy water acquisition processes.

Regular Mining and Reclamation Permit - The Colorado Mined Land Reclamation Division has authority to regulate oil shale operations in a fashion similar to regulation of coal mining operations.

The most thorough project review will generally be that performed by the Colorado Mined Land Reclamation Division (MLRD). The review would be comprehensive, just as is the coverage of the Minerals Management Service in its review of the Detailed Development Plan. To date, however, the MLRD has not taken a highly visible role. For the projects on federal lands, the MMS has been the principal regulatory control agency with the MLRD deferring to the MMS review."

TABLE 8-7

LISTING OF COLORADO PERMITS FOR AN OIL SHALE PROJECT

PERMIT	AGENCY
<u>Exploration/Prospecting</u>	
Notice of Activity-Exploration Permit	Division of Mines, State Bureau of Land Commissioners
Notice of Intent to Conduct Prospecting Operation	Mined Land Reclamation Division
<u>Leasing</u>	
Mining Lease	State Board of Land Commissioners (SBLC)
<u>Mine Plans/Reclamation</u>	
Regular Mining and Reclamation Permit (or Limited Impact or Special Mining Permit)	Mined Land Reclamation Division
<u>Air Quality</u>	
Open Burning Permit	Air Pollution Control District
Air Pollutant Emission Permit	Air Pollution Control District
<u>Water Quality</u>	
NPDES Permit	Water Quality Control District (WQCD)
Approval of Location and Construction of Water Works	WQCD
Site Approval of Sewage Treatment Facility	WQCD
Water Quality Certificate	WQCD

TABLE 8-7 (CONT.)

PERMIT	AGENCY
<u>Solid Waste</u>	
Certification of Solid Waste Disposal Site	Radiation and Hazardous Waste Control Division
<u>Wildlife</u>	
Fish and Wildlife Collection Permit	Division of Wildlife
<u>Historical and Archaeological Requirements</u>	
Cultural Resources Clearance	Colorado State Historical Society
<u>Water Supply</u>	
Permit to Construct or Relocate an Exempt Well Outside Designated Basins	Division of Water Resources (DWR)
Permit to Construct or Relocate a Non-Exempt Well Outside Designated Basins	DWR
Permits to Construct a Well and Appropriate Designated Groundwater	DWR
Permit for Bedrock Aquifer Well	DWR
Application for Water Rights	District Water Courts
<u>Dams, Reservoirs and Bridges</u>	
Approval of Location and Construction of Water Works	WQCD
Approval of Plans for Reservoir	DWR
Permit to Construct an Erosion Control Dam	DWR

TABLE 8-7 (CONT.)

PERMIT	AGENCY
<u>Rights-of-Way</u>	
Rights of Way Over State Land	SBLC
<u>Transportation/Road Use</u>	
Special Transport Permit	Dept. of Highways
Survey Permit	Dept. of Highways
Access Approach Permit	Dept. of Highways
Certificate for Petroleum Transport and Storage	Dept. of Labor
Application for Certificate as a Common Carrier	Public Utilities Commission (PUC)
Permit for a Contract Carrier	PUC
<u>Explosives</u>	
Application to Store, Use and Transport Explosives	Div. of Mines (DOM)
Diesel Permit	DOM
Certificate for Boilers	DOM

In Utah, twenty-seven permits were identified, with the state's lower total reflecting fewer mine safety regulations and water quality/supply permits. These Utah permits are listed in Table 8-8. The major permits are similar to those for Colorado, representing air quality, water quality (although Utah does not have NPDES authority), water supply, solid waste, and mining permits. The Division of Oil, Gas and Mining (DOGM) covers oil shale as well as coal mining projects. A few oil shale developers have submitted applications to the DOGM for review. These projects completed the process over 2 years ago.¹²

TABLE 8-8

LISTING OF UTAH PERMITS FOR OIL SHALE PROJECTS

PERMIT	AGENCY
<u>Exploration</u>	
Notice of Intention to Mine	Division of Oil, Gas & Mining (DOGM)
Permit to Commence Non-Coal Exploration Activities	DOGM
<u>Leasing</u>	
State Mineral Lease	Division of State Lands (DSL)
<u>Mining Plans/Reclamation</u>	
Permit to Mine	DOGM
<u>Air Quality</u>	
Open Burning Permit	Division of Environmental Health (DEH)
Review and Approval of Air Pollution Sources	DEH
<u>Water Quality</u>	
Permit for Discharge of Wastewater into State Waters	DEH
<u>Solid Waste</u>	
Approval of Disposal of Solid Waste	Division of Water Rights (DWR)
<u>Wildlife</u>	
Certification of Registration to Take Protected Wildlife	Division of Wildlife Resources

TABLE 8-8 (CONT.)

PERMIT	AGENCY
Notice of Intent to Divert a Canal, Reservoir, or Other Waterway Containing Protected Aquatic Wildlife	Division of Wildlife Resources
Approval of a Development Proposal Impinging on the Provo-Jordon River Parkway and its Drainages	Division of Parks and Recreation
<u>Historical and Archaeological Requirements</u>	
Permit to Explore, Excavate or Remove Archaeological or Paleontological Remains	DSL
Application to Remove a Heritage Tree	DSL
<u>Water Supply</u>	
Certification of Appropriation of Water	DWR
Application for Change of Point of Diversion, Place, or Nature of Use of Water	DWR
Well Drillers Permit	DWR
Relocation or Alteration of Natural Stream	DWR
<u>Dams, Reservoirs and Bridges</u>	
Approval of Construction or Repair of a Dam or Impoundment	DWR

TABLE 8-8 (CONT.)

PERMIT	AGENCY
<u>Rights-of-Way</u>	
Rights-of-Way Across State Lands	DSL
Easement Across State Wildlife Resource Lands	Division of Wildlife Resources
Utility Easement on State Park Lands	Division of Parks and Recreation
Use Permit on State Park Lands	Division of Parks and Recreation
Special Use Permit for State Lands	DSL

NOTES TO SECTION EIGHT

1. Personal communications between Anne Sayigh of ERCO and Tom Heinrichs, Magma Power Co., June 23, 1982, and Dwight Carey, Republic Geothermal Inc., July 23, 1982, were most helpful. Other communications are noted where applicable.
2. Personal communications between Anne Sayigh of ERCO and William Isherwood, Minerals Management Service several dates were most helpful. Other communications are noted where applicable.
3. Based on Jet Propulsion Laboratory study, Analysis of Requirements for Accelerating the Development of Geothermal Energy Resources in California, November 1977.
4. Same as Note 3.
5. Instruction Memorandum No. 82-64, U.S. Department of the Interior, Bureau of Land Management, Subject: Environmental Reviews in the Geothermal Leasing Program, Nov. 5, 1981.
6. Same as Note 5.
7. Personal communication between John Eyraud of ERCO and Eric G. Hoffman, Minerals Management Service, Grand Junction, Colorado, April 21, 1982.
8. Dr. Allan Sass, "Commercially Producing Oil Shale: In-Situ is the Answer," World Oil, June 1980, p. 167.
9. Office of Technology Assessment, An Assessment of Oil Shale Technologies, June 1980, p. 346.
10. Same as Note 9.
11. Same as Note 9.
12. Personal communication between John Eyraud of ERCO and Ron Daniels, Utah Division of Oil, Gas and Mining, April 14, 1982.

SECTION NINE

THE EXTENT AND COST OF PROJECT DELAYS DUE TO REGULATION

The project networks for each resource area illustrate the close relationship between project activities and permit requirements. Permit approvals generally must be received before any land disturbances can occur and before any pollutants are emitted to the environment. This fact of permit processes raises questions about the seriousness of project delays which can be caused by regulatory authorities in the conduct of their duties.

In this section, data on the frequency and length of delays due to selected major permit processes is reviewed. The APD process for oil and gas operators, the federal mine plan review process for coal mine operators, and several other permits applicable to any energy development project are considered. Historical data on program performance as well as updates on attempts to improve permitting efficiency are described.

For this section, the cost of permitting delays were assessed for representative costs of delay for oil and gas and for coal projects. In the methodology used, delay costs were based on the interest charges (or opportunity cost) for the cumulative capital investment in a project. An additional component of delay costs is estimated based on assumptions concerning the rate of spending of direct cost and overhead costs in accounts which cannot be postponed or deferred during delays. The estimation procedure gives an indication of the relative seriousness of delays at various stages of a project.

9.1 Oil and Gas Project Delays Due to Permitting

The networks presented in Section Six indicate the principal permits needed for oil and gas operations due to federal and various state authorities. The networks also can be used in assessing the existing delays or the potential for delays due to the government approval processes. The problems posed by delays and their measurement are discussed in this section.

In everyday practice, the existence of delays due to regulatory processes is arguable. The entire time required for a permit review may appear to be purely a delay to a developer. This viewpoint would be supported if the developer's equipment and employees were completely unutilized during the review.

From society's viewpoint, the review process has a legitimacy based on its authorizing legislation. The regulatory agency, in carrying out its permit review is ensuring that the goal of the legislation is being achieved. It follows then that a "reasonable" review time is not a delay in this broader sense.

In this study review times will generally be compared with an estimate of a "reasonable" time period for permit review. This "reasonable" period is readily definable in all cases where its used because it can be based on either the stated goals of the regulatory authority or on constraints on the review process, such as public comment periods, which establish minimum review periods. Unfortunately, data on review time are available for only a few of the more crucial permit programs.

For other permits, such as the notable air and water permits, estimates of review times are noted in the state network and are considered below.

For oil and gas operations, analysis was performed of the major federal permits and of selected state permits. The individual programs covered are (1) the Application for Permit to Drill (APD) process; (2) Rights-of-way approvals; (3) air pollution permits, with special emphasis on California; (4) water and waste discharge permits and (5) other state permits.

9.1.1 The Application for Permit to Drill Process

The only federal permit approval on the critical path for oil and gas developers in the network analyses is the Application for Permit to Drill process instituted by the Minerals Management Service (formerly the Conservation Division of the USGS) of the Department of the Interior. The Application for Permit to Drill (APD) process has received by far the greatest attention of all permit programs from industry groups, and appropriately from government regulatory improvement efforts. In this section, problems with the existing APD program are reviewed and the program modifications currently being considered are examined.

As was noted in the literature review summary in Section Three of this report, many APD submissions have faced lengthy review times. The length of the MMS processing time has been documented in studies by the General Accounting Office, the American Petroleum Institute and the Independent Petroleum Association of Mountain States.¹

A summary of the API study data, for the most recent time period analyzed, is shown in Table 9-1. Data are shown for six separate MMS (then part of the USGS) field offices in three of the Rocky Mountain States. This region became the focal point of APD difficulties with a surge of drilling activities in recent years.

The API study reported a mean processing time of 67 days for API submissions in the period June 1979 to January 1980. This average is more than double the stated MMS goal of a 30-day review time. The averages for the separate offices, however, are highly variable. All four of the Wyoming offices achieved or nearly achieved the 30-day review time objective. The Billings, MT and Salt Lake City, UT offices had much longer review times, averaging between 85 and 113 days. One clue to the Salt Lake City problems is the much larger workload of APD's in that district as can be discerned in the table.

The study performed for the Independent Petroleum Association of Mountain States (IPAMS) was able to use more recent data collected by the MMS North Central Region during the first five months of 1981. This survey, which is summarized in Table 9-2, provided monthly breakdowns of processing time for three district offices. The more recent study does not show a reduction in processing time for any office, and the overall regional processing time is almost identical to the earlier study.

In fact, some adjustments had been made by MMS in the period between January 1980 and January 1981. The district office in the North Central and Central Regions (covering Colorado, Utah, Wyoming, Montana) were realigned during that time, partly in response to perceived problems with APD handling. The Salt Lake City workload was cut substantially

TABLE 9 -1

MEDIAN AND MEAN APD PROCESSING TIMES
BY USGS OFFICE (DAYS)

MINERAL MANAGEMENT SERVICE, OFFICE LOCATION	NO. OF APD'S PROCESSED 6/77 - 1/80	PROCESSING TIME		
		MEDIAN (10-Day INCREMENTS MEASURED)	MEAN	RANGE
Salt Lake City, Utah	1862	81-90	113	1-756
Rock Springs, Wyoming	1028	21-30	47	2-272
Casper, Wyoming	780	21-30	27	1-247
Newcastle, Wyoming	758	31-40	44	1-291
Thermopolis, Wyoming	490	21-30	28	1-110
Billings, Montana	712	71-80	85	1-538
Total	5630	51-60	67	1-756

Sources: Analyses of Delays in the Processing of Applications for Permits to Drill and Pre-staking Clearance Applications, Everett Associates for the American Petroleum Institute, June 1981.

NOTE: The figures for median, mean and range were derived from the study results for the last measurement period in the study of June 1979 to January 1980.

TABLE 9-2

NORTH CENTRAL MMS REGION:
AVERAGE DAYS FOR APD APPROVAL
BY DISTRICT, JANUARY-MAY 1981

MONTH	BILLINGS		CASPER		ROCK SPRINGS		REGION	
	# APD's APPROVED	AVE. TIME	# APD's APPROVED	AVE. TIME	# APD's APPROVED	AVE. TIME	# APD's APPROVED	AVE. TIME
January 1981	25	112.68	47	56.16	35	48.59	107	66.43
February 1981	31	101.23	51	74.25	80	34.32	162	63.67
March 1981	31	73.64	58	57.84	45	39.41	134	53.63
April 1981	42	82.29	67	61.16	30	45.90	139	64.23
May 1981	31	95.65	79	54.08	32	50.69	142	66.81

SOURCE: Analysis and Recommendations to Improve Federal Application for Permit to Drill Process, RPC, Inc. for Independent Petroleum Association of Mountain States.

and processing time had been improved in that office as a result.²

Despite these modifications in ADP handling, the overall trend in recent years had been for continued lengthening of processing times. From 1977 through 1981, APD processing in the Rocky Mountain area had been slowed considerably due to increased application volumes, and greater concern for environmental protection. The 13-point Multipoint Surface Use and Operating Plan, governing the information to be included with the APD, was instituted in 1976 adding significantly to the required actions of MMS personnel. This lengthening trend has been the basis for industry complaints about the APD process.

The wide variability in processing time among the district offices has several sources. APD handling is not given the same priority in all offices. The Rock Springs, Wyoming office, where review times are briefest, has been noted for the high priority given APD's. The Montana and Utah offices are apparently less focused on APD handling.³ Processing times are also influenced by the cooperation received from the local land management agency. Attitudes in BLM offices, for example, show some variability.⁴

Another component of the delay potential for oil drilling concerns the Pre-Staking Clearance (PSC) or Preliminary Environmental Review (PER) which precedes the APD process. The PSC approval is needed prior to entry by the developer to the lease, and is intended by MMS to be passed on within 15 days of a request. From 1977 to 1980, studies noted increases in PSC processing times from a day or two to 2 weeks, with some requests exceeding the statutory limit of 15 days. One reason for the PSC delays is the slower processing of the ensuing APD.⁵ Because the PSC is so

closely tied to the APD, slower handling of the latter reduces the incentive to provide rapid turnaround of the former.

The various studies of the APD process have included analyses of the reasons for delay. In general some delays are inevitable given the complexity of the review process which includes coordination of other agency inputs. The major steps in the process include (1) review of pre-staking clearance request (including coordination with the surface management agency); (2) review of the APD; (3) review of the multipoint surface use plan; (4) completion of an archaeological clearance; (5) a joint on-site inspection including the MMS representative, the land management agency and the operators; and (6) completion of a categorical exclusion review or preparation of an Environmental Assessment. The requirements for cooperation and communication through so many discrete steps with a changing cast of participants means that some difficulties are quite likely. The Bureau of Land Management, which is most often the surface management agency, participates in many stages of this process. A flow diagram of the PSC and APD process is shown in Figure 9-1.

Furthermore, the application requirements as perceived by regulatory officials often differ among MMS district offices. The interpretations of Notice to Lessees, No. 6 (NTL-6), the federal document governing the APD process, vary among district engineers. An oil company with limited experience in an area may face some difficulties before it comes to understand the locally defined application requirements. Additional confusion has also been noted concerning completion of the legal information required in the APD. Developers occasionally fail to identify the responsible (liable) parties sufficiently to satisfy MMS requirements.

Figure 9–1. Summary of the Pre-Stake Clearance and Application for Permit to Drill Approval Process.

An enumeration of the reasons for delay from the published literature was presented above in Section Three (Literature Review) and is reproduced in Table 9-3. In the study cited, problems with the archaeological clearances were the most frequently cited reason for a processing time of over 100 days. The environmental assessment requirement is the second most frequent source of delay followed by the failure of the applicant to properly designate the operator or agent for the site. Slow BLM processing of their portion of the APD review which includes right-of-way approvals, is also a frequent case of delay. A summary of the difficulties which can occur in each category of delay is provided below.

Archaeological work on an oil and gas site may be delayed for several reasons. A shortage of qualified archaeologists and problems caused by bad weather (e.g., snowfall makes a surface reconnaissance impossible) are among the common problems. Also there has been confusion about the extent of the archaeological surveys which should be performed and wide variations in interpretation are possible.⁶

The second leading cause of delay, preparation of environmental assessments (EA), has been partly rectified since the API (Everett Associates) study was completed. The greater use of Categorical Exclusion Reviews (CER), in order to identify for study only genuinely sensitive areas, has quickened the review process. In most cases drilling sites can be exempted from the EA requirement, reducing the APD processing time by 3 or 4 days. EA's are still needed for the first confirmation drilling of an oil or gas field.

Full EIS's are rarely needed for onshore oil or gas extraction projects. Two projects in the Mountain states in recent years have required EIS's due to, in one case, the

TABLE 9-3

REASONS CITED FOR DELAYS BEYOND
100 DAYS IN APD PROCESSING

REASON	DELAY OCCURRENCES (PROCESSING TIME OVER 100 DAYS)		
	PRIMARY REASON FOR DELAY	ONE OF MULTIPLE REASONS FOR DELAY	TOTAL NUMBER OF DELAY OC- CURRENCES
1. Archaeological clearance	66	59	125
2. Environmental analysis	60	58	88
3. Designation of operator or agent	43	38	81
4. Slow BLM processing	57	22	79
5. Bonding	44	26	70
6. APD stipulation decisions	42	16	58
7. Heavy office workload	24	14	38
8. Surface Management Agency (USFS, Bur. of Rec.)	24	8	32
9. Special Use Permits	5	26	31
10. Surface owner agreement	23	5	28
11. Onsite inspection	22	1	23
12. Other ^a	13	5	18
13. Roadless area access	12	6	18
14. Weather	12	3	15
15. APD incomplete	11	3	14

^aIncludes delays with a frequency of less than four occurrences; examples: hydrogen sulfide, drilled in trespass, replacement well, location abandoned, drilling mud program.

Source: Everett Associates, Analysis of Delays in the Processing of Applications for Permits to Drill and Pre-Staking Clearance Applications, June 1981, p. 32.

extremely sensitive site area for a new drilling project and, in the other case, for development of a sour gas field which would require significant air pollution controls.⁷ These projects are unusual cases, however, and EIS preparation rarely needs to be considered.

Delays due to the designation of the operator or agent in the APD occur because many leases have a large number of fractional-interest owners. Identification and obtaining of clearances from all such owners can be quite time-consuming. Also the GAO study notes that this requirement is not clearly stated in NTL-6 so that operators may omit the necessary information in their first submittal. The need for resubmission of the ADP package lengthens the review process.

9.1.1 Planned Modifications to the APD Process

The delays evident in the APD program have been duly noted by the Minerals Management Service and significant changes are planned. In early 1982 the MMS has stayed the revision-writing until revised operating regulations which govern the region and district office procedures were completed. Now, however, the revisions to the NTL-6 are being prepared. Meetings with industry personnel have been held to solicit comments and to explain the planned changes. Proposed revisions to the regulations are slated to be published in the Federal Register in December 1982.⁸

One goal of the revisions will be to shorten the review process to ensure quicker handling. Comments of industry groups, particularly the Rocky Mountain Oil and Gas Association (RMOGA), have been received and are being actively considered. RMOGA prepared a complete revised text of NTL-6

specifying the industry's recommendations for a more streamlined process. The RMOGA recommendations include simplification of the multipoint surface use and operating plan, reduction in the amount of information concerning possible production equipment to be on-site (during drilling the position and type of production equipment may not have been determined), simplification of the topographic maps to be included and reduction in the description of area roads.⁹

The RMOGA suggestions also call for the elimination of the pre-staking clearance process in favor of an on-site inspection prior to submission of the APD. Necessary stipulations for drilling operations on the lease (from the surface management agency representative), modifications in the exact drilling location and identification of any other problems would be handled at that time. The resulting APD submission could then completely reflect the results of the site visit, eliminating the frequent need to submit more information. Also, the principal cooperative meeting between the MMS and the surface management agency would be achieved immediately.

RMOGA also suggests timeframes for the new APD process totalling 25 days. This period would allow 15 days for completion of the on-site meeting and only 10 days for review of the complete APD submission. The APD processing will be further aided by revisions to the BLM handling of rights-of-way requests, as discussed in the next section.

In summary, recent history shows that the APD process was causing hindrances and delays in oilfield operations. A variety of elements in the process were potential sources of delays, particularly the completion of environmental and archaeological reviews, the need for coordination with developers and other federal agencies, and a lack of clarity

in the application requirements. It is expected that the MMS will respond to these issues in modifying the APD process during the fall of 1982. In achieving its stated goal of 30-day reviews, the MMS is expected to consider the RMOGA as one basis for streamlining the permit procedures.

9.1.2 Acquisition of Off-Lease Rights-of-Way

Oil and gas operators wishing to develop a federal lease may need to acquire off-lease rights-of-way through other federal lands in the area. State and private land rights-of-way may also be needed. The right-of-way acquisition process may be fairly complex and troublesome in some cases, although for the large majority of wildcat wells no special problems are encountered. In this section, the process of obtaining federal right-of-way permits is considered. State lands are a smaller issue as much less land is state-owned and fewer problems are encountered.

As the network diagrams noted, off-lease rights-of-way are generally requested at the time of submission of the APD. This pattern is the official policy of BLM, the largest surface management agency, because it allows for economies in the reviewing processes. Federal surface management agencies are involved in the APD review (as discussed in the previous section) and simultaneous review of the off-lease rights-of-way request can be conveniently performed. Developers are also content with this arrangement although, in some cases, problems with the rights-of-way requests have delayed the entire APD process.

Given the coordination with the APD, rights-of-way processing may be expected to require approximately 2 months. The review time is highly variable, however,

depending on the project requirements and the size of the right-of-way. Most rights-of-way involve road construction. One may distinguish short or temporary rights-of-way, which can often be obtained with little difficulty, from long rights-of-way, where the probability of processing difficulties is greater. The extent of the environmental disturbance varies with the length, bearing capacity requirements and permanence of the roads needed.

When delays have occurred, the longer approval time is required not for administrative handling but for actual resolution of the difficulty.¹¹ For example, if the right-of-way is routed through an area with a high probability of cultural resource value, federal archaeologists may withhold approval pending additional surveys of the area. A "typical" archaeological survey will require 3 or 4 months. Once the survey is completed, and changes to the right-of-way application are made (if needed), then approval may be granted.

The vast majority of rights-of-way requests are handled routinely, with few applications requiring environmental study. With 4,000 rights-of-way requests granted per year by BLM, only 10 projects or less at a time are likely to be undergoing a full EIS process.¹² Many requests would undergo the brief environmental assessment process. The greatest level of concern for rights-of-way for oil and gas operations is applied to projects on the Alaskan North Slope. The sensitivity of the tundra permafrost regions to damage is a frequent concern.

Processing patterns for rights-of-way are approximately the same for other surface management agencies. Forest Service lands tend to be of greater environmental and

recreational value than BLM lands, but few EIS's are required. Use of the environmental assessment memos, often 1 to 2 pages in length, are most common.¹³ Bureau of Indian Affairs (BIA) lands are subject to special requirements due to the need to obtain tribal clearances for some activities. However, most requests are routinely handled within 3 months.¹⁴

In terms of streamlining the right-of-way review process, the surface management agencies have taken several steps. New right-of-way policies were adopted by the surface management agencies in 1981 to facilitate application handling. The rights-of-way requests to all agencies are now submitted on identical application forms. Procedural changes were also made and are now being monitored by agency personnel. One BLM official reported that further changes may be made, after the APD process is revised, if rights-of-way handling is creating delays. In any case, BLM is expecting to comply with the timeframe to be developed by MMS for the APD process.¹⁵

9.1.4 Air Quality Permits for Oil and Gas Operations

Few conventional (primary recovery) oil and gas extraction projects are hindered by the need to obtain air quality permits. Air pollution permits, however, are important obstacles to oil field operations which involve either special treatment requirements, such as sour gas processing, or tertiary oil recovery projects which involve steam generation for reservoir stimulation.

Conventional drilling and primary recovery activities do not require federal PSD permits but often require a state or local air permit. Conventional oilfield systems are

allowed emissions of up to 250 tons/yr of a pollutant (oil field operations are not one of the 28 industrial categories with emission limits of 100 tons/yr) before the PSD permit is applicable. In-field combustion equipment is the primary source of oil field air pollution and actual emissions from most oil field equipment are fairly modest. Depending on the location of a field, electric power lines can be accessed, or equipment can be operated with produced natural gas. The applicability of a state or local air permit depends principally on equipment needs and on the minimum emissions levels allowable in the area which range from 250 tons/yr down to any non-zero emission level. The most significant pollutants emitted are SO₂ and NO_x.

Air quality permits may have a restraining effect, however, on major in-field processing operations such as sour gas processing plants. Production of natural gas containing hydrogen sulfide may require installation of sulfur recovery scrubbing equipment and full consideration of air quality impacts. PSD permits have been required, in recent years, for 2 sour gas plants in Wyoming. In one instance, air quality impacts were considered great enough to require preparation of an EIS.¹⁶

The restraining influence in such cases is more directly related to the regulatory requirements which specify mandatory control techniques than to permitting systems themselves, although PSD permits may take from 5 months to 1 year to process. Because sulfur recovery equipment is not economically justifiable below a minimum-level of production, this requirement leads, in some cases, to cancelled projects. In such instances the poor project economics cannot support the air quality control requirements or other processing costs.¹⁷

A more frequent permit problem occurs with the siting of steam generation systems for heavy oil recovery in California. Industry representatives note that advance planning of a year or more is needed for obtaining approvals from the local regulatory agencies (i.e., California Air Pollution Control Districts or APCD's) and from EPA (if a PSD permits is needed it is issued from the EPA Region IX office in San Francisco). Natural gas is often not available and developers must use high-sulfur produced oil for powering the steam generating equipment. The local APCD's issue a permit for each item of air polluting equipment including steam generators, tank heaters, well heads and truck loading racks. Often the installation of flue-gas desulfurization units for SO₂ control are necessary to meet emission standards. In the late 1970's the Kern County APCD in Southern California became overwhelmed with applications for emission permits. The volume of applications was created largely due to efforts by companies to avoid PSD requirements then coming into effect, and did not constitute a genuine demand for new installations.¹⁸ Other issues specific to California's State Implementation Plan hindered effective processing of this backlog. Lengthy delays were experienced by some companies in the period 1977 to 1979.

Studies of permitting delays have used California heavy-oil steam-stimulation projects as examples of unnecessary delays. One study, funded by the Business Roundtable, examined case study evidence of problems caused by the Clean Air Act.¹⁹ Of the 92 cases described, 4 appear to be California steam projects (the location of projects and company names were not revealed). The difficulties encountered in the 4 cases are as follows:²⁰

1. Delays occurred in obtaining permit approvals due to evolving regulatory requirements and interagency disagreements among the county, the state Air Resources Board and EPA. A period of 35 months was required for obtaining permit approvals, with an additional 24 months needed for corporate planning changes and internal developments.
2. Delays were created (between 1977 and 1979) by implementation of the CAA Amendments and disputes over the acceptability of modeling techniques. Delays of over 2 years resulted.
3. Project delays were due to economic risks posed by regulatory requirements for SO₂ scrubbers. The company postponed the project for 4 years until oil prices rose sufficiently to again justify the necessary investment.
4. As for the project described in #3 above, delays occurred because of economic risks posed by SO₂ scrubbers. The project was delayed more than 4 years.

In examining these case studies, the first two refer to exceptional permitting delays caused by evolving regulations. The last two were not permitting delays but merely project cancellations due to unfavorable economics which were blamed on scrubber costs.

The current situation (Summer 1982) in California has stabilized, although permitting requirements are more difficult than those encountered elsewhere. The Kern County APCD reports that many applications can be handled in 4 months. If a PSD permit is needed a full 7 month permit is typical combining the federal and state reviews.²¹ This period encompasses a 1-month application completeness review and a 180-day review period.

Oil company officials report that 1/2 to 2 years for small to large projects should be set aside in the state to obtain the necessary permits.²² Companies will not make equipment purchase commitments until California Authority to Construct permits have been obtained.²³ High capital costs for a steam generating unit (approximately \$500,000) combined with the uncertainties of the California air quality permitting process are the reasons for this pattern.

Also some companies have additional difficulties due to a lack of air pollution emission offsets which can be applied to new projects. In the PSD program, companies may construct a new emission source if they provide for control of other emissions so as to leave the total area emissions unchanged. This problem is becoming quite significant in California where companies cannot make the tradeoffs among sources so as to allow new construction.

The overall effect of air quality permitting on the industry has been to create some localized difficulties but few problems for most developers of extraction projects. Kern County, California, is the principal area where the full complexity of air quality regulations impinges on development activities. There the oil industry faces Clean Air Act compliance headaches similar to those faced by other industries producing significant emissions. The difficulties in this area are related to both the substance of the Clean Air Act and also to the complexity of regulatory processes which lengthen the application and approval tasks.

In streamlining air permitting requirements to encourage development, several possibilities exist. In California, creation of an effective system for banking or trading of

PSD offsets would aid selected oil companies. This idea has been initiated in some counties but is not widespread. Improved interaction between the federal EPA and the California Air Pollution Control Districts would also reduce developer headaches.

9.1.5 Other Permits for Oil and Gas Operations

Other permits required for oil and gas developers are rarely sources of delays. Industry experience with several such permits are discussed below.

NPDES Permits - surface discharges of produced water are less common than reinjection. Where they are needed, NPDES permits have not presented major problems for the industry. In most cases, such discharges are uncommon unless the produced water quality is quite high. In that case it may be discharged to agricultural water users. Otherwise, operators must provide sufficient cleanup to meet the EPA Effluent Guideline limitations on oil and grease in the discharged water. Reinjection of the produced water is a preferred disposal method in most situations.

Non-compliance with NPDES permits has been observed in various areas. Some operators may choose to drain their water reserve pits and are unaware of the effluent guideline restrictions imposed by the Clean Water Act regulations.²⁴ The extent of such actions is not known, although contact to the Montana Department of Health and Environmental Sciences indicated "a large number" of operators were not in compliance.²⁵ The possibility of non-compliance suggests that firms are not hindered by NPDES permit requirements and that often firms may choose to ignore them in cases where hindrance is possible.

Water Appropriation - several methods exist for obtaining water supplies for field operations so few developers are not closely tied to state water appropriation processes. Water may be (1) brought in by tank truck (for small quantities), (2) purchased from nearby landowners, or (3) supplied by water wells. Appropriation permits are needed in the last case leading perhaps to lengthy review procedures. Such permits have not proven to be difficult with the exception of those issued by New Mexico and Colorado. The Colorado situation is due to a large backlog of permits, which has created waiting periods of up to 7 months or longer.

Waste Disposal Permits - states regulate the use and construction, and abandonment of the reserve pits used for oilfield wastes such as muds, and skimmed oils. The state regulations provide for ground and surface water protection during operations. Permits for reserve pits do not require long approval processes. Wyoming does not require a permit for a reserve pit, while Colorado's state drilling permit also covers use of a reserve pit. Restrictions on developers more frequently occur as penalties after proven non-compliance with state regulations.

Allowable techniques for operation and closure of reserve pits vary by state and within states. The lining of pits is required in some states (e.g., Montana). Closure requirements for reserve pits may allow evaporation (e.g., leaving the pit to stand through the summer), or removal of wastes for disposal in an approved landfill. These activities are regulated by the state agencies handling oil and gas operations and/or water quality protection in the various states. The developers contacted did not report difficulties or delays due to disposal of reserve pit wastes.

State Drilling Permits - all state oil and gas regulatory bodies provide rapid reviews of drilling requests. Review times vary from one to 10 days, with all agencies showing an ability to respond immediately to urgent requests.

9.2 Coal Mining Project Delays Due to Permitting

A coal mining project requires complex preparations as befits a large-scale construction effort and a major land disturbance activity. The network analysis in Section Seven has illustrated the numerous activities involved including environmental studies, facility design, permitting, equipment purchasing, construction and mining. In this section, the effect of permitting delays on the development time for coal mine projects will be examined. The discussion will follow the format of the previous oil and gas section in examining data on permit review periods and delays for major permit programs.

The analysis of permit delays in coal mine development is complicated by the influence of market factors. In particular, a mining company may move quite slowly through development in periods of slack demand. In the network analysis, this trait of mining projects is suggested by the activity labelled "Market Development". The activity must be completed before the company begins entering into equipment purchase commitments. In practice, market development is an absolutely necessity in early project stages and serious efforts to develop the mine will not proceed until a sale is completed. In the current market (Summer 1982) demand in industrial coal markets is slow and this fact has been reflected in the urgency of company efforts.

The influence of slack demand is important because of the nature of the permitting process. Permitting activities involve some interaction between the government agency and the applicant in which the two groups respond (in the best case) to each others needs. Most government agencies attempt to comply with the needs of permit applicants as in the case of requests for expediting of permit reviews. Many government personnel, for example, indicated that the company's interest in begining operations influenced the priority given to a permit application.

Even for the lengthy coal mine permit processes, the interests of the company in rushing its application through affects (1) the company's own quickness of response to requests for more information, and (2) the government agency's speed of deliberation. When the company is not concerned over the length of the review, as in periods of slack coal demand, the eventual reviews are notably longer.

The effect of this informal interaction and the market influences will be noted where applicable in the sections. The most important permit process, the OSM mine plan review, is discussed first, followed by sections on air, water and other permits.

9.2.1 Review of the Mine Plan Application

The Office of Surface Mining (OSM) mine plan review program is the most important and most complex permitting requirement facing coal mine operators. Other permitting activities are increasingly overshadowed by the mine plan review. Furthermore, some states require that all other

permits be received prior to issuance of the SMCRA mine permit. This requirement adds to the prominence of the mine plan review.

The brief history of the OSM program must be considered before data on review times is examined. The Surface Mining Control and Reclamation Act was passed in 1977, and regulations were issued in 1979. The regulations written by the Office of Surface Mining were, however, subjected to court challenges, and both the Carter and Reagan administrations urged easing of the rules. OSM has also endeavored to improve the clarity of the standards and to allow for greater flexibility in state operations. As a result of these influences, substantial changes to the OSM regulations governing the content of mine plans were proposed on June 25, 1982. Also, changes to regulations governing the division of responsibilities at the state and federal level for control of federal coal mining were proposed on June 9, 1982.

The complexity of the OSM program development has been increased by the transfer of authority to state programs approved by OSM. The transfer to Western states is occurring in two stages through (1) granting of state primacy for the SMCRA permanent program, and (2) negotiation of a Cooperative Agreement for federal lands in states with approved programs (see Section Seven above for a discussion of the OSM program).

The organizational changes which have been taking place mean that there is little basis for analysis of program operations. In general, the OSM program procedures have not been sufficiently established to justify extensive criticism of processing delays in mine plan reviews. The evolution of the program has been too rapid and with recently

announced reviews in the OSM regulations such past performance data as is available should be carefully used.

The status and changing nature of the program has four broad effects on processing efficiency. First, technical personnel have little chance to adapt to the requirements of their job. Second, as with any new regulatory program, the exact content and interpretation of the program has not been fully defined, leading to confusion and differing interpretations of regulations. Resolution of disputes can delay processing. Third, the knowledge that revised regulations will be issued may slow processing as applicants (or government personnel) await new developments. The effect of this trait has been seen in early 1982, when the revised regulations were expected. Fourth, the need of all existing and new mine operators to submit new permit applications creates an instant backlog for the reviewing agency, which must be worked through. The state of Utah, for example, reports a current backlog of over twenty mine plans which were submitted in the first stages of the state program operation.

Before examining OSM review times, consideration should be given to the question: what would constitute a "reasonable" review time for a mine plan? One may consider both what is possible and what other permits require. If an EIS is to be included, preparation of that document requires approximately 12 months, due to the public notification and comment period requirements. This time cannot be reduced in all likelihood. Other analyses as may be required could be performed concurrently with the EIS, so that EIS defines the time frame for the entire review. In cases where an EIS is not required, a briefer review of perhaps 4-6 months is conceivable.

In the federal coal network (Figure 7-1), a mine plan review period of 15 months was shown, covering a 9-month Apparent Completeness Review (ACR) and a 6-month Technical Review. The Environmental Assessment (EA) or Environmental Impact Statement (EIS) are also completed concurrently to these reviews. The ACR includes a time allowance (the exact length of the allowance was not estimated) for company responses for more information. In actual practice, some ACR periods have lasted several years while new data submissions by the mining company are prepared.

With the setting of regulatory actions thus described, information of mine plan reviews can be presented. A summary of the OSM review times for western coal mines is provided in Table 9-4, with data shown for 4 of the study states. (Among the other states in the study, Alabama, Alaska, California, and New Mexico no useful data is available.) The data cover reviews of new mine plans or of major modifications as performed by OSM from 1978 to Spring 1981. The influence of state programs on reviews were not considered. The times are measured from first submission of the mine plan to final approval by the Assistant Secretary for Energy and Minerals within the Department of the Interior. A qualitative judgment was also made for the study referenced in the table of the seriousness of the environmental issues involved for each mine. An issue was considered serious if it was thoroughly assessed in the Technical and Environmental Analysis for the project, or if a stipulation about the issue was made part of the mine plan approval. All of the large (over 2.5 million ton/year) surface mines were determined to present significant environmental issues.

TABLE 9-4

OSM REVIEW TIMES FOR NEW MINES AND
MAJOR MODIFICATIONS

MINE/STATE	PRODUCTION (MM TONS/YR)	MINE TYPE ^a	SERIOUS ENVIRON- MENTAL ISSUES (YES OR NO)	OSM APPROVAL TIME (MONTHS)
Reinau #2, CO	.1	U	No	4
Hawk's West, CO	.4	U	No	11
Reinau #2, CO	.5	U	No	12
Eagle, CO	.5	U	Yes	5
Colowyo, CO	1.5	S	No	3
Energy 1 & 2, CO	1.5	S	No	2.5
Energy 1 & 2, CO	1.5	S	No	4
Energy #2, CO	1.9	S	Yes	4.5
Energy 1 & 2, CO	1.5	S	No	6
Rosebud, MT	3	S	Yes	28
Big Sky, MT	4.2	S	Yes	16
Absaloka, MT	4.5	S	Yes	22.5
Spring Creek, MT	7	S	Yes	25
Gordon Creek #2, UT	.3	U	Yes	6
Huntington, UT	1	U	Yes	16
Skyline, UT	5	U	Yes	22
Dave Johnston, WY	1	S	No	4
Buckskin, WY	3	S	Yes	20
Black Butte, WY	6.3	S	Yes	29
Coal Creek, WY	10	S	Yes	24.5
Caballo, WY	11.5	S	No	26
Rawhide, WY	12	S	Yes	24
Rojo Caballo, WY	13	S	Yes	23

Source: Impact of Government Regulations on Coal Mine Start-up and Production, Policy Planning & Evaluation, May 1981.
The entires under "Serious Environmental Issues" for the Black Butte and Absaloka mines were changes from "no" to "yes" by ERCO staff.

^aA "U" signifies an underground mine. An "S" signifies a surface mine.

The mine plan review times are widely variant. Plans for small underground mines in Colorado and Utah were among the most quickly approved plans, the longest reviews were most consistently applied to the large surface mining operations in Wyoming. Additional sources of variability, other than mine size, may have included (1) completeness of the plan submission, (2) responsiveness of the company to requests for additional information, (3) urgency or interest of the company to begin operations, (4) administrative patterns of operation, and (5) variations in existing backlogs at time of plan submission.

The influence of mine size on the OSM review times can be ascertained by graphing review time (y axis) onto production levels (x axis) as shown in Figure 9-2. A clear correlation may be noted. The logic of this relationship is simple, the volume of production is tied to the extent of land disturbance, and this to the extent of the review necessary.

However, the seriousness of the environmental issues involved was found to be statistically insignificant in its affect on review times.²⁷ This result is suprising because, in examining the review process, significant environmental concern deter approval. Indeed, it appears that the technique used to measure "significant environmental issue" did not fully capture the variable's influence. The review process focusses on sensitive environmental problems, and OSM reviewers will ask mine operators to develop additional control measures as needed. The process of finding solutions to such concerns can be time consuming such as if a wildlife habitat is to be relocated. The negotiations involved lengthen the review period in most cases.

Figure 9-2. Relationship of Mine Size to OSM Review Time.

Furthermore the influence of environmental issues on review times is institutionalized through the EA or EIS process. When a mine plan is received, OSM considers whether an EIS must be prepared or if the much briefer EA (Environmental Assessment) will be adequate. This stage of the review (shown in the federal coal permit network in Figure 7-1 between nodes 21 and 24) is called the Determination of Significant Impacts. When an EIS is required, a full year is generally needed to complete the NEPA process. This length for the procedure is virtually irreducible because of the statutory requirements for public notice and public comment periods and other elements. An EA can be completed within three months. Thus, the nature of the EIS process strongly suggests that mines which create notable environmental impacts will have lengthier reviews.

9.2.1.1 Federal and State Cooperation on Mine Plan Reviews

By focusing on the federal OSM reviews, the role of state agencies in mine plan approval processes is ignored. However, the relationship of federal and state authorities is central to the approval process, with state agencies now taking the greater part of the review responsibilities.

The SMCRA program is intended to be a state-operated program with federal government involvement needed only in non-participating states and for federal lands. All of the western states with significant activity have received primacy for their mine regulation programs. The OSM regional offices, which were staffed in order to handle the interim OSM program, have been reduced in size, with

review functions being transferred to OSM technical centers and state offices.

With the reduced federal role, review responsibilities have been increasingly handled at the state level. For federal coal the technical analysis of the mine plan, which includes the review of operation and reclamation plans, is performed at the state level. OSM participates in the environmental analysis. The transfer of authority for federal coal to the state is limited by statutory delegations of Department of the Interior authority. DOI is not allowed under the National Environmental Policy Act from transferring its NEPA responsibilities to the states. DOI is also required under the Mineral Leasing Act of 1920, as amended, to perform an "independent analysis" mining activities where federal resources are involved. Thus, OSM is prohibited from relying entirely on state analysis of mine plans.

However, the pattern of cooperation between OSM and a coal mining state for federal coal mine plan reviews is in the process of further clarification. As mentioned, proposed rule changes for federal lands were prepared by OSM and published in the Federal Register on June 9 and June 25, 1982. Under the proposed regulations, states with cooperative agreements (agreements between the state and OSM governing the management of federal coal within the state) would "assume a largely independent role in the review and approval of [SMCRA] permit applications" for activities on federal lands. The state would take the lead role for permit review, ensuring consultation with OSM or other federal agencies only as the state may desire. OSM would continue to be responsible for ensuring compliance with the NEPA law.

In this arrangement the NEPA review will constitute the "independent analysis" required of the DOI under the Mineral Leasing Act of 1920, as amended.²⁸ The intent of the proposed rulemaking is to further the transfer of review authority to the state, and to reduce the potential duplication of state and federal reviews.

The ultimate effect of the new federal land regulations on permit review periods is uncertain. While states will be allowed to issue permits without OSM concurrence, actual mining may not begin until the OSM approval is received. OSM officials report that the agency makes an effort to be responsive to the needs or desires of the applicant and the state in regards to expeditiousness of reviews. This in instances where the state has completed its review, OSM appears likely to quicken its pace. As was noted in Section Seven, several states have incorporated deadlines for review into their procedures. Colorado, to mention the most extreme case, allows only a 6-month period for both completeness and final reviews. The federal program, which includes no such guidelines, may lag behind the state agency processing time in these cases. If an EIS is needed, then the federal approval may be significantly slower than the state review.

9.2.2 Air Pollution Permits

Air pollution permits represent a major environmental clearance that must be obtained by potential energy developers. These permits are obtained under state law, as coal mines generally are not covered by permitting requirements under the Federal PSD program. States require facility construction permits for emission sources. The source review may include a PSD review (as it does in Montana where coal mines are covered by PSD permitting requirements) or

it may not (as in Wyoming and Colorado). On-site preparation plants or mine-mouth power plants greatly complicate the air quality issues and may lengthen this permit process.

Air pollution permits have not been sources of delay for mine developments in many cases. A major study of air permit problems identified only two mine developments which were adversely affected by the Clean Air Act.²⁹ The circumstances for the first case identified are described further below and involved conflicts with air quality in a national park. In the second case, thermal dryers in a coal preparation plant in the Appalachian state were of concern. A solution of raising the stack height at the site was eventually agreed to.

Many companies appear to have requested and received air permits prior to most development work. For example, permits have been issued in Wyoming for federal leases which are not yet being developed. Data on permits issued to both developed and undeveloped leases in the Powder River basin are shown in Table 9-5. Air emissions have been permitted for large scale production on six undeveloped leases.

The early requests for air permits are encouraged by the limited emissions which will be allowed in a given region. New emission sources are allowed only until national ambient air quality standards are reached, assuming that PSD rules do not apply. Mining companies thus have an incentive to file their request for emissions approval as early as possible. The result of this system is that companies attempt to reserve a share of the clean air resource for their use. Returning to Table 9-5, it

TABLE 9-5

APPROVED AND FORECASTED PRODUCTION LEVELS
FOR MINES IN POWER RIVER BASIN, WY
(Million Tons/Year)

MINE	COVERED IN APPROVED AIR PERMIT	ANTICIPATED 1991 CAPACITY	FORECAST IN HIGH-DEMAND SCENARIO FOR 1991
<u>Developed-Federal</u>			
Buckskin	6	6.2	6.2
Rawhide	24	24	30.7
Eagle Butte	29	25	35.2
Wyodak	3	5	4.9
Rajo Caballos	20	15	12.5
Cordero	24	24	20.5
Coal Creek	18	12	10.1
Jacobs Ranch	16	16	15.3
Black Thunder	20.5	20.5	19.4
Dave Johnston	NA	3.8	3.8
<u>Developed-non-Federal</u>			
Fort Union	1.2	0	-
Clovis Point	4.0	5.0	-
<u>Undeveloped-favorable Federal development prospects</u>			
North Rochelle	-	8	5.9
Wildcat	10	7	5.1
South Rawhide	7	12	8.8
Dry Fork	15	8	5.9
East Gillette	11	15	11
Rochelle	-	6	6.0
North Antelope	5	5	5
Antelope	12	8	8

Source: An Assessment of Development and Production Potential of Federal Coal Leases, Office of Technology Assessment, December 1981.

can be seen that for developed leases, air pollution permits have been received well in advance of production. For the developed mines listed, all but two have approved air quality permits equal to or exceeding their 1991 mine capacity.

Future growth could be limited in certain areas if additional companies are unable to obtain permits as needed. Modeling of air quality parameters might show, for example, that the late-applying mines would cause pollutant levels to exceed the National Ambient Air Quality Standards. However, this modeling would need to assume that the maximum allowed production by the existing mines was occurring even if such production levels are never actually achieved. This potential for restraining growth is a concern particularly for the Powder River Basin in Wyoming where the close proximity of the mines increases the interdependence of the pollution sources.

Other controversies involving air quality have been generated by the potential for air quality impacts in Class I regions (maximum air quality protection areas) in the Western states. Air pollution impacts affecting Bryce Canyon National Park in Utah were the basis of a petition to OSM to prevent mining of the Alton coal fields in Southern Utah. Under the SMCRA program, lands may be designated unsuitable for mining if it is shown that mining will "affect fragile ... lands with significant damage to important ... aesthetic values or natural systems."³⁰ In this case, OSM used PSD standards as an evaluation benchmark. OSM found that mining would cause a reduction in scenic vistas visible from the park and create high noise levels in portions of the park. The air pollution impacts thus caused the area to be identified as unsuitable

to prevent mining of the Alton coal fields in Southern Utah. Under the SMCRA program, lands may be designated unsuitable for mining if it is shown that mining will "affect fragile ... lands with significant damage to important ... aesthetic values or natural systems."³⁰ In this case, OSM used PSD standards as an evaluation benchmark. OSM found that mining would cause a reduction in scenic vistas visible from the park and create high noise levels in portions of the park. The air pollution impacts thus caused the area to be identified as unsuitable for mining. Other impacts on Class I areas are possible near Powder River basin which could affect the Cloud Peak Primitive Area in the Bighorn Mountains and Devils Tower, and in North Dakota coal fields near Theodore Roosevelt National Park.³¹

These issues described above concern the substance of the Clean Air Act rather than permitting procedures. To date procedural issues have not been the major concern. Some delays have occurred but, with the early applications being filed, such delays are unlikely to obstruct mine development. The seriousness of delays varies among state offices. An official in the Wyoming DEQ noted that statutory deadlines for review of air permits of 4 months were not being met due to work backlogs. This delay is causing the Wyoming air program to operate with approximately the 6 month cycle of other states. Also such delays are not unique to energy firms and affect all industries applying more or less equally. The larger controversies involve the actual regulations in the Clean Air Act and not the performance of regulatory duties.

9.2.3 Water Pollution Permits

Water discharges are regulated under federal NPDES permits and in mine plan reviews and may be supplemented by state water pollution laws. The NPDES program, like other programs, is designed to allow the transfer of responsibility to the states. All of the study states except Utah and Alaska have authority for issuance of NPDES permits. The NPDES covers point source discharges only. All other discharges are described in the hydrological data included in the mine plan.

NPDES permits and supplementary state water pollution concerns have not been a major source of delay according to discussions with industry and regulatory personnel. The effluent standards for coal mine discharges are readily measured and control measures, principally the building of sedimentation ponds, are well established. In the Western states, mines produce alkaline mine drainage, which is easier to manage than the acidic drainage in the East. There are few major trace metal pollutants in the discharges. Potential impacts are generally related to sediment.

Normally, all sedimentation ponds in a mine area are covered under one permit. In some cases, up to 30 distinct discharge points would be covered. In the procedures followed by the Region VIII EPA in Denver, each discharge included in the permit is identified by a serial number. As discharge points are changed in the course of mining, the mining company can modify the existing permit by submitting a map with the newly designated outfalls, reassigning serial numbers as necessary. This procedure eliminates the need to reissue permits for each shift in discharge points.

Although not a major permitting obstacle in itself, the NPDES permit is duplicative given the comprehensive water pollution review for the OSM mine plan. This duplication encouraged an effort begun under the Carter Administration to develop a Memorandum of Understanding (MOU) between EPA and OSM. The MOU would transfer authority for the NPDES permits applied to coal mines from EPA to OSM. However, the MOU was not completed under the Carter Administration and no efforts have been made by the Reagan Administration to renew discussions. Completion of the agreement, while perhaps desirable, would involve difficult problems of federal and state interactions. The NPDES and the SMCRA programs are operated at both federal and state levels depending on the specific area in question. In adding NPDES to the SMCRA program, all possible permutations of federal-federal, federal-state, state-federal and state-state interaction would be involved. The legal issues in the MOU could veto even an earnest effort to reach an agreement.

The other hydrologic impacts are described in the mine plan. The operator must provide for aquifer protection, as well as model the impact of pit dewatering or of stream alteration on the hydrologic character of the area. Water issues are frequently among the most serious in the mine plan, and can significantly increase the total review time for the mine plan. Requests for additional hydrological data are frequently made to mine plan applicants.

9.2.4 Water Appropriation Permits

Water appropriation permit processes are among the longest in the Western states. The length of the processes is related to the seriousness of water allocation issues in this arid region. Limited water supplies could constrain mining development in selected locales.

When permit processes have become lengthy, it has been largely because of this competition for limited water sources and not due to inefficiencies or complications in regulatory actions. Such delays should not be called permitting delays, because they represent the outcome of procedures developed for allocating a scarce public resource. The nature of water appropriation processes can be judged by considering two states with perhaps the most lengthy review processes: New Mexico and Utah.

In New Mexico, long delays in appropriation occur due to (1) the state's desire to protect limited water supplies, and (2) due to the scheduling system used to differentiate applicants. New Mexico has moved slowly to allow developers access to the state's water supply. For the major aquifers in the state, no appropriation permits have been issued. The only exceptions to this have been the few mine companies which obtained water because their water rights pre-dated the protection of a given basin, or permits were obtained for water from minor aquifers.³³ With regard to scheduling of applications, New Mexico rates potential water users according to the date of their application. In the current New Mexico queue of potential users, some applicants have been waiting for allocations since 1979.³⁴ The long review process involves detailed hydrological studies of the impacts of new allocations on existing users and court battles to settle such issues are common.

Thus far, water appropriation difficulties have not prevented any coal mine developments in the state. However, further developments in the San Juan River basin, the main coal-resource area, could run into competition from uranium mines and agricultural and other water uses. The outcome of this competition cannot be determined at this time.

In Utah, a similar situation exists. New appropriation requests are not usually made because most of the water supplies in the state have designated users. The Colorado River, for example, is fully appropriated. Coal companies choose instead to purchase existing rights (or to purchase shares in companies with such rights). The applicable permit is then the Application for Change in Point of Diversion. This process requires 4-6 months with most of the review time being necessary to verify that other users will not be adversely affected.

The other states with major coal mining have provided fewer water use controversies. In general, the more mountainous states of Montana, Wyoming and Colorado have greater precipitation and less competition for water. In the important Powder River Basin, for example, there are few competing users. Mine plan modifications have been needed, however, for the protection of alluvial valley floors, which have hydrological significance. In west-central Colorado, the Mount Gunnison Mine has been under study because of potential effects of mining on other waters uses in the area.³⁵

The length of time needed for water use permit approvals is well known, allowing mine operators to make early requests for appropriations. Examination of the permits obtained for selected mines indicates that water appropriation permits may be approved several years before other permits are completed.

As with other environmental areas, many aspects of water use are considered in the OSM mine plan review. The SMCRA program requirement to recharge groundwater capacity, for example, is now a key concern for hydrologic analysis by the mining company. The extensive hydrologic data

required in the mine plan is prominent among industry complaints about the SMCRA program. Failure to submit sufficient data has caused delays in numerous reviews.³⁶ Monitoring requirements are also extensive and have been criticized as over-demanding by industry.

To summarize, water resource issues reflect a serious regional issue of water availability. Permitting delays have been avoided in many cases by early application or by purchases of existing rights. Other delays may occur due to the hydrologic data requirements of the OSM mine plan. Future water supply difficulties are possible in selected locales such as the San Juan River Basin in New Mexico.

9.2.5 Other Coal Mining Permits

Various additional permits are required for coal mine operations. The potential impact of these on delays is briefly described below.

Federal Rights-of-way - during the lengthy process of environmental data collection, any necessary rights-of-way across federal lands adjoining the coal lease may be obtained. During the environmental studies themselves, minimal land disturbance is involved and rights-of-way are not necessary.

Wildlife Permits - wildlife issues are significant in some mine areas, most notably in southern Wyoming. Federal wildlife permits for protection of endangered or threatened species and the OSM permit both provide for wildlife protection. Fish and wildlife agencies have an

opportunity to consult on mine plans in all states. Any delays in permitting due to wildlife issues are likely to result from substantive disputes about wildlife impacts in the course of the EIS review.

MSHA Permits - MSHA approvals are needed for design of the safety systems in the mine. Disputes about MSHA permits have developed because of confusion or disagreement about the appropriateness of MSHA standards in certain mines. The MSHA permit process itself is fairly brief, lasting at most 2 months, and need not be completed until the actual beginning of operations. In normal circumstances MSHA permits will be off the critical path and have long float times.

9.2.6 Mining Operations on Federal vs. Private Lands

Federal lands are subject to special management requirements as provided for in the federal legislation governing mining on public lands. In short, the Secretary of the Interior is responsible for the protection of all public interests for the protection of all public interests with regard to federal landholdings including receipt of royalty values for production, fair market value for lease sales, efficient and diligent production of mineral resources, and the protection of environmental values. These responsibilities cannot be transferred to the states. The process of carrying out the duties inherent in these responsibilities leads to additional permitting and regulatory controls over energy projects on federal lands as opposed to private lands. The impact of this differential treatment on the two types of projects is considered in this section.

Projects on federal lands are distinguished at several points in their development. Generic project stages and the differences in permitting are described below in Table 9-6. Additional federal permits or regulations apply at exploration and leasing, but most permits apply to projects on either federal or private lands.

The key permit is, of course, the mine plan approval required under the SMCRA program. The conduct of this program depends on whether the state in question has been granted authority for program operation. If the state has SMCRA authority, then its regulations are at least as stringent as the federal regulations. The mine operator, in preparing a complete state-required mine plan, would simultaneously be meeting federal standards. If the state is not the regulating authority, then the federally required mine plan would represent the most comprehensive application procedure and would (generally) satisfy the state requirements.

In neither case is there a marked difference between the permitting for federal or private lands. Consider the case where the state has authority for the SMCRA program. The state will therefore apply the SMCRA standards to all mining activities in the state. With federal lands, of course, the actual mine plan review is split between federal and state authorities. On the presumption that the federal offices are less responsive than state offices, a federal coal mine may face a more lengthy permit review. The differences, however, are not substantive for the programs.

The Federal Lands Program of the Office of Surface Mining has attempted to eliminate the differences in handling of federal and private lands. In the preamble to recent revisions in the federal lands program (FR, June 9, 1982,

TABLE 9-6

GENERIC PERMITTING ACTIVITIES FOR MINING
ON FEDERAL AND PRIVATE LANDS

PROJECT STAGE	PERMITS REQUIRED	
	FEDERAL	PRIVATE
Exploration	BLM Coal Exploration License; MMS Exploration Plan Approval; State approvals (drilling)	State approvals (drilling, exploration)
Leasing	Bidding for Federal Lease; Completion of Lease Agreement	Private agreements for purchase
Design Work & Environmental Studies	Full complement of environmental studies	Full complement of environmental studies
Mine Plan Preparation:		
-If state has approved program	Meet state standards (will meet federal standards)	Meet state standards
-If state does not have approved program	Meet federal standards (will meet state standards)	Meet federal standards
Environmental & Safety Permitting	EPA, MSHA permits, state permits	EPA, MSHA permits, state permits
Mine Equipment, Procurement, & Construction	None	None

pg. 25093) it is stated, "Under the proposed regulations, the same performance standards, and essentially the same permitting requirements would apply on both Federal and private lands within a state." The regulations referred to allow the states to have a more independent and complete authority for permitting for federal lands than had previously been the case.

Even with the Federal Land Program revisions, some differences in practice will occur in permitting of federal and private lands. Certain Western states (e.g., Colorado) have mandated review deadlines for their mine plan review agencies which are both strict and brief. In Colorado's case, only 6 months for review are allowed. The federal OSM offices have no such guidelines for their reviews of federal coal mines. Individuals in OSM have indicated that OSM endeavors to cooperate with state deadlines but this is not a formal policy. Also, under the new Federal Lands Policy referenced above, states have greater authority over federal coal mines and may issue permits to such mines before the OSM review has been completed. However, mining may not begin until the federal review is complete. This arrangement allows the federal review to lag behind the state review and, by extension, federal coal mining to be delayed beyond the review of a private-land mine.

For other aspects of the mining preparations, such as for land and lease acquisition, mines on private lands may have greater legal difficulties than do mines on federal lands. In mines in areas where federal lands are not predominant, numerous private individuals may own a portion of the intended mine area. The negotiation of agreements with all parties may be more time-consuming than the reaching of federal lease agreements.

In general, the involvement of the federal government has in the past and will continue to slow the development of federal mines as compared to mines on private lands. The significance of the difference, however, appears to be small and is being reduced by further changes in the Federal Land Program. With the emergence of state agencies with authority for the SMCRA program, differences in regulation and permitting of federal and private lands have become minor relative to the overall complexity of the mine planning and permitting activities.

9.3 Costs of Project Delays

Any project which is delayed will be forced to absorb certain costs, attendant to the need to maintain staff, extend loan arrangements, and sustain overhead costs. The amount of such expenses is unique to each project but depends mainly upon the size of the undertaking, the type of financing used and the flexibility inherent in contractual agreements. The exact amount of such costs would be difficult to establish in many cases because of (1) ambiguities in accounting for certain continuing overhead expenses, and (2) uncertainties in the definition of delay.

For this study, a methodology was developed which could be applied to available data in order to arrive at a measure of delay costs. The technique was applied separately to sets of "representative" project costs for an oil and gas play and for a large western surface mine. Because of the limited data available (in a format useful for this task), the results of this estimation procedure should be considered only as an indication of representative delay costs and as a delineation of the distribution of costs among project stages.

The discussion of delay costs considers the possibility of actual stoppages in mine construction or operation. In actual practice, complete work stoppages are rare. Firms may be allowed to continue operations during negotiations with regulatory authorities, particularly if cooperation in good faith is shown by the energy firm.

9.3.1 Types of Delay Costs

Project delays generate various costs for the owner/operator. The main types of delay costs are discussed below.

Increases in Direct Costs - delays will tend to increase project costs by creating inefficiencies in the conduct of work. It may generally be assumed that a company can divert or lay off most workers during even brief delays, but that the process of start-up and shutdown will generate some additional costs. Also, certain facility or equipment maintenance operations must be maintained during delays. Financial penalties for cancellation or modification of orders may be incurred. Finally, in areas with harsh winters, delays may cause additional wintertime work at lower productivity levels.

Increases in Indirect (Overhead Costs) - if a project is delayed, energy companies will need to monitor and manage developments over a greater length of time. Management functions and some overhead charges will thus continue during an interruption in construction or operations. The ability and desire of management to reduce such charges and divert resources to other areas will vary directly with the length of the delay. Lease terms and permit or license durations may expire necessitating additional expenditures.

Increases in Interest Charges for Debt Capital - the debt portion of project funding will produce interest charges per unit of time. A lengthening of the project's development phase will create additional periods of interest charges, and perhaps serious financial difficulties. The payments to reduce the principal borrowed may need to be re-scheduled, resulting in increased charges due to refinancing.

Increases in Opportunity Costs for Equity Capital - an implicit charge may also be assigned to the equity portion of the capital investment. If a project is delayed, all funds which have already been committed, i.e. those funds spent for labor or materials, are prevented from being put into productive use. Unused funds, by contrast, may be diverted to other productive uses (e.g., investment in high-yield financial instruments) for the duration of the delay. The opportunity costs of equity capital therefore may be considered for all funds already used in the project.

Inflation is also frequently mentioned as causing additional costs during delays.³⁷ The passage of time will, in a period of inflation, mean that remaining uncontracted labor and material charges will be increased. The total capital expenditure will thus increase.

However, the appropriateness of inflation as a source of delay costs should be carefully considered. During a work stoppage, all unexpended funds could be placed in other yielding assets (e.g., financial instruments) earning a nominal rate of return which incorporates the effect of inflation. When work resumes, the energy firm could then use its capital (plus interest) to handle upcoming project expenses.

Furthermore, project revenues are also subject to a general inflation trend. Downstream income from sales may be subject to a sustained period of inflation before such revenues are actually received, offsetting the costs of inflated construction prices. Possible problems result only if there are differentials between the rates of inflation for construction costs and product revenues. If the former rate is greater, an inflation penalty may actually occur for the developer. If no such differential exists, then the real effect of inflation is virtually nil.

In this study, no accounting for the effects of inflation have been included. While the overall effect of inflation on project financing is considerably more complex than for the example used here, the final result of inflation is not significantly dissimilar to the negligible effects noted here.

The most complete line of inquiry into delay costs would involve the complete re-estimation of the net present value of a project's cash flow given the cost and revenue adjustments caused by regulatory delays. In such an approach, the cost inputs would be increased to account for all probable overruns. Interest charges would be forecast farther into the future and revenue streams and payback schedules would be set back. Once these adjustments were made (and the net present value of the project was recalculated), the change in the net present value (NPV) would provide a measure of the effect of delays on the overall project attractiveness. The change in NPV takes into account the size and timing of all adjustments.

However, for this study, measures of delay costs were used which could be based on available industry information, without requiring modeling of specific project revenue streams. The more general industry-wide focus of the study, with the interest in a more generic definition of delay costs, encouraged this approach.

Three components of delay cost were developed to approximate the effects of the four cost-increasing tendencies described previously. (The third and fourth items were combined into a single capital charges category.) These measures represent the (1) direct costs, (2) overhead costs, and (3) capital charges.

The delay measures are based upon project costs and the rate of spending implicitly represented. Estimates of the expenditures for individual projects were derived from the published literature. In these source documents, expenditures are defined by project stages, each of which encompasses a share of the network activities depicted previously for the energy projects. The format for these cost estimates allows for the estimation of delay costs at each project stage. The stages included for the coal mining project, for example, cover exploration, lease acquisition, predevelopment (covering environmental studies, engineering and design work and permitting) and development.

The first delay cost measure represents the problem of non-postponable direct and operating costs. For each project stage, a portion of the estimated direct or operating costs are judged to be non-postponable. The percentages used range from 0% (for some early exploration efforts) to 20% (for development activities). The percentages estimate the amount of spending which cannot immediately be halted if

project delays occur. The payment to field office staffs, payment of equipment penalties, inefficiencies or productivity declines due to start-up and other factors are assumed to be covered by these percentages.

The second delay cost measure covers overhead spending, estimated at 5% of direct and operating costs. During delays it is presumed that management functions such as project budgeting and rescheduling functions will need to be maintained. Some monitoring of the regulatory situation will also be on-going.

The third measure covers the capital charges to all previously expended or committed funds for the project. The charges are, for this study, assumed to be tied to interest rates and reflect both increased debt-service payments or opportunity costs for equity capital. For the cost estimates shown, a 15% interest rate has been assumed, which translates into a 1.171% month, simple interest charge. This interest factor is charged against the cumulative capital amount invested in a project. This capital charge factor is the most important element of the delay costs.

The capital charges were measured at the midpoint of each project stage. For example, midway through the development stage, the monthly interest factor was charged to the accumulated project investment (the sum of spending on previous project stages and one-half of the spending on the development stage).

The appropriateness of the costing methodology may be gauged by the actual budget allotments to overhead and other accounts in project budgets or in project cost studies. A sampling of the budget measures used in 6 studies of coal

mine costs is shown in Table 9-7 for the purposes of comparison.

TABLE 9-7

COMPARISON OF OVERHEAD AND CONTINGENCY
COST PERCENTAGES IN COAL MINE CAPITAL COST STUDIES

STUDY AUTHOR	PERCENT OF DIRECT COST USED		
	OVERHEAD	CONTINGENCY	TOTAL
OTA (1979)	15	-	-
Berkshire (1979)	5	15	20
Shelly and Loy (1979)	10	15	25
Katell (1978)	5	20	25
Katell and Hemenway (1974)	5	15	20
Hileman et al. (1970)	3	10	13

Source: See bibliography in Appendix A for full citations.

The delay costs for direct cost accounts are considered first. The non-postponable capital and operating costs should bear a resemblance to the contingency accounts allowed in actual project budgets, as shown in Table 9-6. The authors used values ranging from 10 to 20 percent, with 15 percent as a group average (the OTA study was attempting to duplicate actual spending, not to forecast future expenditures and thus no contingency account was used). The use of the 20 percent factor for some project stages may, therefore, be considered somewhat high. The factor has nevertheless been

judged most representative of non-postponable direct spending, and is within the range of the studies shown.

In the overhead category, 3 of the 6 others used a "5% of direct costs" range as was used here, although 2 other authors used notably higher rates. The use of the fairly conservative 5% for overhead costs is justifiable because our interest is only in overhead resources which cannot be quickly transferred to other tasks, and the smaller figure is a better representation of this.

The three delay factors used by ERCO are each defined in terms of the rates of monthly spending. It is then possible to derive for a representative project, the approximate costs of a delay of "x" months. In practice, however, the delay costs reflecting direct or overhead spending per month can only be considered applicable for brief delays of, by judgment, 3 months or less. It is obvious that the rate of expenditure during a delay is a function of the anticipated length of the delay itself. All direct or overhead spending ultimately becomes postponable as a delay lengthens and strains a company's resources, and as the company reassesses its situation. In simple terms, over lengthy delays, direct and overhead spending rate will tend toward zero.

This fact places greater emphasis on the capital charges as the main cost of delay. This measure comes closest to expressing the pure time-based costs of interrupting an industrial project, although it does not represent these costs fully. A complete delay analysis would involve derivation of the change in the net present value of the project, using appropriate discount rates project lifetimes, and revenue projections.

As mentioned, a capital charge rate of 15 percent per year (1.171 percent per month) is charged to the cumulative project expenditures. Given current interest rates (Summer, 1982) this interest factor is conservative. Furthermore, the factor does not reflect the losses due to deferring project revenues. Such revenues for an energy project would generally be sufficient to product a rate of return on investment of 30 percent or more. This level of return would be expected at a minimum for major new projects. Because of the significant financial risks of energy projects, company managements would seek returns much higher than 15 percent.

Thus the use of a 15 percent capital charge rate may understate the true costs of delays during a project. For this study, it was judged more appropriate to use lower measures of the delay costs which would be defensible, given the approximate basis of the estimates themselves.

9.3.2 Delay Costs for Oil and Gas Operators

The delay cost estimation methodology described above was applied to a capital cost estimate for a successful oil and gas play in the continental United States. The available cost estimates are expressed in 1979 dollars. The source for this data with some modifications by ERCO, is the Office of Technology Assessment study, The Management of Fuel and Non-Fuel Minerals on Federal Lands, as previously referenced in the network development in Section Six.

For the oil and gas project, five successive stages of activities were defined covering early exploration (consisting of 2 stages: Regional Appraisal and Detailed Reconnaissance), focused exploration, permitting and drilling for the

wildcat well, and development. The stages, their duration, and the associated capital costs are shown in Table 9-8.

For the first two stages, covering early exploration, no attempt was made to assign delay costs. Early exploration activities involve the identification and preliminary selection of drilling prospects. The involvement of regulatory authorities at this stage is minimal, with permits needed principally for access to lands for seismic work. More importantly, because drilling sites have not yet been identified, it is not appropriate to speak of project delays at that point. Difficulties with any individual site would not obstruct the general exploration activities.

With the next stages, the project becomes focused on a few drilling prospects. Capital expenditures are made for land acquisition in anticipation of drilling, and for continued mapping and modeling of the geologic structures. Possible monthly delay costs can be considered although prior to drilling, regulatory problems are not terribly important. If such problems do occur, it was judged that all but 10 percent of the direct spending could be immediately deflected to other oil and gas plans. This estimate may understate the average delay costs given the possibility of fixed rental costs for some oil field leases.

With drilling, on-site activity grows significantly. Spending covers drilling rig rental, site preparation, employment of the field crew, and the arrival of temporary drilling and production support facilities. At this stage it was estimated that all but 20 percent of the direct spending could be reallocated to other projects. However, delays at the time of drilling are sufficiently "downstream" so as to create large capital charges, as well as losses due

TABLE 9-8

OIL AND GAS PROJECT COSTS AND DELAY COSTS (\$000)

PROJECT STAGE	(a) ESTIMATED DURATION (Months)	DIRECT CAPITAL COSTS			OVERHEAD COSTS		DELAY COSTS		
		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		TOTAL COSTS	NON-POST- PONEABLE COSTS	NON-POST- PONEABLE MONTHLY SPEND- ING RATE	CUMULATIVE CAPITAL COSTS	OVERHEAD COSTS (5% of b)	OVERHEAD MONTHLY SPENDING RATE (f/a)	MONTHLY CAP- ITAL CHARGES TO CUMULA- TIVE COSTS ^a	TOTAL MONTHLY DELAY COSTS (d+g+h)
Regional Appraisal	6	----- Delay costs not considered -----							
Detailed Reconnaissance and Data Interpretation	38	----- Delay costs not considered -----							
Investigation of Target Area and Land Acquisition	26	3,600	360 (10%)	13.8	3,600	180	6.9	21.1	41.8
Permitting, Drilling, and Production Testing of Exploratory Well	8.5	5,000	1,000 (20%)	117.6	8,600	250	29.4	71.4	218.4
Development	20	5,250	1,050 (20%)	52.5	13,850	263	13.1	131.4	197.0
Totals	98.5	13,850			13,850	693			

Source: ERCO estimates. Column (b) data is derived from Management of Fuel and Non-Fuel Resources on Federal Lands, Office of Technology Assessment, 1979.

^aA 15% annual interest rate (1.171% per month) was applied to the cumulative capital expenditure at the midpoint of each stage.

to nonpostponable direct spending. For a major oil company, in particular, considerable expenditures, representing years of study, have been made prior to the identification of individual drilling prospects.

During development, delay costs would also be significant. Funds are expended for the construction of field facilities for continual production. Among the specific items of note are the placement of oil storage tanks, construction of gathering pipelines, drilling of development wells, and improvement of area roads. Again, it was estimated that only 20 percent of the direct spending is nonpostponable if a delay occurs. Losses due to capital charges are at their greatest level here, reflecting the substantial expenditures for field development and all previous activities. In this analysis, with the project spending estimates of the OTA study, monthly delay costs during development were calculated at approximately \$200,000.

9.3.3 Delay Costs for Coal Mine Operators

The delay cost estimation methodology was similarly applied to a capital cost estimate for a large Western surface mine (5 million tons per year). The cost estimate selected for use was derived from the study Basic Estimated Capital Investment and Operating Costs for Subbituminous and Lignite Coal Strip Mines, by Louis H. Berkshire of the Department of Energy, Morgantown, West Virginia (1979). The study was selected because it represented costs for the large strip mines which are of greatest interest here. Also the cost format was appropriate for the delay cost estimation procedure developed for this study. The details of the cost estimate are provided in Table 9-9.

TABLE 9-9

CAPITAL INVESTMENT SUMMARY FOR
5-MM TON PER YEAR COAL MINE

	QUANTITY	COST	TOTAL COST
Exploration			213,000
Lease Acquisition			6,100,000
Pre-Development			
Environmental studies		450,000	
Engineering and design		1,052,000	
			1,502,000
Development			
Topsoil removal and reclamation			
Wheel tractor scraper	4	\$1,174,000	
Bulldozer	4	1,068,000	
Overburden removal			
Dragline	1	31,980,000	
Cable handler and reel	1	84,000	
Bulldozer	1	267,000	
Coal removal and loading			
Coal loading shovel	1	2,332,000	
Front-end loader	1	352,000	
Coal drill	2	107,000	
Explosive truck	1	12,000	
Coal haulage, truck	8	4,624,000	
Maintenance equipment			
Road grader	2	336,000	
Water truck	2	118,000	
Lubrication truck	1	56,000	
Fuel truck	1	16,000	
Mechanic truck	2	60,000	
Welding truck	2	50,000	
Electrician truck	2	28,000	
Supply truck	1	18,000	
Pickup truck	6	48,000	
Crane truck	1	126,000	
Auxiliary			
Pump (portable)		16,000	
Floodlights and towers		21,000	
Communication		21,000	
Power setup		702,000	
Cable		747,000	
Explosive storage facilities		27,000	
Office and washhouse		267,000	
Shop and warehouse		615,000	
Oil and storage facilities		43,000	
Initial road construction		214,000	
Site preparation		133,000	
Silo and unit train loading facilities		5,225,000	
Total Direct			50,887,000
Field Indirect(2%)			1,018,000
Total Development			51,905,000
Total Capital Investment			59,720,000

Source: Basic Estimated Capital Investment and Operating Costs for Subbituminous and Lignite Coal Strip Mines, Louis H. Berkshire, Department of Energy, Morgantown, W. Va., 1979.

The delay cost calculations are displayed in Table 9-10, using the same format as for the oil and gas costs. Five project stages were defined with the fifth ("Begin to Mine" stage) not being considered for delay cost estimation. The duration of each activity is drawn from the coal project network used in Section Seven.

The first two stages in the coal project are of small significance in delay costs, although this was partially due to the specific set of cost estimates used. Exploration costs in the estimates used are minor, set at \$213,000. In some cases, exploration costs are likely to be greater than this estimate. However, all exploration costs are not attributable to examining a single site. As in the oil and gas case, project costs were considered relevant only beyond the point where a potential mining prospect was identified.

Lease acquisition costs were derived from a separate source, i.e., the OTA study used in the previous section on oil and gas delay costs (see Section 9.3.1). If the lease size is assumed to be 100 million tons (a reserve able to support a 5-MM ton/yr mine for 20 years) then the lease costs used were 6.1 ¢/ton. This figure is slightly above the 5 ¢/ton sale cost of the April 1982 Powder River lease sale. Prior to 1971, federal leases could be obtained at \$10,000 or less (Cannon, 1974). However, the higher figure was used for this example, on the assumption that the lease was obtained at a later date. Still higher lease acquisition costs could also have been used. Private sector transactions for coal reserves range in price from 20¢ to \$1 per ton.

Capital expenditures in the range of \$1.5 million were assumed for mine planning and design, and for environmental studies. Mining companies have reported spending \$2-\$4 million on the environmental studies alone.

TABLE 9-10

COAL MINING PROJECT COSTS AND DELAY COSTS (\$000)

PROJECT STAGE	(a) ESTIMATED DURATION (Months)	DIRECT CAPITAL COSTS				OVERHEAD COSTS		DELAY COSTS	
		(b) TOTAL COSTS	(c) NON-POST- PONEABLE COSTS	(d) NON-POST- PONEABLE MONTHLY SPEND- ING RATE	(e) CUMULATIVE CAPITAL COSTS	(f) OVERHEAD COSTS (5% of b)	(g) OVERHEAD MONTHLY SPENDING RATE (f/a)	(h) MONTHLY CAP- ITAL CHARGES TO CUMULA- TIVE RATES ^a	(i) TOTAL MONTHLY DELAY COSTS (d+g+h)
Exploration	16	213	0 (0%)	0	213	11	0.7	1.2	6.9
Lease Acquisition	3	6,100	0 (0%)	0	6,313	NA	NA	NA	NA
Pre-Development (Environmental Studies, Engin- eering, Design)	33	1,502	150 (10%)	4.6	7,815	75	2.3	82.7	89.6
Development (Equipment procure- ment, construction)	46	51,905	10,381 (20%)	225.7	59,720	2,596	56.4	395.4	677.5
Begin to mine	24	-----Delay costs not considered -----							
Totals	122 ^b	59,720			59,720	2,682			

Source: ERCO estimates. Column (b) data is derived from Table 9-8.

^aA 15% annual interest rate (1.171% per month) was applied to the cumulative capital expenditure at the midpoint of each stage.

^bThe total duration is longer than the critical path because of overlaps in the development stage with other stages.

By this third stage of the project, delay costs have almost doubled. Overhead spending and notpostponable direct costs are modest, estimated at \$6,900 per month. However, capital charges reflecting mainly the cost of stage 2 (lease acquisition) and stage 3 are \$82,700 per month. However, if an inexpensive pre-1971 lease is held, delay costs at this stage remain quite small.

At stage 4, development, huge capital outlays are made. In this estimate, total capital spending during development is \$52 million. The greatest expenditure for the dragline (\$32 million, see Table 9-9) with additional spending for coal hauling trucks (8 trucks for \$4.6 million), wheel tractor scraper (4 scrapers for \$1.2 million) and bulldozers (4 dozers for \$1.1 million).

With these major outlays, delay costs increase substantially. Nonpostponable direct spending becomes significant because field crews and managers cannot be easily reassigned. Capital cahrges are quite larges, estimated at nearly \$400,000 per month. Should permit problems cause postpone-ment of the it digging or overburden removal operations, total delay costs could be \$677,000 per month. Again, direct and overhead costs would be fully applicable only for delays brief enough not to allow personnel reassignments and other adjustments. However, capital charges could remain applicable for some time unless other mines can fully utilize the equipment purchases.

During the final project stage in which land disturbances occur, work stoppages are rare. The mining company may be able to negotiate a settlement with the regulatory authority to allow operations to proceed. However, project delays do occur due to permitting difficulties.

The pattern of the delay costs shown here roughly follows that occasionally evident in the coal mining industry. During a long lead-time, significant project delays may occur due to permitting controversies, market uncertainties, financing difficulties, or leasing problems. Delays due to these factors are important but do not quickly bankrupt firms. With actual mine construction, however, the level of mine site activity increases sharply. The size and rate of expenditures also increases. Delays may then be seen to visibly affect a major undertaking, and delay costs will bring serious financial repercussions to the affected company.

NOTES TO CHAPTER NINE

1. See bibliography for U.S. General Accounting Office, 1951a; Everett Associates, 1981 (funded by American Petroleum Institute) and Independent Petroleum Association of the Mountain States, 1981.
2. Analysis and Recommendations to Improve Federal Application for Permit to Drill Process, Independent Petroleum Association of the Mountain States, p. 34.
3. Analysis and Recommendations, p. 44.
4. Analysis and Recommendations, p. 45.
5. See Note 1.
6. Are Agencies Doing Enough or Too Much for Archeological Preservation? Guidance needed, U.S. General Accounting Office, April 1981.
7. Personal communication between John Eyraud of ERCO and Tom Loomis of the Bureau of Land Management, June 24, 1982.
8. Personal communication between John Eyraud of ERCO and Dan Patton of the Bureau of Land Management, June 24, 1982.
9. RMOGA Recommended Revisions to Requirements in the Application for Permit to Drill Process, Rocky Mountain Oil and Gas Association.
10. Same as Note 8.
11. Same as Note 8.
12. Personal communication between John Eyraud of ERCO and Sheldon Weil of the Bureau of Land Management, June 24, 1982.
13. Personal communication between John Eyraud of ERCO and Mr. Daugherty of the Forest Service, December 4, 1981.
14. Personal communication between John Eyraud of ERCO and Dorothy Vail, of the Bureau of Indian Affairs, Billings Montana, May 20, 1981.
15. Same as Note 8.

16. Same as Note 7.
17. See, for example, "Effects of the Clean Air Act on Industrial Planning and Development, Analysis of Case Studies," Volume II, Case Study Summaries, Environmental Research & Technology, July 1981.
18. The Impacts of Environmental Regulations on Thermal Enhanced Oil Recovery in Kern County, California, Energy Resources Co., April 1980, p. 3-11.
19. Effects of the Clean Air Act, Vol. I-III.
20. Same as Note 17.
21. Personal communication between John Eyraud of ERCO and Clifton Calderwood of the Kern County Air Pollution Control District, Bakersfield, California, December 20, 1982.
22. Personal communication between John Eyraud of ERCO and Don Gallaher of the Getty Oil Co., March 15, 1982.
23. Personal communication between John Eyraud of ERCO and Brett Braden of the Santa Fe Corporation, March 17, 1982.
24. Personal communication between John Eyraud of ERCO and a representative of the EPA, Denver Office, June 24, 1982.
25. Personal communication between John Eyraud of ERCO and Steve Pilcher of the Montana Department of Health and Environmental Sciences, June 12, 1982.
26. The only federal mine permitted in this state was La Ventana mine in New Mexico. The permitting of La Ventana involved an unusually lengthy process because of some controversies regarding land ownership. The eventual regulatory delay was approximately 6 years.
27. Impact of Government Regulations on Coal Mine Start-Up and Production, Policy, Planning, and Evaluation, May 1981, p. 33.
28. Personal communication between John Eyraud of ERCO and Mel Schilling of the Office of Surface Mining, Denver, Colorado, June 29, 1982.
29. Same as Note 17.

30. 30 CFR 762.11 (b)(2).
31. An Assessment of Development and Production Potential of Federal Coal Leases, Offices of Technology Assessment, December 1981, Chapter 10.
32. Personal communication between John Eyraud of ERCO and Chuck Collins of the Wyoming Department of Environmental Quality, July 2, 1982.
33. Personal communication between John Eyraud of ERCO and Mr. Compton of the Office of the State Engineer, Santa Fe, New Mexico, April 13, 1982.
34. Same as Note 33.
35. Same as Note 31.
36. Same as Note 31.
37. See, for example, the statement of Chevron Oil Corp. officials concerning delays in an offshore project, Oil and Gas Journal, May 25, 1981, p. 139.
38. Leased and Lost: A Study of Public and Indian Coal Leasing in the West, J. Cannon, 1974.
39. See, for example, Coal Week, May 10, 1982.

SECTION TEN

CONCLUSIONS AND RECOMMENDATIONS

The permitting systems described thus far involve a complex of agencies and regulations with diverse legislative underpinnings. In this section, conclusions about the status and efficiency of these permitting systems are discussed. Recommendations were also prepared suggesting rearrangements of the permitting processes. The scope of the recommendations takes into account the existing legislative basis of the regulatory processes and some of the issues involved in making adjustments to the permitting systems.

The general conclusions and recommendations to the study are presented first (Section 10.1). Separate sections then follow for each of the distinct resource areas.

10.1 Conclusions and Recommendations for All Resource Areas

A number of conclusions and recommendations can be introduced at a general level and then separately considered in the content of each resource area. The permitting systems all evidence a degree of similarity and many of the problems discussed in this report are of a generic nature, that is, they influence all permitting or regulatory processes and not just those applying to specific types of resources. Thus the general conclusions and recommendations are set forth below.

Conclusions

1. The duration of project leadtimes is due largely to non-regulatory activities, although regulatory activities lengthen the leadtimes till further. Among the energy resource areas covered here, permitting activities lengthen the critical time path for projects by 3 months to 1 year on average, although greater impacts certainly occur. For the "representative" energy projects defined in the network models, the total project leadtimes varied from approximately 8 to 15 years. It may be concluded from the network models that elimination of all permitting and regulatory requirements would not dramatically shorten total project leadtimes.
2. Many agencies have recently taken steps to improve their administrative processes for permit review. Significant revisions are now being developed or have been instituted for (1) applications for Permit to Drill (MMS), (2) rights-of-way approvals (federal surface management agencies), and (3) geothermal energy project plan reviews. The Office of Surface Mining, through proposed rulemaking in June 1982, has also endeavored to give state regulatory agencies greater flexibility in their coal mining regulatory programs. In general, a substantial amount of procedural streamlining, which is internal to agencies or divisions, has occurred in the past two years or is underway at this time (September 1982).
3. Most of the permit approvals applicable to a given project are independent of one another and can be obtained concurrently. The majority of the separate approvals likely to apply are minor permits and do not involve lengthy reviews. Simplification or streamlining of these processes is not likely to affect project leadtimes. This conclusion was reached by consideration of the network diagrams.
4. The principal opportunity for permit streamlining is through the consolidation of major permitting authority in individual agencies. Duplication or overlap of environmental reviews occurs principally because agencies with comprehensive (or nearly comprehensive) review authority (e.g. OSM, MMS) exist along side agencies with specific environmental control responsibilities (e.g., EPA or authorized state agencies). Consolidation of permitting authority would improve the technical efficiency of permit reviews. This issue is discussed further immediately below.

Recommendations

1. Consolidation of permitting authority should be pursued although legal, administrative and political issues will restrict the scope for such changes. This avenue constitutes the primary area where permit streamlining could noticeably reduce project leadtimes and paperwork burdens for developers. Memorandums of Understanding between agencies would be a principal means of managing the necessary cooperation. However, the actual potential for such changes is limited. The constraining factors include the following:
 - (a) Integration of two federal regulatory programs, each of which provides for transference of authorities to states, raises difficult questions of federal and state interaction;
 - (b) Federal agencies are unable to delegate their NEPA responsibilities for federal lands, thus incomplete transference of authority may occur.
 - (c) The present alignment of federal agencies represents a political status quo for competing interests. Changes to agency responsibilities, such as would modify the existing balance, would be difficult to implement. It may prove politically difficult to reach consensus agreement on significant changes in agency responsibilities.
2. Statutory or other strict review guidelines should be more widely used in federal permitting programs. Statutory guidelines are commonly employed in state agencies where they contribute to the expediency of operations. The deadlines also provide developers with greater certainty about the timeframe for regulatory action. At the federal level, selected environmental programs (NPDES and PSD) have review deadlines, but these are the exception. Other agencies (e.g., MMS) make use of internally-imposed deadlines in their programs.
3. More intensive management of inter-agency consultations during permit reviews should be made in order to reduce total review times. A frequent element of lengthy permit reviews is difficulty in obtaining responses or consultation from other agencies. This recommendation is related to number 2 above which provides for strict statutory or other guidelines for reviews. In this case, the imposition of deadlines after which agency approval is assumed could be utilized.

10.2 Conclusions and Recommendations for Oil and Gas Permitting Studies

The permitting processes applicable to oil and gas developments on federal lands were examined through delineation of federal and state permits and through utilization of network analysis techniques. In this section, conclusions about the permit systems are presented. Recommendations about possible improvements in the permit systems are also given, immediately following the conclusions.

Conclusions

1. Regulatory activities have a modest impact on the total lead time for oil and gas projects. The permits most likely to be on the critical path are the Application for Permit to Drill (MMS) and rights-of-way requests (federal surface management agencies). These permits, which are usually obtained simultaneously, require an average of three months each for processing. The APD permit, however, is needed for each well drilled on federal lands in a project, and difficulties vis a vis rig scheduling, can arise.
2. Environmental and other permits (e.g., water appropriation) do not delay most projects, but are important in selected cases or in certain areas. Many projects have limited requirements for air emission, water discharge (beyond the reinjection or discharge controls of oil and gas regulatory commissions) or water appropriation permits. Examples of projects where these approvals become prominent are (1) tertiary oil recovery projects in Southern California (air permits); (2) sour gas processing facilities in various locales (air permits); (3) conventional oil and gas projects in areas where water purchases or other alternatives to water appropriation are not available. Numerous additional examples of projects with important environmental permitting requirements could be cited.
3. Given the mobility of production operations and the geographic spread of oil and gas resources, many firms appear to avoid federal lands. Many of the firms contacted expressed annoyance with the additional permit requirements (most notably the data requirements of the APD and rights-of-way permits) of operations on

federal lands. State drilling permit processes are notably more simple and expeditious than the federal APD in all western states.

4. Although permitting requirements are less extensive for oil and gas than for other resource areas, permit scheduling problems frequently occur. Project activities and permitting are performed within a brief timeframe as imposed by the demands of scheduling for drilling rigs. Drilling contractor services are expensive and tightly scheduled. If a developer has not obtained the requisite drilling or other permits, an immediate financial burden is imposed. Some of the firms contacted indicated that permitting responsibilities may not be fully observed in all cases by all firms.
5. Numerous minor permits and modifications are required of oil and gas developers by state regulatory agencies, but these permits present few difficulties. The routine permitting requirements imposed by state oil and gas commissions (or similar regulatory agencies) are uniformly straightforward and expeditious. Overall, permit requirements vary little in substance among states.

Recommendations

1. The current effort by the MMS to reform the APD process should be carried out. The APD process, with the length delays observed in recent years, has had a very notable and negative effect on the expediency of permitting on federal leases. A substantive reform proposal has been prepared by the Rocky Mountain Oil and Gas Association (RMOGA) to streamline the review process. These RMOGA suggestions, which provide for a more efficient interaction between the developer and government personnel, are being actively considered by the MMS.
2. Continued review of the rights-of-way permitting process by the federal agencies involved should be encouraged. Problems and delays in rights-of-way processing had been noted by BLM and other federal agencies with surface management responsibilities. In response, changes in handling procedures were made and the efficacy of the changes is now being monitored. The modifications provide for a briefer environmental review and for uniformity in review procedures across agencies.

10.3 Conclusions and Recommendations for Coal Mining Permit Systems

The permit and network analysis performed for coal mine regulatory processes was presented in Section Seven. The federal and state permits were delineated and displayed in network diagrams. The networks depict the relationships among non-regulatory and regulatory activities for coal mine developments.

In this section, conclusions and recommendations about the permit systems are presented. The conclusions are listed first.

Conclusions

1. Regulatory activities require an estimated 30 months of the total 10-year lead time on coal mining projects. Removal of all regulations would, however, shorten the project lead time by 12 months. The result is due to the considerable overlap of regulatory activities with non-regulatory activities. The 30-month requirement for obtaining government approvals includes (1) 12 months for environmental studies, (2) a 3-month period for final preparation of the mine plan, and (3) 15 months for the Apparent Completeness Review and Technical Review of the mine plan. Other important regulatory activities, including review for other federal permits and preparation of the EIS, would be concurrent with these critical-path activities.
2. The review of the mine plan by the Office of Surface Mining (OSM) or by the state regulatory authority has proven to be a lengthy process, but many significant modifications are still being made to improve the clarity and control of the regulatory system. For some large surface mines, several years have been required for approval. Long processing time is still expected in many states (e.g., Utah, Wyoming) because of the backlog of mine plans for review. However, the SMCRA program is still transitional in terms of (1) the

continuing definition of the mining regulations, and (2) the transfer of authority from the federal government to state governments. With regard to the first point, the areas of greatest confusion involve hydrologic data requirements, fish and wildlife impact studies, and archaeological study requirements.

3. The role of state regulatory agencies in the mine plan reviews, including those for federal lands, has been expanding. Cooperative Agreements have been signed or will soon be signed by OSM with the regulatory agencies of the western coal mining states. The agreements allow the state agency to participate in the mine plan review for federal lands. Further proposed changes to the Federal Lands Program will allow state agencies to issue permits and provide all but the final environmental review of the mine plans. The latter responsibility must be retained by OSM under its NEPA responsibilities.
4. The expediency of key permit reviews for coal mine projects is frequently affected by the urgency of the mining company's application. Regulatory agencies can expedite the approval process in order to help a company meet its commitments. This factor has frequently been noted in the case of mine plan reviews. Companies which are seeking to begin operations soon can urge OSM (or state agencies) to move quickly. In contrast, many companies do not wish to proceed with the permit process when they have not successfully contracted their future coal production. This is currently occurring (Summer 1982) due to slack market demand. Such companies will be slow to respond to requests for more information (to support the mine plan review) made by OSM or the state regulatory agency.
5. Permitting delays for coal mining projects are particularly costly if they occur during the "development" stage of operations when the large capital and operating costs are being incurred. The cost analysis for coal mining clearly shows that delays are much more costly at the later stages immediately prior to actual mining. The capital charges accrued by all previous project spending are quite substantial at that point. At early project stages, large outlays have not yet been made for engineering, facility design, and capital equipment.

6. Difficulties and confusion with permit processes are likely to continue until the burden of paperwork upon coal mine operators is reduced. In addition to the obvious burdens placed upon coal mine companies, unfortunate side effects occur which imperil smooth functioning. In particular, mine company officials become unable to distinguish important data submissions from relatively unimportant data submissions. Company efforts tend, therefore, to be directed indiscriminately toward the completion of application requirements rather than toward seeking of genuine solutions to environmental issues. The requests for additional information made by regulatory agencies tend to encourage this attitude by appearing random, contradictory or excessive. In this vein, some company officials find it difficult to take permitting processes seriously.
7. Many permit programs appear to run smoothly, and have generated relatively little animosity from developers. Few complaints were received regarding MSHA permits, NPDES or other state water discharge permits, or sedimentation pond construction permits (state permits only). Future difficulties are anticipated by many companies concerning air emission and water appropriation permits, although even in these complex regulatory areas, few problems have been encountered in the past.

Recommendations

1. Completion of a Memorandum of Understanding (MOU) between OSM and EPA for NPDES permit reviews would expedite this permit process. The mine plan provides for an extensive review of the mine site hydrology, planned discharges, sedimentation pond construction plans, and other factors relevant to the NPDES permit. The NPDES permits could be handled within the context of this review, thus providing for a simplification of regulatory matters facing coal mine companies. It should be noted, however, that the completion of the MOU will involve resolution of significant legal and administrative issues concerning the transference of authority among a complex of federal and state agencies.
2. Additional expenditures by state and federal agencies to hire qualified personnel would improve mine plan review processes. The complex mine plan review requires experienced technical personnel. However, such personnel are frequently hired away from government agencies by mining companies in the area. The shortage of qualified personnel and rapid personnel turnover contributes to the delays in mine plan handling.

3. As is frequently encouraged by regulatory agencies, coal mine companies should make contact with government personnel early in their project planning cycle. The incentives for early communication of project plans include (1) the greater likelihood that the environmental studies will meet the requirements of the regulatory agencies, (2) the early identification of serious environmental problems for an intended site, such as would restrict or veto the mining operation, and (3) a related point, that unexpected issues will not arise late in the project, creating expensive delays. Many regulatory agencies encourage or require early meetings with mine developers at this time.

10.4 Summary of Geothermal and Oil Shale Permitting System

Taking a broad overview, the arrangement of regulatory responsibilities is similar for geothermal and oil shale resources on federal lands. In each case, the Minerals Management Service has a virtually comprehensive responsibility for the control of energy development and for the provision of environmental protection during such development. In addition, the full range of specific environmental permits applies to geothermal or oil shale projects.

In this section, conclusions and recommendations concerning permitting systems for geothermal and oil shale resources are discussed. Geothermal permitting systems are considered first.

10.4.1 Geothermal Permitting Systems

Conclusions

1. Modifications to the MMS Operating Procedures Have Improved Processing. The multiple MMS reviews were previously thought to require an excessive amount of data on environmental impacts. For reviews occurring early in a project, the environmental data were required before the developers could accurately assess the probable scope of their operations. However, the recent guidance provided to field offices provides for "phased environmental reviews," which efficiently limits the scope of early project reviews. This adjustment improves and rationalizes the review processes.
2. With the streamlining of federal procedures, geothermal developments on federal lands are not significantly more complicated than those on nonfederal lands from a regulatory point of view. Most of the developers contacted for this study were aware of the modifications in the MMS procedures and noted improvements in processing time. The other federal surface management agencies which cooperate with the MMS reviews have also expedited their procedures. Several developers commented that permit processes on nonfederal lands are now more complex and confusing. California, with the CEQA, has extensive environmental approval requirements, for example.
3. With the exception of California, western states have had little experience in permitting for geothermal developments, leading to a potential for delays in analysis, for jurisdictional disputes, or other problems. Also, the developers contacted commented on the lack of coordination in many states in permitting for energy projects. These factors may combine to leave government officials unsure of the appropriate type or level of review needed for alternative energy projects. In comparison, California has a well-charted process for regulatory review of energy projects.

4. The development of geothermal resources is subject to water appropriation processes in some states, leading to possible permitting delays. Utah, for example, requires an original water appropriation request to be filed for geothermal wells. In that case, a six-month review process is normally required. Water appropriation permits can often be lengthy processes due to the water scarcity in arid western regions. The potential for long delays for geothermal developers is limited, however, by the fact that the deep water resources are not likely to be exploited by other water users, and few disputes from competing users are likely to arise.
5. Recent activities in the geothermal area have focused on improving the processing time for lease requests by reducing the large backlogs at federal agencies. The Forest Service, in particular, has been tardy in its response to lease requests. Additional efforts have been made to educate the relevant federal personnel in the technology and environmental impacts of geothermal operations.

10.4.2 Oil Shale Permitting Systems

Conclusions

1. Permitting activities occupy an estimated three and one-half years of the critical path for oil shale projects, but elimination of all regulations would only reduce project lead times by one year. During many of the regulatory activities (such as performance of environmental studies) necessary engineering and design work is likely to be taking place. The exact scheduling and organization of regulatory and non-regulatory activities will vary by organization and circumstance, but considerable overlap of permitting and engineering work appears likely. (This conclusion assumes, however, that exceptional regulatory problems are not encountered.)
2. The procedures for review of Detailed Development Plans by the MMS have been set forth to encourage reviews within six months. By setting forth a timeline for reviews of the DDPs, the Minerals Management Services employs an approach similar to the use of statutory guidelines for major permit reviews. Because the DDPs are comprehensive project documents, requiring a full environmental review, a six-month timeline appears reasonable for agency performance.
3. Oil shale projects are of interest and concern to numerous regulatory and non-regulatory groups. The projects involve a greater variety of complex environmental issues than do the other resource areas. This fact, combined with the developmental stage of the technology, produces a confluence of public pressures and concern which affects and can complicate permit processes. In such situations, coordination of permit processes can be helpful by improving communication among regulatory agencies and with public interest groups.
4. Substantial uncertainties remain concerning the regulation and thus the permitting of oil shale projects. Among the potential issues are: (1) air emission limitations, restricting the industry as a whole, (2) groundwater pollution impacts due to in-situ operations, (3) disposal standards for spent shale under RCRA regulations, and (4) regulation of operations under the TSCA legislation. These uncertainties, although generally due to the substance of environmental regulation and not to the permitting process itself, add to the difficulty and risk of development perceived by oil shale companies.

5. The involvement of the regulatory agency (the MMS) in design of environmental study programs should reduce the potential for submission of inadequate environmental data. Currently, the MMS requires approval of the Baseline Data Collection Plan, thus initiating an involvement in the environmental studies attendant on the project. Communication may be maintained during the performance of environmental studies leading up to submission of the Detailed Development Plan. This arrangement is also informally used in environmental studies for coal mine projects, although patterns and levels of cooperation between the developer and the regulatory agency are more varied.

Recommendations

1. Overall coordination of permitting requirements is valuable for oil shale projects. Oil shale operations are large, highly visible, industrial operations which require the approval of numerous regulatory agencies. The project size, extent of land disturbance, and relative novelty of oil shale projects insure that permitting issues will not be routinely handled in the near future. As a result, permitting coordination through systems such as the Colorado Joint Review Process is appropriate. Such a system would allow for channeling of project data to regulatory agencies and for notifying developers of their permitting responsibilities. Since the Joint Review Process already exists in Colorado, the primary oil shale state, a useful mechanism is already in place for most developers.

This type of process is based on the assumption that developers will be willing and able to work openly with the regulatory authorities. Among the resources studied, oil shale firms appear most likely to accept such a public and visible regulatory process. The extremely long planning and construction lead time for a commercial oil shale facility presents, in any event, a long period of exposure to public scrutiny.

2. Although many factors must be considered, centralization of regulatory authority with the MMS would further streamline permitting activities. Under existing arrangements, the MMS is responsible for review of the Detailed Development Plans, which cover environmental impacts on all media. Permit reviews for water discharges, air emissions, spent shale disposal, and perhaps other outfalls, could be handled in conjunction with the DDP review. Transference of authority to MMS from the one federal (EPA) and numerous state agencies (state agencies with delegations for the NPDES or PSD programs and so on) would, however, be an extremely complex undertaking. The topic of permit consolidation is discussed in the earlier section of general recommendations.
3. An effort should be made to clarify the regulatory issues facing oil shale developers. As mentioned above, several issues have yet to be resolved concerning regulation of oil shale projects. The major issues all involve pending rulemaking by divisions of the EPA and thus an effort within that agency would largely be sufficient for the questions to be covered. The effort should entail actual rulemaking to establish regulations, or preparation of a guidebook for permit writers in oil shale areas.

APPENDIX A

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APPENDIX B

SYNOPSIS OF SELECTED STUDIES

TABLE B-1

LISTING OF THE SELECTED STUDIES REVIEWED IN THIS APPENDIX

1. Actions Needed to Increase Federal Onshore Oil and Gas Exploration and Development, General Accounting Office, 1981.
2. Analysis of Delays in the Processing of Applications for Permits to Drill and Pre-Staking Clearance Applications, Everett Associates for American Petroleum Institute and Rocky Mountain Oil and Gas Association.
3. An Assessment of Development and Production Potential of Federal Coal Leases, Congress of the United States, Office of Technology Assessment, 1981.
4. Cooperation and Conflict: Regulating Coal Production, United States Regulatory Council, 1981.
5. Coordinated Regulatory Management Process and Information System. Southern States Energy Board, 1981.
6. Environmental, Legal, and Political Constraints on Power Plant Siting in the Southwestern United States, Michael S. Hamilton and Norman Wengert, Colorado State University Experiment Station, March 1980.
7. Geothermal Development on Federal Lands - The Impediments and Solutions, Wapora Inc., for the Department of Energy, 1978.
8. Geothermal Streamlining Recommendations - Streamlining the Federal Leasing and Environmental Review Procedures, Streamlining Task Force, 1979.
9. Impact of Government Regulations on Leadtimes of Coal Facilities, Policy Planning and Evaluation for the Department of Energy, 1980.
10. Issues Facing the Future of Federal Coal Leasing, General Accounting Office, 1979.
11. Issues Surrounding the Surface Mining Control and Reclamation Act, General Accounting Office, 1979.
12. Low-Rank Coal Study - National Needs for Resource Development, Energy Resource Co. Inc. for the Department of Energy, 1980.

TABLE B-1 (CONT.)

13. Major Legislative and Regulatory Impediments to Conventional and Synthetic Fuel Energy Development, American Petroleum Institute, 1980.
14. McGraw-Hill's Quick and Easy Guide - Coal Mine Permitting, J. Russell Boulding, 1980.
15. Permitting and Siting of Energy Products: Causes of Delays, State Solutions, Doug Linkhart, Western Governor's Policy Office, 1981.
16. Public Lands Politics, Interest Group Influence on the Forest Service and the Bureau of Land Management, Paul J. Culhane.
17. Simplifying the Federal Coal Management Program, General Accounting Office, 1981.
18. Staff Report to the Federal Trade Commission on Energy Land Policy, Federal Trade Commission, 1975.
19. Synthetic Fuel Project Generic Environmental Licensing Analysis, Environmental Applications Inc., 1980.
20. Where We Agree: Report of the National Coal Policy Project, Francis X. Murray, ed., 1978.

Actions Needed to Increase Federal Onshore Oil and Gas
Exploration and Development, General Accounting Office,
February 11, 1981.

The GAO was asked to examine methods for expediting the exploration and development of oil and gas from federal lands. Such activities are hampered by (1) the unavailability for leasing of prospectively valuable federal oil and gas lands; (2) the imposition of restrictions on leased lands, and (3) lengthy delays in the approval of leases and drilling permits. To examine these problems, GAO researchers surveyed federal agency personnel and agency files in five states, and also studied the recent history of BLM leasing decisions.

The GAO concluded that large land areas are being withdrawn from exploration without systematic investigation of their energy or mineral potential. In some cases, lands of known energy potential are being withdrawn, generally as the result of formal actions authorized by law or regulation. However, some tracts are withdrawn through BLM "no leasing" judgments based only on management fiat. Exploration has also been restricted or deferred in potential wilderness areas, despite Congressional approval for exploration until December 31, 1983. Still further withdrawals have occurred through land appropriation by the Department of Defense, which disputes that it is subject to the land management policies authorized in the Federal Land Policy and Management Act. Finally, exploration has been slowed by restrictive stipulations placed on leases. At least 1 million acres of leasable lands are subject to "no surface occupancy" restrictions, including 345,000 acres in the Wyoming Overthrust Belt.

Another obstacle to rapid development has been delays in the approval of federal leases and federal drilling

permits. The BLM itself was responsible for most of the lease approval delays due to inaction, lack of agency follow-up reviews, and mailing errors. GAO noted that BLM had not established deadlines or cooperative agreements with other agencies in order to facilitate processing. Environmental analyses or deferrals of leasing in study areas were also noted as major causes of delays. GAO collected quantitative data on the length and frequency of these delays.

In the case of Applications to Drill submitted to MMS, GAO noted that the common delays were in: (1) obtaining information from applicants, (2) securing archaeological clearances, and (3) receiving recommendations on protection of surface resources from other federal agencies. GAO recommended that processing timeframes and deadlines be established and that applicant and operator responsibilities be clarified.

GAO made several recommendations to the Secretary of the Interior to resolve land management errors. The most notable recommendations are listed below:.

1. Establish criteria on which "no-leasing decisions" must be based. Records on such decisions should also be kept in order to permit periodic Congressional oversight.
2. Require BLM to inventory lands which have been closed by management decision to oil and gas leasing.
3. Direct the MMS to review the oil and gas potential of Fish and Wildlife refuges in the lower 48 states, and then to seek regulatory changes to make these lands available for leasing in a manner compatible with their fish and wildlife resources.

Several other recommendations, dealing more directly with the conduct of permitting programs, were also developed for the Secretary of the Interior as follows:

1. Direct BLM to modify its guidelines implementing NEPA to defer the requirement for environmental study for oil and gas activities until surface disturbance is proposed.
2. Direct BLM to establish standard timeframes for completion of lease processing, and to keep record of processing delays.
3. Direct BLM to seek cooperative agreements with surface management agencies to develop cooperative agreements and goals for lease processing.
4. Direct BLM to develop a standard follow-up system for tracking outstanding lease applications.
5. Direct MMS to state in its guidelines (Notice to lessees No. 6) what the operator is required to submit to meet the Survey's legal and administrative requirements.
6. Direct MMS to provide a completeness review of Applications to Drill within 7 days of submittal.
7. Direct the MMS to develop standard procedures for tracking and recording actions taken on Applications for Permits to Drill.
8. Direct the MMS to coordinate with operators so that an archaeologist is available during joint-site inspections.

Analysis of Delays in the Processing of Applications for Permits to Drill and Pre-Staking Clearance Applications,
Everett Associates for American Petroleum Institute and Rocky Mountain Oil and Gas Association.

The Everett Associates study was designed to measure the length of time needed to obtain APD and PSC approvals from the USGS by oil and gas operators. Reasons for the delays

in receiving approvals were then analyzed in order to derive recommendations for improving procedures. The study was based on an examination of MMS monthly reports over a 32-month period.

The authors measured the mean and median approval times for the APD's and PSC's, and noted that approval times grew significantly during the study period. Delay data indicated the following difficulties in order of their frequency:

(1) slow BLM reviews of applications, (2) failure of applicant to designate operator or agent, (3) delays in archaeological clearances, (4) delays in completing environmental analysis, (5) failure to obtain surface owner agreements, (6) heavy office workloads, (7) bonding delays, (8) other incomplete items in the APD, (9) delays in reviews by surface management agency, (10) slow preparation of stipulations by surface management agency, and (11) delays in onsite inspections. One obvious value of the Everett study is original data collection effort on which delay data could be based.

The authors used their research results to make numerous recommendations for expediting the permit process. The recommendations are summarized below:

1. Designation of Agent or Operator - Assign all responsibility and liability for leasehold operations to the party filing the APD, rather than to the leaseholder. The burden of leaseholder-operator relationships would be transferred from the federal government to the parties themselves.
2. Archaeological Clearances - Despite the bottlenecks involved in obtaining archaeological clearances and the infrequency of significant findings, government agencies have not taken any steps to evaluate the merits of archaeological reviews. Such an evaluation is justified to insure that the costs of the archaeological requirements are commensurate with the benefits.

3. Environmental Assessment - Problems of obtaining needed environmental assessments were reduced due to changes in MMS guidelines requiring assessments only for the first confirmation of drilling in an oil or gas field. The authors worried, however, that this gain may be eliminated due to further revisions in MMS guidelines, and urged that the problem be closely monitored.
4. Bonding - Bonding of only the operator rather than the lessee would simplify this requirement. The industry and the federal agencies should discuss this or other types of streamlining procedures which would better reflect the actual risks incurred by the government.
5. Incomplete APD's - Increased use of industry workshops or training programs along with more vigilant communication of changing requirements by MMS would help in this area.

Several other minor recommendations were also made concerning onsite inspection delays and other practical details.

An Assessment of Development and Production Potential of Federal Coal Leases, Congress of the United States, Office of Technology Assessment, 1981.

The OTA study involved a major Congressional effort to assess the amount of coal which can be developed from existing federal coal leases. As such, the study focus is notably different from that of the other studies performed. The principal question asked is "How much coal could possibly be produced from federal leases by 1986 and 1991?" The issue is handled less as a forecast of production than as a technical estimate of possible production given the following basic factors: (1) the coal reserves on the leases, (2) the extent of permitting and development, (3) market demand levels expected, (4) probable environmental constraints, and

(5) transportation constraints. The study summary is largely potential production-level estimates for the important Western coal-producing states (which have 99 percent of federal production). The source material for the report is a detailed survey of existing federal lease areas and their production levels.

The OTA study does not evaluate the issues of cost or lengthened development process caused by regulations nor does it evaluate the extent to which recoverable federal reserves will be affected by environmental concerns under the renewed federal coal leasing program. Thus the report provides good background material but little data directly relevant to permitting activity. However, data are presented on the amount of leased federal coal that has been or may be prohibited from development by regulations. The data is derived on a case-by-case basis. The OTA study also provides an excellent summary of the main environmental issues and the regulatory implications involved for coal mining.

Cooperation and Conflict: Regulating Coal Production,
United States Regulatory Council, 1981.

The Regulatory Council Coal Project was initiated in response to industry charges that regulatory overlaps and inconsistencies can adversely affect coal production in the United States. To examine this issue, the Council asked mine operators to identify regulatory problems arising from duplicative requirements. Complaints were also received about the operation of individual agencies. In all, 60 complaints were received and considered by the Council. A "Problem Analysis" of the complaints was prepared in which the complaints were grouped by topic and examined for

validity. In addition, the Appendix of the report provides a summary and analysis of each individual complaint, with a "Resolution" of each item presented.

A total of eight conclusions were reached by the Regulatory Council. The conclusions are listed below:

1. Problems from overlapping and inconsistent regulations occur more frequently between federal and state agencies than between federal agencies.
2. A significant portion of the overlap and inconsistency in the regulatory process arises in the enforcement of the regulations.
3. Coal operators have been affected by disagreements between OSM and state agencies on how to implement the new surface reclamation regulatory program.
4. Overlapping reporting requirements and redundant permitting requirements are a significant problem to the coal operator.
5. Coal operators face regulatory problems because they are unaware of the substance of agency requirements.
6. Strict statutory time limitations placed by Congress on the development of the surface reclamation program have raised uncertainty concerning how the Surface Mining Control and Reclamation Act will be implemented and enforced.
7. The use of "performance standards" rather than "design standards" can provide needed flexibility in complying with regulations.
8. The Council's efforts to resolve problems of regulatory overlap and duplication have shown that regulatory agencies at both the federal and state level share an interest in resolving problems of interagency overlap and duplication.

Coordinated Regulatory Management Process and Information System, Southern States Energy Board, June 1981.

This report by the Southern States Energy Board (SSEB) was prepared in response to perceived weaknesses in regulatory programs. In particular, the Southern States Energy Board endeavored to develop a system to provide for coordination and planning of the diverse permitting activities which control energy developments. This study presents the system concept and a demonstration information system. This management system was designed to provide four functions: (1) to monitor and evaluate the regulatory process, (2) to inventory proposed energy facilities and project future capacity, (3) to determine future agency workloads, and (4) to pinpoint procedural problems and to improve the review process. A major foundation of the study was the perceived lack of coordination among local, state and federal officials in permitting activities.

The main outputs of the SSEB report are the samples of a Coordinated Regulatory Management Process and a Regulatory Management Information System. The former outlines steps which can be taken to insure coordination of the various regulatory authorities. Central to this plan is the formation of a "project team" consisting of representatives of the developer and various regulatory agencies. The team then prepares its own workplan for coordination and expedition of the permit review processes. The use of network charts are recommended to aid in tracking the progress of individual projects.

The Regulatory Management Information System can be developed independently of the management process if automated information handling is desired. The RMIS includes

several modules designed to store and organize data around distinct interests such as project information, permit requirements, schedules and so on. The schedule module would include a PERT/CPM capability which may exist separately of the other modules.

The SSEB study is noteworthy because it represents an exploration of several of the issues being considered by ERCO. The management process described represents a "soft" and generic approach to permit expediting.

Like other similar ideas, the SEEB approach may be dependent upon the developer's willingness to publically describe his project at an early stage, and to fully interact with regulatory agencies. The automatic management system may be useful to agencies handling large numbers of permits and projects. However, the system's capability for analysis of permit processes per se is limited to the PERT/CPM network which may be included. The other modules are of general information storage and retrieval types.

Environmental, Legal, and Political Constraints on Power Plant Siting in the Southwestern United States, Michael S. Hamilton and Norman Wengert, Colorado State University Experiment Station, March 1980.

This study, by political scientists at Colorado State University, resulted from a major study of siting for power plants. The report includes several sections, each of which represents a distinct line and method of inquiry. First, a political analysis of selected siting issues is performed.

Second, the mechanics of the site selection process are examined through collecting data on permit requirements and reasons for delay. The role of local controls, including zoning and local environmental regulations, is considered. Finally, a number of case histories are provided.

The second major section, covering permitting and project delays, is of greatest interest here. The study's authors collected data on the number of permits required for 24 power plants around the Southwest. The number of permits required varied widely even within states due to the specific characteristics in different locales. (Unfortunately, the title of the permits required is not shown.) Because the study is focused on power plant siting and special consideration is not given to federal lands, the permit data are not directly applicable.

The data on regulatory delays are interesting, but again, caution is needed in interpreting the results. The authors collected data on all power plant delays over a 10-year period, from secondary sources. The data indicate that regulatory delays run a poor third to vendor-related delays (late equipment deliveries, faulty installations, initial operating difficulties) and labor-related delays (strikes, low productivity). Regulatory delays caused 51 of 419 instances noted. The cautionary point is that power plant construction is a more complex process than simply initiation of energy exploration. Business-related delays (e.g., financial problems, labor difficulties) are much more common. The relatively minor role of regulatory delays is therefore not necessarily applicable to energy exploration.

Geothermal Development on Federal Lands - The Impediments and Solutions, Wapora, Inc. for the Department of Energy, January 1978.

The Wapora, Inc. study was commissioned by the Department of Energy in order to examine the slow progress of the geothermal process. The study authors reviewed the leasing and regulatory process for geothermal lands, and performed original data collection on the delays in leasing approvals. The study results are of interest because it is one of the few reports which focuses on regulatory delays in energy exploration and basic development activities.

Wapora, Inc. concluded that there were a number of problem areas in which federal procedures should be improved. Recommendations were developed for improving the environmental review process and for sundry other processing points. The environmental review steps were found to be especially repetitious and obstructive. In particular, it was suggested that developers be allowed to perform controlled drilling and exploration to "identify" the resource (determine its local characteristics and potential) without triggering a full environmental review. If the exploration is fruitful, then a plan of development and production would be prepared, and this document would then serve as the basis for a single comprehensive environmental review. Several other minor recommendations in procedural affairs were also made.

Geothermal Streamlining Recommendations - Streamlining the Federal Leasing and Environmental Review Procedures, Streamlining Task Force, January 1979.

The Geothermal Task Force was organized from government agencies concerned with leasing and permitting relevant to

geothermal development. Thus, the study group included representatives of BLM, USGS, DOE, and the Forest Service.

The Task Force developed 19 recommendations for improving leasing, permitting and environmental review procedures. Many of the recommendations covered general management issues such as the institution of geothermal training programs for field managers and the preparation of permitting manuals and handbooks, and are not restated here. The more relevant recommendations for this study are listed below:

1. Require DOI (or DOA) to respond within 30 days for noncompetitive lease applications.
2. Require DOI to respond within 30 days for postlease permit applications.
3. Provide leases based upon separate environmental assessment of exploration and development phases so as to reduce the assessment burden on pre-lease activities.
4. Use generalized, areawide environmental assessments in prelease reviews and detailed site-specific studies only for postlease actions.

Impact of Government Regulations on Leadtimes of Coal Facilities, Policy Planning and Evaluation for the Department of Energy, August 1980.

The Impact of Government Regulations study, performed for the Department of Energy, was designed to measure the average project delays caused by environmental and other regulatory processes. For this study, the major permits required for coal facility operations were analyzed within the larger structure of overall project planning.

The authors considered 10 types of coal-related projects, e.g., coal mining on federal lands or construction of a railroad extension to a coal mine, and defined representative project plans for each. For the coal mine example, normal project phases were defined including lease acquisition, drilling studies, equipment procurement, facility construction, erection of equipment and mine development. Within the context of these project phases, activities were described for performing environmental studies and obtaining permits from regulatory authorities. Next, PERT networks were prepared in order to show the probable elapsed time through each stage of the project planning efforts. The PERT diagrams illustrated the critical path for each project and also measured the time delays attributable solely to government regulations.

Government regulations were judged to account for 11 of 90 months in the planning horizon for coal mining projects on federal lands. This relatively small effect was attributable to the normally long leadtimes for many basic project phases, such as design, exploratory drilling and project decision making.

As important as the time delay is the increase in uncertainty due to permitting. Obtaining approval for the complex mine plans required by the Office of Surface Mining can add greatly to uncertainty about project scheduling and about the eventual project feasibility. In particular, equipment orders, which would be made well in advance of mining, may be held up until the major regulatory questions are involved.

The Impact of Government Regulations is an interesting and original contribution to the permitting literature. The

goal of the study was purely one of measurement, and no analysis of the permitting process itself was attempted. This methodological approach is admirable, but may nevertheless obscure some issues or elements of regulatory delay. For example, the strictness of the PERT network system used, by not allowing greater scope for project uncertainties and by not incorporating probabilistic outcomes at each decision point along a critical path, may oversimplify the impact of permitting requirements.

Issues Facing the Future of Federal Coal Leasing, General Accounting Office, June 25, 1979.

The GAO report is organized around topical issues which are important to the federal coal leasing program. The issues covered are more basic than the conduct of permitting programs and refer more to basic land management issues and divisions of responsibility. Among the topics covered are: (1) how the multiple and often conflicting goals of federal land management authorities should be balanced, (2) how the Departments of Energy and Interior might work together effectively, and (3) various lease management issues.

Most of the study conclusions are of a general nature, such as suggestions for further study of federal coal production potential. The study authors urged the Department of Energy to actively pursue its mandated objectives of fostering competition and implementing appropriate lease bidding system. Beyond these items, however, the authors endeavored only to clearly present the issues.

One of the areas recommended for further study is that of streamlining permit procedures. Very general concerns about permitting delays were indicated.

Issues Surrounding the Surface Mining Control and Reclamation Act, General Accounting Office, September 21, 1979.

This GAO report reviews several developmental problems for the Office of Surface Mining. The permanent regulatory program of OSM had been delayed in its development, causing confusion and delays for states preparing to take over the program. The report also describes some initial operating problems with the program including (1) differences in federal and state enforcement philosophies, and (2) potential areas of regulatory overlap. On the latter point, little substantive detail was presented. The report serves this project mainly for its background information on the organization of the Office of Surface Mining.

Low-Rank Coal Study - National Needs for Resource Development, Energy Resource Co. Inc. for the Department of Energy, November 1980.

The Low-Rank Coal Study is designed to be a comprehensive analysis of the potential ~~for~~ and problems of developing U.S. reserves of lignite, subbituminous and peat resources. The report covers (1) a characterization of the resource, (2) an evaluation of all the technology needed to extract, process, transport and utilize the resource, (3) an analysis of regulatory impact on development, (4) a market analysis, and (5) a review of necessary R&D work.

It is topic 3, an analysis of regulatory impacts on development, which is of interest for this project. The Low-Rank study includes a review of all the permits required for a specific California power plant project. Listings are also provided of the regulations governing various aspects of development for each Western state. For example, there

are presentations of the different air pollution standards, and of the different mining control laws in each state. Like several other studies, there is also a review of all the federal legislation which impacts energy development. The information parallels some of the topics covered in this study. However, the Low-Rank study only explicates some aspects of the permit process without analyzing it per se. No recommendations for changes in permit procedures were stated.

Major Legislative and Regulatory Impediments to Conventional and Synthetic Fuel Energy Development, American Petroleum Institute, March 1, 1980.

The API study summarizes many industry complaints about delays in project development caused by government regulation. The study has two main sections consisting of (1) a review of the major federal legislation which impacts energy projects, and (2) detailed case studies of the delays which troubled four major energy projects, including the Sohio pipeline project. A third and smaller section of the study presents the results of two surveys of project delays. The first survey, performed by API, focuses on delays caused by the Clean Air Act. The second was performed by the Mid-Continent Oil and Gas Association and covers Army Corps of Engineer permit delays, principally involving dredge and fill permits (Section 404 permits, authorized by the Federal Water Pollution Control Act).

The API study provides some interesting case study data on the major energy projects, and also original survey data. Beyond these contributions, no information of direct relevance to permitting processes was uncovered.

McGraw-Hill's Quick and Easy Guide - Coal Mine Permitting,
J. Russell Boulding, 1980.

The McGraw-Hill guidebook is designed to aid coal industry personnel in preparing permit applications for compliance with the Surface Mining Control and Reclamation Act program. The book explains the statutory sources of regulatory requirements and presents a strategy for gathering and organizing the necessary information.

The guidebook's usefulness to this project is provided by its explication of the information requirements for the SMCRA permit application. Also, an appendix provides a clear description of the role of federal agencies in coal-mining regulation. No procedural recommendations or estimates of permitting costs are attempted.

Permitting and Siting of Energy Products: Causes of Delays,
State Solutions, Doug Linkhart, Western Governor's Policy
Office, June 1981.

The Western Governors' Policy Office (WESTPO) study presents state perspectives on the problem of expediting regulatory approvals of energy projects. A brief review of some recent project histories is provided, and conclusions are noted about the principal causes of delay. A description is also included on the formal and informal measures implemented by Western states to improve the permit processes.

As an original study of the regulatory process, the WESTPO study is of no consequence. The report is quite short and represents more of a policy statement/political viewpoint than a research study. The report has been summarized here only because of its statements on problems

in the regulatory process. The study conclusions are noted below:

1. Environmental regulations are not the major cause of energy project delays.
2. In those cases where environmental regulations have delayed projects, the actions of state agencies were not a major cause of the problem.
3. States are the most appropriate focal points for coordination of reviews and approvals of energy projects.
4. Informal efforts by states to prevent delays (e.g., pre-application meetings, improvement of employee attitudes) have been more numerous and effective than formal methods (e.g., Alaska Master Permit Application).
5. States need the flexibility to design their own approach to project expediting and coordination.

Public Lands Politics, Interest Group Influence on the Forest Service and the Bureau of Land Management, Paul J. Culhane.

Public Land Politics provides an intensive examination of the land management policies of the U.S. government as carried out by the Forest Service and the Bureau of Land Management. The book presents a study of public administration policies as carried out by the Forest Service and BLM in a situation of diverse interest group pressures. Mr. Culhane examines the theory that regulatory agencies are invariably "captured" and used by the private interests they are supposed to regulate. He concludes that the "capture" thesis is seriously misleading, and that both these agencies are able to represent the public interest in the management of federal lands. The professionalism of the personnel, combined with the "multiple-use" mandates of their authorities, allows each agency to make sound long-term judgments for land use policies.

The book offers a much more interpretative narrative on the legislative history of federal land policy than is provided by other studies. Thus, it provides excellent background on the impact and context for the major legislation. The book also provides a thorough explanation of agency functions which helps clarify many leasing and permitting activities.

Simplifying the Federal Coal Management Program, General Accounting Office, August 20, 1981.

This GAO report is a very brief exploration of the conduct of coal lease management on Federal lands. A large study was initially defined, but cancelled in order to avoid duplication with other study efforts. After cancellation, a brief summary of the preliminary study conclusions was prepared.

One point of particular interest in the GAO study is the analysis of duplicative environmental reviews in coal mine permitting. Mine plans on Federal coal leases are required by both the NEPA and SMCRA legislation to include environmental data. The Office of Surface Mining, in implementing the NEPA regulations, requires that an environmental impact statement be prepared. It also requires that a Technical and Environmental Assessment (TEA) be prepared covering the methods for achieving environmental performance standards. The TEA is designed to address both the SMCRA and NEPA review requirements.

Where states have been authorized to administer the SMCRA program, the state agency will prepare the TEA. However, in such cases, OSM will proceed to prepare a

separate EIS for NEPA compliance, despite the lack of substantive differences between the two documents. The GAO reported that both state and federal officials agreed that this process was duplicative and unnecessary.

Several alternatives to the duplication of efforts were suggested by GAO, including:

1. Having state agencies prepare the EIS's.
2. Having applicants submit environmental data in the EIS format as part of the mine plan package.
3. Exempting the mine plan review process from preparation of an EIS.

A summary discussion of each alternative was provided.

Staff Report to the Federal Trade Commission on Energy Land Policy, Federal Trade Commission, October 1975.

The FTC study is principally an examination of the effect of energy lands leasing policies on competition in energy industries. The study also examines the extent to which the policies have satisfied the Department of the Interior goals of orderly development, environmental protection, and receipt of fair market value. The study concludes that in most cases, competition is not seriously damaged and the Department of Interior goals are satisfied.

The FTC study does not discuss permitting procedures, but only the economic aspects of leasing policies. No major use of the study is planned.

Synthetic Fuel Project Generic Environmental Licensing Analysis, Environmental Applications Inc., February 1980.

The Synthetic Fuel Project study provides a discussion of the major federal and state regulations that could impact the scheduling and development of a coal-liquefaction facility. The study was designed to aid the planning of a major energy company. The legislative and regulatory background of environmental permitting is presented. Specific critical-path licensing schedules were prepared for hypothetical projects in North Dakota, Montana, and Wyoming.

The Synthetic Fuel Project is useful in providing a relatively comprehensive discussion of each major environmental regulation as it applies to a potential project. However, the study was designed only to explain the regulatory and permitting processes and does not critically review the structure of such systems. Data on federal and state regulations and on typical project review times were obtained from the study.

Where We Agree: Report of the National Coal Policy Project, Francis X. Murray, ed., 1978.

The National Coal Policy Project brought together coal industry, government, and environmental specialists for discussions on the state of coal mining operations in the United States. Among the topics discussed were the regulatory issues of central concern to both groups. The purpose of the discussions was to define the principles of coal mining regulation that both groups have accepted (where we agree) and to make recommendations for further improvements in governmental management.

The tenor of the recommendations is quite general, as befits the basic level of the discussions. Industry and environmental groups combined to encourage further rationalization of coal mining regulations. The participants also urged that funding levels and professional requirements be kept high for regulatory programs.

APPENDIX C

PERMIT LISTINGS FROM SELECTED MINE PLANS

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PERMIT LISTINGS FROM SELECTED MINE PLANS

The application process of the Office of Surface Mining requires coal companies to identify all other permits which are expected to be required. These permits are generally enumerated in the early sections of the multi-volume mine plans submitted by the companies.

The listings provided in 16 recent mine plans are presented here in order to provide additional data on the number and range of permits which may be required. The mines are located in the states of Colorado (4), Montana (2), Utah (3), and Wyoming (8), and provide a check on the accuracy of the permit networks presented in Section Seven. The data also establishes the repetitive nature of much permitting, such as for the permits needed for each sedimentation pond, or the numerous water appropriation permits required.

The completeness and accuracy of the lists as well as the nature of the mining operations represented is varied. Some firms listed only a few major permits, whereas others provided comprehensive coverage. No attempt was made to check or improve the accuracy of the listing for each mine. Note also that some of the permits refer to approvals which are no longer applicable. An example of this occurs in cases where Mining Plan Approvals of the USGS are included. The OSM program superseded the USGS approval process. The obsolete permits were obtained years ago for existing mines.

WYOMING

Company: Mobil Oil Corp.

Mine (Mine Type): Roja Caballos (surface)

Location: Campbell County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Mining and Reclamation Plan and EIS	OSM
Scoria Contract for Sale of Units of Materials	BLM
Wyoming Permit to Mine - Interim Permit	Wyoming Dept. of Environmental Quality (DEQ), Land Quality Division
Wyoming License to Mine	DEQ, Land Quality Div.
Wyoming Permit to Mine	DEQ, Land Quality Div.
Air Quality Permit	DEQ, Air Quality Div.
Air Quality Permit to Operate	DEQ, Air Quality Div.
Permits to Appropriate Groundwater	Office of State Engineer
Permit to Discharge and Operate (NPDES)	DEQ, Water Quality Div.
Permit to Construct Public Water Supply and Wastewater Facility	DEQ, Water Quality Div.
Permits to Construct Plant Site Settling Ponds (3)	DEQ, Water Quality Div.
Permit to Construct Mine Pit Settling Pond	DEQ, Water Quality Div.
Permits to Construct Mining Area Settling Ponds (20)	DEQ, Water Quality Div.
Permits to Construct Mining Area Sumps (2)	DEQ, Water Quality Div.
Permit to Appropriate Groundwater (Pit Dewatering)	Office of State Engineer

WYOMING (continued)

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Reservoir Permits	Office of State Engineer
- Plant Site Water Storage Pond	
- Plant Site Settling Ponds (3)	
- Mining Pit Settling Pond	
- Mining Area Settling Ponds	
- Mining Area Sumps	
Approval to Construct and Operate a Solid Waste Disposal Site During Construction	DEQ, Solid Waste Management Div.
Special Use Lease and Approval of Mining and Reclamation Plan	Commissioner of Public Lands

Company: Antelope Coal Co.

Mine (Mine Type): Antelope Mine (surface)

Type of Submission: New Mine Application

Location: Converse County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Exploration License	BLM
Special Use Permits	FS
Environmental Impact Statement or Notice of Insignificant Impact	OSM (Part of Mine Plan Review)
Approval of Water Supply	EPA
Air Construction Permit	DEQ, Air Quality Div.
Air Operating Permit	DEQ, Air Quality Div.
NPDES	DEQ, Water Quality Div.

WYOMING (continued)

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Sediment Runoff Control Plan	DEQ, Water Quality Div.
Sedimentation Pond Construction Permit	DEQ, Water Quality Div.
Wastewater Treatment Facility Construction Permit	DEQ, Water Quality Div.
Solid Waste Disposal Permit	DEQ, Solid Waste Div.
Appropriation of Surface Water and/or Groundwater	State Engineer
Permit to Mine	DEQ, Land Quality Div.
Industrial Siting Permit	Industrial Siting Council
Archaeological Clearance	Wyoming Recreation Commissioner
County Development Permit	Converse County

Company: Carter Mining Co.

Mine (Mine Type): Rawhide (surface)

Location: Campbell County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Rawhide Mining and Reclamation Plan	OSM
Prevention of Significant Deterioration	EPA
Notice of Proposed Construction or Alteration (Site Construction)	FAA
Explosives License	Dept. of Treasury, Bureau of Alcohol, Tobacco, and Firearms

WYOMING (continued)

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Radio License	FCC
Permit to Construct Dam (3)	MSHA
Wyoming License to Mine (2)	DEQ, Land Quality Div.
Wyoming Permit to Mine (3)	DEQ, Land Quality Div.
New Source (Air) Construction Permit (1974)	DEQ, Land Quality Div.
Permit to Operate	DEQ, Air Quality Div.
Air Quality Construction Permit (1976)	DEQ, Air Quality Div.
NPDES (5)	DEQ, Water Quality Div.
Permit to Appropriate Surface Water (4)	Wyoming State Engineer
Permit to Construct (Sedimentation Ponds, 3)	DEQ, Land Quality Div.
Permit to Construct and Operate (Sedimentation Ponds, 4)	DEQ Land Quality Div.
Permit to Appropriate Groundwater (4)	Wyoming State Engineer
Industrial Siting Permit	Wyoming Industrial Siting Council
Solid Waste Disposal	DEQ, Solid Waste Management
Scientific Permit	Wyoming Game and Fish Dept.
Permit to Construct Water Supply and Sewage Treatment System	DEQ, Water Quality Div.

WYOMING (continued)

Company: Carter Mining Co.

Mine (Mine Type): Caballo (Surface)

Location: Campbell County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Caballo Mining and Reclamation Plan	OSM
Explosives License	Dept. of Treasury, Bureau of Alcohol, Tobacco and Firearms
Radio Licenses (5)	FCC
Notice of Proposed Construction of Alteration (2)	FAA
Waiver of Obstruction Lighting Requirement	FAA
Permit to Construct Dam (2)	DEQ, Land Quality Div.
WY License to Mine	DEQ, Land Quality Div.
New Source Construction Permit (Air)	DEQ, Air Quality Div.
Permit to Operate (Air)	DEQ, Air Quality Div.
NPDES (5)	DEQ, Water Quality Div.
Permit to Appropriate Surface Water (3)	WY State Engineer
Permit to Construct (Sedimentation Ponds, 2)	DEQ, Water Quality Div.
Permit to Construct and Operate (Sedimentation Ponds, 3)	DEQ, Land Quality Div.
Permit to Appropriate Groundwater (6)	WY State Engineer
Solid Waste Disposal	DEQ, Solid Waste Management
Permit to Construct Septic Wastewater Systems (5)	DEQ, Water Quality Div.
Scientific Permit	WY Game and Fish Dept.

WYOMING (continued)

Company: Cordero Mining Co.

Mine (Mine Type): Cordero (Surface)

Location: NA

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Mining and Reclamation Plan (1976)	USGS
Production Increase Approval	USGS
Legal Identity Report	MSHA
Materials License	U.S. Nuclear Regulatory Commission
Approval to Construct (1975)	EPA
Initial Permit to Construct	DEQ, Air Quality Div
Permit to Operate	DEQ, Air Quality Div
Increase Coal Production Approval	DEQ, Air Quality Div
Open Burn Explosive Packaging	DEQ, Air Quality Div
WY Permit to Mine (Original and 4 Amendments)	DEQ, Land Quality Div
NPDES	DEQ, Water Quality Div
Permit to Construct (Settling Ponds, 3)	DEQ, Water Quality Div
Permit to Construct (Sewage, Septic Systems, 2)	DEQ, Water Quality Div.
Industrial Waste Facility	DEQ, Solid Waste Div
Groundwater Permits (5)	WY State Engineer
Monitoring Well Permits (25)	WY State Engineer
Surface Water Permits (4)	WY State Engineer

WYOMING (continued)

Company: Wyodak Resources Development Corp

Mine (Mine Type): Wyodak (Surface)

Location: Campbell County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Identification Number	MSHA
Reservoir, Sedimentation Pond, Test Well and Monitor Well Permits	WY State Engineer
Permits to Construct (Sedimentation Ponds)	DEQ, Water Quality Div.
NPDES (2)	DEQ, Water Quality Div
Solid Waste Disposal Permit (2)	DEQ, Solid Waste Div.

Company: NERCO, Inc.

Mine (Mine Type): Jim Bridger Mine (Surface)

Type of Submission: Revision to Original Plan

Location: Sweetwater County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Permit to Mine (and amendment)	DEQ, Land Quality Div.
License to Mine	DEQ, Land Quality Div.
Prmit to Construct (2)	DEQ, Water Quality Div.
NPDES	DEQ, Water Quality Div.
Solid Waste Permit	DEQ, Solid Waste Management
Surface Water Appropriations	WY State Engineer

WYOMING (continued)

Company: Kerr McGee Coal Co.

Mine (Mine Type): Clovis Point Mine (Surface)

Location: Campbell County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Ground Control Plan	OSM
Safety Plans	MSHA
CPSIUM 137	U.S. Nuclear Regulatory Commission
WY Permit to Mine	DEQ, Land Quality Div
WY License to Mine	DEQ, Land Quality Div
Construction Permit (2, amendment)	DEQ, Air Quality Div
Operating Permit for Coal Prep. Plant License to Mine (Air)	DEQ, Air Quality Div
NPDES	DEQ, Water Quality Div
Construction Permit (3)	DEQ, Water Quality Div
Sewage Collection & Treatment Permit	DEQ, Water Quality Div
Waste Treatment Permits	DEQ, Water Quality Div
Topsoil Removal Plans and Other Mining Operators (8)	DEQ, Land Quality Div
Permit for Sediment Control Structures (6)	DEQ, Land Quality Div
Solid Waste Disposal, Permit Renewal	DEQ, Solid Waste Div
Industrial Waste Facility	DEQ, Solid Waste Div

WYOMING (continued)

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Blasting Plan Approvals	DEQ, Land Quality Div
Water Appropriation (4)	WY State Engineer
Groundwater Appropriation (18)	WY State Engineer

COLORADO

Company: The Pittsburg & Midway Coal Co.

Mine (Mine Type): Mine Edna (Surface)

Location: Routt County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Mining and Reclamation Plan	OSM
Federal Coal Lease Strip Mine Plan	USGS
Dept of Army Permit	U.S. Army Corps of Engineers
Permit to Use High Explosives	Dept. of Treasury, Bureau of Alcohol, Tobacco and Firearms
License to Manufacture Blasting Agents	Dept of Treasury, Bureau of Alcohol Tobacco and Firearms
Radio License, Special Industrial Mobile License	Federal Communication Commission
Special Industrial Base Mobile Relay	Federal Communication Commission
Emission (Air)	CO Dept. of Air Pollution Control Division
NPDES	CO Dept. of Water Quality Control Division
Water Well Permit (2)	CO Div. of Water Resources
Permit to Store and Use Explosives	CO Div. of Mines, Dept. of Natural Resources
Water Quality Certification	Water Quality Div. CO Dept. of Health
Zone or Special Use Permit for Surface Coal Mining	Routt County Regional Planning Commission

COLORADO

Company: Western Fuels Association, Inc.

Mine (Mine Type): Deserado (Surface)

Location: Rio Blanco County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Underground Mining Permit	OSM
Rights-of-Way (Multiple)	BLM
Temporary Use (test wells)	BLM
404 Permit	Corps of Engineers
Prospecting Notice	CO Mined Land Reclamation Board (MLRD)
Regular Permit	MLRB
NPDES	CO Dept of Health, Water Quality Control Division
Air Emission Permit	CO Dept of Health, Air Pollution Control Division
Wastewater Treatment Plan	CO Dept of Health, Occ. & Rad. Div.
Potable Water Permit	CO Dept. of Health, OCC & Rad Div
100-Year Flood Threat Certification	CO Dept of Health, Occ & Rad Div
Groundwater Use Plans	CO Dept of Nat. Resources (DNR), Div. of Water Resources
Water Court Application for Water Use	DNR, Div of Water Resources

COLORADO (Continued)

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Water Storage Rights (Sedimentation Ponds)	DNR, Div. of Water Resources
Permit to Build Dam (Sedimentation Ponds)	DNR, Div. of Water Resources
Notice of Activity	DNR, Div. of Mines
Permit to Store and Use Explosives	DNR, Div. of Mines
Underground and Utility Permit	CO Dept of Highways
Permit for Special Transportation Highway	CO Dept of Highways
Solid Waste Disposal Permit	Rio Blanco County Planning Dept
Special Use Permit	Rio Blanco County Planning Dept
Building Permit	Rio Blanco County Planning Dept
Permission to Survey	Rio Blanco County Utility Corridor Commission

COLORADO (Continued)

Company: Western Slope Carbon, Inc.

Mine (Mine Type): Hawk's Nest (Underground)

Location: Gunnison County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Mining and Reclamation Plan	OSM
Mining Plan	USGS
Permit to Move Earth Materials	BLM
Roof Control and Ventilation Plans	MSHA
NPDES	CO Dept of Health, Water Quality Control Division
Air Emission Permits	CO Dept of Health, Div of Air Pollution Control
Mining Permit	CO Mined Land Reclamation Board
Licenses to Operate	CO Dept of Natural Resources (DNR), Div. of Mines
Water Use (Well) Permit	CO Div of Water Resources

Company: Mid-Continent Resources Inc.

Mine (Mine Type): Coal Basin (Underground)

Location: Pitkin County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Mining and Reclamation Plan	OSM
Special Use Permits (Road, Waste Disposal, Powerline)	FS

COLORADO (Continued)

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
New Sewage Treatment Plan Site Approval	FS
Permit to Transport, Ship or Receive Explosive	Dept of Treasury, Bureau of Alcohol, Tobacco and Firearms
Approval of Updated Mine Plan	USGS
Approval of Modification to Training Plans and Safety Plans	MSHA
Air Emission Permit	CO Dept of Health, Air Quality Div.
NPDES	DOH, Water Quality Control Div
Reclassification of Waste System	DOH, Plant Operating Certification Board
Water Wells Permits	CO Dept of Water Resources
Notice of Activity	DNR, Div of Mines
Permits to Store and Use Explosives	DNR, Div of Mines
Permit for Underground Diesel Engines	DNR, Div. of Mines
Approval of Safety Plans	DNR, Div. of Mines
Approval of Mine Plans and Modifications	CO MLRB
Special Review Use Permit	Board of County Commissioners, Pitkin County, CO
Septic Tank Permit, Coal Basin Mechanic Shop	Pitkin County Health Dept
Building Permits	Pitkin County Building Inspector

MONTANA

Company: Peabody Coal Co.

Mine (Mine Type): Big Sky (Surface)

Location: Rosebud County, Montana

PERMITS LISTED IN MINE PLAN

ISSUING AUTHORITY

(Only applicable laws are listed.
The relevant permits are not
identified.)

Company: Decker Coal Co.

Mine (Mine Type): Decker East Pit (Surface)

Location: Decker County, Montana

PERMITS LISTED IN MINE PLAN

ISSUING AUTHORITY

Mining and Reclamation Plan

OSM

(Title not listed)

Corps of Engineers

Right-of-Way (Powerline)

BLM

Air Quality Permit

MT Dept of Environ-
mental Sciences
(DES), Air Quality
Bureau

State Air Construction Permit

DES, Air Quality
Bureau

State Water Quality Permit

DES, Water Quality
Bureau

Water Appropriations

MT Dept. of
Natural Resources

Open Burning Permit

DES, Air Quality
Div.

Waste Disposal Permit

DES, Solid Waste
Management Bureau

UTAH

Company: Natomas Trail Mountain Coal Company

Mine (Mine Type): Trail Mountain (Underground)

Location: NA

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Mining and Reclamation Plan	OSM
Mining and Reclamation Plan	Utah Division of Oil, Gas and Mining
NPDES	Utah Dept of Health, Environmental Health Div.
Permit Approval on Sediment Pond	Utah Dept of Health, Environmental Health Div. and Utah Dept. of Natural Resources, State Engineer
Special Use Permit	U.S. Forest Service (Manti-LaSal National Forest)

Company: Plateau Mining Company

Mine (Mine Type): Star Point (Underground)

Location: Carbon County

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Mining and Reclamation Plan	OSM
Surface Disturbance and Reclamation Plan	FS
Right-of-Way (for access road)	BLM
Right-of-Way (for refuse pile extension)	BLM
NPDES	EPA

UTAH

PERMITS LISTED IN MINE PLAN	ISSUING AUTHORITY
Mining Plans	MSHA
Mining and Reclamation Plan	Utah Div of Oil, Gas and Mining
Notice of Intent to Commence Mining	Utah Div. of Oil, Gas, and Mining
Domestic Water System	Utah Dept of Health
Sewage System Approval	Utah Dept. of Health
Permit to Operate Diesel Equipment Underground	Utah Industrial Commission
Notice of Intention	Utah Dept. of Health Bureau of Air Quality
Solid Waste Disposal Permit	Utah Dept. of Health
Underground Water Appropriation	Utah State Engineer
Water Right Application	Utah Div. of Water Rights
Building Permit	Carbon County, UT