DES 07-60

Draft Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement

Vol. 3

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Volume 3: Chapters 7, 8, & 9 and Appendices A – H

December 2007

BLM

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Volume 3: Chapters 7, 8, & 9 and Appendices A – H

U.S. Department of the Interior
Bureau of Land Management

December 2007

MISSION STATEMENT

It is the mission of the Bureau of Land Management (BLM), an agency of the Department of the Interior, to manage BLM-administered lands and resources in a manner that best serves the needs of the American people. Management is based upon the principles of multiple use and sustained yield taking into account the long-term needs of future generations for renewable and nonrenewable resources.

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NOTATION

The following is a list of acronyms and abbreviations, chemical names, and units of measure used in this document. Some acronyms used only in tables may be defined only in those tables.

GENERAL ACRONYMS AND ABBREVIATIONS

ACEC	Area of Critical Environmental Concern
AGFD	Arizona Game and Fish Department
AGR	aboveground retort
ANFO	ammonium nitrate and fuel oil
API	American Petroleum Institute
APLIC	Avian Power Line Interaction Committee
APP	Avian Protection Plan
AQRV	air quality related value
ARCO	Atlantic Richfield Company
ATP	Alberta Taciuk Process
AWEA	American Wind Energy Association
BA	biological assessment
BCD	barrels per calendar day
BLM	Bureau of Land Management
BMP	best management practice
BO	biological opinion
BOR	U.S. Bureau of Reclamation
BPA	Bonneville Power Administration
BSD	barrels per stream day
CAA	Clean Air Act
CAPP	Canadian Association of Petroleum Producers
CARB	California Air Resources Board
CASTNET	Clean Air Status and Trends NETwork
CBOSC	Cathedral Bluffs Oil Shale Company
CCW	coal combustion waste
CDOT	Colorado Department of Transportation
CDPHE	Colorado Department of Public Health and Environment
CDW	Colorado Division of Wildlife
CEQ	Council on Environmental Quality
CFR	*Code of Federal Regulations*
CHL	combined hydrocarbon lease
CIRA	Cooperative Institute for Research in the Atmosphere
CPC	Center for Plant Conservation
CRBSCF	Colorado River Basin Salinity Control Forum

CRS	Colorado Revised Statutes
CRSCP	Colorado River Salinity Control Program
CSS	cyclic steam stimulation
CSU	Controlled Surface Use
CWA	Clean Water Act
CWCB	Colorado Water Conservation Board
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOL	U.S. Department of Labor
DOT	U.S. Department of Transportation
EA	environmental assessment
EGL	EGL Resources, Inc.
EIA	Energy Information Administration
E-ICP	bare electrode in situ conversion process
EIS	environmental impact statement
EMF	electric and magnetic fields
E.O.	Executive Order
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EQIP	Environmental Quality Incentives Program
ESA	Endangered Species Act of 1973
EUB	Alberta Energy and Utilities Board
FHWA	Federal Highway Administration
FLPMA	Federal Land Policy and Management Act of 1976
FONSI	Finding of No Significant Impact
FR	*Federal Register*
FTE	full-time equivalent
FY	fiscal year
GCR	gas combustion retort
GHG	greenhouse gas
GIS	geographic information system
GSENM	Grand Staircase–Escalante National Monument
HAP	hazardous air pollutant
HAZCOM	hazard communication
HMA	Herd Management Area
HMMH	Harris Miller Miller & Hanson, Inc.
I-70	Interstate 70
IARC	International Agency for Research on Cancer

ICP	in situ conversion process
IEC	International Electrochemical Commission
IPPC	Intergovernmental Panel on Climate Change
ISA	Instant Study Area
ISWS	Illinois State Water Survey
JMH CAP	Jack Morrow Hills Coordinated Activity Plan
KOP	key observation point
KSLA	Known Sodium Leasing Area
LAU	Lynx Analysis Unit
LPG	liquefied petroleum gas
L_{dn}	day-night average sound level
L_{eq}	equivalent sound pressure level
M&I	municipal and industrial
MFP	Management Framework Plan
MIS	modified in situ recovery
MLA	Mineral Leasing Act
MMC	Multi Minerals Corporation
MMTA	Mechanically Mineable Trona Area
MOU	Memorandum of Understanding
MSHA	Mine Safety and Health Administration
MSL	mean sea level
MTR	military training route
NAAQS	National Ambient Air Quality Standards
NADP	National Atmospheric Deposition Program
NAGPRA	Native American Graves Protection and Repatriation Act
NCA	National Conservation Area
NCDC	National Climate Data Center
NEC	National Electric Code
NEPA	National Environmental Policy Act of 1969
NHPA	National Historic Preservation Act of 1966
NLCS	National Landscape Conservation System
NMFS	National Marine Fisheries Service
NNHP	Nevada Natural Heritage Program
NOI	Notice of Intent
NORM	naturally occurring radioactive materials
NOSR	Naval Oil Shale Reserves
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NRA	National Recreation Area
NRHP	*National Register of Historic Places*
NSC	National Safety Council

NSO	No Surface Occupancy
NWCC	National Wind Coordinating Committee
OHV	off-highway vehicle
OOSI	Occidental Oil Shale, Inc.
OPEC	Organization of Petroleum Exporting Countries
OSEC	Oil Shale Exploration Company
OSHA	Occupational Safety and Health Administration
OTA	Office of Technology Assessment
PA	Programmatic Agreement
PADD	Petroleum Administration for Defense District
PAH	polycyclic aromatic hydrocarbon
PCB	polychlorinated biphenyl
PEIS	programmatic environmental impact statement
PFYC	Potential Fossil Yield Classification
P.L.	Public Law
PM	particulate matter
$PM_{2.5}$	particulate matter with a mean aerodynamic diameter of 2.5 µm or less
PM_{10}	particulate matter with a mean aerodynamic diameter of 10 µm or less
PPE	personal protective equipment
PSD	Prevention of Significant Deterioration
R&I	relevance and importance
RBOSC	Rio Blanco Oil Shale Company
RCRA	Resource Conservation and Recovery Act of 1976
RD&D	research, development, and demonstration
RF	radio frequency
RMP	Resource Management Plan
ROD	Record of Decision
ROI	region of influence
ROW	right-of-way
SAGD	steam-assisted gravity damage
SDWA	Safe Drinking Water Act of 1974
SFC	Synthetic Fuels Corporation
SHPO	State Historic Preservation Office(r)
SIP	State Implementation Plan
SMA	Special Management Area
SMP	suggested management practice
SPR	Strategic Petroleum Reserve
SRMA	Special Recreation Management Area
SSI	self-supplied industry
STSA	Special Tar Sand Area
SWCA	SWCA, Inc., Environmental Consultants
SWPPP	Stormwater Pollution Prevention Plan

TDS	total dissolved solids
THAI	toe to head air injection
TIS	true in situ recovery
TMDL	Total Maximum Daily Load
TOSCO	The Oil Shale Corporation
TSCA	Toxic Substances Control Act of 1976
TSDF	treatment, storage, and disposal facility
UDEQ	Utah Department of Environmental Quality
UDNR	Utah Department of Natural Resources
UDWR	Utah Division of Wildlife Resources
USACE	U.S. Army Corps of Engineers
USC	*United States Code*
USDA	U.S. Department of Agriculture
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VCRS	Visual Contrast Rating System
VOC	volatile organic compound
VRI	visual resource inventory
VRM	Visual Resource Management
WDEQ	Wyoming Department of Environmental Quality
WGFD	Wyoming Game and Fish Department
WRAP	Western Regional Air Partnership
WRCC	Western Regional Climate Center
WSA	Wilderness Study Area
WSR	Wild and Scenic River
WTGS	wind turbine generator system
WYCRO	Wyoming Cultural Records Office

CHEMICALS

CH_4	methane	NO_x	nitrogen oxides
CO	carbon monoxide	O_3	ozone
CO_2	carbon dioxide	Pb	lead
H_2S	hydrogen sulfide	SO_2	sulfur dioxide
NH_3	ammonia	SO_x	sulfur oxides
NO_2	nitrogen dioxide		

UNITS OF MEASURE

ac-ft	acre foot (feet)
bbl	barrel(s)
Btu	British thermal unit(s)
°C	degree(s) Celsius
cfs	cubic foot (feet) per second
cm	centimeter(s)
dB	decibel(s)
dB(A)	A-weighted decibel(s)
°F	degree(s) Fahrenheit
ft	foot (feet)
ft^2	square foot (feet)
ft^3	cubic foot (feet)
g	gram(s)
gal	gallon(s)
GJ	gigajoule(s)
gpd	gallon(s) per day
gpm	gallon(s) per minute
GW	gigawatt(s)
GWh	gigawatt hour(s)
h	hour(s)
ha	hectare(s)
Hz	hertz
in.	inch(es)
K	degree(s) Kelvin
kcal	kilocalorie(s)
kg	kilogram(s)
km	kilometer(s)
km^2	square kilometer(s)
kPa	kilopascal(s)
kV	kilovolt(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
L	liter(s)
lb	pound(s)
m	meter(s)
m^2	square meter(s)
m^3	cubic meter(s)
mg	milligram(s)
mi	mile(s)
mi^2	square mile(s)
min	minute(s)
mm	millimeter(s)
mm^2	square micrometers
MMBtu	thousand Btu
mph	mile(s) per hour
MW	megawatt(s)
Pa	pascal(s)
ppm	part(s) per million
psi	pound(s) per square inch
rpm	rotation(s) per minute
s	second(s)
scf	standard cubic foot (feet)
t	metric ton(s)
W	watt(s)
yd^2	square yard(s)
yd^3	cubic yard(s)
yr	year(s)
µg	microgram(s)
µm	micrometer(s)
$µm^2$	square micrometer(s)
$µm^3$	cubic micrometer(s)

ENGLISH/METRIC AND METRIC/ENGLISH EQUIVALENTS

The following table lists the appropriate equivalents for English and metric units.

Multiply	By	To Obtain
English/Metric Equivalents		
acres	*0.4047*	hectares (ha)
cubic feet (ft^3)	0.02832	cubic meters (m^3)
cubic yards (yd^3)	0.7646	cubic meters (m^3)
degrees Fahrenheit (ºF) –32	0.5555	degrees Celsius (ºC)
Feet (ft)	0.3048	meters (m)
gallons (gal)	3.785	liters (L)
gallons (gal)	0.003785	cubic meters (m^3)
inches (in.)	2.540	centimeters (cm)
miles (mi)	1.609	kilometers (km)
miles per hour (mph)	1.609	kilometers per hour (kph)
pounds (lb)	0.4536	kilograms (kg)
short tons (tons)	907.2	kilograms (kg)
short tons (tons)	0.9072	metric tons (t)
square feet (ft^2)	0.09290	square meters (m^2)
square yards (yd^2)	0.8361	square meters (m^2)
square miles (mi^2)	2.590	square kilometers (km^2)
yards (yd)	0.9144	meters (m)
Metric/English Equivalents		
centimeters (cm)	0.3937	inches (in.)
cubic meters (m^3)	35.31	cubic feet (ft^3)
cubic meters (m^3)	1.308	cubic yards (yd^3)
cubic meters (m^3)	264.2	gallons (gal)
degrees Celsius (ºC) +17.78	1.8	degrees Fahrenheit (ºF)
hectares (ha)	2.471	acres
kilograms (kg)	2.205	pounds (lb)
kilograms (kg)	0.001102	short tons (tons)
kilometers (km)	0.6214	miles (mi)
kilometers per hour (kph)	0.6214	miles per hour (mph)
liters (L)	0.2642	gallons (gal)
meters (m)	3.281	feet (ft)
meters (m)	1.094	yards (yd)
metric tons (t)	1.102	short tons (tons)
square kilometers (km^2)	0.3861	square miles (mi^2)
square meters (m^2)	10.76	square feet (ft^2)
square meters (m^2)	1.196	square yards (yd^2)

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7 CONSULTATION AND COORDINATION

7.1 PUBLIC SCOPING

The BLM published the NOI to prepare the *Oil Shale and Tar Sands Resources Leasing PEIS* in the *Federal Register* (70 FR 73791–73792) on December 13, 2005 (the title has subsequently been changed to the *Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and PEIS*). The NOI identified planning criteria, initiated the public scoping process, and invited interested members of the public to provide comments on the scope and objectives of the PEIS and to identify issues to be addressed in the planning process. The BLM conducted scoping from December 13, 2005, through January 31, 2006. During that period, the BLM invited the public and interested groups to provide information on resource use, land allocations, and development and protection opportunities for consideration in preparation of the PEIS.

During the scoping process, the public was given three means of submitting comments to the BLM on the PEIS:

- Open public meetings, which were held in Salt Lake City, Utah (January 10); Price, Utah (January 11); Vernal, Utah (January 12); Rock Springs, Wyoming (January 13); Rifle, Colorado (January 18); Denver, Colorado (January 19); and Cheyenne, Wyoming (January 20);

- Traditional mail; and

- Directly through a Web site on the Internet.

This variety of ways to communicate issues and submit comments was provided so as to encourage maximum participation. All comments, regardless of how they were submitted, received equal consideration.

It is estimated that as many as 5,000 people participated in the scoping process by attending public meetings, providing comments, requesting information, or visiting the Oil Shale and Tars Sands PEIS Web site (http://ostseis.anl.gov). Approximately 4,735 individuals, organizations, and government agencies provided comments on the scope of the PEIS, including the verbal comments provided at the public meetings. Comments were received from 9 state agency divisions (6 from Utah and 3 from Wyoming), 10 federal agency offices (1 from the NPS, 2 from the USFWS, 1 from the EPA, 1 from a USACE office, 3 from the USFS, and 2 from the BLM), 11 local government organizations (City of Rifle, Colorado; Coalition of Local Governments; Colorado River Water Conservation District; Garfield County Board of County Commissioners; New Castle Colorado Town Council; Pitkin County Colorado; Pitkin County Colorado Board of Commissioners; Saratoga-Encampment-Rawlins Conservation District, Wyoming; Sweetwater County Wyoming, Commissioner; Sweetwater County Wyoming, Conservation District; and Uintah County Commission), and more than 60 other organizations (including environmental groups, interest groups, consulting firms, and industry). Of the comments received in writing, as opposed to those submitted verbally at the public meetings, about 94% were submitted by mail and 6% were submitted via the online comment form.

Comments originated from all 50 states, the District of Columbia, Puerto Rico, 15 foreign countries, and the Armed Forces Europe. Approximately 90% of the comments originated from states outside the three-state study area. The comments that originated within the study area were distributed as follows: 256 comments from Colorado, 110 comments from Utah, and 35 comments from Wyoming. During the scoping period, more than 7,000 visits were made to the Oil Shale and Tar Sands PEIS Web site (http://ostseis.anl.gov) by more than 3,600 different individuals.

The BLM published a scoping report (BLM 2006) that summarizes and categorizes the major themes, issues, concerns, and comments expressed by private citizens, government agencies, private firms, and nongovernmental organizations. These comments were considered in developing the alternatives in this PEIS. Copies of the scoping report, individual letters, electronic comments, and other written comments received during scoping are available on the Oil Shale and Tar Sands PEIS Web site (http://ostseis.anl.gov).

7.2 GOVERNMENT-TO-GOVERNMENT CONSULTATION

The BLM works on a government-to-government basis with Native American Tribal entities. As a part of the government's Treaty and Trust responsibilities, the government-to-government relationship was reaffirmed by the federal government on May 14, 1998, with E.O. 13084 and strengthened on November 6, 2000, with E.O. 13175 (U.S. President 1998, 2000). The BLM coordinates and consults with Tribal governments, Native communities, and Tribal individuals whose interests might be directly and substantially affected by activities on public lands. It strives to provide the Tribal entities sufficient opportunities for productive participation in BLM planning and resource management decision making. In addition, Section 106 of the NHPA requires federal agencies to consult with Indian Tribes for undertakings on Tribal lands and for historic properties of significance to the Tribes that may be affected by an undertaking (36 CFR 800.2 (c)(2)). BLM Manual 8120 (BLM 2004a) and Handbook H-8120-1 (BLM 2004b) provide guidance for Native American consultations.

The BLM developed a process to offer specific consultation opportunities to "directly and substantially affected" Tribal entities, as required under the provisions of E.O. 13175 and to Indian Tribes as defined under 36 CFR 800.2(c)(2). Starting in February 2006, Tribal entities located in or with interests in the three-state study area were contacted by mail by the BLM State Directors. Table 7.2-1 lists the Tribal entities that were contacted by each state and describes the status of the ongoing consultations with each Tribe. At the time that this Draft PEIS was completed, six Tribes (San Juan Southern Paiute Tribe, Ute Indian Tribe, Ute Mountain Ute Tribe, White Mesa Band of Ute Mountain Ute Tribe, Pueblo of Santa Clara, and Pueblo of Zuni) and five Navajo Chapters (Aneth, Navajo Mountain, Oljato, Red Mesa, and Teecnospos) had yet to respond to the BLM's request for consultation. Four Tribes (Pueblo of Laguna, Pueblo of Nambe, Pueblo of Zia, and Southern Ute Tribe) and two Navajo Chapters (Dennehotso and Mexican Water) have indicated that further consultation is not needed. Eight Tribes have

TABLE 7.2-1 Government-to-Government Consultation Summary

Tribes Contacted for Consultation on the PEIS	Status of Consultation Process
Colorado	
Southern Ute Indian Tribe, Ignacio, CO	The Tribe has indicated that further consultation is not needed.
Ute Mountain Ute Tribe, Towoac, CO	No response to initial consultation letter. Follow-up consultation will be conducted.
Utah	
Hopi Tribe, Kykotsmovi, AZ	The Tribe has indicated it would be interested in the portion of the study area located in eastern Utah as far north as Price; no additional specific information or concerns have been conveyed to the BLM, to date.
Kaibab Paiute Tribe, Fredonia, AZ	The Tribe has expressed interest in development associated with a specific STSA; the Tribe has not conveyed any specific information or concerns to the BLM, to date.
Navajo Nation, Window Rock, AZ	The BLM has provided additional information at the request of the Tribe; the Tribe has not conveyed any specific information or concerns to the BLM, to date.
Navajo Nation, Aneth Chapter, Montezuma Creek, UT	No response to initial consultation letter. Follow-up consultation will be conducted.
Navajo Nation, Dennehotso Chapter, Dennehotso, AZ	The Tribe has indicated that further consultation is not needed.
Navajo Nation, Mexican Water Chapter, Teecnospos, AZ	The Tribe has indicated that further consultation is not needed.
Navajo Nation, Navajo Mountain Chapter, Tonalea, AZ	No response to initial consultation letter. Follow-up consultation will be conducted.
Navajo Nation, Oljato Chapter, Monument Valley, UT	No response to initial consultation letter. Follow-up consultation will be conducted.
Navajo Nation, Red Mesa Chapter, Montezuma Creek, UT	No response to initial consultation letter. Follow-up consultation will be conducted.
Navajo Nation, Teecnospos Chapter, Teecnospos, AZ	No response to initial consultation letter. Follow-up consultation will be conducted.
Northwestern Band of Shoshone Nation, Pocatello, ID	The Tribe has expressed concern with certain specific areas that fall within the PEIS study areas, but has not subsequently conveyed any specific information or concerns to the BLM.
Paiute Indian Tribe of Utah, Cedar City, UT	The Tribe has expressed an interest in consulting with the BLM and becoming involved in development of the PEIS; no meetings with the BLM have been conducted, to date.
Pueblo of Laguna, Laguna, NM	The Tribe has indicated that further consultation is not needed.
Pueblo of Nambe, Santa Fe, NM	The Tribe has indicated that further consultation is not needed.
Pueblo of Santa Clara, Espanola, NM	No response to initial consultation letter. Follow-up consultation will be conducted.

TABLE 7.2-1 (Cont.)

Tribes Contacted for Consultation on the PEIS	Status of Consultation Process
Utah (Cont.)	
Pueblo of Zia, Zia Pueblo, NM	The Tribe has indicated that further consultation is not needed.
Pueblo of Zuni, Zuni, NM	No response to initial consultation letter. Follow-up consultation will be conducted.
San Juan Southern Paiute Tribe, Tuba City, AZ	No response to initial consultation letter. Follow-up consultation will be conducted.
Ute Indian Tribe, Fort Duchesne, UT	The Tribe has indicated to the BLM that it would like to be consulted regarding potential leasing for commercial oil shale and/or tar sands development on split estate lands located in the Hill Creek Extension of the Uinta and Ouray Reservation prior to any parcel being put up for leasing.
White Mesa Band of the Ute Mountain Ute Tribe, Blanding, UT	No response to initial consultation letter. Follow-up consultation will be conducted.
Wyoming	
Northern Arapaho Tribe, Fort Washakie, WY	The BLM met with the Tribe at a joint meeting with the Eastern Shoshone Tribe in Ethete, WY, on August 25, 2006; a second meeting was conducted with the Tribe, by phone, on October 5, 2006. Subsequently, the Tribe requested and received copies of ethnohistory and cultural resource overview documents being prepared in conjunction with the PEIS,
Eastern Shoshone Tribe, Fort Washakie, WY	The BLM met with the Tribe at a joint meeting with the Northern Arapaho in Ethete, WY, on August 25, 2006.
Shoshone-Bannock Tribes, Fort Hall, ID	The BLM has provided additional information at the request of the Tribe and has contacted specific individuals at the request of the Tribe; the Tribe has not conveyed any specific information or concerns to the BLM, to date.

expressed an interest in consultation with the BLM for this project, as summarized in Table 7.2-1.

The BLM will continue to consult with interested Tribes and also will continue to keep all Tribal entities informed about the NEPA process for the PEIS. In addition, the BLM will continue to implement government-to-government consultation on a case-by-case basis for site-specific oil shale and tar sands resource development projects.

7.3 COORDINATION OF BLM STATE AND FIELD OFFICES

This PEIS is being prepared by the BLM to evaluate potential land use plan amendments for oil shale and tar sands resources on public lands in three states. The BLM Washington, D.C., Office has worked extensively with the BLM state offices and multiple field offices throughout the course of this PEIS to ensure adequate coordination. BLM state office and field office representatives have worked directly with BLM Washington, D.C., Office staff to share relevant information about the existing planning documents and decisions, the location and nature of natural and cultural resources within the study area, and other land uses within the study area.

In addition, the BLM Washington, D.C., Office Public Affairs Division has coordinated with Public Affairs Office staff from each of the state offices. Jointly, these staff have been responsible for coordinating all public involvement activities related to the PEIS (e.g., public meetings, local public notifications, and advertisements); conducting the government-to-government consultation process with Tribes; responding to any questions regarding the PEIS received from local parties; and forwarding, as appropriate, any questions or comments regarding the PEIS to appropriate minerals and resource staff.

Coordination with BLM state office and field office staff will continue throughout the preparation of the PEIS to ensure that the analysis adequately reflects state- and local-level concerns and issues regarding oil shale and tar sands resources development.

7.4 AGENCY CONSULTATION AND COORDINATION

The BLM invited 50 federal, Tribal, state, and local government agencies to participate in preparation of the Oil Shale and Tar Sands PEIS as cooperating agencies. Fourteen agencies expressed an interest in participating as cooperating agencies, and MOUs between these agencies and the BLM were established. The following agencies are participating as cooperating agencies on the PEIS:

- NPS;
- BOR;
- USFS;
- USFWS;
- State of Colorado, Department of Natural Resources;
- State of Utah;
- State of Wyoming;
- Garfield County, Colorado;

- Mesa County, Colorado;
- Rio Blanco County, Colorado;
- Duchesne County, Utah;
- Uintah County, Utah;
- City of Rifle, Colorado; and
- Town of Rangely, Colorado.

Interactions with the cooperating agencies have included notification of the opening of the scoping period; briefing on the draft alternatives; review of preliminary, internal drafts of the PEIS; and informal meetings and discussions.

As required under Section 106 of the NHPA of 1966, as amended, the BLM has initiated consultation with the Colorado, Utah, and Wyoming SHPOs, the Advisory Council on Historic Preservation, and the Tribes listed in Section 7.2 regarding the proposed plan amendments discussed in Chapter 2 and Appendix C.

In accordance with the Memorandum of Agreement (Appendix G of BLM 2002) between the BLM and the USFWS, the BLM will consult with the USFWS regarding the proposed plan amendments discussed in Chapter 2 and Appendix C. These consultations will be conducted in accordance with the requirements of Section 7 of the ESA (16 USC 1536).

In addition to coordination with each of the three states in preparation of the PEIS, prior to the approval of proposed plan amendments, the governor of each state will be given the opportunity to identify any inconsistencies between the proposed plan amendments and state or local plans and to provide recommendations in writing (during the 60-day consistency review period).

7.5 EXPLANATION OF THE PUBLIC PROTEST PROCESS FOR THE PROPOSED LAND USE PLAN AMENDMENTS

As discussed in Chapter 2 and Appendix C, the BLM proposes to amend 12 land use plans in Colorado, Utah, and Wyoming to adopt specific decisions rendered in the PEIS related to land use designations for oil shale and tar sands resources. A 30-day public review and protest period will begin on the date the Notice of Availability of the Final PEIS is published in the *Federal Register*. In accordance with 43 CFR, 1610.5-2, any person who (a) participates in the planning process leading to the proposed amendment and (b) has an interest that is or may be adversely affected by the amendment of a land use plan may protest the proposed amendment. A protest may raise only those issues that were submitted for the record during the planning process. These issues may have been raised by the protesting party or others. New issues may not be brought into the record at the protest stage. Specific information about the public protest process, including how to file a protest, will be provided when the Final PEIS is released.

7.6 REFERENCES

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BLM, 2004a, *Manual 8120—Tribal Consultation under Cultural Resources*, Release 8-74, U.S. Department of the Interior.

BLM, 2004b, *Handbook H-8120-1—General Procedural Guidance for Native American Consultation*, Release 8-75, U.S. Department of the Interior.

BLM, 2006, *Summary of Public Scoping Comments for the Oil Shale and Tar Sands Resources Leasing Programmatic Environmental Impact Statement*, prepared by Argonne National Laboratory, Argonne, Ill., for Bureau of Land Management, Solid Minerals Group, Washington, D.C., Jan.

U.S. President, 1998, "Consultation and Coordination with Indian Tribal Governments," Executive Order 13084, *Federal Register* 63:27655, May 19.

U.S. President, 2000, "Consultation and Coordination with Indian Tribal Governments," Executive Order 13175, *Federal Register* 65:67249, Nov. 9.

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Georgia Anast	B.A., Mathematics/Biology; 16 years of experience in environmental assessment.	Comment/response manager
Thomas E. Baldwin	Ph.D., Sociology; 31 years of experience in demography, human ecology, and social impact analysis.	Social impact analysis
Brian L. Cantwell	B.S., Forestry; 25 years of experience in cartography and GIS mapping.	Technical lead for GIS mapping
Young-Soo Chang	Ph.D., Chemical Engineering; 19 years of experience in air quality and noise impact analysis.	Affected environment, air quality and emissions, noise
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Heidi M. Hartmann	M.S., Environmental Toxicology and Epidemiology; 20 years of experience in exposure and risk analysis and environmental impact assessment.	Document manager; Health and safety; cumulative impacts summary
John Hayse	Ph.D., Zoology; 22 years of experience in ecological research and environmental assessment.	Ecological resources analysis (aquatic)
Elizabeth Hocking	J.D., 16 years of experience in regulatory and policy analysis.	Regulatory requirements

Patricia Hollopeter	M.A., Philosophy; 24 years of experience in editing and writing.	Lead editor
Xi Hiu Jiang	A.A.S; 6 years of experience in mapping and database design.	GIS data collection
Ronald Kolpa	M.S., Inorganic Chemistry; B.S., Chemistry; 31 years of experience in environmental regulation, auditing, and planning.	Technical lead for hazardous materials and waste management, and noise; technology overview for oil shale
Veerabhadra (Rao) R. Kotamarthi	Ph.D., Chemical Engineering; 15 years of experience in modeling and analysis of atmospheric chemical and physical processes.	Affected environment, meteorology
Kirk E. LaGory	Ph.D. Zoology, M.En., Environmental Science; 32 years of experience in ecological research, 21 years in environmental assessment.	Technical lead for ecological resources analysis; threatened and endangered species
Paul Marcou	B.S., Geographic Information Systems and Cartography; 10 years of experience in GIS mapping and data analysis.	GIS mapping
James E. May	M.S., Water Resources Management; B.A., Zoology; 32 years of experience in natural resources management; 4 years of consulting experience in land use planning and NEPA compliance.	Co-Project Manager
H. Robert Moore	B.S., Forest Management and Engineering; 40 years of experience in natural resource management; 12 years in natural resource program management and coordination.	Public involvement, land-use planning, management team consultation
Matthew E. Nesta	B.S., Earth Science; 8 years of experience in GIS mapping and remote sensing.	GIS analysis, data acquisition, map compilation
Lee A. Northcutt	A.A.; 18 years of experience in program and editorial assistance; 12 years in environmental impact statement preparation.	Glossary, List of Preparers
John Quinn	M.S., Geology; 19 years of experience in hydrogeology.	Technical lead for water resources and for soils and geology
Pam Richmond	M.S., Computer Science; 11 years of experience in multimedia development and Web design/programming.	Web site interface design and programming

Albert E. Smith	Ph.D., Physics; 31 years of experience in air quality and environmental assessment.	Technical lead for noise impacts; technology overview for tar sands
Karen P. Smith	M.S., B.A., Geology; B.A., Anthropology; more than 20 years of experience in geology, regulatory and policy analysis, and environmental assessment.	Technical lead for land use; Chapters 1 and 2
Robert Sullivan	M.L.A., Landscape Architecture; 20 years of experience in visual impact analysis and simulation; 13 years in Web site development.	Technical lead for visual impact analysis; public Web site development
Bruce Verhaaren	Ph.D., Archaeology; 19 years of experience in archaeological analysis; 16 years in environmental assessment and records management.	Records management
William S. Vinikour	M.S., Biology with environmental emphasis; 30 years of experience in ecological research and environmental assessment.	Ecological resources analysis (wildlife)
Robert A. Van Lonkhuyzen	B.A., Biology; 18 years of experience in ecological research and environmental assessment.	Ecological resources analysis (plant communities and habitats)
Konstance L. Wescott	M.A., Anthropology; B.A., Mathematics and Sociology/Anthropology; 20 years of experience in archaeology, 18 years in environmental assessment.	Co-Project Manager; technical lead for paleontology; cultural resources
C. Ron Yuen	Ph.D., Geology; 22 years of experience in engineering geology, environmental geology, and hydrogeology.	Surface water resources, water demand

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9 GLOSSARY

Abiotic: Refers to nonliving objects, substances, or processes. The abiotic factors of environment include light, temperature, and atmospheric gases.

Aboveground retorting: *see* Retorting.

Acre-foot (ac-ft): A term used in measuring the volume of fluid. An acre-foot is the amount of fluid required to cover 1 acre to a depth of 1 ft, or 43.540 cf^3 (325,829 gal).

Adaptive management: A management system that is designed to make changes (i.e., to adapt) in response to new information and changing circumstances.

Adiabatic change: Change in the volume and pressure of a parcel of gas without an exchange of heat between the parcel of gas and its surroundings.

Aerodynamics: The study of the forces exerted on and the flow around solid objects moving relative to a gas, especially the atmosphere.

Aggregate: Mineral materials such as sand, gravel, crushed stone, or quarried rock used for construction purposes.

Air density: The weight of a given volume of air. Air is denser at a lower altitude, lower temperature, and lower humidity.

Air quality: Measure of the health-related and visual characteristics of the air. Air quality standards are the prescribed level of constituents in the outside air that cannot be exceeded during a specific time in a specified area.

Air toxics: Substances that have adverse impacts on human health when present in ambient air.

All-American Roads: Roads selected for this designation by the U.S. Department of Transportation because of their important scenic, natural, historical, cultural, archaeological, or recreational qualities. They provide an exceptional traveling experience such that motorists go to these highways as a primary reason for their trip.

Alluvial fan: A gently sloping mass of unconsolidated material (e.g., clay, silt, sand, or gravel) deposited where a stream leaves a narrow canyon and enters a plain or valley floor. Viewed from above, it has the shape of an open fan. An alluvial fan can be thought of as the land counterpart of a delta.

Alluvial: Formed by the action of running water; of or related to river and stream deposits.

Alluvium: Sediments deposited by erosion processes, usually by streams.

Ambient air: The surrounding atmosphere as it exists around people, plants, and structures.

Ambient noise level: The level of acoustic noise existing at a given location, such as in a room or somewhere outdoors.

American Antiquities Act of 1906: Prohibits excavating, injuring, or destroying any historic or prehistoric ruin or monument or object of antiquity on federal land without the prior approval of the agency with jurisdiction over the land.

American Indian Religious Freedom Act of 1978: Requires federal agencies to consult with Tribal officials to ensure protection of religious cultural rights and practices.

Anthropogenic: Human made; produced as a result of human activities.

API gravity: A measurement convention established by the American Petroleum Institute for expressing the relative density of petroleum liquids to water; the greater the API gravity, the less dense the material.

Aquifer: An underground bed or layer of earth, gravel, or porous stone that yields usable quantities of water to a well or spring.

Archaeological and Historical Preservation Act of 1966, as amended: Directly addresses impacts or cultural resources resulting from federal activities that would significantly alter the landscape. The focus of the law is the creation of dams and the impacts resulting from flooding, creation of access roads, etc. Its requirements, however, are applicable to any federal action.

Archaeological site: Any location where humans have altered the terrain or discarded artifacts during prehistoric or historic times.

Archeological Resources Protection Act of 1979: Requires a permit for excavation or removal of archeological resources from public or Native American lands.

Areas of Critical Environmental Concern (ACECs): These areas are managed by the Bureau of Land Management (BLM) and are defined by the Federal Land Policy and Management Act of 1976 as having significant historical, cultural, and scenic values, habitat for fish and wildlife, and other public land resources, as identified through the BLM's land use planning process.

Argillaceous: Used to describe a rock containing a large percentage of clay.

Attainment area: An area considered to have air quality as good as or better than the National Ambient Air Quality Standards for a given pollutant. An area may be in attainment for one pollutant and in nonattainment for others.

Attenuation: The reduction in level of sound.

Authigenic: Formed in place; typically refers to minerals formed in place after the sediments were deposited.

Bald and Golden Eagle Protection Act of 1940: Act making it unlawful to take, pursue, molest, or disturb bald and golden eagles, their nests, or their eggs. Permits must be obtained from the U.S. Department of the Interior (DOI) in order to relocate nests that interfere with resource development or recovery.

Best management practices (BMPs): A practice or combination of practices that are determined to provide the most effective, environmentally sound, and economically feasible means of managing an activity and mitigating its impacts.

Biological Assessment: A document prepared for the Endangered Species Act of 1973 (ESA) Section 7 process to determine whether a proposed major construction activity under the authority of a federal action agency is likely to adversely affect listed species, proposed species, or designated critical habitat.

Biological Opinion: A document resulting from formal consultation with the U.S. Fish and Wildlife Service (USFWS). The document presents the opinion of the USFWS as to whether a federal action is likely to jeopardize the continued existence of listed species or result in the destruction or adverse modification of critical habitat.

Biomass: Anything that is or has once been alive.

Biota: The living organisms in a given region.

Bitumen: A mix of hydrocarbons with a high carbon-to-hydrogen ratio, which may contain elevated concentrations of sulfur, nitrogen, oxygen, and heavy metals.

Boiler slag: A noncombustible by-product collected from the bottom of furnaces that burn coal for the generation of steam. When molten boiler slag comes in contact with water it fragments into coarse, black, angular particles having a smooth, glassy appearance. These particles are used for blasting grit and roofing granules.

Boreal forest: A forest that grows in regions of the northern hemisphere with cold temperatures; made up of mostly cold-tolerant coniferous species such as spruce and fir.

Borrow pit: A pit or excavation area used for gathering earth materials (borrow) such as sand or gravel.

Broadband noise: Noise that has a continuous spectrum, that is, energy is present at all frequencies in a given range. This type of noise lacks a discernible pitch and is described as having a “swishing” or “whooshing” sound.

Browse: Shrubs, trees, and herbs that provide food for wildlife.

Bureau of Land Management (BLM): An agency of the U.S. Department of the Interior that is responsible for managing public lands.

Bureau of Land Management (BLM) "Gold Book:" Comprehensive guidance on the design, construction, maintenance, and reclamation of sites and access roads.

Candidate species: Plants and animals for which the USFWS has sufficient information on their biological status and threats to propose them as endangered or threatened under the ESA, but for which development of a listing regulation is precluded by other higher-priority listing activities.

Canopy: The upper forest layer of leaves consisting of tops of individual trees whose branches sometimes cross each other.

Carbon monoxide (CO): A colorless, odorless gas that is toxic if breathed in high concentrations over an extended period. Carbon monoxide is listed as a criteria air pollutant under Title I of the Clean Air Act.

Carrion: The dead, decomposing flesh of an animal.

Chaparral: A plant community of shrubs and low trees adapted to annual drought and often extreme summer heat and also highly adapted to fires recurring every 5 to 20 years.

Char: The organic residue remaining on the spent shale.

Clean Air Act (CAA): Establishes national ambient air quality standards and requires facilities to comply with emission limits or reduction limits stipulated in State Implementation Plans (SIPs). Under this Act, construction and operating permits, as well as reviews of new stationary sources and major modifications to existing sources, are required. The Act also prohibits the federal government from approving actions that do not conform to SIPs.

Clean Water Act (CWA): Requires National Pollutant Discharge Elimination System (NPDES) permits for discharges of effluents to surface waters, permits for storm water discharges related to industrial activity, and notification of oil discharges to navigable waters of the United States.

Clearcut: The removal or cutting of all trees in an area of forest land at one time. An area of forest land from which all trees have recently been harvested.

Coal production (on BLM lands): The Mineral Leasing Act of 1920, as amended by the Federal Coal Leasing Amendments Act of 1976, requires competitive leasing of coal. These leases require payment of a royalty rate of 12.5% for surface-mined coal (8% for coal mined by underground methods), diligent development of commercial quantities of coal within 10 years of lease issuance, and stipulations to protect other resources within the lease. The BLM routinely inspects all coal to ensure accurate reporting of coal production and maximum economic recovery of the coal resource.

Code of Federal Regulations* (CFR)*: A compilation of the general and permanent rules published in the *Federal Register* by the Executive departments and agencies of the United States government. It is divided into 50 titles that represent broad areas subject to federal regulation. Each volume of the CFR is updated once each calendar year and is issued on a quarterly basis.

Colluvium: A general term to include loose rock and soil material that accumulates at the base of a slope as the result of mass wasting processes.

Combined Hydrocarbon Lease (CHL): Lease issued in a Special Tar Sand Area (STSA) for the removal of gas and nongaseous hydrocarbon substances other than coal, oil shale, or gilsonite.

Combined Hydrocarbon Leasing Act of 1981: Act that amended the Mineral Leasing Act of 1920 to authorize the Secretary of the Interior to issue CHLs in areas containing substantial deposits of tar sands, which were to be designated as STSAs.

Confined aquifer: An aquifer in which groundwater is confined under pressure that is significantly greater than atmospheric pressure.

Conifers: Cone-bearing trees, mostly evergreens, that have needle-shaped or scale-like leaves.

Conterminous United States: The 48 mainland states, excluding Alaska and Hawaii.

Controlled Surface Use (CSU): (1) Use and occupancy is allowed (unless restricted by another stipulation), but identified resource values require special operational constraints that may modify the lease rights. CSU is used for operating guidance, not as a substitute, for the No Surface Occupancy (NSO) or timing stipulations. (2) Stipulations to be attached to oil and gas leases to protect specific areas or resources, such as riparian and wetland areas, rivers, sensitive species, viewsheds, and watersheds.

Corona discharge: A noise having a hissing or crackling character.

Corona/corona noise: The electrical breakdown of air into charged particles. The phenomenon appears as a bluish-purple glow on the surface of and adjacent to a conductor when the voltage gradient exceeds a certain critical value, thereby producing light, audible noise (described as crackling or hissing), and ozone.

Council on Environmental Quality (CEQ): Established by NEPA. CEQ regulations (40 CFR Parts 1500–1508) describe the process for implementing NEPA, including preparation of environmental assessments (EAs) and environmental impact statements (EISs), and the timing and extent of public participation.

Cradle-to-Grave: A procedure in which hazardous materials are identified and followed as they are produced, treated, transported, and disposed of by a series of permanent, linkable, descriptive documents (e.g., manifests). Commonly referred to as the cradle-to-grave system.

Criteria air pollutants: Six common air pollutants for which National Ambient Air Quality Standards (NAAQS) have been established by the U.S. Environmental Protection Agency (EPA) under Title I of the Clean Air Act (CAA). They are sulfur dioxide, nitrogen oxides, carbon monoxide, ozone, particulate matter ($PM_{2.5}$ and PM_{10}), and lead. Standards were developed for these pollutants on the basis of scientific knowledge about their health effects.

Critical habitat: The specific area within the geographical area occupied by the species at the time it is listed as endangered or threatened. The area in which physical or biological features essential to the conservation of the species are found. These areas may require special management or protection.

Crude oil: A mixture of hydrocarbons formed from organic matter. *See also* Shale oil.

Cryptobiotic organisms: Soil-dwelling organisms, including cyanobacteria (blue-green bacteria), microfungi, mosses, lichens, and green algae found in surface soils of the arid and semiarid West. These organisms perform many important functions, including fixing nitrogen and carbon, maintaining soil surface stability, plant growth, and preventing erosion. They bind together with soil particles to create a crust.

Cuesta: An asymmetrical ridge with one steep face (an escarpment slope) and an opposite, gently inclined face (a dip-slope).

Cultural resources: Archaeological sites, architectural structures or features, traditional use areas, and Native American sacred sites or special use areas that provide evidence of the prehistory and history of a community.

Culvert: A pipe or covered channel that directs surface water through a raised embankment or under a roadway from one side to the other.

Cumulative impacts: The impacts assessed in an EIS that could potentially result from incremental impacts of the action when added to other past, present, and reasonably foreseeable future actions, regardless of what agency (federal or nonfederal), private industry, or individual undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

Cut slope: An earthen slope that is cut; for example, a trail built lower than the existing terrain would result in a cut slope.

Dawsonite: dihydroxy sodium aluminum carbonate; found in the lower portion of the northern province of the Piceance Basin; can be used as a source of alumina.

Decibel (dB): A standard unit for measuring the loudness or intensity of sound. In general, a sound doubles in loudness with every increase of 10 decibels.

Decibel, A-weighted [dB(A)]: A measurement of sound approximating the sensitivity of the human ear and used to characterize the intensity or loudness of a sound.

Decommissioning: All activities necessary to take out of service and dispose of a facility after its useful life.

Demographics: Specific population characteristics such as age, gender, education, and income level.

Dendritic drainage pattern: In hydrologic terms, the form of the drainage pattern of a stream and its tributaries when it follows a treelike shape, with the main trunk, branches, and twigs corresponding to the main stream, tributaries, and subtributaries, respectively, of the stream.

Dermal: Of or pertaining to the skin.

Desert scrub: Community characterized by plants adapted to seasonally dry climate.

Dewater: To remove or drain water from an area.

Dewatering: Removal or separation of a portion of the water in a sludge or slurry to dry the sludge so that it can be handled and disposed of; removal or draining the water from a tank or trench.

Dielectric fluids: Fluids that do not conduct electricity.

Diluents: Light petroleum liquids used to dilute bitumen and heavy oil so that they can flow through pipelines.

Direct impact: An effect that results solely from the construction or operation of a proposed action without intermediate steps or processes. Examples include habitat destruction, soil disturbance, and water use.

Disseminated: Occurring as scattered particles in the rock.

Downwarp: A downward bend or gradual sinking of land with respect to its previous level.

Ecological refugium: *See* Refugium.

Ecological resources: Fish, wildlife, plants, biota, and their habitats, which may include land, air, and/or water.

Ecoregion: A geographically distinct area of land that is characterized by a distinctive climate, ecological features, and plant and animal communities.

Ecosystem: A group of organisms and their physical environment interacting as an ecological unit.

Electromagnetic fields (EMFs): Fields that surround both large power lines that distribute power and the smaller electric lines in homes and appliances. Generated when charged particles (e.g., electrons) are accelerated. EMFs are typically generated by alternating current in electrical conductors. They may also be referred to as EM fields.

Electromagnetic interference: Any electromagnetic disturbance that interrupts, obstructs, or otherwise degrades or limits the effective performance of electrical equipment. It is caused by the presence of electromagnetic radiation.

Emergency Planning and Community Right-to-Know Act (EPCRA): This Act requires emergency release notification, hazardous chemical inventory reporting, and toxic chemical release inventory reporting by facilities, depending on the chemicals stored or used and their amounts.

Emissions: Substances that are discharged into the air from industrial processes, vehicles, and living organisms.

Empirical: Based on experimental data rather than theory.

Endangered Species Act of 1973 (ESA): Requires consultation with the USFWS and/or the National Marine Fisheries Service to determine whether endangered or threatened species or their habitats will be impacted by a proposed activity and what, if any, mitigation measures are needed to address the impacts.

Endangered species: Any species (plant or animal) that is in danger of extinction throughout all or a significant part of its range. Requirements for declaring a species endangered are found in the ESA.

Endemic: Unique to a particular region.

Environmental Assessment (EA): A concise public document that a federal agency prepares under NEPA to provide sufficient evidence and analysis to determine whether a proposed action requires preparation of an EIS or whether a Finding of No Significant Impact can be issued. An EA must include brief discussions on the need for the proposal, the alternatives, the environmental impacts of the proposed action and alternatives, and a list of agencies and persons consulted.

Environmental Impact Statement (EIS): A document required of federal agencies by NEPA for major proposals or legislation that will or could significantly affect the environment.

Environmental justice: The fair treatment of people of all races, cultures, incomes, and educational levels with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.

Ephemeral stream: A stream that flows only after a storm or during snowmelt, and whose channel is, at all times, above the water table; groundwater is not a source of water for the stream. Many desert streams are ephemeral.

Epicenter: The point on the earth's surface that is directly over the focus of an earthquake.

Erosion: The wearing away of the land surface by running water, wind, ice, or other geologic agents.

Escarpments: The topographic expression of a fault.

Estate lands: *See* Split estate lands.

Evaporite: A sedimentary rock formed when a saline solution evaporates. Evaporites are typically formed when a saline lake dries up or due to evaporation in tidal marshes in hot, arid climates.

Evapotranspiration: The loss of water from the soil both by evaporation and by transpiration from the plants growing in the soil.

Executive Order: A President's or Governor's declaration that has the force of law usually based on existing statutory powers and requiring no action by the Congress or state legislature. http://www.legal-explanations.com/definitions/executive-order.htm

Exotic species: A plant or animal that is not native to the region where it is found.

Exploration and Mining Activity (on BLM land): Exploration refers to exploring for minerals by way of drilling, trenching, etc. Mining refers to the extraction and processing of minerals. Exploration and mining activities on BLM-managed lands are regulated under 43 CFR Part 3809, which provides for three levels of activity. The first, causal use, requires no contact with the BLM. The second, a notice, is filed for activities that disturb less than 5 acres unreclaimed per calendar year. The third, a plan of operations, is filed for activities that exceed 5 acres unreclaimed per calendar year. Plans of operation require BLM approval and are subject to NEPA.

Exposure pathway: The path from sources of pollutants via soil, water, or food, to man and other species or settings.

Extant: Currently existing.

Extensive Recreation Management Areas: All BLM-administered lands outside Special Recreation Management Areas. These areas may include developed and primitive recreation sites with minimal facilities.

Extirpation: The elimination of a species or subspecies from a particular area, but not from its entire range.

Federal Cave Resources Protection Act of 1988: Allows the collection and removal of resources from federal caves only when a permit has been authorized by the Secretary of Agriculture or the Secretary of the Interior.

Federal land: Land owned by the United States, without reference to how the land was acquired or which federal agency administers the land. *See also* Public land.

Federal Land Policy and Management Act of 1976 (FLPMA): Act requiring the Secretary of the Interior to issue regulations to manage public lands and the property located on those lands for the long term.

Federal Mine Safety and Health Act of 1977: Act requiring the U.S. Department of Labor's (DOL's) Mine Safety and Health Administration (MSHA) to inspect all mines each year to ensure safe and healthy work environments for miners.

Feedstock: Raw material required for an industrial process.

Flare: A control device that burns hazardous materials to prevent their release into the environment; may operate continuously or intermittently, usually on top of a stack.

Fledging success: The average number of offspring fledged (i.e., raised until they leave the nest) per female.

Floaters: Nonbreeding adult and subadult birds that move and live within a breeding population.

Floodplain: Mostly level land along rivers and streams that becomes covered by water when the river overflows its banks.

Flora: Plants, especially those of a specific region, considered as a group.

Fluvial: Pertaining to a river; fluvial sediments are deposited by rivers.

Fly ash: Small particles of airborne ash produced by burning fossil fuels. Fly ash is expelled as noncombustible airborne emissions or recovered as a by-product for commercial use (e.g., as a replacement for Portland cement used in concrete).

Flyway: A concentrated, predictable flight path of migratory bird species from their breeding ground to their wintering area.

Forbs: Nonwoody plants that are not grasses or grasslike.

Fragmentation of habitat: The breaking up of a single large habitat area such that the remaining habitat patches are smaller and farther apart from each other.

Frost heave: Expansion in soil volume due to the formation of ice. It is generally expressed as an upward movement of the ground surface.

Fugitive dust: The dust released from activities associated with construction, manufacturing, or transportation.

Gallinaceous birds: Heavy-bodied largely ground-feeding domestic or game birds, including chickens, pheasants, turkeys, grouse, partridges, and quail.

Geologic resources: Material of value to humans that is extracted (or is extractable) from solid earth, including minerals, rocks and metals; energy resources; soil; and water.

Geology: The science that deals with the study of the materials, processes, environments, and history of the earth, including the rocks and their formation and structure.

Geotechnical: Related to the use of scientific methods and engineering principles to analyze and predict the behavior of earth materials. Geotechnical engineers deal with soil and rock mechanics, foundation engineering, ground movement, deep excavation, and related work.

Geothermal energy: Energy that is generated by the heat of the earth's own internal temperature. Sources of geothermal energy include molten rock, hot springs, geysers, steam, and volcanoes.

Geothermal production: Electricity produced from the heat energy of the earth. This energy may be in the form of steam, hot water, or the thermal energy contained in rocks at great depths. The BLM leases geothermal rights to explore for and produce geothermal resources from federal lands or from subsurface mineral rights held by the government.

Gilsonite: A form of natural asphalt found in large amounts only in the Uintah Basin of Utah. Discovered in the 1860s, it was first marketed as a lacquer, electrical insulator, and waterproofing compound about 25 years later by Samuel H. Gilson.

Grazing permits and leases (on BLM land): A grazing permit authorizing grazing of a specified number and class of livestock within a grazing district on a designated area of land during specified seasons each year. A grazing lease authorizes the grazing of livestock on public land outside grazing districts during a specified period of time. Grazing privileges are measured in terms of animal unit months.

Groundwater: The supply of water found beneath the earth's surface, usually in porous rock formations (aquifers), which may supply wells and springs. Generally, it refers to all water contained in the ground.

Habitat: The place, including physical and biotic conditions, where a plant or animal lives.

Halite: Common table salt, NaCl.

Hazardous air pollutants (HAPs): *See* Air toxics.

Hazardous Material Transportation Law: This law (Title 49, Sections 5101–5127 of the *United States Code*) is the major transportation-related statute affecting transportation of hazardous cargoes. Regulations include The Hazardous Materials Table (49 CFR 172.101), which designates specific materials as hazardous for the purpose of transportation, and Hazardous Materials Transportation Regulations (49 CFR Parts 171–180), which establish packaging, labeling, placarding, documentation, operational, training, and emergency response requirements for the management of shipments of hazardous cargos by aircraft, vessel, vehicle, or rail.

Hazardous material: Any material that poses a threat to human health and/or the environment. Hazardous materials are typically toxic, corrosive, ignitable, explosive, or chemically reactive.

Hazardous waste: By-products of society that can pose a substantial or potential hazard to human health or the environment when improperly managed. Possesses at least one of four characteristics (ignitability, corrosivity, reactivity, or toxicity), or appears on special EPA lists.

Hedonic statistical framework: A method of assessing the impact of various structural (number of bedrooms, bathrooms, square footage, age, etc.) and locational attributes (local amenities, fiscal conditions, distance to workplace, etc.) on residential housing prices.

Herbaceous plants: Nonwoody plants.

Hertz (Hz): The unit of measurement of frequency, equivalent to one cycle per second.

Historic properties: Any prehistoric or historic districts, sites, buildings, structures, or objects included in, or eligible for inclusion in, the *National Register of Historic Places* (NRHP) maintained by the Secretary of the Interior. They include artifacts, records, and remains that are related to and located within such properties.

Historic site: The site of a significant event, prehistoric or historic activity, or structure or landscape (existing or vanished), where the site itself possesses historical, cultural, or archeological value apart from the value of any existing structure or landscape.

Hydrocarbon: Any compound or mix of compounds, solid, liquid or gas, comprised of carbon and hydrogen (e.g., coal, crude oil, and natural gas).

Hydrology: The study of water that covers the occurrence, properties, distribution, circulation, and transport of water, including groundwater, surface water, and rainfall.

Hypolimnetic: The deeper, cooler portions of a reservoir or lake that result from stratification. (Stratification refers to the division of water in lakes and ponds into layers with different temperatures and oxygen content).

Impact: The effect, influence, alteration, or imprint caused by an action.

Impact-producing factor: An activity or process that causes impacts to the environmental or socioeconomic setting, such as water use, surface disturbance, numbers of employees hired, or solid and liquid waste generation.

Impoundment: A body of water or sludge confined by a dam, dike, floodgate, or other barrier. An impoundment is used to collect and store water for future use.

Incidental take: To harass, harm, wound, or kill threatened or endangered species as an unintentional consequence of project construction or operations.

Indigenous: Native to an area.

Indirect impact: An effect that is related to but removed from a proposed action by an intermediate step or process. An example would be changes in surface water quality resulting from soil erosion at construction sites.

Infrasound: Sound waves below the frequency range that can be heard by humans (about 1 to <20 Hz). Infrasound can often be felt, or sensed as a vibration, and can cause motion sickness and other disturbances.

Infrastructure: The basic facilities, services, and utilities needed for the functions of an industrial facility or site.

In situ processing: Processing that liquefies and mobilizes the kerogen (oil shale) or bitumen (tar sands) in place by circulating a heated working medium such as gas, superheated water, or steam, or by using underground electric heaters.

In situ: In its original place; unmoved, unexcavated; remaining at the site or in the subsurface.

Interbedded: Alternating layers of different character.

Intermittent streams: A stream that flows most of the time but occasionally is dry or reduced to a pool stage when losses from evaporation or seepage exceed the available streamflow.

Intermontane: Between or surrounded by mountains.

Invasive species: Any species, including noxious and exotic species, that is an aggressive colonizer and can out-compete indigenous species.

Isochronal: Recurring at regular intervals; of equal time.

Just-in-Time ordering strategy: A strategy for managing materials used at a project that ensures materials become available as needed to support activities but are not stockpiled at the project location in excess of what is needed at any point in time. The just-in-time approach controls costs by avoiding the accumulation of inflated inventories, reducing the potential for stockpiled materials to go out of date or otherwise become obsolete, and minimizing product storage and management requirements. When applied to hazardous chemicals, this approach reduces waste generation, the potential for mismanagement of materials, and the overall risk of adverse impacts resulting from emergency or off-normal events involving those materials.

Joint: A fracture or parting in rock, without movement.

Kerogen: The hydrocarbon in oil shale. Kerogen is a pyrobitumen, and oil is formed from kerogen by heating. It consists chiefly of low forms of plant life; chemically it is a complex mixture of hydrocarbon compounds of large molecules, containing hydrogen, carbon, oxygen, nitrogen, and sulfur. Kerogen is the chief source of oil in oil shales.

Lacustrine: Pertaining to a lake. Lacustrine sediments are deposited in lakes.

Laydown area: An area that has been cleared for the temporary storage of equipment and supplies. To ensure accessibility and safe maneuverability for transport and off-loading of vehicles, lay-down areas are usually covered with rock and/or gravel.

L_{dn}: The day-night average sound level. It is the average A-weighted sound level over a 24-hour period that gives additional weight to noise that occurs during the night (10:00 p.m. to 7:00 a.m.).

Leachate: A liquid that results from water collecting contaminants as it trickles through wastes, agricultural pesticides, or fertilizers. Leaching may occur in farming areas, feedlots, and landfills, and may result in hazardous substances entering surface water, groundwater, or soil.

Leaching: The process by which soluble substances are dissolved and transported down through the soil by recharge.

Lead: A gray-white metal that is listed as a criteria air pollutant. Health effects from exposure to lead include brain and kidney damage and learning disabilities. Sources include leaded gasoline and metal refineries.

Lease: A contract in legal form that provides for the right to develop and produce resources within a specific area for a specific period of time under certain agreed-upon terms and conditions.

Lek: A traditional site that is used year after year by males of certain bird species for communal display as they compete for female mates. Leks are generally areas supported by low, sparse vegetation or open areas surrounded by sagebrush that provide escape, feeding, and cover.

Leq: Equivalent/continuous sound level. L_{eq} is the steady sound level that would contain the same total sound energy as the time-varying sound over a given time.

Limestone: A sedimentary rock consisting of more than 50% calcium carbonate ($CaCO_3$).

Listed species: Any species of fish, wildlife, or plant that has been determined, through the full, formal ESA listing process, to be either threatened or endangered.

Losing streams: Streams that seem to disappear because they flow into an aquifer.

Low-frequency sound: Sound waves with a frequency in the range of 20 to 80 Hz. The range of human hearing is approximately 20 to 20,000 Hz.

Mahogany Zone: The Mahogany Zone (Parachute Member) in the Piceance Creek Basin consists of kerogen-rich strata and averages 100 to 200 ft thick. This zone extends to all margins of the basin and is the richest oil shale interval in the stratigraphic section.

Management Framework Plan (MFP): A land use plan that establishes land use allocations, multiple use guidelines, and management objectives for a given planning area. The MFP planning system was used by the BLM until about 1980.

Marlstone: An earthy or impure argillaceous limestone.

Marsh: A wetland where the dominant vegetation is nonwoody plants, such as grasses, as compared with a swamp where the dominant vegetation is woody plants, such as trees and shrubs.

Mechanical noise: Noise caused by the vibration or rubbing of mechanical parts.

Mesic: Refers to a habitat that is neither wet or dry; intermediate in moisture, without extremes.

Mesocyclone: A cyclonically rotating vortex, around 2 to 6 mi in diameter, in a convective storm.

Mineral Leasing Act of 1920 (MLA): Authorizes the agency to issue rights-of-way grants for oil and gas gathering and distribution pipelines and related facilities not already authorized through a lease, and oil and natural gas transmission pipelines and related facilities.

Mineral materials (salable): For BLM-managed land, these are defined as minerals such as common varieties of sand, gravel, pumice, and clay that are not obtainable under the mining or leasing law, but that can be obtained through purchase or free use permit under the Materials Act of 1947, as amended.

Mitigation: A method or process by which impacts from actions can be made less injurious to the environment through appropriate protective measures. Also called mitigative measure.

Monocline: An open, step-like fold in rock over a large area.

Montane: A section of a mountainous region below the timberline, characterized by cool, moist temperatures and dominated by evergreen trees.

Mudflat: A flat sheet of mud between the high and low tide marks. Also, the flat bottoms of lakes, rivers, and ponds, largely filled with organic deposits, freshly exposed by a lowering of the water level.

Nahcolite: Sodium bicarbonate or baking soda ($NaHCO_3$).

National Ambient Air Quality Standards (NAAQS): Air quality standards established by the CAA, as amended. The primary NAAQS specify maximum outdoor air concentrations of criteria pollutants that would protect the public health within an adequate margin of safety. The secondary NAAQS specify maximum concentrations that would protect the public welfare from any known or anticipated adverse effects of a pollutant.

National Conservation Areas: Areas designated by Congress to provide for the conservation, use, enjoyment, and enhancement of certain natural, recreational, paleontological, and other resources, including fish and wildlife habitat.

National Environmental Policy Act of 1969 (NEPA): Requires federal agencies to prepare a detailed statement on the environmental impacts of their proposed major actions significantly affecting the quality of the human environment.

National Historic Preservation Act of 1996, as Amended (NHPA): Requires federal agencies to take into account the effects of their actions on historical and archaeological resources and consider opportunities to minimize their impacts.

National Historic Trails: These trails are designated by Congress under the National Trails System Act of 1968 and follow, as closely as possible, on federal land, the original trails or routes of travel with national historical significance.

National Landscape Conservation System (NLCS): Created by the BLM in June 2000 to increase public awareness of BLM lands with scientific, cultural, educational, ecological, and other values. It consists of National Conservation Areas, National Monuments, Wilderness Areas, Wilderness Study Areas, Wild and Scenic Rivers, and National Historic and Scenic Trails.

National Monument: An area owned by the federal government and administered by the National Park Service, the BLM, and/or U.S. Forest Service for the purpose of preserving and making available to the public a resource of archaeological, scientific, or aesthetic interest. National monuments are designated by the president, under the authority of the American Antiquities Act of 1906, or by Congress through legislation.

National Natural Landmark: An area of national significance, designated by the Secretary of the Interior or the Secretary of Agriculture, that contains outstanding examples of the nation’s natural heritage.

National Outstanding Natural Areas: Areas of public land that are either Congressionally or administratively designated on the basis of their exceptional, rare, or unusually natural characteristics.

National Parks: Public lands set aside by an act of Congress because of their unique physical and/or cultural value to the nation as a whole. These lands are administered by the National Park Service.

National Pollutant Discharge Elimination System (NPDES): A federal permitting system controlling the discharge of effluents to surface water and regulated through the CWA, as amended.

National Recreation Area: An area designated by Congress to conserve and enhance certain natural, scenic, historic, and recreational values.

National Recreation Trails: Trails designated by the Secretary of the Interior or the Secretary of Agriculture that are reasonably accessible to urban areas and meet criteria established in the National Trails System Act.

National Register of Historic Places: A comprehensive list of districts, sites, buildings, structures, and objects that are significant in American history, architecture, archaeology, engineering, and culture. The National Register is administered by the National Park Service, which is part of the U.S. Department of the Interior.

National Scenic Trails: These trails are designated by Congress and offer maximum outdoor recreation potential and provide enjoyment of the various qualities—scenic, historical, natural, and cultural—of the areas through which these trails pass.

National Wild and Scenic River: A river or river section designated by Congress or the Secretary of the Interior, under the authority of the Wild and Scenic Rivers Act of 1968, to protect outstanding scenic, recreational, and other values and to preserve the river or river section in its free-flowing condition.

National Wildlife Refuge System: A designation for certain protected areas in the United States, managed by the USFWS, that includes all lands, waters, and interests therein administered by the USFWS as wildlife refuges, wildlife ranges, wildlife management areas, waterfowl production areas, and other areas for the protection and conservation of fish, wildlife, and plant resources.

Native American Graves Protection and Repatriation Act: This Act established the priority for ownership or control of Native American cultural items excavated or discovered on federal or tribal land after 1990 and the procedures for repatriation of items in federal possession. The Act allows the intentional removal from or excavation of Native American cultural items from federal or tribal lands only with a permit or upon consultation with the appropriate tribe.

Nitrogen dioxide (NO_2): A toxic reddish brown gas that is a strong oxidizing agent, produced by combustion (as of fossil fuels). It is the most abundant of the oxides of nitrogen in the atmosphere and plays a major role in the formation of ozone.

Nitrogen oxides (NO_X): Nitrogen oxides include various nitrogen compounds, primarily nitrogen dioxide and nitric oxide. They form when fossil fuels are burned at high temperatures and react with volatile organic compounds to form ozone, the main component of urban smog. They are also a precursor pollutant that contributes to the formation of acid rain. Nitrogen oxides are one of the six criteria air pollutants specified under Title I of the CAA.

No Surface Occupancy (NSO): A fluid mineral leasing stipulation that prohibits occupancy or disturbance on all or part of the lease surface in order to protect special values or uses. Lessees may develop the oil and gas or geothermal resources under leases restricted by this stipulation through use of directional drilling from sites outside the no surface occupancy area.

Noise Control Act of 1972: Requires that noise levels of facilities or operations not jeopardize public health and safety. States are authorized to establish their own noise levels.

Nominal (measurement): A design value, based on experience and generally reflecting accepted industry practice. A nominal value (e.g., depth of a tower foundation) may change depending on the conditions at a specific location.

Nonattainment area: The EPA's designation for an air quality control region (or portion thereof) in which ambient air concentrations of one or more criteria pollutants exceed NAAQS.

Nonenergy leasables: All solid nonenergy mineral that private entities produce under leases issued by the BLM. These entities pay royalties to the federal government based on the value of the mineral they produce. Most of these minerals are used in industry and include sodium, bicarbonate, and potash.

Non-point-source contaminant: Forms of diffuse pollution caused by sediment, nutrients, and organic and toxic substances originating from land use activities; these substances are carried to lakes and streams by surface runoff. Non-point source pollution is contamination that occurs when rainwater, snowmelt, or irrigation water washes off plowed fields, city streets, or suburban backyards. As this runoff moves across the land surface, it picks up soil particles and pollutants, such as nutrients and pesticides.

Noxious plants/noxious weeds: Those plants regulated by law or those that are so difficult to control that early detection is important.

Occupational Safety and Health Administration (OSHA): Congress created the OSHA under the Occupational Safety and Health Act on December 29, 1970. Its mission is to prevent work-related injuries, illnesses, and deaths.

Off-highway vehicle (OHV): Any motorized vehicle capable of or designed for travel on or immediately over land, water, or other natural terrain.

Offsets: Reductions in emissions that are caused by an activity not directly related to the source creating the emissions. Offsets are used to stabilize total emissions in a particular area.

Oil and gas leasing (on BLM land): The BLM leases oil and gas rights to explore for and produce oil and gas resources from federal lands or mineral rights owned by the federal government. Federal oil and gas leases may be obtained and held by any adult citizen of the United States.

Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005: As part of the Energy Policy Act of 2005, Congress declared that oil shale and tar sands (and other unconventional fuels) are strategically important domestic energy resources that should be developed to reduce the Nation's growing dependence on oil from politically and economically unstable foreign sources.

Oil shale: A term used to cover a wide range of fine-grained, organic-rich sedimentary rocks. Oil shale does not contain liquid hydrocarbons or petroleum as such but organic matter derived mainly from aquatic organisms. This organic matter, kerogen, may be converted to oil through destructive distillation or exposure to heat.

Organism: Any form of plant or animal life.

Outwash plain: A smooth plain covered by deposits from water flowing from glaciers.

Overburden: The surface soil that must be moved away to get at coal seams and mineral deposits.

Ozone (O_3): A strong-smelling, reactive toxic chemical gas consisting of three oxygen atoms chemically attached to each other. It is formed in the atmosphere by chemical reactions involving NO_x and volatile organic compounds. The reactions are energized by sunlight. Ozone is a criteria air pollutant under the CAA and is a major constituent of smog.

Paleontological resources: Fossilized remains, imprints, and traces of plants and animals preserved in rocks and sediments since some past geologic time.

Paleontology: The study of plant and animal life that existed in former geologic times, particularly through the study of fossils.

Particulate matter: Fine solid or liquid particles, such as dust, smoke, mist, fumes, or smog, found in air or emissions. The size of the particulates is measured in micrometers (μm). One micrometer is 1 millionth of a meter or 0.000039 inch. Particle size is important because the EPA has set standards for $PM_{2.5}$ and PM_{10} particulates.

Parturition areas: Birthing areas commonly used by more than a few female members of a population. Generally used when referring to ungulates, such as elk and mule deer.

Passerines: Perching birds or songbirds.

Perennial streams: Streams that flow continuously.

Permissible exposure limit (PEL): The maximum amount or concentration of a chemical that a worker may be exposed to under OSHA regulations.

Permit: A revocable authorization to use public land for a specified purpose for up to three years. (BLM glossary)

Personal protective equipment (PPE): Clothing and equipment that are worn to reduce exposure to potentially hazardous chemicals and other pollutants.

Petroglyphs: Carvings in rock that express artistic or religious meaning.

Photovoltaic system: A system that converts light into electric current.

Phreatophytic: Relating to deep-rooted plants that obtain water from a permanent ground supply or from the water table.

Physiography: The physical geography of an area or the description of its physical features.

Pigs: Devices routinely introduced into pipelines to clean the inner wall of the pipe and monitor for critical conditions that could compromise the integrity or efficiency of the pipeline, such as cracks, corrosion, and pipe deformations.

Planetary boundary layer: The bottom layer of the atmosphere that is in contact with the surface of the earth. Within this layer, the effects of friction are significant. It is roughly the lowest 1 or 2 km of the atmosphere.

Plateau: A large, flat area of land that is higher than the surrounding land.

Playa: A dry, vegetation-free area in the bottom of an undrained desert basin. It may contain deposits of clay, silt, or sand and, frequently, soluble salts of sodium, calcium, potassium, etc.

Playa lake: A shallow, intermittent lake in an arid or semiarid region. It occupies a playa and may dry up in the summer.

PM_{10}: Particulate matter with a mean aerodynamic diameter of 10 μm (0.0004 in.) or less. Particles less than this diameter are small enough to be deposited in the lungs. PM_{10} is one of the six criteria air pollutants specified under Title I of the CAA.

$PM_{2.5}$: Particulate matter with a mean aerodynamic diameter of 2.5 μm (0.0001 in.) or less.

Policy: A plan of action adopted by an organization.

Pollutant: Any material entering the environment that has undesired effects.

Polycyclic aromatic hydrocarbons (PAHs): Aromatic hydrocarbons containing more than one fused benzene ring. PAHs are a carcinogenic component of the tar sands and oil shale. PAHs are commonly formed during the incomplete burning of coal, oil and gas, garbage, or other organic substances.

Polychlorinated biphenhyls (PCBs): A group of manufactured organic compounds made up of carbon, hydrogen, and chlorine. They were used in the manufacture of plastics and as insulating fluids for electrical equipment. Because they are very stable and fat-soluble, they accumulate in ever-higher concentrations as they move up the food chain. Their use was banned in the United States in 1979.

Population: A group of individuals of the same species occupying a defined locality during a given time that exhibit reproductive continuity from generation to generation.

Potable water: Water that can be used for human consumption.

Preference right lease areas: In the context of the BLM's ongoing oil shale research, development, and demonstration (RD&D) program, an area reserved by the holder of an RD&D lease for future leasing for the commercial development of oil shale, subsequent to review and approval by the BLM.

Prevention of Significant Deterioration (PSD) Program: An air pollution permitting program intended to ensure that air quality does not diminish in attainment areas.

Processing technologies: *See* Retorting.

Programmatic Agreement: A document that records the terms and conditions agreed upon to resolve the potential adverse effects of a federal agency program, complex undertaking, or other situations in accordance with Section 800.14(b), "Programmatic Agreements," of 36 CFR Part 800, "Protection of Historic Properties."

Public Land Order (PLO): An order affecting, modifying, or canceling a withdrawal or reservation that has been issued by the Secretary of the Interior pursuant to powers of the President delegated to the Secretary by Executive Order 9146 of April 24, 1942, or 9337 of April 24, 1943.

Public land: Any land and interest in land (outside of Alaska) owned by the United States and administered by the Secretary of the Interior through the BLM.

Putrescible waste: Solid waste that contains organic matter that can rot or decompose.

Pyrolysis: Chemical decomposition by the action of heat.

Raptor: Bird of prey.

Reclamation: Returning disturbed lands to a form and productivity that will be ecologically balanced and in conformity with a predetermined land management plan.

Recharge: The addition of water to an aquifer by natural infiltration (e.g., rainfall that seeps in to the ground) or by artificial injection through wells.

Recreation Opportunity Spectrum (ROS) Class: A tool commonly used by federal land management agencies to determine the level of development, the types of facilities that are appropriate, and the type of recreational opportunities that one will experience. Six recreation opportunity classes have been developed: primitive, semiprimitive nonmotorized, semiprimitive motorized, roaded natural, rural, and urban.

Refugium: An area where special environmental circumstances have enabled a species or a community of species to survive after extinction in surrounding areas.

Region of influence (ROI): Consists of the counties in each of the three states (Colorado, Utah, and Wyoming) in which each oil shale and tar sands resource is located.

Relict: A remnant or fragment of the vegetation of an area that remains from a former period when the vegetation was more widely distributed.

Research Natural Areas: Areas designated or set aside by Congress or by a public or private agency to protect natural features or processes for scientific and educational purposes.

Resource Conservation and Recovery Act (RCRA): Regulates the storage, treatment, and disposal of hazardous and nonhazardous wastes.

Resource Management Plan (RMP): A land use plan that establishes land use allocations, multiple use guidelines, and management objectives for a given planning area. The RMP planning system has been used by the BLM since about 1980.

Retort: A device or process used for extraction or distillation of valuable resources from complex mixtures. In oil shale processing, a retort is a mechanical device in which mined and sized oil shale is heated to cause the pyrolysis of its kerogen organic fraction to produce organic liquids known as raw shale oil.

Retorting: Processing technologies for separating valuable resources from their parent ores or extracting them from their natural settings. Retorting of oil shale involves removing kerogen from the oil shale, usually by burning or heating the shale, and subsequent chemical conversion of the kerogen into synthetic crude oils. Retorting can be carried out in surface vessels (surface retorting) or underground in fractured shale. Chemical treatment processes also may be applied. Aboveground retorting (AGR) technologies are used to process mined oil shale; the retorting processes are typically preceded by a variety of pretreatment activities, including crushing, sizing, and sorting. By-products of aboveground retorting of oil shale include flammable low-molecular weight organic gases and "spent shale" (that which is left of the original oil shale after kerogen has been removed).

Riffle: A rapid, turbulent flow of water over a shallow area in a stream. Riffles add oxygen to the water as water is churned and provide habitat for many invertebrates.

Right-of-way (ROW): A legal right of passage over another person's land; public land authorized to be used or occupied pursuant to a ROW grant.

Right-of-way corridor: A designated parcel of land, either linear or areal in character, that has been identified through the land use planning process as the preferred location for existing and future ROW grants and would accommodate more than one type of ROW or one or more ROWs that are similar, identical, or compatible.

Rights-of-Way Grant: The authorization to use a particular parcel of public land for specific facilities for a definite time period; authorizes the use of a ROW over, upon, under, or through public lands for construction, operation, maintenance, and termination of a project.

Riparian: Relating to, living in, or located on the bank of a river, lake, or tidewater.

Rolling footprint: Development that occurs incrementally so that, at any given time, some portion of a lease area is involved in active development, another portion is involved in preparation for a future development phase, another portion is undergoing restoration after development, and the remainder of the lease area is essentially undeveloped. Ultimately, the entire lease will be developed and then restored, but the amount of acreage that is disturbed at any given time is a subset of the entire lease.

Room-and-pillar entries: Refers to a system of mining in which typically flat-lying beds of coal or ore are removed from haulage-ways (entries) and selected areas called rooms. Pillars of unmined coal are left between the rooms to support the roof.

Run-of-mine: Refers to ore in its natural, unprocessed state; pertaining to ore just as it is mined.

Safe Drinking Water Act (SDWA): This Act authorizes development of maximum contaminant levels for drinking water applicable to public water systems (i.e., systems that serve at least 25 people or have at least 15 connections).

Salt: Any compound formed by the reaction of an acid and a base. The sodium salts formed in saline lakes are typically the reaction products of carbonic acid (H_2CO_3) with sodium derived from the weathering of any number of minerals containing sodium. Carbonic acid is formed when atmospheric carbon dioxide dissolves in water.

Sandstone: A sedimentary rock composed primarily of sand-sized (0.0025 to 0.08 in.) grains.

Savannah: A flat grassland of tropical and subtropical regions usually having distinct periods of dry and wet weather.

Scrubbers: Any of several forms of chemical/physical devices that remove sulfur compounds formed during coal combustion.

Section 7 of the Endangered Species Act: Requires all federal agencies, in “consultation” with the USFWS, to ensure that their actions are not likely to jeopardize the continued existence of listed species or result in destruction or adverse modification of critical habitat.

Sedges: Perennial nonwoody plants that resemble grasses in that they have relatively narrow leaves. They are common to most freshwater wetlands.

Sediment: Materials that sink to the bottom of a body of water, or materials that are deposited by wind, water, or glaciers.

Sedimentary rock: Rock formed at or near the earth’s surface from the consolidation of loose sediment that has accumulated in layers through deposition by water, wind, or ice, or deposited by organisms. Examples are sandstone and limestone.

Sedimentation: The removal, transport, and deposition of sediment particles by wind or water.

Seeps: Wet areas, normally not flowing, arising from an underground water source. Any place where liquid has oozed from the ground to the surface.

Seismic: Pertaining to any earth vibration, especially that of an earthquake.

Sensitive species: A plant or animal species listed by the state or federal government as threatened, endangered, or as a species of special concern. The list of BLM sensitive species varies from state to state, and the same species can be considered sensitive in one state but not in another.

Seral: The state of development in ecological succession.

Shake-down tests: Tests conducted to demonstrate that equipment is operational and meets performance requirements.

Shale oil: A crude liquid hydrocarbon obtained from oil shale by distillation. The shale oil may be refined into normal petroleum products such as gasoline and diesel fuel.

Shortite: Sodium calcium carbonate ($Na_2Ca_2(CO_3)_3$.

Shrub steppe: Habitat composed of various shrubs and grasses.

Silt: Sedimentary material consisting of fine mineral particles intermediate in size between sand and clay.

Siltation: The deposition or accumulation of silt.

Siltstone: A sedimentary rock composed primarily of silt-sized (0.00016 to 0.0025 in.) grains.

Slash: Any tree-tops, limbs, bark, abandoned forest products, windfalls, or other debris left on the land after timber or other forest products have been cut.

Sludge: A dense, slushy, liquid-to-semifluid product that accumulates as an end result of an industrial or technological process designed to purify a substance; A semisolid residue from any of a number of air or water treatment processes; can be a hazardous waste.

Solid Waste Disposal Act: An act that regulates the treatment, storage, or disposal of solid, both hazardous and nonhazardous waste, as amended by RCRA and the Hazardous and Solid Waste Amendments of 1984.

Sound pressure level: The level, in decibels, of acoustic pressure waves. Very loud sounds have high sound pressure levels; soft sounds have low sound pressure levels. A 3-dB increase in sound doubles the sound pressure level. Zero decibels is the threshold of human hearing. The maximum level of human hearing is around a 120-dB sound pressure level, which is the level where people begin to experience pain because of the high sound pressure levels.

Special areas: Areas of high public interest and containing outstanding natural features or values. BLM special areas include National Wild and Scenic Rivers, National Wildernesses, National Conservation Areas, National Scenic Areas, National Recreation Areas, National Monuments, National Outstanding Natural Areas, National Historic Landmarks, National Register of Historic Places, National Natural Landmarks, National Recreational Trails, National Scenic Trails, National Historic Trails, National Backcountry Byways, Areas of Critical Environmental Concern, Research Natural Areas, Important Bird Areas, United Nations Biosphere Reserves, and World Heritage Sites.

Special Recreation Management Areas (SRMAs): An area that possesses outstanding recreation resources or where recreation use causes significant user conflicts, visitor safety problems, or resource damage.

Special Status species: Includes both plant and animal species that are proposed for listing, officially listed as threatened or endangered, or are candidates for listing as threatened or endangered under the provisions of the ESA; those listed by a state in a category such as threatened or endangered, implying potential endangerment or extinction; and those designated by each BLM State Director as sensitive.

Species of Special Concern: A species that may have a declining population, limited occurrence, or low numbers for any of a variety of reasons.

Spent shale: By-product of aboveground retorting of oil shale, that is, what is left of the original oil shale after kerogen has been removed; spent shale is typically disposed of as a waste or used in reclamation of the oil shale mine.

Split estate lands: Lands where the owner of the mineral rights and the surface owner are not the same party in interest. The most common split estate is federal ownership of mineral rights and other-interest ownership of the surface. The federal government can lease the oil and gas rights without surface owner consent, where such a condition occurs.

Spoilbank: A pile of soil, subsoil, rock, or other material excavated from a drainage ditch, pond, or other cut. A deposit at the surface of the mine of mined material (e.g., coal).

State Historic Preservation Officer (SHPO): The state officer charged with the identification and protection of prehistoric and historic resources in accordance with the National Historic Preservation Act.

State Implementation Plan (SIP): A plan for controlling air pollution and air quality in that state; each state must develop its own regulations to monitor, permit, and control air emissions within its boundaries.

Steppe: *See* Shrub-steppe.

Stipulation: A provision that modifies standard lease rights and is attached to and made a part of the lease.

Strata: Single, distinct layers of sediment or sedimentary rock.

Strategic Petroleum Reserve (SPR): The largest stockpile of government-owned emergency crude oil in the world. It was established in 1975 in the aftermath of the 1973–1974 oil embargo to provide emergency crude oil supplies for the United States. The oil is stored in underground salt caverns in Texas and Louisiana.

Stratification: Separating into layers. Stratification refers to the division of water in lakes and ponds into layers with different temperatures and oxygen content.

Stratigraphy, subsurface: The arrangement (in layers) of different types of geologic materials located below the surface of an area.

Subalpine: The growing or living conditions in mountainous regions just below the timberline.

Substation: Consists of one or more transformers and their associated switchgear. A substation is used to switch generators, equipment, and circuits or lines in and out of a system. It is also used to change ac voltages from one level to another.

Sulfur dioxide (SO_2): A gas formed from burning fossil fuels. Sulfur dioxide is one of the six criteria air pollutants specified under Title I of the CAA.

Sulfur oxides (SO_x)): Pungent, colorless gases that are formed primarily by fossil fuel combustion. Sulfur oxides may damage the respiratory tract, as well as plants and trees.

Surface mining: Removal of a mineral by stripping off the overburden, removing the mineral, and then replacing the overburden and topsoil.

Surface retorting: *See* Retorting.

Surface water: Water on the earth's surface that is directly exposed to the atmosphere, as distinguished from water in the ground (groundwater).

Switchgear: A group of switches, relays, circuit breakers, etc., used for controlling distribution of power to other distribution equipment and large loads.

Syncline: A downward, trough-shaped configuration of folded, stratified rocks.

Syncrude: Synthetic crude oil.

Talus: Rock debris accumulated at the base of the cliff or slope from which they have broken off.

Tar sands: Also referred to as "oil sand" or "bituminous sand," tar sand is a sedimentary material composed primarily of sand, clay, water (in some deposits) and organic constituents known as bitumen. Processing of tar sands involves separating the bitumen fraction from the inorganic materials and subsequently upgrading the bitumen through a series of reactions to produce a synthetic crude oil feedstock that is suitable for further refining into distillate fuels in conventional refineries.

Terrace: A step-like surface, bordering a valley floor or shoreline, that represents the former position of a floodplain, lake, or seashore.

Terrestrial: Belonging to or living on land.

Thermal maturity: The amount of heat, in relative terms, to which a rock has been subjected. A thermally immature rock has not been subjected to enough heat to begin the process of converting kerogen to oil and/or gas. A thermally overmature rock has been subjected to enough heat to convert it to graphite. These are the two extremes, and there are many intermediate stages of thermal maturity.

Threatened species: Any species that is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range. Requirements for declaring a species threatened are contained in the ESA.

Timing limitations (seasonal restriction): Prohibits surface use during specified time periods to protect identified resource values. The stipulation does not apply to the operation and maintenance of production facilities unless the findings of analysis demonstrate the continued need for such mitigation and that less stringent, project-specific mitigation measures would be insufficient.

Topography: The shape of the earth's surface; the relative position and elevations of natural and human-made features of an area.

Total dissolved solids (TDS): The dry weight of dissolved material, organic and inorganic, contained in water. The term is used to reflect salinity.

Total Maximum Daily Load (TMDL): The sum of the individual wasteload allocations for point sources, load allocations for nonpoint sources and natural background, plus a margin of safety. TMDLs can be expressed in terms of mass per time, toxicity, or other appropriate measures that relate to a state's water quality standard.

Toxic Substances Control Act (TSCA): An Act authorizing the EPA to secure information on all new and existing chemical substances and to control any of these substances determined to cause an unreasonable risk to public health or the environment.

Transformer: A device for transferring electric power from one circuit to another in an alternating current system. Transformers are also used to change voltage from one level to another.

Transponder: A device that transmits and responds to radio waves.

Trona: Soda ash; a major source of sodium minerals ($Na_2(CO_3)(HCO_3)2H_2O$.)

Turbidity: A measure of the cloudiness or opaqueness of water. Typically, the higher the concentration of suspended material, the greater the turbidity.

Understory species: Plants that grow beneath a forest canopy.

Unfossiliferous: Not fossil bearing.

U.S. Environmental Protection Agency (EPA): The independent federal agency, established in 1970, that regulates federal environmental matters and oversees the implementation of federal environmental laws.

Undissected: A plateau or other relatively level surface that has not been deeply cut by streams.

Valid existing rights: Legal interests that attach to a land or mineral estate that cannot be divested from the estate until that interest expires or is relinquished.

Viewshed: The total landscape seen or potentially seen from all or a logical part of a travel route, use area, or water body.

Visitor days: One visitor day equals 12 visitor hours at a site or area.

Visual impact: The creation of an intrusion or perceptible contrast that affects the scenic quality of a landscape.

Visual Resource Management (VRM) System: Procedures and methods that support decision-making for planning activities and reviews of proposed developments on BLM-administered lands.

Visual Resource Management Classes: VRM classes identify the degree of acceptable visual change within a particular landscape. A classification is assigned to public lands based on the guidelines established for scenic quality, visual sensitivity, and visibility *(see Section 3.8*).

Visual resources: Refers to all objects (man-made and natural, moving and stationary) and features such as landforms and water bodies that are visible on a landscape.

Vitrinite reflectance (Ro): A measure of the percentage of incident light reflected from a polished surface of vitrinite. It is a measure of the thermal maturity of a sedimentary rock containing kerogen. It is an indicator of whether a source rock has been heated enough to produce oil, oil and gas, or gas only.

Vitrinite: A type of organic material found in coal.

Volatile organic compounds (VOCs)**:** A broad range of organic compounds that readily evaporate at normal temperatures and pressures. Sources include certain solvents, degreasers (benzene), and fuels. Volatile organic compounds react with other substances (primarily nitrogen oxides) to form ozone. They contribute significantly to photochemical smog production and certain health problems.

Wastewater: Water that typically contains less than 1% concentration of organic hazardous waste materials.

Water quality: The condition or purity of water with respect to the amount of impurities in it.

Watershed: An area from which water drains to a particular body of water. Watersheds range in size from a few acres to large areas of the country.

Wetlands: Areas that are soaked or flooded by surface or groundwater frequently enough or long enough to support plants, birds, animals, and aquatic life. Wetlands generally include swamps, marshes, bogs, estuaries, and other inland and coastal areas and are federally protected.

Wild and Scenic Rivers (WSR) Act: Primary river conservation law enacted in 1968. The Act was specifically intended by Congress to balance the existing policy of building dams on rivers for water supply, power, and other benefits, with a new policy of protecting the free-flowing character and outstanding values of other rivers.

Wild Horse and Burro Act: Act passed by Congress in 1971 giving BLM the responsibility to protect, manage, and control wild horses.

Wild Horse and Burro Adoption Program: BLM program that offers excess animals for adoption to qualified people. After caring for an animal for 1 year, the adopter is eligible to receive title, or ownership, from the federal government.

Wild horses and burros: Unbranded and unclaimed horses or burros roaming free on public lands in the western United States and protected by the Wild Free-roaming Horse and Burro Act of 1971. They are descendants of animals turned loose by, or escaped from, ranchers, prospectors, Indian Tribes, and the U.S. cavalry form the late 1800s through the 1930s.

Wilderness Areas: Areas designated by Congress and defined by the Wilderness Act of 1964 as places "where the earth and its community are untrammeled by man, where man himself is a visitor who does not remain." Designation is aimed at ensuring that these lands are preserved and protected in their natural condition.

Wilderness Study Areas (WSAs): Areas designated by a federal land management agency as having wilderness characteristics, thus making them worthy of consideration by Congress for wilderness designation.

Wind rose: Weather map showing the frequency and strength of winds from different directions. A wind rose for use in assessing consequences of airborne releases also shows the frequency of different wind speeds for each compass direction.

Xeric: Low in moisture.

APPENDIX A:

OIL SHALE DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW

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APPENDIX A:

OIL SHALE DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW

This appendix describes the geology of the oil shale resource area, the resource, the history of oil shale development in the western United States, and provides an overview of the technologies that have been applied to oil shale development. Technologies that may be employed in future developments on U.S. Department of the Interior (DOI), Bureau of Land Management (BLM)-administered lands are introduced. Technologies that are addressed in the *Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement (PEIS)* include those used for recovery (i.e., mining), processing (i.e., retorting and pyrolysis of the hydrocarbon fraction), and upgrading of oil shale resources.[1] Assumptions regarding these technologies were developed to support analyses in the PEIS and are also presented in this appendix.

Currently, there is no commercial production of oil from oil shale being undertaken in the United States. While recently there has been a great deal of interest in the potential of oil shale resources, utilization of this material is still in the research and development mode. Recent technological developments have proven to be of great interest, and those developments, along with technologies that were developed during the last wave of interest in oil shale, are now being considered for application in tapping this potential resource.

Development of oil shale resources is expected to proceed gradually and to be led by activities on the six sites located in Colorado and Utah (see Section 1.4.1 of the main text of the PEIS) that are included in the BLM's oil shale research, development, and demonstration (RD&D) program. Chapter 9 of the PEIS provides a glossary of technical terms, including geologic terms, used in the PEIS and its appendices.

A.1 DESCRIPTION OF GEOLOGY

Oil shale is a term used to cover a wide range of fine-grained, organic-rich sedimentary rocks. Oil shale does not contain liquid hydrocarbons or petroleum as such but organic matter derived mainly from aquatic organisms. This organic matter, kerogen, may be converted to oil through destructive distillation or exposure to heat.

Numerous deposits of oil shale are found in the United States. The most prospective shale deposits are contained within sedimentary deposits of the lacustrine Green River Formation of Eocene age. These deposits exist in the greater Green River Basin (including Fossil Basin and

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1 Retorting and pyrolysis are key steps in oil shale processing. Retorting is a process that causes thermal desorption of organic fractions of the oil shale from the mineral fractions. The recovered organic fraction is then distilled, or pyrolyzed, to produce three products: crude shale oil, flammable hydrogen gas, and char. These processes are described further in Section A.3.2.

Washakie Basin) in southwestern Wyoming and northwestern Colorado, the Piceance Basin in northwestern Colorado, and the Uinta Basin in northeastern Utah.[2] Because of the deposits' size and grade, most investigations have focused on the oil shale deposits in these basins. As discussed in Section 1.2 of the main text of the PEIS, in defining the scope of analysis for the PEIS, the BLM identified the most geologically prospective areas for oil shale development on the basis of the grade and thickness of the deposits. For the purposes of this PEIS, the most geologically prospective oil shale resources in Colorado and Utah are defined as those deposits that are expected to yield 25 gal of shale oil per ton of rock (gal/ton) and are 25 ft thick or greater. In Wyoming, where the oil shale resource is not of as high a quality as it is in Colorado and Utah, the most geologically prospective oil shale resources are those deposits that are expected to yield 15 gal/ton or more shale oil and are 15 ft thick or greater. Figure A-1 shows the Green River Formation basins, which were mapped on the basis of the extent of the Green River Formation, and the most geologically prospective oil shale resources within those basins.[3]

In addition to limiting the scope of analyses to the most geologically prospective resources, the BLM has determined that, for the purposes of establishing a commercial leasing program for oil shale development on public lands, oil shale resources that are covered by more than 500 ft of overburden would not be available for application for leasing using surface mining technologies under the scope of this PEIS. This limitation is based on the assumption that 500 ft is about the maximum amount of overburden where surface mining can occur economically, using today's technologies. Figure A-1 shows the areas within the three-state region where surface mining would be considered under the commercial leasing program on the basis of the overburden thickness.[4] Although some of the oil shale resources outcrop in Colorado and have overburden thicknesses of less than 500 ft, the distribution of these areas presents a relatively narrow band of lands within which it would be difficult to assemble a logical mining unit; therefore, surface mining projects in Colorado are not evaluated in this PEIS.

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[2] The Piceance Basin is not referred to or described consistently in published literature. Some publications describe the Piceance Basin as an area encompassing more than 7,000 mi^2 and consisting of a northern province and a southern province, separated approximately by the Colorado River and Interstate 70 (I-70). Other publications refer to the southern province as the Grand Mesa Basin. Oil shale is present in both provinces, with the richest oil shale deposits in the north, and smaller, isolated deposits in the south. Various authors have used the terms "Piceance Basin" and "Piceance Creek Basin" to refer to either the overall basin or the northern area. In this PEIS, the focus is on the northern province, where the richest and thickest reserves are located, and the study area will be referred to as the "Piceance Basin."

[3] Numerous sources of information were used to define the boundaries of the Green River Formation basins and the most geologically prospective oil shale resources. The basin boundaries were defined by digital data provided by the U.S. Geological Survey (USGS) taken from Green (1992), Green and Drouillard (1994), and the Utah Geological Survey (2000). The most geologically prospective oil shale resources in the Piceance Basin were defined on the basis of digital data provided by the USGS taken from Pitman and Johnson (1978), Pitman (1979), and Pitman et al. (1989). In Wyoming, the most prospective oil shale resources were defined on the basis of detailed analyses of available oil shale assay data (Wiig 2006a,b). In Utah, the most prospective oil shale resources were defined by digital data provided by the BLM Utah State Office.

[4] The areas within the most geologically prospective oil shale areas where the overburden is 0 to 500 ft thick were mapped on the basis of a variety of sources of information. In Colorado, the area was defined on the basis of data published in Donnell (1987). In Utah, the area was mapped on the basis of data provided by the Utah Geological Survey (Tabet 2007). In Wyoming, the area was mapped on the basis of data provided by Wiig (2006a,b).

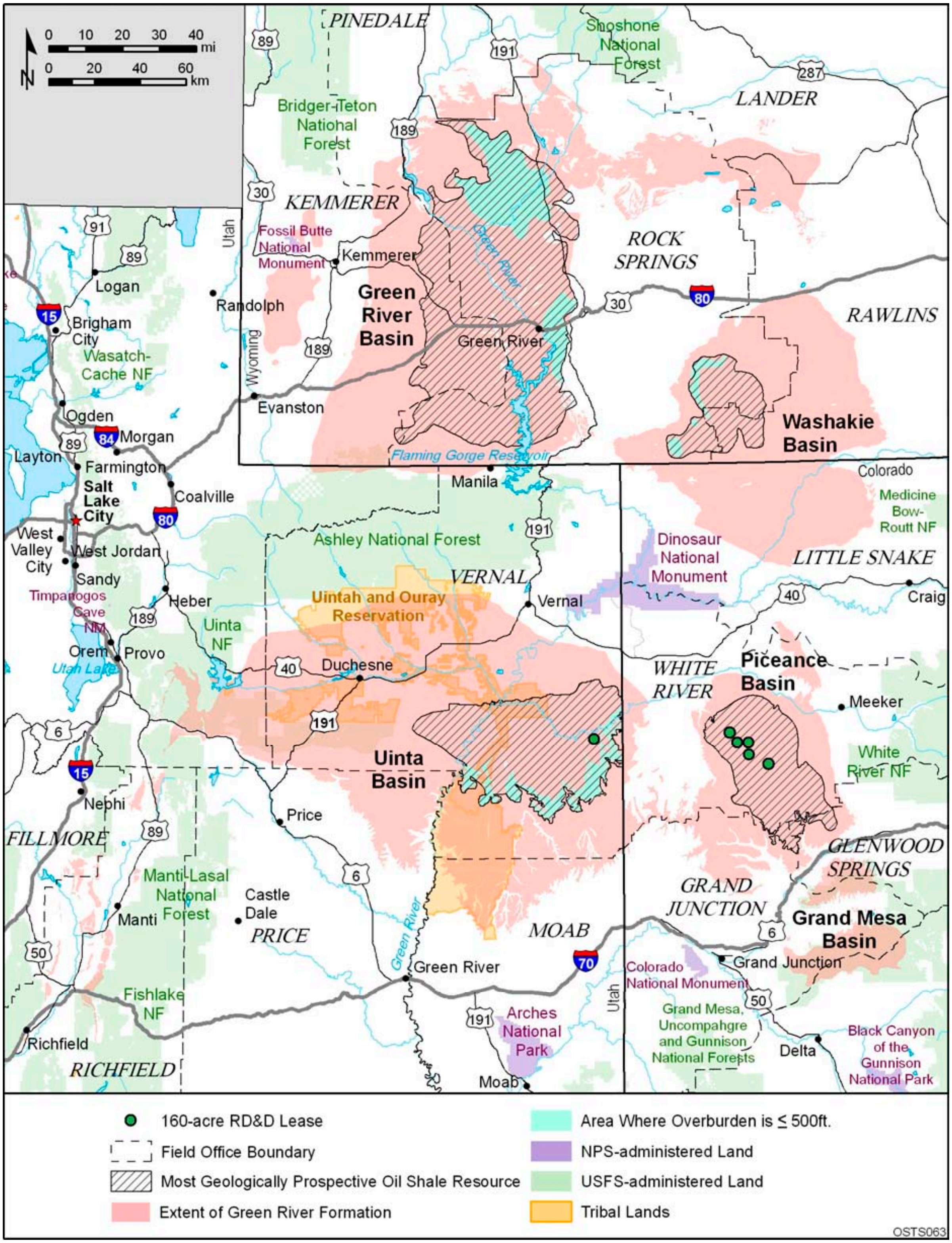

FIGURE A-1 Green River Formation Basins in Colorado, Utah, and Wyoming; Most Geologically Prospective Oil Shale Resources; Areas Where the Overburden above the Oil Shale Resources is ≤500 ft; and Locations of the Six RD&D Projects

A.1.1 Depositional Environment

The Green River Formation was originally deposited in two basins that were later warped into four large structural basins and then elevated several thousand feet above mean sea level (MSL). The major streams and their tributaries traversing the region have eroded much of the sediments from these exhumed basins. The stream erosion has exposed the oil shale on cliffs and ledges in many places. Gentle folds and minor faults deform the deposits locally, but the sedimentary rocks of the oil shale areas as a whole are remarkably undisturbed structurally. Exceptions occur in the areas where the strata are steeply tilted on the flanks of the Uinta Mountains in Utah and Wyoming and along the Grand Hogback in Colorado.

Lacustrine sediments of the Green River Formation that have become oil shale were deposited in two large lakes that occupied 24,000 mi^2 in several sedimentary structural basins in Colorado, Wyoming, and Utah during early through middle Eocene time (40 to 65 million years ago). These basins are separated by the Uinta Mountain uplift and its eastward extension, the Axial Basin anticline. The Green River lake system was in existence for more than 10 million years during a time of a warm-temperate to subtropical climate. The two large lakes initially were freshwater but became quite saline with time.

Fluctuations in the amount of inflowing stream waters caused large changes in the areal extent of the lakes as evidenced by widespread intertonguing of marly (clay and carbonate-rich) lacustrine strata with beds of land-derived sandstone and siltstone. During arid times, the lakes contracted in size and the lake waters became increasingly saline and alkaline. The lake-water content of soluble sodium carbonates and chloride increased, while the less soluble calcium, magnesium, and iron carbonates were precipitated with organic-rich sediments.

During the driest periods, the lake water reached salinities sufficient to precipitate the sodium minerals nahcolite, halite, and trona. The water filling the pore spaces in the sediments was also sufficiently saline to precipitate disseminated crystals of nahcolite, halite, and dawsonite along with a host of other carbonate and silicate minerals (Milton 1977). In Wyoming (Lake Gosiute), trona was precipitated. In Colorado (Lake Uinta), the minerals halite, nahcolite, and dawsonite were precipitated. Why the two lakes precipitated different mineral salts is unknown, but the resulting deposits of trona, nahcolite, and dawsonite constitute an immense potential mineral supply.

The warm, alkaline waters of the Eocene Green River lakes provided excellent conditions for the abundant growth of blue-green algae (cyanobacteria) that is thought to be the major precursor of the organic matter in the oil shale. During times of freshening waters, the lakes hosted a variety of fishes, rays, bivalves, gastropods, ostracods, and other aquatic fauna. Areas peripheral to the lakes supported a large and varied assemblage of land plants, insects, amphibians, turtles, lizards, snakes, crocodiles, birds, and numerous mammals (McKenna 1960; MacGinitie 1969; Grande 1984). These areas where saline minerals are intermixed with oil shale are referred to in this document as “multimineral zones.”

A.1.2 Piceance Basin, Colorado

The Piceance Basin is located mainly in the Colorado Plateau physiographic province. The overall basin is more than 100 mi long and 60 mi wide, with an area more than 7,000 mi^2. The Piceance Basin is simultaneously a structural, depositional, and drainage basin. The structural basin is downwarped and surrounded by uplifts resulting from the Laramide Orogeny. This tectonic activity created a depositional basin that filled with sediments from the surrounding uplands, mainly during the Tertiary period. The basin has a northern province and a southern province (Topper et al. 2003) separated approximately by the Colorado River and I-70. Oil shale is present in both provinces.

Within the Piceance Basin, the upper bedrock stratigraphy consists of a series of basin-fill sediments from the Tertiary period (Topper et al. 2003). The uppermost unit is the Uinta Formation, which consists of up to 1,400 ft of Eocene-age sandstone, siltstone, and marlstone. Below the Uinta Formation is the Eocene Green River Formation, which can be up to 5,000 ft thick and includes four members: the Parachute Creek (keragenous dolomitic marlstone and shale), the Anvil Points (shale, sandstone, and marlstone), the Garden Gulch (claystone, siltstone, clay-rich oil shale, and marlstone), and the Douglas Creek (siltstone, shale, and sandstone). The Eocene-Paleocene Wasatch Formation underlies the Green River Formation and is approximately 6,900 ft thick near the town of Rifle, Colorado. Exposed Wasatch rocks include clays and shales with some interbedded sandstone and are found in the lowest elevations between the base of the cliffs and the major streams (the Colorado River, Government Creek, and Parachute Creek). The Wasatch Formation is a significant oil and natural gas–producing unit in the region. Below the Wasatch are the Cretaceous Mesaverde Group (sandstone and shale), the Cretaceous Mancos Shale, and older sedimentary formations atop Precambrian rock. The Mesaverde Group is the major oil- and gas-producing formation in the Piceance Basin.

The main oil shale members of interest in the Piceance Basin are the Parachute Creek and Garden Gulch Members. The grade of oil shale varies with location and depth, but the Parachute Creek Member has the richest material and includes the Mahogany Zone.

Elsewhere in the region, the Grand Hogback exposes Paleozoic and Mesozoic sedimentary bedrock units that dip steeply to the west and southwest. Tertiary basalt flows cover much of the higher-elevation areas south of the Colorado River (i.e., Battlement Mesa) and the White River Plateau to the northeast. Quaternary alluvium occurs as a broad belt along the lower reaches of Parachute, Rifle, and Government Creeks and along the Colorado River (Widmann 2002). Quaternary alluvium of varying thickness is present in the significant drainages of the basin.

Although the oil shale deposits in Colorado cover the smallest geographical area, they are the richest, thickest, and best-known deposits. In addition, natural gas production is prolific from formations located stratigraphically below the oil shale, with 4 of the top 35 natural gas fields in the United States located in the southern Piceance Basin. Substantial quantities of saline minerals (halite, dawsonite, and nahcolite) are intermixed or intermingled with oil shale in certain zones in the northern half of the basin. Three layers of nahcolite are present near the base of this saline zone, and two halite-bearing strata exist in the upper part of the zone. The dawsonite and other saline minerals are finely disseminated in and associated with beds of oil shale, which are up to 700 ft thick near the center of the basin. Dyni (1974) estimated the total nahcolite resource at 29 billion tons. Beard et al. (1974) estimated nearly the same amount of nahcolite and 17 billion tons of dawsonite. Both minerals have value for soda ash. Dawsonite has potential value for its alumina content and most likely would be recovered as a by-product of an oil shale operation. One company is presently solution mining about several hundred thousand tons/yr of nahcolite in the northern part of the Piceance Basin at depths of about 1,970 ft (Day 1998). The BLM has identified an area in the Piceance Basin, referred to as the Multimineral Zone, where development of nahcolite, dawsonite, or oil shale cannot result in destruction of another resource.

About 80% of the potential oil shale resources of the Green River Formation, or about 1.2 trillion bbl of oil equivalent, is found in west-central Colorado's Piceance Basin. Of the total potential resource, about 480 billion bbl are contained in deposits averaging at least 25 gal/ton. The higher-grade shale sections range from 10 ft to more than 2,000 ft in thickness and may be covered with overburden ranging up to 1,600 ft thick.

A.1.3 Uinta Basin, Utah

In Utah, oil shale deposits are found in the Parachute Creek Member of the Green River Formation, which intertongues with but generally occurs above the Douglas Creek Member. As many as eight oil shale zones have been identified in the Parachute Creek Member; the richest oil shale is found in the Mahogany Zone, which contains up to 100 ft or more of rock that averages 15 gal/ton. Figure A-2 is a generalized stratigraphic section of the rich and lean oil shale zones of the Parachute Creek Member of the Green River Formation in the Uinta Basin, Utah. The thickness of the different zones shown in the stratigraphic section is not constant, but varies across the basin. No single comprehensive and modern study of the oil shale resources of the entire Uinta Basin has been carried out. An early study of the Uinta Basin (Cashion 1967), based on less data than are available today, yielded a potential resource estimate for the Mahogany oil shale zone that is at least 15 ft thick and contains an average yield of at least 25 gal/ton of 26.8 billion bbl (Table A-1). A more recent study (Truedell at al. 1973), based on a greater amount of drilling data

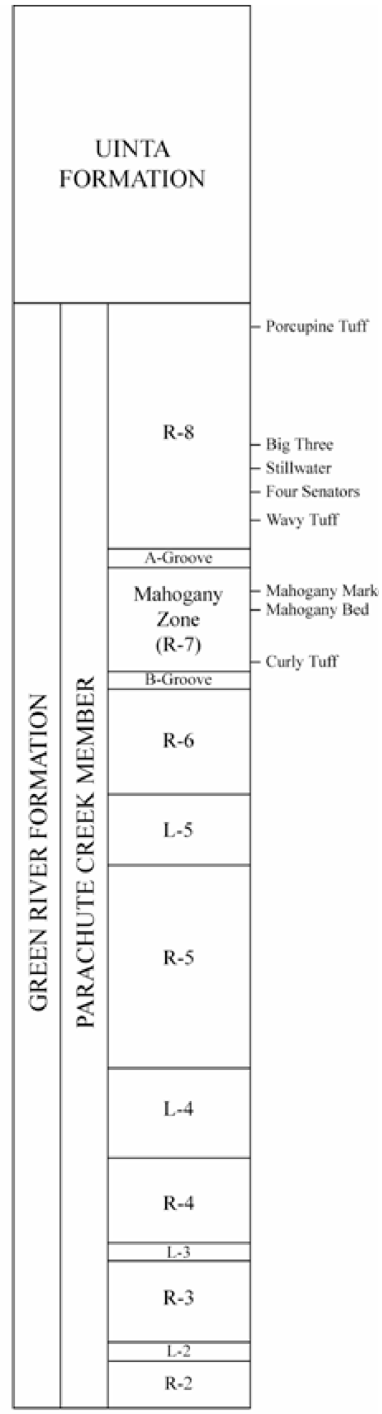

FIGURE A-2 Generalized Stratigraphic Section of the Parachute Creek Member of the Green River Formation in the Uinta Basin Utah ("R" = rich oil shale zone; "L" = lean oil shale zone [adapted from Young 1995])

TABLE A-1 Estimated In-Place Oil Shale Resources in the Southeastern Portion of the Uinta Basin Based on a Minimum Thickness of 15 ft and Various Expected Yields (in gal/ton)[a]

Green River Formation Mahogany Zone	Acreage	Average Resource (bbl/acre)	Total In-Place Resource (million bbl)
At depths < 3,000 ft below the surface			
Average yield of 30 gal/ton	293,787	63,485	18,651
Average yield of 25 gal/ton	361,990	74,093	26,821
Average yield of 15 gal/ton	426,507	117,126	49,955

[a] 1 bbl oil shale = 42 gal.

Source: Cashion (1967); higher yield portions are subsets of the 15 gal/ton resource.

but limited to the southeastern portion of the Uintah Basin, estimated that within the Mahogany Zone, which is at least 25 ft thick and contains an average of 25 gal/ton, there is a resource of at least 31 billon bbl (Table A-2). This upward resource revision indicates that the early estimate provided by Cashion (1967) is conservative, and that more work is necessary to comprehensively define the oil shale resource potential of the entire Uinta Basin.

A major fault, the Uinta Basin boundary fault, lies in the subsurface near the northern margin of the Uinta Basin (Campbell 1975). In the Wastach Plateau along the western margin of the Uinta-Piceance Province, several north-south fault systems that are an eastward extension of basin and range-style tectonism disrupt the geologic units. The Uinta Basin is filled by as much as 17,000 ft of Upper Cretaceous and Paleogene lacustrine and fluvial sedimentary rocks (Bradley 1925; Cashion 1967; Fouch 1985). On the Douglas Creek arch, which separates the Uinta Basin from the Piceance Basin, the Green River Formation has been eroded away. Uppermost Cretaceous and lowermost Tertiary strata dip 4° to 6° toward the axis of the Uinta Basin. The younger Uinta and Duchesne River Formations of late Eocene to earliest Oligocene age dip less steeply. The Green River Formation reaches a maximum depth of 20,000 ft along the basin axis in the north-central part of the Uinta Basin. The Green River Formation lies below the Altamont-Bluebell oil field (Fouch et al. 1994). The Green River Formation contains significant oil- and gas-producing reservoirs in the Uinta Basin, including those at Altamont-Bluebell, Cedar Rim, Brundage Canyon, Monument Butte, Eight Mile Flat North, Uteland Butte, Pariette Bench, Natural Buttes, Horseshoe Bend, and Red Wash fields. The eastern Uinta Basin also hosts significant gas-producing reservoirs in deeper Tertiary and Cretaceous reservoirs over much of the same area containing valuable oil shale deposits in the Green River Formation. Conflicts with conventional oil and gas development in the Uinta Basin may be an obstacle to the future development of Utah's oil shale deposits.

The largest areal extent of the oil, shale–bearing Green River Formation occurs in Utah. The richest shales in Utah occur in the east-central part of the Uinta Basin, at depths ranging from 0 ft at the outcrop to 4,800 ft below the surface. These rich deposits contain more than 300 billion bbl. The existence of sodium minerals has been shown in a few Utah core holes;

TABLE A-2 Estimated In-Place Oil Shale Resources in the Southeastern Portion of the Uinta Basin Based on a Minimum Expected Yield of 25 gal/ton and a Minimum Thickness of 25 ft[a]

Green River Formation	Acreage	Average Resource (bbl/acre)	Total In-Place Resource (million bbl)
At depths < 3,000 ft below the surface			
Parachute Creek Member, Mahogany Zone	410,400	75,707	31,080
Total			31,080

[a] 1 bbl oil shale = 42 gal.

Source: Trudell et al. (1973).

the extent of these minerals, however, has not been defined. The potential for conflicts between the development of sodium minerals and oil shale in the Green River Formation would need to be analyzed on a site-specific basis. The eastern Uinta Basin also contains significant deposits of the solid hydrocarbon gilsonite, which has been mined there for about 100 years and is processed and used in inks, paints, oil well drilling muds and cements, asphalt modifiers, and a wide variety of chemical products. These vertical gilsonite dikes strike between 40º and 70º west of north, have strike lengths ranging from less than 1 mi to nearly 14 mi, range in width from a fraction of 1 in. up to 18 ft, and are generally found in the strata above the Green River Formation (Verbeek and Grout 1992). Conflicts may exist between the existing development of gilsonite and the future development of oil shale in the Uinta Basin.

A.1.4 Green River and Washakie Basins

The Eocene Green River Formation of southwestern Wyoming was deposited in Lake Gosiute, which occupied parts of the present-day Green River, Fossil Butte, Bridger, Great Divide, Washakie, and Sand Wash Basins, which are referred to here as the Green River and Washakie Basins, as shown in Figure A-1. Lake Gosiute existed for about 4 to 8 million years during Eocene time. The lake history is characterized by two major high-water stands separated by a low-water stand; these correspond to the Tipton, Wilkins Peak, and Laney Members of the Green River Formation (Bradley 1964).

Lake Gosiute formed in a basin bounded by uplifted Precambrian, Paleozoic, and Mesozoic rocks that were uplifted to form mountains rising to about 6,500 ft above MSL (Bradley 1963). Initially, several thousand feet of fluvial sediments were deposited in the basin during the Paleocene and early Eocene. These deposits constitute the main body of the Wasatch Formation, which probably accumulated on a fairly featureless alluvial plain. Continued down-warping of the basin relative to surrounding mountains caused the area to become poorly drained, and Lake Gosiute formed in the center of the basin, gradually expanding to an area of several thousand square miles (Bradley 1964). The lacustrine Green River Formation was deposited in the central part of the basin and the fluvial Wasatch Formation along the basin margins. The two formations interfinger in such a way as to demonstrate three major stages in the history of Lake Gosiute. The lower Tipton Member of the Green River Formation was deposited during a high stand, when a large, relatively freshwater lake occupied the Basin (Bradley 1964; Wolfbauer 1971). The overlying Wilkins Peak Member, however, accumulated in a playa-lake complex that occupied a much smaller area (Eugster and Surdam 1973; Bradley 1973; Eugster and Hardie 1975). The lake expanded following Wilkins Peak time, and the Laney Member of the Green River Formation was deposited during this high-water stand (Surdam and Stanley 1979). Lake Gosiute occupied the basin for several million years during the early and middle Eocene, and the Laney stage of the lake may have lasted about 1 million years on the basis of potassium/argon dating of tuff beds in the Wilkins Peak and Laney reported by Mauger (1977). Subsequently, this basin was deformed into the Bridger, Washakie, Great Divide, and Sand Wash Basins by post-middle and pre-late Eocene uplifts (Pipiringos 1961).

Additional oil shale resources are also found in the Washakie Basin east of the Green River Basin. Trudell et al. (1973) report that several members of the Green River Formation on Kinney Rim on the west side of the Washakie Basin contain sequences of low- to moderate-grade oil shale. Two sequences of oil shale in the Laney Member, 36 and 138 ft thick, average 17 gal/ton and represent as much as 67,908 bbl/acre of in-place shale oil. A total estimate of the resource in the Washakie Basin was not reported for lack of subsurface data.

In general, Wyoming oil shales tend to be thin and of only moderate quality. The oil shale beds tend to be almost flat, and each bed shows the same basic characteristics throughout most of the deposit. Most of the known Wyoming deposits of higher grade oil shale occur in the Green River Basin and are estimated to contain 30 billion bbl of shale oil. Leaner shales exist over a wider area, including the entire Washakie Basin. Overburden depth ranges from 400 to 3,500 ft. Trona and halite are associated with or adjacent to the shallow oil shale deposits in the Green River Basin of Wyoming; however, the amount and extent of dawsonite and other saline minerals have not been established. Tables A-3 and A-4 show estimated oil shale resources of the Green River and Washakie Basins, respectively.

The Wilkins Peak Member of the Green River Formation in the Green River Basin in southwestern Wyoming contains not only oil shale but also the world's largest known resource of natural sodium carbonate, known as trona. The trona resource is estimated at more than 115 billion tons in 22 beds ranging from 4 to 32 ft in thickness (Wiig et al. 1995). In 1997, trona production from five mines was 16.5 million tons (Harris 1997). Trona is refined into soda ash, which is used in the manufacture of bottle and flat glass, baking soda, soap and detergents, waste treatment chemicals, and many other industrial chemicals. One ton of soda ash is obtained from about 2 tons of trona ore. Wyoming trona supplies about 90% of U.S. soda ash needs. About one-third of the Wyoming soda ash is exported. Natural gas is also present in the Green River oil shale deposits in southwestern Wyoming, but in unknown quantities.

A.2 HISTORY OF OIL SHALE DEVELOPMENT

The worldwide history of oil shale applications reaches far back in time. For example, Speight (1990) reports that oil shales were sources of fuel as early as 800 A.D., oil shale deposits

TABLE A-3 Estimated In-Place Oil Shale Resources in the Green River Basin Based on a Minimum Expected Yield of 15 gal/ton and a Minimum Thickness of 15 ft[a,b]

Formation	Acreage[c]	Average Resource (bbl/acre)	Total In-Place Resource (million bbl)
At depths ≤500 ft below the surface			
Laney Member	147,085	59,912	8,812
Wilkins Peak Member	248,003	163,515	40,552
Tipton Member	54,247	100,346	5,443
Total			54,808
At depths >500 ft and <3,000 ft below the surface			
Laney Member	670,730	87,725	58,840
Wilkins Peak Member	1,105,165	144,943	160,185
Tipton Member	1,066,047	138,222	147,351
Total			366,377

[a] 1 bbl oil shale = 42 gal.

[b] Totals may be off because of rounding.

[c] Total acreages shown do not account for overlap of the classifiable oil shale zones among the different formation members.

Source: Wiig (2006c).

in what is now the British Isles were worked during Phoenician times, and applications of oil shale as fuel in Austria have been recorded as early as 1350 A.D. Commercial production of shale oil as a fuel is said to have begun in France in 1838 (Kilburn 1976; Speight 1990).

In the United States, use of oil shale as a fuel is reported to have occurred in the 1800s. The first retort for processing oil shale in the United States is reported to have been constructed in 1917 near Debeque, Colorado (Kilburn 1976). Mining and processing of oil shale occurred in Elko, Nevada, as early as 1921 when the Catlin Oil Company attempted to distill organic materials from oil shale with the aid of water from nearby hot mineral springs (Garside and Schilling 1979). In collaboration with Shell Oil Company, Fishell developed a detailed chronology of oil shale development in western Colorado (interested readers should refer to Fishell and Shell Oil Company 2003). A history of the Federal Prototype Oil Shale Leasing Program is provided in a report published by the U.S. Congress Office of Technology Assessment (OTA 1980a). The establishment of the U.S. Naval Oil Shale Reserve by the U.S. Government was likely the inaugural event in oil shale's more formally directed and extensively documented developmental history.

The history of oil shale development as a commercial fuel in the United States is characterized by boom and bust cycles, tied most directly in time to the availability of economical supplies of conventional crude oil, both foreign and domestic. The period immediately following the Arab Oil Embargo of 1973 is generally considered to be the period of

TABLE A-4 Estimated In-Place Oil Shale Resources in the Washakie Basin Based on a Minimum Expected Yield of 15 gal/ton and a Minimum Thickness of 15 ft[a,b]

Formation	Acreage[c]	Average Resource (bbl/acre)	Total In-Place Resource (million bbl)
At depths ≤500 ft below the surface			
Laney Member	25,218	177,179	4,468
Wilkins Peak Member	0	0	0
Tipton Member	4,086	31,681	129
Luman Tongue	13,636	188,067	2,564
Total			7,162
At depths >500 ft and <3,000 ft below the surface			
Laney Member	184,137	232,802	42,867
Wilkins Peak Member	2,893	21,504	62
Tipton Member	46,189	36,419	1,682
Luman Tongue	52,388	68,199	3,573
Total			48,184

a 1 bbl oil shale = 42 gal.

b Totals may be off because of rounding.

c Total acreages shown do not account for overlap of the classifiable oil shale zones among the different formation members.

Source: Wiig (2006c).

most intense interest in oil shale and the period during which the majority of technological advancements took place. During this period, numerous projects were undertaken, most occurring on government land with government involvement in both technical direction and subsidy. When the price and availability of conventional crude oil stabilized around 1982, interest in oil shale development dropped precipitously and, with the exception of a few minor research ventures, all field activities of a commercial nature, and most complementary technology developments, virtually ceased.

During and immediately after this intense period of oil shale RD&D, numerous comprehensive technology evaluations were published, either as progress reports for individual government-sponsored projects or as overviews of the industry sector in general. Environmental, economic, engineering, and social footprints were exhaustively defined. Operating data from pilot plants and laboratory simulation studies were extrapolated to characterize and compute the environmental impacts that could be expected from the most probable types and scales of future commercial oil shale ventures. Complementary investigations were conducted in laboratories on the chemistries of kerogen, the organic fraction of oil shale, and the products of its modification to produce conventional fuels through pyrolysis and upgrading activities. Thermodynamics, reaction mechanisms, and kinetics of kerogen pyrolysis were defined, and relationships between conditions during pyrolysis and the chemical composition of the resulting "crude shale oil" were established.

With the introduction of mass production of automobiles and trucks in the United States in the early 1900s, a temporary shortage of gasoline encouraged the exploitation of oil shale deposits for transportation fuels. Many companies were formed to develop the oil shale deposits of the Green River Formation in the western United States, especially in Colorado. Thousands of oil placer claims were filed on public lands in the western United States. However, the discovery and development of large deposits of conventional oil in West Texas led to the demise of these early oil shale enterprises by the late 1920s (Dyni 2003).

In 1967, the DOI began an aggressive program to investigate the commercialization of the Green River Formation oil shale deposits. The dramatic increase in petroleum prices resulting from the Organization of Petroleum Exporting Countries (OPEC) oil embargo of 1973 triggered another resurgence of oil shale activities during the 1970s and into the early 1980s. In 1974, several parcels of public lands overlying oil shale resources in Colorado, Utah, and Wyoming were put up for competitive bid under the Federal Prototype Oil Shale Leasing Program. Under this program, oil companies leased four tracts on public lands (two in Colorado referred to as C-a and C-b and two in Utah referred to as U-a and U-b). In addition to these four federal projects, several projects were initiated on private lands. These projects are summarized below by state.

A.2.1 Colorado Activities

- ***Atlantic Richfield Company (ARCO), Ashland Oil, Shell Oil, and The Oil Shale Corporation (TOSCO)*** leased Tract C-b, in 1976, following the withdrawl of ARCO and TOSCO from the venture, Ashland and Shell submitted the first detailed development plan to the Oil Shale Project Office. It outlined a conventional underground room-and-pillar method of mining with surface retorting of the mined shale. In 1977, after a 1-year suspension to resolve technical issues, Shell had dropped out and Occidental Oil Shale, Inc. (OOSI) joined Ashland to develop the resource using OOSI's modified in situ (MIS) process. The MIS method of oil shale mining deviated from the plan first described and offered enhanced recovery and a possible solution to some of the technical problems that formed the basis for suspension. Ashland withdrew from the project in April 1979 and Tenneco joined OOSI in September 1979 to form the Cathedral Bluffs Oil Shale Company (CBOSC). Tract operations began that year. Production, service, and ventilation/escape shafts were sunk to a depth of 1,969 ft, holding ponds were completed, and office facilities were constructed, along with a mine power substation, natural gas supply building, sewage treatment plant, and a manway and utility tunnels. In 1981, CBOSC announced a project reassessment, and major plan construction was put on hold. In 1983, CBOSC applied for and received financial assistance from the U.S. Synthetic Fuels Corporation (SFC), a government-funded entity established to foster development of an oil shale industry. A revised plan of development was submitted to produce 14,100 bbl of shale oil per day. The detailed development plan proposed an underground room-and-pillar mine, an aboveground oil shale retort, mine and surface processing facilities, and an oil upgrading facility. None of this occurred, however. In 1984, SFC board members stepped down; and, as a result, no contract with SFC was secured. In 1985, CBOSC continued negotiations with SFC. At the same time, a bill was passed in the House to abolish SFC. A similar amendment in the Senate failed, 43 to 40. President Reagan signed Public Law 99-190, which provided, as part of overall appropriations, for the termination of SFC within 120 days, and the rescindment of all funds not yet committed. In 1986, negotiations for the suspension of the Tract C-b lease and shaft pumping cessation were initiated. The suspension was granted in 1987. Pumping on the production and maintenance shafts stopped in 1991, and the headframe was removed in 2002. No shale oil was ever produced from this federal lease.

- ***Occidental Oil Shale, Inc.***, used the Logan Wash facility as a testing site for the MIS process planned at Colorado lease Tract C-b and considered for Tract C-a. The 10-mi^2 site was purchased from private sources in 1972. Mining began in 1972, and by 1981, six retorts were developed and burned to produce a total of 94,500 bbl of shale oil. Initial in-situ retorts on the site consisted of three experimental-size operations, each producing 1,200 to 1,600 bbl of shale oil in total. Three considerably larger retorts were developed and burned following satisfactory completion of the first units. Retorts 5 and 6 were constructed under a cooperative agreement with the U.S. Department of Energy (DOE). These two retorts produced nearly 58,300 bbl of shale oil from the 3-year, $29 million program. About 450 people were employed at the Logan Wash site.

- ***Union Oil Company of California*** began acquiring oil shale properties in Colorado around 1921 in the Parachute Creek area of the Piceance Basin north of the town of Parachute in Garfield County, Colorado. Union owned the mineral rights under nearly 50 mi^2 of oil shale lands. From 1955 through 1958, Union built and operated a surface retort on its Colorado properties. The facility produced about 800 bbl of shale oil per day using a unique upflow retort process. More than 13,000 bbl of this shale oil were successfully processed into gasoline and other products at a Colorado refinery. However, low crude oil prices in the 1960s prevented further process development. With the rapid rise in price and uncertain availability of foreign crude oil in the early 1970s, Union reactivated R&D in its upflow retorting process. Continuing improvements were made in efficiency and product quality. In the fall of 1980, construction began on the first phase of Union's 50,000-bbl/day oil shale facility. The first phase of the project called for surface retorting of raw shale retrieved from a room-and-pillar mine. Union spent more than $1.2 billon, with substantial financial assistance from the federal government. Union began production in 1984, but did not ship its first barrel of oil until December of 1986. Union was able to produce shale oil and upgraded this shale oil to syncrude at its commercial oil shale production at the Parachute Creek plant. Union began shipping synthetic crude from its Parachute Creek plant to a Chicago refinery and was producing about 6,000 to 7,000 bbl/day in 1989 at its peak production, sustained by a federal subsidy. The Parachute Creek plant had approximately 480 workers and 200 contract employees. The oil shale project was shut down in June 1991.

- ***The Exxon-TOSCO Colony Project*** was established in 1963 as a joint venture among Sohio, the Cleveland Cliff Iron Company, and TOSCO. Beginning in 1965, various companies acquired and sold an interest in the Colony Project, resulting by 1980 in ownership by Exxon Corporation (60%) and TOSCO (40%). The Colony Project controlled a 22-mi^2 resource block. Starting in 1964 and ending in the early 1970s, approximately 200,000 bbl of shale oil were produced experimentally at the TOSCO II Semi-Works Plant. In the 1970s, a prototype mine and plant operation proved the viability of the underground mining plan with aboveground processing using the "TOSCO II" retort method. Plans called for the mining of oil shale processed through pyrolysis and the upgrading of facilities. Design and engineering work for a commercial plant progressed through various stages. The underground mine was to be worked with room-and-pillar methods, proceeding with the conventional cycle of drilling, charging, blasting, wetting of rock piles, loading, hauling, scaling, and roof bolting. Run-of-mine shale was to be crushed to the desired retort feed size in two stages. Retorting and upgrading facilities would recover upgraded shale oil, ammonia (NH_3), sulfur, and coke from the crushed shale. Fuels produced for internal combustion would include treated fuel gas, a liquid carbon stream, fuel oil, and diesel fuel. The kerogen content of raw shale was to be converted into the above hydrocarbon vapors and liquids using six individual "TOSCO II" retorting trains. Upgrading included coking, gas recovery and treating, and hydrotreating. Exxon planned to invest up to $5 billion in a planned 47,000-bbl/day plant using a TOSCO retort design. After spending more than $1 billion, Exxon announced on May 2, 1982, that it was closing the project and laying off 2,200 workers. No shale oil was ever produced commercially.

- ***Gulf Oil Company and Standard Oil Company of Indiana*** leased Federal Prototype Oil Shale Tract C-a from the DOI for $210.3 million. Tract C-a was the first federal tract to be leased as part of the DOI's program to test the environmental and economic feasibility of oil shale development. Tract C-a was located in Rio Blanco County at the head of Yellow Creek on the western edge of the Piceance Creek Basin. Gulf and Standard later formed the Rio Blanco Oil Shale Company (RBOSC), a 50:50 general partnership, to develop the 5,100-acre tract. Originally, Tract C-a was to be developed as an open pit mine. However, the DOI did not make additional federal land available for off-tract disposal of processed shale and overburden. There were also air quality issues and other constraints with the pit mining concept. After a 1-year suspension of operations, RBOSC decided to develop the tract by underground MIS methods. In February 1979, the company purchased OOSI's MIS technology. In the commercial phase, plans called for shale oil to be transported to existing Gulf or Standard corporate refineries. Tract C-a was a one-level operating mine, with driftwork essentially completed for three underground demonstration retorts. A conventionally sunk production shaft, vent shaft, service shaft, and production shaft were built. Approximately 500 people were employed during the construction phase of this project. RBOSC started construction of a 4,000-ton Lurgi-Ruhrgas surface retort in the spring of 1981. The retort, capable of processing about 2,000 bbl/day, went on stream in 1983. The surface retort processed oil shale removed and brought to the surface prior to burning the underground retorts. In October 1980, RBOSC ignited the first of three demonstration MIS retorts. The burn was scheduled to last 9 weeks. The demonstration retort was ignited at the top, some 670 ft below the earth's surface. This was the first burn in the company's $140-million program to demonstrate commercial feasibility of the MIS technology; 1,750 bbl of oil were recovered from the first retort. Two additional burns were conducted in 1981, which recovered approximately 23,000 bbl of shale oil. The retorts were prematurely flooded in 1984 because of pump failure, and the company was unable to resume operations. Approximately 150 people were employed during the operational phase of this project.

- ***TRW, Inc.'s*** Naval Oil Shale Reserves (NOSR) Project was conducted under the direction of the Secretary of Energy and included three sections of land known as NOSR 1, 2, and 3. NOSR 1 and 3 were located in Colorado and NOSR 2 was located in Utah. In 1977, TRW was chosen to be the prime engineering and management contractor for the project, which involved performing a 5-year, $62 million resource, technology, environmental, and socioeconomic assessment to advise the DOE on what should be done with the NOSR. The TRW, Inc., team included Gulf Research and Development Company, TOSCO, C.F. Braun and Company, and Kaiser Engineers. The assessment was to be completed in 1984. In September of 1980, DOE released a draft EIS that discussed other fuel alternatives to oil shale and explored five NOSR development approaches ranging from leasing to industry to a government-owned facility. The report recommended that the biggest return to the federal government would be through production of the natural gas reserves.

- ***Multi Minerals Corporation (MMC)***, a subsidiary of the Charter Company, signed an agreement in April 1979 to operate a U.S. Bureau of Mines research tract known as Horse Draw. MMC hoped to offset much of the expense of mining oil shale by recovering nahcolite and dawsonite, two potentially valuable minerals found within the shale. The company also hoped to prove that its Integrated In Situ recovery method was environmentally acceptable; this process reportedly did not produce spent shale residue on the surface, nor did it use or contaminate surface water. In 1977 and 1978, the U.S. Bureau of

Mines opened an experimental mine that included a 2,370 ft-deep shaft with several room-and-pillar entries in the northern part of the Piceance Basin to conduct research on the deeper deposits of oil shale, which are commingled with nahcolite and dawsonite. Large-scale process testing began in mid-1981, when construction of the company's adiabatic retort in Grand Junction was completed. The company's experimental mining involved room-and-pillar mining in a bedded nahcolite and shale zone about 8 ft thick, averaging about 60% nahcolite. The shafts were used to obtain geologic and hydrologic data in the deeper end of the Piceance Basin. The site was closed in the late 1980s.

- ***Equity Oil Company and DOE*** launched a project known as the BX In Situ Oil Shale Project in 1977 to test a method of in situ retorting that frees the kerogen from the shale by injecting superheated steam into the permeable leached zone underlying a site owned by Equity, Exxon, and Atlantic Richfield southwest of Meeker in Rio Blanco County, Colorado. Project field tests began in June 1979 and continued for 2 years on a 1-acre site within the 1,000-acre tract owned by Equity and its partners. Steam injections for a sustained period began in June 1980. By August, the formation showed signs of continued and steady heating. By August 1981, 625,000 bbl of water-turned-steam had been injected into 8 project wells and approximately 100 bbl of shale oil had been recovered. Equity's principle oil shale interest focused on the leached zone; the only zone in the Piceance Basin that has native permeability sufficient to initiate in situ recovery without fracturing or premining of bedrock. The injected steam process evolved from both laboratory and fieldwork begun in the 1960s. These tests used natural gas rather than steam. Laboratory results showed that the oil recovered was superior in quality to that produced in conventional surface retorts, possibly because of lower temperatures and the absence of any oxidizing gases. While evaluating the project in 1970, Equity determined that superheated steam could be used to lower costs. Beginning in April 1971, the BX project was converted to steam, and injections were performed almost continuously until the research project was suspended for financial reasons 4 months later. From this latest research, Equity determined that water from the leached zone may be used, thus eliminating the need to import water. Equity also found that a minimum amount of surface disruption results from the construction and operation of the process. With only minor alterations, the existing BX oil shale site was utilized for the reactivated program in 1977. Achieving the needed temperatures and pressures required a reasonably sophisticated steam-generating plant, water storage facilities, and an instrumentation system to monitor both equipment and project performance.

- ***Chevron Shale Oil Company's (Chevron)*** historic involvement with oil shale in Colorado involves the work of three corporations: Chevron Corp, Texaco Inc., and Getty Oil Company. Texaco merged with Getty in 1984, and Chevron and Texaco merged in 2001. Properties were acquired by the companies beginning in the 1930s, and today the combined oil shale acreage totals about 100,000 acres in Mesa and Garfield Counties. The lands are managed by Chevron Shale Oil Company, a division of Chevron USA, Inc. Early work by Chevron was mainly resource evaluation and mapping. In the 1970s, Chevron and Texaco participated in a consortium of companies that supported the Paraho Oil Shale Project at the Anvil Points facility, west of Rifle, Colorado. The surface retort produced more than 100,000 bbl of shale oil for the U.S. Navy. In 1981, Chevron Shale Oil Company and Conoco Shale Oil, Inc., began the Clear Creek project on a 25,000-acre tract of private land north of DeBeque. Chevron Shale Oil Company was the operator. The goal of the project was to produce 100,000 bbl of shale oil by the mid-1990s. The oil shale was to come from an underground mine, which started construction in 1981. The company developed a second generation surface retorting process called the Staged Turbulent Bed at its Richmond, California, laboratory. Tests were made using a 1-ton/day and a 4-ton/day plant. The next phase was the Semi-Works Development Project. A 350-ton/day retort was constructed and successfully tested at the Chevron refinery near Salt Lake City, Utah. Crushed rock was moved to the retort by rail. A small amount of shale oil was produced, but because of the drop in oil prices, mine construction was halted in 1984. The commercial phase of the project was not reached, and the mine has remained closed.

A.2.2 Utah Activities

In Utah, six oil shale projects were planned that progressed to various stages of development. The six projects are described below (DOE 1981). From 1954 through 1990, several companies and governmental agencies drilled at least 200 oil shale exploration wells in the Uinta Basin and conducted Fischer assays on the oil shale core samples. In addition to the core samples, the USGS had an oil shale program from the late 1950s through the 1970s that collected cutting samples from more than 400 oil and gas wells penetrating the oil shale–bearing portion of the Green River Formation. Fischer assays also were conducted on those samples. Data on the thickness, depth, and Fischer assay information exist for the oil shale interval in the Parachute Creek Member of the Green River Formation from more than 600 wells spread across the Uinta Basin, but mainly from the southeastern quarter of the basin.

- ***Geokinetics, Inc***., was originally organized in 1969 as a minerals development company; it was reorganized in 1972 as a joint venture with a group of independent oil companies to develop an in situ technique to extract shale oil. The company began design and cost studies of a horizontal modified in situ process in preparation for the anticipated Federal Prototype Oil Shale Lease Program sale. Small-scale pilot tests in steel retorts were carried out to simulate the horizontal process in 1974 and early 1975. Starting in April 1975, field tests of the in situ method were carried out, and by late 1976 the basic parameters for an in situ process were established. From 1977 through 1979, the process was scaled up substantially from early tests, and rock-breaking designs for the underground retorts were improved and tested. From 1980 through 1982, Geokinetics, funded in part by DOE, blasted 24 experimental underground retorts and tested them. These tests cumulatively produced 15,000 bbl of oil. By 1982, the company had settled on a 2,000-bbl/day design for its commercial retort and had acquired 30,000 acres of nonfederal leases, with an estimated resource of 1.7 million bbl of oil (averaging 20 gal/ton). Between 1972 and 1982, the company drilled at least 32 core holes on its leases in the Uinta Basin and conducted Fischer assays on oil shale samples from those wells.

- ***Magic Circle Energy Corporation*** acquired the 76,000 acres of State of Utah leases composing the Cottonwood Wash properties from the Western Oil Shale Corporation in July 1980 through an exchange of stock. The Cottonwood Wash properties contained an estimated 2.1 billion bbl of oil with a grade in excess of 15 gal/ton, and at a depth between 1,500 and 2,000 ft. Magic Circle spent more than $1 million to perform feasibility studies, initiate permit applications, and perform initial coring for resource definition, mine design, and environmental evaluation, but no mine or plant construction nor oil shale production took place on this project.

- ***Paraho Development Corporation*** was organized in Grand Junction, Colorado, in 1971, to develop oil shale technology. The company acquired leases along the White River in Utah near the border with Colorado, but no work was performed on the property. The company conducted several retort research projects in Colorado with several other industry partners to achieve an oil recovery averaging 90% of the in-place oil. On the basis of this research, the company was contracted by DOE to produce 100,000 bbl of shale oil. Paraho used the Anvil Points facility to conduct a 105-day continuous-stream operation in the late 1970s that produced the contracted amount of shale oil with 96% oil yields. The oil market deteriorated before a commercial plant could be permitted and built on the Utah leases.

- ***Syntana-Utah*** was a joint venture of the Synthetic Oil Corporation and Quintana Minerals Corporation that was formed in late 1980. This venture acquired a State of Utah lease on Section 16, T9S, R25E, on which it planned to construct an underground mine and surface retort operation that could produce 24,500 tons/day of 25 gal/ton oil shale. Limited effort was spent identifying the depth, thickness, and grade of the oil shale to quantify the oil shale resource on the lease. Two, and perhaps more, drill holes were completed on the property to facilitate mine and retort engineering design.

- ***TOSCO Development Corporation*** acquired 29 separate State of Utah oil shale leases comprising 14,688 acres of land about 35 mi south of Vernal, Utah. These leases were generally located in T9S and T10S, and R21E and R22E. Between 1977 and 1981, TOSCO drilled eight or more core holes to help define the oil shale resource and to initiate basic actions leading to a site-specific EIS for a 66,000-ton/day mine with a production capacity of

47,000 bbl/day employing multiple TOSCO II retort facilities. Subsequent deterioration of oil prices led to the cancellation of the project before final permitting and construction began.

- ***White River Shale Oil Corporation (WRSOC)*** was a joint venture of three major oil companies: Phillips, Sohio, and Sunoco. Sunoco and Phillips were the successful bidders for the 5,120 acres composing the U-a federal lease tract that sold for $75.6 million at the 1974 Federal Prototype Oil Shale Lease Program sale. Shortly after the first sale, Sohio joined the venture and the WRSOC was formed. In 1975, the group paid an additional $45.1 million and acquired the 5,120-acre U-b tract that was adjacent to the U-a tract. Between 1974 and 1976, the WRSOC drilled 18 wells on its leases and created a detailed development plan that was submitted to the federal government in mid-1976. The development plan called for a 179,000-ton/day mine that would be supported by a 100,000-bbl/day surface retort at full commercial operation. Later that year, the leases were suspended because of environmental and land title issues and remained suspended until the early 1980s. Once these issues were resolved, the venture ultimately constructed mine service buildings, water and sewage treatment plants, and a 1,000-ft-deep vertical shaft and inclined haulage way to the high-grade Mahogany Zone of oil shale. Several tens of thousands of tons of oil shale were extracted to test mining conditions and retort technology and economics. The project was abandoned before commercial operations were achieved when market conditions deteriorated in the mid-1980s.

Although the six Utah oil shale projects reached various stages of completion during the late 1970s and 1980s, none were able to reach commercial operation. Both mining with surface retort and in situ recovery methods of shale oil were investigated in Utah. The legacy of the surge of interest in oil shale development in the late 1970s and early 1980s is a wealth of resource, engineering, and baseline environmental data that will be useful in future efforts to develop oil shale resources.

A.3 TECHNOLOGY OVERVIEW

With the cessation of commercial development, there have been some minor evolutionary changes to oil shale development technologies, but some ongoing research has the potential of precipitating major revolutionary changes in oil shale development technologies. Notwithstanding these recent research initiatives, the technology evaluations conducted at the end of the zenith of oil shale development activities are still largely valid, despite the majority of them being produced more than 20 years ago. The few technology evaluation updates that have been published in more recent years rely primarily on the data and conclusions from those original evaluations and are unique only to the extent that they incorporate the results of the few ongoing research projects and anticipate the technology transfers that would likely be made from other mining and energy sectors. The information provided in this section brings forward the most relevant data and conclusions from the most comprehensive and reliable previous reviews.

Development of oil shale resources fundamentally occurs in three major steps: (1) recovery or extraction from the natural setting, (2) processing to separate organic and inorganic constituents, and (3) upgrading the organic components in anticipation of further refining into conventional fuels. The physical and chemical features of oil shale deposits and other circumstantial factors associated with their deposition compose the economic and engineering parameters that dictate the most appropriate development schemes. Typical development schemes always involve each of the above major steps, although many permutations of these steps are possible and many interim steps may also be necessary. This appendix provides descriptions of each of these major actions, the technologies that have been developed for each, their advantages and disadvantages, and their potentials for environmental impact.

A.3.1 Recovery of Oil Shale

A variety of technologies have been developed and commercially applied to oil shale recovery or extraction, and others are in the R&D phase. Other technologies that have proven their worth in other mining industry sectors conceptually apply to oil shale, but have yet to be applied at commercial scales. Efforts to recover oil shale resources have the potential to be both the most energy intensive and most environmentally problematic steps of oil shale development; advancements in recovery technologies ensure that greater portions of resources will be economically recoverable, operating costs will be minimized, and recovery efficiencies will be maximized. Resource extraction techniques can be generally categorized as direct or indirect recovery. Direct recovery involves the removal of the oil shale from its formation for ex situ processing. Indirect or in situ recovery involves some degree of processing of the oil shale while it is still in its natural depositional setting, leading ultimately to the removal or extraction of just the desired organic fraction. Additional aboveground processing of that fraction is still typically required.

A.3.1.1 Direct Recovery Mining Technologies

Surface mining techniques (e.g., strip mining and/or pit mining) as well as subsurface mining techniques (e.g., room-and-pillar (shaft) mining, longwall mining, and other derivatives) have been successfully employed in the recovery of oil shale. For oil shale deposits relatively close to the surface, conventional strip mining technologies could be employed to retrieve the oil shale. As discussed in Section A.1, the BLM has limited its evaluation of the impacts of surface mining for oil shale to areas within the most geologically prospective oil shale areas where the overburden ranges in thickness from 0 to 500 ft. The areas where the overburden is 0 to 500 ft that potentially will be made available for application for leasing using surface mining technologies are limited to part of the Uinta Basin in Utah and parts of the Green River and Washakie Basins in Wyoming (Figure A-1). Surface mining will not be considered in Colorado because the distribution of areas where the overburden thickness is less than 500 ft is dispersed enough as to make it difficult to assemble a logical mining unit. In Utah, about 133,194 acres of land within the most geologically prospective oil shale area have an overburden thickness of 0 to 500 ft. In Wyoming, the corresponding area includes about 380,220 acres.

Conventional strip mining techniques and equipment developed in other mining industry sectors, primarily coal, can be applied directly to strip mining of near-surface oil shale deposits. Most oil shale deposits have distinct bedding planes. Experience has shown that shear strengths along these bedding planes are substantially less than across the planes, thereby ensuring that, in many instances, strip mining techniques using draglines and/or shovels will be successful without additional efforts to fracture the formation (e.g., through the use of explosives) (DOE 2004a).[5] However, enhancement of natural fractures through the use of explosives (typically ammonium nitrate/fuel oil mixtures) or high-pressure water injection (hydrofracturing) is still commonly employed in strip mining operations. Depending on the formation thickness, strip mining may proceed through excavation of a series of "benches," each 30 to 50 ft deep.

Both strip mining and pit mining can be successfully applied to near-surface deposits with generally flat formation orientations. Both methods use similar types of equipment: shovels, bucket-wheel excavators, draglines, conveyors, trucks, scrapers, etc. The most probable combination of mining equipment would involve diesel-powered shovels loading materials into haul trucks ranging in size from 240- to 400-ton capacity.

Pit mining does not typically require any ventilation or special considerations for the presence of methane (CH_4), but typically utilizes explosives to rubblize the formation before removal. Both surface mining methods impact significant land areas. Both require separate areas for temporary storage of overburden. Strip mines are often developed in such a manner that previously evacuated areas can be used to receive processing waste (retort ash); however, operations involving pit mines must utilize a separate area for retort ash disposal.

According to Nowacki (1981), technological benefits of surface mining can include:

- Low cost (over the life of the operation) and high productivity relative to other mining techniques;
- Flexibility to adjust to changes in formation geometries;
- High production tonnages;
- Previously mined areas provide storage areas of future overburdens or disposal areas for spent shale; and
- Technologies are well established, and operating logistics have been optimized.

However, environmental impacts can be significant, including:

- Substantial land areas disturbed, loss of habitat (both at the working face and at stockpile areas);

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5 This same engineering feature of low shear strength in the bedding planes can also preempt the successful application of room-and-pillar mining techniques.

- Substantial amounts of overburden and spent shale requiring management;
- Potential for ground and surface water impacts (pollution as well as altered drainage patterns);
- Potential for air quality impacts from fugitive dust as well as from operation of equipment, much of which utilizes internal combustion engines;
- Noise impacts from equipment vehicle operations, especially crushing and grinding operations and the use of explosives to loosen materials before removal (when necessary);
- Initial capital investment may be high (necessarily very large mining/haulage equipment) to ensure high productivity; and
- Land reclamation programs may extend well beyond cessation of mining operations (adapted from Nowacki 1981).

Although surface mining techniques are well established and may be the most economical, they are accompanied by significant environmental impacts to the land and groundwater and surface waters and the ecosystems that rely on them, as well as impacts to visual resources (Nowacki 1981). Consequently, while these extraction techniques were among the first investigated for oil shale development, they quickly fell out of favor by 1977 in deference to subsurface mining or in situ recovery techniques for resource extraction, and only a handful of field tests or large-scale operations were actually conducted utilizing surface mining techniques (Nowacki 1981). All but one of the projects under consideration as part of the BLM's oil shale RD&D program (see Section A.5.3) focus on in situ processing rather than surface extraction and ex situ processing, suggesting that surface mining has a lower likelihood of being part of future development proposals.

For deeper deposits where surface mining is infeasible or prohibitively expensive, or for deep deposits that are accessible through outcrops along erosion faces, room-and-pillar mining techniques such as those used in coal mining have been successfully applied. The typical cycle of activities in room-and-pillar mining involves drilling, charging, blasting, wetting, crushing, loading, hauling, scaling, and roof bolting (DOE 1982).

Ventilation is necessarily continuous in virtually all room-and-pillar mining operations to provide for worker safety and is essential in "gassy" mines where explosive methane gas is present at concentrations greater than 1%. The excavated rooms are typically 60 ft wide by 90 ft high. Pillars (undisturbed formations) are 30 to 45 ft thick, depending on the engineering parameters of the particular formation and structural support demands dictated by the amount and type of overburden. In general, as much as 75% of the shale can be recovered by using this technique, especially in shallower formations (DOE 1982). Access to the mine is either by shaft, decline, or both.

Infrastructure necessary to support underground mining includes systems for both process and potable water, conveyor systems, crushing systems, and haulage systems. Mixtures of ammonium nitrate and fuel oil are typically used to rubblize the formation prior to crushing. Typically, primary and even secondary crushing are conducted within the mine before oil shale is brought to the surface. Pumping systems to manage formation water are also typically present. Electric power and vehicle/equipment fuels (typically diesel) are also required. A variation on this technique, chamber-and-pillar mining, has also been advanced. In chamber-and-pillar mining, chambers are cut perpendicular to the main entry shaft. This technique offers particular advantages to oil shale mining in that the chamber heights can be variable, in accordance with formation geometries, and, once excavated, the chamber may serve as a convenient disposal area for spent oil shale. Essentially the same types of support equipment are required for chamber-and-pillar mining as for room-and-pillar mining.

A.3.1.2 Indirect or In Situ Recovery Techniques

Much attention has been paid to the development of in situ or indirect retrieval or extraction techniques in which just the kerogen fraction is actually recovered from the formation. Under normal conditions of temperature and pressure in the formation, kerogen is immobile. This fact is irrelevant and even beneficial if direct recovery techniques are employed. However, it becomes the most significant limiting factor when direct recovery is not possible or economical. To address these limitations, numerous indirect recovery techniques have been developed. In its simplest manifestation, an indirect recovery technique increases the mobility of kerogen within the formation by heating it to lower its viscosity, allowing it to “flow” through the formation for removal by conventional oil and gas recovery techniques. The two primary indirect recovery techniques, true in situ recovery (TIS) and MIS, both transfer heat to the formation; they differ, however, in the actions that are taken before formation heating is attempted. TIS involves introducing heat without prior efforts to significantly alter the formation’s permeability. MIS involves first altering the natural formation by increasing the extent of formation fracturing, thus theoretically improving the efficiency of formation heating and facilitating the movement of mobilized kerogen to points of retrieval.

For any in situ process, some minimal amount of formation disturbance is required to provide a path through which to introduce the heat source and through which kerogen can flow to points of recovery. For TIS, such intrusions are minimal and typically involve no more than installing a collection of conventionally sized wells.[6] Heat can then be introduced into the formation by a variety of mechanisms, most often by steam injected into either vertically or horizontally oriented boreholes or wells, but also by the application of alternative energy technologies such as microwave heating, radio frequency heating, or electric resistance heating. Typically, the same pathways into the formation by which heat is introduced are used to recover the heated, mobilized kerogen using conventional liquid extraction technologies.

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6 However, depending on the natural degree of fracturing, the permeability of the formation may still need to be enhanced through the use of explosives or by hydrofracturing. Even when these steps are taken, the extraction technique may still be called TIS.

Intrusion into and alteration of the formation are somewhat greater for MIS techniques. Typically, explosives are introduced to enhance the degree of natural fracturing, thus facilitating the flow of heated kerogen to points of extraction. Subsequently, anywhere from 10 to 30% (by volume) of the formation is mined by conventional techniques (and later processed above ground) to create voids in the formation that serve as retorting chambers from which the formation is heated and at or near which the mobilized kerogen is accumulated and extracted. First-generation in situ heating technologies were designed to mobilize the kerogen in the formation by reducing its viscosity while not changing its chemical composition. However, the majority of investigations into in situ heating technologies focused not only on the mobilization of kerogen, but also its pyrolysis. Such in situ pyrolysis techniques are discussed in Section C.3.2.

Enhanced oil recovery (EOR) technologies developed for the conventional crude oil and tar sands industries also have potential application to oil shale recovery. Both secondary and tertiary techniques have been developed. Secondary techniques essentially involve mechanical displacement of oil by the use of high-pressure immiscible gases or water. Waterflooding and high-pressure gas flooding are examples. Tertiary EOR techniques can be grouped into two categories: miscible techniques and thermal techniques. Miscible techniques involve the introduction of materials that dissolve the oil, increasing its ability to move through the formation to a recovery well. Thermal techniques introduce heat, lowering the oil's viscosity, thus facilitating its movement through the formation. Solvent flooding may involve the use of such materials as raw naphtha, a collection of light molecular weight aliphatic hydrocarbons, that is a principal feedstock for gasoline or other products of partial crude oil refining. Tertiary techniques often follow or are superimposed upon secondary techniques. For example, the injection of high-pressure steam combines a secondary displacement technique with a tertiary thermal technique. Many of these techniques have also been successful in enhancing the recovery of bitumen[7] from tar sands. While most of these techniques are typically applied near the end of the useful life of a conventional crude oil deposit, they can be used for dislodging or mobilizing kerogen in the early phases of formation development, either alone or in conjunction with the conventional heating technologies discussed above. Overviews of some of the most promising EOR technologies are provided below. More detailed discussions of EORs can be found in *Enhanced Oil Recovery; Secondary and Tertiary Methods* (Schumacher 1978) or any of the numerous other technical publications on these technologies.

- ***Steam Injection Technologies.*** Steam injection has been used for decades to enhance recovery of crude oil or to mobilize heavy oils for retrieval. One such technology adapted to recovery of bitumen from tar sand, cyclic steam stimulation (CSS), may be applicable to oil shale recovery. CSS involves the injection of steam at high pressure and temperature into the deposit, causing the oil sand to fracture, simultaneously lowering the viscosity of the bitumen as it absorbs heat from the steam. The fluidized bitumen is then recovered by strategically placed conventional liquid recovery wells, together with steam

[7] Bitumen is the name commonly given to the organic fraction present in tar sands. Chemically it is a member of the asphaltene fraction of conventional crude oil.

condensates. Steam injections are repeated over time until all of the bitumen is recovered.

A second widely used steam injection technology, steam-assisted gravity drainage (SAGD), is being used for retrieval of bitumen from tar sands in the vast deposits occurring in Alberta and Saskatchewan Provinces in Canada. SAGD is closely related to CSS in its technological approach; however, its mechanisms for recovery of mobilized/liquefied resources are unique. SAGD consists of two horizontal wells, a production well near the bottom of the formation and a steam injection well approximately 6 m above and aligned with the production well. Steam is circulated between the two wells, causing heating of the intervening formation by conduction. Once communication is achieved, the steam rises in the formation due to its relatively light density, heating the formation above the injection well. The heated oil, steam condensate, and formation water are then collected in the production well.

- ***Waterflooding.*** As the name implies, waterflooding involves the injection of water at high pressure to mechanically displace oil from rock pores and fissures. The process can also enhance formation permeability by hydrofracturing (or hydraulic fracturing), causing additional fractures in the formation through increases in hydrostatic pressure. Waterflooding and hydrofracturing are relatively inexpensive, but require extensive amounts of water.

- ***High-Pressure CO_2 Flooding***. This technology applies carbon dioxide (CO_2) at high pressures and has two distinct advantages: displacement and removal of additional kerogen not recoverable through conventional mining techniques or in situ heating techniques, and the possible sequestration of CO_2 released from aboveground oil shale processing activities or produced through the operation of various combustion sources to produce process steam or power. One of the potential large environmental impacts from oil shale development is the release of copious amounts of CO_2 during retorting and/or formation heating. Carbon dioxide has been used successfully in crude oil production as an effective enhanced recovery technique. After displacing crude oil from rock pores, the CO_2 is bound indefinitely within those pores. Such sequestration may therefore be a valuable pollution control mechanism for oil shale development, while at the same time improving kerogen recovery efficiencies.

- ***Solvent Flooding.*** Solvent flooding technologies are similar to steam injection technologies, substituting solvents for steam and relying on chemical dissolution of the kerogen rather than liquefaction through use of steam. Various organic solvents can be used. Solvent flooding is often performed with two horizontally oriented wells; an upper well into which the solvent is injected and a lower well from which kerogen, diluted with solvent, and, in some cases, partially upgraded, can be recovered. Other well combinations for solvent injection and product recovery have also proven successful. Solvent injection offers a number of important benefits over steam injection: (1) little to no processing water is required; (2) the technique involves lower capital costs since steam does not need to be produced, recovered, and recycled; (3) the solvent and potentially higher organic recovery rates are possible; and (4) partial upgrading of the kerogen may result from its interactions with the solvents selected.

- ***Electromagnetic Heating.*** Another family of technologies accomplishes formation heating through the application of electromagnetic energy. Electromagnetic energy at relatively low power levels was initially developed for formation imaging, relying on the different resistivities of rocks, formation water, and oil being observable as they absorb induced energies. At higher levels of applied power, electromagnetic energy can be used to heat the formation. Energies throughout the energy spectrum can be used—low-frequency electric resistive heating to higher frequency radio-wave and microwave heating. Electromagnetic heating technologies have potential applicability in those formations where more common steam injection technologies have limited success (e.g., low permeability formations, thin or highly heterogeneous formations, or especially deep formations) and may have an advantage in terms of delivering heat to greater depths in the formation. Electromagnetic heating is also particularly effective in reducing the viscosity of the organic phase, and, thus, is especially applicable to the recovery of bitumen from tar sands and kerogen from oil shales, either as the primary technology, or as a source of formation heating used in conjunction with, or prior to, other recovery technologies. The rates at which a formation must be heated by any of these technologies vary with formation characteristics, but typically the process can be expected to take 6 months to years of constant application of electromagnetic heating to create a sufficient temperature rise in the formation to dramatically increase organic retrieval efficiencies.

  Raytheon has successfully developed a radio-frequency (RF) heating technology for application to oil shale recovery (Cogliandro 2006). Field experience indicates that this technology results in rapid heating and volatization of water, which, in turn, results in microfracturing of the formation, enhancing formation permeability and product recovery. Consequently, no preliminary steps designed to remove the majority of free formation water are necessary. Experience to date indicates that the Raytheon RF heating technique could be successfully applied to exploit formations with as little as 150 ft of overburden (the minimum thickness needed to prevent "bleeding" of induced RF energy at the surface). Applying the RF heating technique, Raytheon has obtained recovery rates of 75% of the oil shale's Fisher Assay value. Some upgrading of initial kerogen pyrolysis products has also been observed. However, in its latest form, the Raytheon RF heating

Carbon Dioxide Sequestration and Its Role in Oil Shale Development

Carbon sequestration is the isolation of carbon dioxide (CO_2) from the biosphere in what are called "natural carbon sinks." The primary "sinks" are the oceans and growing vegetation that consumes CO_2 by the process of photosynthesis. However, sequestration of CO_2 in underground rock formations is also possible. In geological sequestration, the CO_2 can be effectively held in small pore spaces in mineral deposits for millions of years. Injecting CO_2 under high pressure into mature crude oil formations, a process known as CO_2 flooding, has long been employed as an enhanced oil recovery (EOR) technique to enhance crude oil recovery capabilities in mature fields. In CO_2 flooding, it is believed that the CO_2 displaces crude oil from mineral pore spaces into formation fractures where it is more easily recoverable. A February 2006 initiative launched by the U.S. Department of Energy's (DOE's) Office of Fossil Energy is specifically aimed at research into the use of CO_2 to enhance domestic oil and gas recovery and simultaneous CO_2 sequestration (see the Web site below). A similar mechanism of kerogen displacement is possible for oil shale formations, many of which are naturally fractured to equal or greater extent than typical crude oil-bearing rock formations.

In addition to a simple mechanical "trapping" of CO_2 in mineral pores, scientists believe that in some formations, a chemical reaction called "carbonation" occurs, converting the CO_2 to thermodynamically stable carbonates, ensuring that the sequestration is virtually permanent. Such reactions are actually acid-base neutralizations; thus minerals containing alkali or alkaline earth metals are most inclined to engage in carbonation. Natural reaction kinetics of such carbonations are slow, however, so such reactions must be artificially encouraged by the introduction of heat and or pressure before becoming effective CO_2 control mechanisms. In addition to their thermodynamic stability, the carbonates formed are relatively insoluble to ground or surface waters with typical pH values. Thus, the carbonates are relatively immobile and unreactive in the environment; therefore, the CO_2 sequestration is not easily reversed. There is a substantial amount of research ongoing on carbon sequestration. The following Web sites and the links therein are recommended for further study: DOE-sponsored Carbon Sequestration research: http://cdiac2.esd.ornl.gov/. DOE's Carbon Dioxide Sequestration Initiative (February 2006): http://www.netl.doe.gov/publications/press/2006/06008-EOR_Sequestration_Initiative.html. Carbon Capture and Sequestration Technologies at MIT: http://sequestration.mit.edu/. The North American Carbon Program: http://www.nacarbon.org/nacp/agencies.html. The following literature review and the references therein on the mechanisms of CO_2 sequestration in minerals are also recommended: http://www.ecn.nl/docs/library/report/2003/c03016.pdf.

technique is intended to be used in conjunction with the injection of supercritical CO_2 to enhance product recovery. Coupling those technologies has resulted in recovery rates as high as 90 to 95%.

- ***Chemically Assisted Recovery Techniques.*** Various chemicals have been used successfully to enhance the recovery of crude oils. The chemicals selected perform various functions, acting as surfactants, electrolytes, mobility buffers, diluents, or blocking agents that effectively block exchange sites in the formation for which oil molecules have an affinity. The selection of chemicals is based on a number of factors, including cost and availability of the chemicals, compatibility of the chemical with the formation, and various other logistical factors. Chemicals such as hydrazine and hydrogen peroxide have been used to initiate thermal recovery, while quinoline, sodium hydroxide, and toluene have been used to enhance thermal recovery initiated by other means (Schumacher 1978).

Experience using chemicals to enhance kerogen recovery is much more limited than it is for crude oils, but some of the concepts on which these chemically enhanced recovery technologies are based may be relevant to oil shale recovery. DOE-sponsored research carried out at Argonne National Laboratory investigated the specific manner in which kerogen molecules were bound to minerals in oil shale. Understanding the nature of this bonding would allow development of chemically enhanced recovery methods, since chemical attack of such bonds would, in theory, release the kerogen (Vandegrift et al. 1980). Follow-up investigations at the University of Colorado, Boulder, conducted laboratory-scale recovery of kerogen using solutions of 10% hydrogen chloride, 80% steam, and 10% CO_2 injected into shale samples at moderate pressures (Ramirez 1989). Some of the results were promising, producing yields of 80% and, in one instance, better than 90% of the Fisher Assay value for the kerogen. The researchers concluded that chemically assisted recovery had promise, but that a key to its success was a dynamic flushing of the formation, rather than a simple saturation of the formation with the chemical solution selected. No further research using similar solutions has been undertaken, however.

A.3.2 Processing Oil Shale

Processing oil shale involves two steps: (1) retorting to separate the organic and inorganic fractions and cause initial chemical transformations in the organic fraction (Section A.3.2), and (2) upgrading the resulting organic retorting products through additional chemical reactions until materials generally equivalent to conventional fuels are produced (Section A.3.2). Myriad physical, chemical, logistical, and environmental issues must be understood and managed for any given process to be technologically successful. Numerous technologies have been advanced for retorting and subsequently upgrading oil shale. However, the heterogeneous nature of oil shale virtually guarantees that no one retorting technology will be best in all circumstances, and further guarantees that a technology’s performance at one location depends on a variety of site-specific factors. In addition to their impact on the yield and quality of final products, many technological issues also greatly influence economics. Availability of support resources such as electric power, heat, processing water, and reactants for use in upgrading reactions, as well as the nature of resulting environmental impacts and requirements for their control or mitigation, greatly impact the overall success, practicability, and cost of any given technology. Energy and environmental efficiencies of oil shale processing technologies play as important a role as the richness and accessibility of the oil shale resource.

The following discussions provide brief descriptions of the technologies that have been identified for oil shale processing and focus on their overall effectiveness and anticipated environmental impacts. No endorsements are implied and no warranty is given that the discussions below represent a comprehensive array of technologies. Attempts were made to develop the evaluations below in terms of resource extraction, retorting, and upgrading. However, the technological approach to oil shale development is more sophisticated than those simplistic, separable steps would imply, as it occurs in a very integrated fashion. Although such integration of distinct steps would result in greater overall efficiencies, each technology is discussed separately in this appendix.

When the oil shale resource is extracted from its formation for ex situ processing, a certain number of preliminary preparatory steps may be required before retorting or upgrading can occur. This might involve separating the oil shale from other extraneous materials and free formation water and crushing it to the uniform particle size specified by the retorting process being used. Primary and secondary crushing often take place within a subsurface mine before the materials are brought to the surface. Uniform particle size of oil shale results in better retorting efficiencies and better overall efficiencies in materials management. When the raw resource has been retrieved from its formation as a liquid through in situ formation heating or other in situ recovery technologies, crushing and sizing are obviously not required; however, other actions such as separation of water (e.g., formation water as well as the condensate that results when steam is used to heat the formation) and removal of entrained fine particulates are necessary prior to any retorting. All such crushing, sizing, and separating technologies are considered to be generic to resource mining and are not otherwise mentioned in the following discussions of particular retorting or upgrading technologies unless they have been shown to play especially critical roles in that technology's overall performance.

Organic fractions of oil shale are separated from the mineral fraction through a process known as retorting. During retorting, kerogen is released from the mineral surface to which it is adsorbed and subsequently undergoes chemical transformations in a process known as pyrolysis. When direct recovery methods are used (e.g., surface or subsurface mining), retorting the recovered oil shale causes thermal desorption of the organic fractions from the mineral fractions and their subsequent destructive distillation or pyrolysis, which produce three product streams: crude shale oil (a collection of condensable organic liquids); flammable hydrogen gases; and char, a solid fraction of organic material that typically remains adsorbed to the mineral fraction of the shale. The char has limited value as an energy source and is typically not further processed, although some retort designs call for it to be burned as a heat source for processing subsequent batches of mined oil shale. The liquid and gaseous products from retorting undergo additional processing to make them suitable for further refining off the mine site or for use on-site as fuel to sustain the mining and retorting operations. When recovery techniques are employed, only the kerogen or its pyrolysis products are recovered, and any subsequent aboveground retorting is conducted simply to complete kerogen pyrolysis. As will be discussed later, some MIS techniques have been specifically designed to accomplish in situ pyrolysis of kerogen. The extent to which that pyrolysis occurs in situ will determine the need for further ex situ processing of recovered organic materials.

A.3.2.1 Aboveground Retorting Technologies

Initial attempts at oil shale pyrolysis were conducted in aboveground retorts (AGRs) by using designs and technical approaches that had been adapted from technologies developed for other types of mineral resource recoveries. There are numerous configurations for AGRs; these are differentiated by the manner in which they produce the heat energy needed for pyrolysis, how they deliver that heat energy to the oil shale, the manner and extent to which excess heat energy is captured and recycled, and the manner and extent to which initial products of kerogen pyrolysis are used to augment subsequent pyrolysis. Technologies include both direct and indirect heating of the oil shale. In direct heat retorting, some of the oil shale is combusted to provide heat for pyrolysis of the remaining oil shale, or some other fuel is burned with the flame impinging directly on the oil shale undergoing retorting. Indirect heating, the more widely practiced alternative, involves the use of gases or solids that have been heated externally using a separate imported fuel or energy source and then introduced into the retort to exchange heat with the oil shale. Indirect heat sources include hot combustion gases or ashes from combustion of an external fuel, ceramic balls that have been heated by an indirect source, or even the latent heat contained in retort ash from previous retort cycles. The flammable hydrocarbon gases and hydrogen produced during retorting are also sometimes burned to support the heating process. While all retorts will produce crude shale oil liquids, hydrocarbon gases, and char, some have been designed to further treat these hydrocarbon fractions to produce syncrude. Other retorting processes contain auxiliary features to treat problematic by-products such as nitrogen- and sulfur-containing compounds, even, in some cases, converting these compounds to saleable by-products.

Comprehensive technical reviews of AGRs are contained in numerous reports published by or on behalf of various federal agencies, including DOE, the U.S. Environmental Protection Agency (EPA), and the U.S. Congress' Office of Technology Assessment (OTA) (DOE 1982, 1983, 1988, 2004a,b; EPA 1977, 1979; NTIS 1979; OTA 1980b). Other technical reviews of AGRs also exist in the open literature (Heistand and Piper 1995).

Pioneering work in the development of AGRs specifically designed for oil shale was conducted in the 1960s under the direction of the U.S. Bureau of Mines. The gas combustion retort (GCR) was the design originally selected by U.S. Bureau of Mines for initial development of the Green River Formation oil shale at its demonstration mine at Anvil Points, Colorado. The GCR was a counterflow direct combustion retort. In addition to a relatively simple design and generally high production efficiencies, the most important advantage to GCRs is that they do not require cooling water, which makes them an excellent fit for the arid regions in which the majority of the Green River Formation oil shale exists. The U.S. Bureau of Mines-led project to develop the GCR involved a consortium of six commercial oil corporations: Mobil Oil, Humble Oil, Pan American, Sinclair, Phillips, and Continental Oil. The U.S. Bureau of Mines GCR designs were the models for many commercial direct combustion counterflow retorts, including the Paraho Direct Mode Retort. Development of the GCR was completed in 1967, before the promulgation of the National Energy Policy Act (NEPA). Consequently, while some environmental impacts of the GCR were identified and measured, a comprehensive appreciation of its environmental impact was not established. However, environmental impacts from direct descendants of the GCR, such as the Paraho Direct Mode Retort, have been extensively defined and quantified.

AGRs have typically assumed the names of the RD&D projects in which they were developed, the corporation that conducted the RD&D, or their original inventors. At least eight separate retort designs have been developed to pilot stages, while only a few have reached commercial-scale applications. The following text, taken largely from the most recent DOE review (DOE 2004a) and from an EPA review (EPA 1979), provides information on a representative cross section of AGR technologies previously developed for application in the oil shale industry. The AGRs that collectively compose a representative sample of AGR technology include Union B, TOSCO II, Paraho (both direct and indirect modes), the Lurgi-Ruhrgas process, and Superior Oil's circular grate retort. Also included is a description of the Alberta Taciuk Process (ATP) technology, which was originally developed for processing tar sands, but is currently being proposed for use in oil shale development.

A.3.2.1.1 Union B Retort. This retort was developed by the Union Oil Company of California (Unocal). It is an example of hot inert gas retorting. Crushed shale (0.32 to 5.08 cm [0.13 in. to 2.00 in.]) is fed through two chutes to a solids pump that moves shale upwards through the retort. The shale is heated to retorting temperatures by interaction with a counterflow of hot recycle gas [510 to 538°C (950 to 1,000°F)], resulting in the evolution of oil shale vapor and gas. Heat is supplied by combustion of the organic matter remaining on the retorted oil shale and is transferred to the (raw) oil shale by direct gas-to-solids exchange. The process does not require cooling water. This mixture is forced downward by the flow of recycle gas and cooled by contact with cold shale entering the retort in the lower section of the retort. Gas and condensed liquids are captured and separated at the bottom of the retort. Liquids are removed. Gases are sent to a preheater and returned to the retort for recovery of heat energy by burning. The captured liquids are further treated for removal of water, solids, and arsenic salts. Once the system reaches equilibrium, no external fuel is required; heat is supplied by the combustion of hydrocarbon gases produced during retorting. Pollution control devices are integrated into the design for removal of hydrogen sulfide (H_2S) gas and NH_3 gas produced during retorting and for treatment of process waters recovered from oil/water separations. Treated waters are recycled, used for cooling the spent shale, or delivered to mining and handling operations and used to moisten the shale for fugitive dust controls.

The Union Retort B design offers particular advantages. The reducing atmosphere maintained in the retort results in the removal of sulfur and nitrogen compounds through the formation of H_2S and NH_3 gas, respectively, both of which are subsequently captured. Forcing the hot, newly formed oil vapors to immediately contact the cooler shale entering the retort results in their rapid quenching. This is thought to minimize polymer formation among the hydrocarbon fractions, improving not only the overall yield of crude shale oil, but also its quality. Additional treatment of the initially formed shale oil and the removal of heavy metals, such as arsenic, results in a final product recovered from the retort that can be used directly as a low-sulfur fuel or delivered to conventional refineries for additional refining.

A.3.2.1.2 TOSCO II Retort. The TOSCO II Retort, developed by The Oil Shale Corporation, is more correctly described as a retorting/upgrading process. Its design is unique in two respects: it is the only retort that has operated in the United States that employs a solid-to-solid heat exchange process, and the only process that fully integrates oil shale retorting and shale oil upgrading steps to produce an upgraded syncrude, as well as liquefied petroleum gas (LPG) and saleable sulfur, NH_3, and coke by-products. Although they are independent of each other, the retort and the various upgrading units are designed to work together.

Crushed and sized (nominally to 1/2 in.) raw oil shale is preheated to 500°F by interaction with flue gases from a ceramic ball heater. The preheated shale is introduced into a horizontal rotary kiln together with 1.5 times its weight in previously heated ceramic balls. The temperature of the shale is raised to its minimal retort temperature of 900°F. The kerogen is converted to shale oil vapors that are withdrawn and fed to a fractionator for hydrocarbon recovery and water separation. Spent shale and the ceramic balls are discharged and separated; the ceramic balls are returned to their heater; and the spent shale is cooled, moistened for dust control, and removed for land disposal. The fractionator separates the shale oil hydrocarbon vapors into gas, naphtha,[8] gas oil, and bottom oil. The gas, naphtha, and gas oil are sent to various upgrading units, while the bottom oil is sent to a delayed coking unit, where it is converted to lighter fractions and by-product coke. Gas oil and raw naphtha are both upgraded in separate hydrogenation units through reaction with hydrogen at high pressure. The hydrogen is actually produced on-site from steam reforming of the fuel gas originally recovered from the retort. In addition to improving the H/C ratio of the hydrocarbons, the hydrogenation units also convert any sulfur present to H_2S and any nitrogen present to NH_3. The NH_3 is captured for sale, while the H_2S is sent for further treatment, where it is converted to saleable sulfur. Other saleable products from the hydrogenation units include LPG and butane.

A.3.2.1.3 Paraho Retorts. The Paraho retorts, developed by Development Engineering, Inc., have been in service in oil shale fields in both Colorado and Brazil. Two versions exist, direct mode and indirect mode, both utilizing vertical retorting chambers. In the direct mode retort, some of the raw shale is ignited in the combustion zone of the retort to produce the heat that pyrolyzes the remaining oil shale present in higher zones. The Paraho direct mode retort is an example of the U.S. Bureau of Mines GCR. In the indirect mode retort, heat is generated in a separate combustion chamber and delivered to lowermost portion of the retorting chamber.

In the direct mode Paraho retort, crushed and sized oil shale is fed into the top of the vertical retorting vessel. At the same time, spent shale (previously retorted oil shale that contains solid carbonaceous char) is ignited in a lower level of the retort. Hot combustion gases rise through the descending raw shale to pyrolize the kerogen. Oil vapors and mists formed in the uppermost portion of the retort are removed. The liquid fraction is captured for further upgrading in independent facilities. The gaseous fraction is cleaned for sale, while a small portion is returned to the retort and combusted together with the spent shale.

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8 "Naphtha" is a general term applied to refined or unrefined petroleum products, not less than 10% of which distill below 347°F (175°C) and not less than 95% of which distill below 464°F (240°C) when subjected to standardized distillation methods (Sax and Lewis 1987).

In the indirect mode Paraho retort, the portion of the vertical retorting chamber that was used for oil shale combustion in the direct mode is now the region of the retort chamber into which externally heated air is introduced. No combustion occurs within the retorting chamber. That separate combustion process is typically fueled by commercial fuels (natural gas, diesel, propane, etc.) that are often augmented with a portion of the fuel gas recovered from the retorting operation. While they are very similar in operation, the direct and indirect mode Paraho retorts offer sufficiently different operating conditions so as to change the composition of the recovered crude shale oils and gases. Oil vapors and mists leave the direct mode retort at approximately 140°F, while the vapors and gases in the indirect mode leave the retorting vessel at 280°F and have as much as nine times higher heating values than gases and vapors recovered from the direct mode retort (102 Btu/scf vs. 885 Btu/scf, or 908 kcal/m^3 vs. 7,560 kcal/m^3) (EPA 1979). This is thought to be due principally to the fact that oil vapors and mists recovered from the direct mode are "diluted" with combustion gases from the combustion of the spent shale at the bottom portion of the retort. Characteristics of the recovered raw shale oil are somewhat different for the direct and indirect mode retorts, but each has characteristics similar to shale oils recovered from other retorts using similar shale heating mechanisms (direct vs. indirect). Retort gases also differ from the two modes. Gases from indirect mode retorts have much lower levels of CO_2 (due to the lack of dilution by gases from direct combustion) but generally higher levels of H_2S, NH_3, and hydrogen, which are thought to be the result of the indirect mode retort having much less of an oxidizing environment than the direct mode retort (EPA 1979).

A.3.2.1.4 Lurgi-Ruhrgas Process. The Lurgi-Ruhrgas technology was developed in Germany for the production of pipeline-quality gas through the devolatilzation of coal fines. The technology has operated at commercial scales for the devolatization of lignite fines, the production of char fines for briquettes from sub-bituminous coal, and the cracking of naphtha and crude oil to produce olefins. As with the Paraho process, the Lurgi-Ruhrgas process was designed from its inception to not only retort kerogen, but also to refine the resulting hydrocarbons into saleable liquid and gaseous petroleum fractions.

In this process, crushed and sized (minus 0.25 in.) oil shale is fed through a feed hopper and mixed with as much as six to eight times its volume of a mixture of hot spent shale and sand with a nominal temperature of 1,166°F and conveyed up a lift pipe. This mixing raises the average temperature of the raw shale to 986°F, a temperature sufficient to cause the evolution of gas, shale oil vapor, and water vapor. The solids mixture is then delivered to a surge hopper to await additional processing in which more residual oil components will be distilled off. The sand, introduced as a heat carrier, is recovered and recycled. The mixture is then returned to the bottom of the lift pipe and allowed to interact with hot combustion air at 752°F. The carbonaceous fraction is burned as the mixture is raised pneumatically up the lift pipe and transferred to a collection bin where the spent shale fines are separated from gases. The hydrocarbon gases and oil vapors are processed through a series of scrubbers and coolers to eventually be recovered as condensable liquids and gases. Because the shale particle size is initially so small, management of fines is critical throughout the process and involves the use of sedimentation and centrifuging as well as numerous cyclones and electrostatic precipitators.

A.3.2.1.5 Superior Oil's Circular Grate Retorting Process. One retort design advanced by Superior Oil theoretically offers substantial environmental advantages over other retorting processes. The design is a counterflow, gas-to-solid heat exchange process conducted in an enclosed circular grate. Shale in a relatively wide range of sizes (0.25 to 4.0 in.) is added, rotated to the first segment of the retort, and heated by a continuously circulating gas medium. Volatilized oil (mists) mixes with the circulating gas and, together with water, is periodically removed from the gas stream. The partially pyrolyzed shale rotates to the next segment of the retort where it is partially oxidized to complete the kerogen pyrolysis and oil evolution. The spent shale cools in the next segment of the grate as it yields heat to the circulating gas. Additional heat is added to the first segment of the grate where initial pyrolysis of raw shale takes place either through direct or indirect combustion of gases recovered from previous shale retorting. This design has been used for many years in the processing of various ores, including iron ores, and consequently has a relatively high reliability factor.

Only pilot-scale experiences exist for this retort when applied to oil shale. However, numerous tests have identified critical control parameters and optimized operations resulting in oil recovery yields greater than 98% Fisher Assay results. From an environmental perspective, the circular grate holds great promise, since it is essentially a sealed operation with hooded enclosures above the grate, to capture hydrocarbon gases and oil mists, and water seals (water troughs) below the grate, where spent shale is discharged. The water seals prevent gas and mist leakage and also provide for the moistening of the spent shale that is necessary for its safe handling and disposal.

Another unique aspect to the Superior circular grate retort is that it was designed to be operated in conjunction with subsystems for the recovery of alumina and soda ash. Thus, this design appears well suited for applications where saline deposits coexist with oil shale or are present above or below the shale. In the Superior Oil circular grate process, spent shale is delivered to subsystems that convert the saline minerals to saleable products. For example, commonly encountered dawsonite [$NaAl(OH)_2CO_3$] can be converted to alumina (aluminum oxide [Al_2O_3] and soda ash [$NaCO_3$]). Further, conditions during kerogen retorting are favorable for the simultaneous conversion of nahcolite ($NaHCO_3$) to soda ash, CO_2, and water.

Technical advantages to this retort include the circumstance that the circulating shale is independent of the circulated gas above it and that considerable experience with this type of retort has identified and resolved the major operational problems. Although designed to operate continuously, the unit can be quickly shut down and restarted. Temperature control is excellent, resulting in high hydrocarbon recovery rates and relatively minor amounts of sintering of the inorganic phase of the shale (Nowacki 1981).

A.3.2.1.6 Alberta Taciuk Process. The ATP is an AGR technology originally researched and designed for the extraction of bitumen from tar sands in Canadian tar sands deposits, some of the largest and richest deposits of their kind in the world. The ATP was developed by UMATAC Industrial Processes, a division of UMA Engineering, Ltd., which supplies the technology under license agreements.

The ATP Processor is the primary processing component of the technology and it works in conjunction with a number of ancillary subsystems that, together, comprise the ATP System. As with many of the retorting technologies discussed above, the ATP System provides more than simple retorting; the Processor, together with its subsystems, can provide primary upgrading of the initial retort products, as well as capture and control of problematic by-products. The ATP is a dry thermal process involving indirect heating of oil shale using countercurrent gas-solid heat exchange as well as the generation of process heat by combustion of coke (carbon present on retorted oil shale solids) in the combustion zone of the kiln. The ATP has been successfully applied to retorting oil shale and has achieved improved yields of kerogen-oil and combustible-gas over other retorting technologies developed and used specifically for the oil shale industry. The ATP provides high heat transfer efficiencies and integral combustion of coke for process heat demands, which minimizes the amount of residual coke remaining on spent shale. This combination minimizes CO_2 release per ton of shale processed and reduces the potential for environmental contamination from improper spent shale disposal (DOE 2004a).

A schematic flow diagram of the ATP System is shown in Figure A-3. A pictorial representation of the functioning of the ATP Processor is shown in Figure A-4.

The ATP System also represents the likely direction of future AGR equipment in that it is fitted with environmental control equipment to lessen the impact of air emissions and water effluents typically resulting from retorting. The ATP technology has successfully operated at semicommercial demonstration scale in Australia and is to be used commercially in China. There is evidence to suggest that the ATP System will also continue to be applied to future oil shale development.[9]

A.3.2.2 In Situ Retorting

First attempts at in situ formation heating were pursued with the intention of mobilizing the kerogen to facilitate its movement through the formation for extraction by conventional pumping/extraction devices. However, the objectives of in situ formation heating investigations quickly expanded to include in situ pyrolysis of the kerogen.[10] Both TIS and MIS recovery techniques have been explored for their compatibility with in situ retorting. While most past research has utilized MIS techniques, recently proposed research has begun to pursue techniques that can more properly be described as TIS.

Myriad in situ retorting designs have been proposed. As a result of his literature review, Lee (1991) has suggested three fundamental design dimensions on which to categorize in situ retorting technologies: (1) the mechanism by which heat is introduced into or produced within

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9 The Oil Shale Exploration Company (OSEC) is one of the applicants whose project is under consideration as part of the BLM’s oil shale RD&D program. OSEC proposes to use a modified version of the ATP system for oil shale development in the Uinta Basin in Utah. Additional details of the OSEC RD&D initiative, as well as the other five RD&D initiatives, are provided in Section A.4.

10 In situ retorting is said to have been attempted in Estonia in the 1940s (EPA 1979).

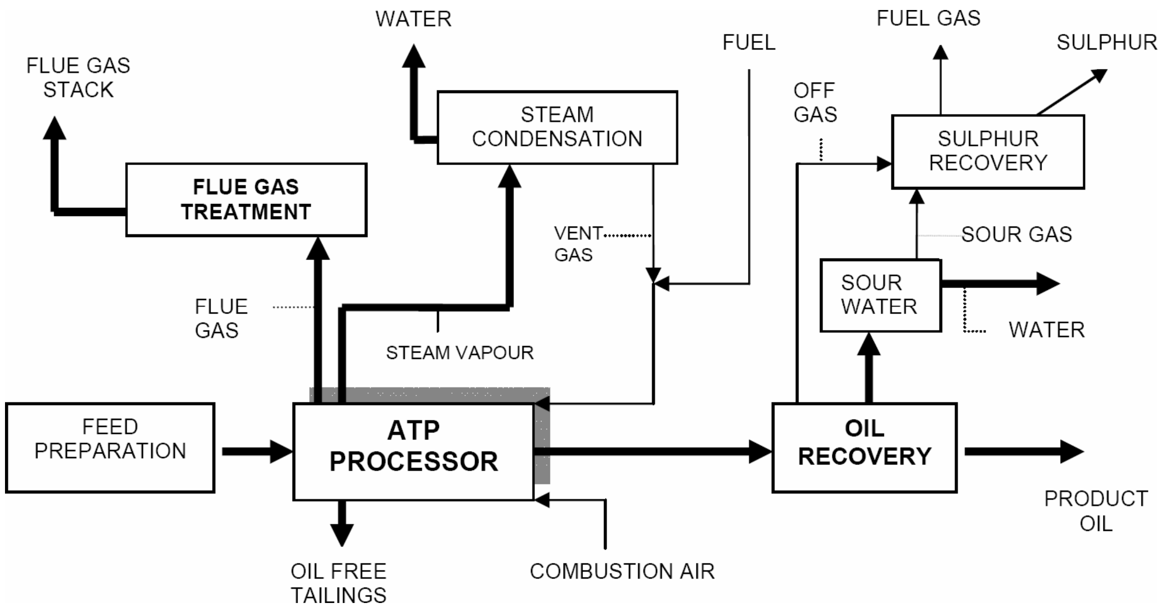

FIGURE A-3 ATP System Flow Diagram Processor (Source: UMATAC Industrial Processes; reprinted with permission)

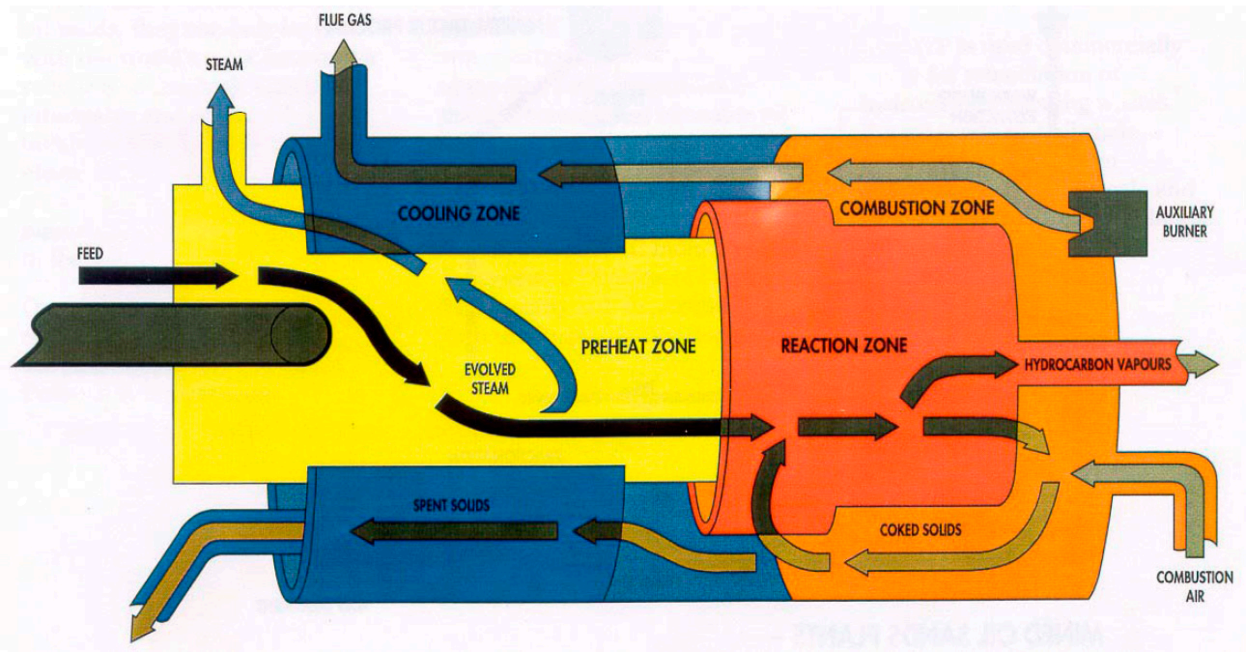

FIGURE A-4 Pictorial Representation of ATP Processor (Source: UMATAC Industrial Processes; reprinted with permission)

the formation, (2) the manner and extent to which the technology modifies natural fracturing patterns in the formation to ensure adequate permeability, and (3) whether the technology employs a TIS or MIS approach to recovery of organics. Lee further notes that most in situ technologies that have undergone field testing qualify as MIS and involve altering the formation by enhancing fracturing and/or by creating voids that would serve as retort chambers. Differences in approaches among MIS technologies center on the manner in which formation voids are formed, the shape and orientation of such voids (horizontal vs. vertical), and the actual retorting and product recovery techniques employed. Retorting techniques can include controlled combustion of rubblized shale, or formation heating by alternative means such as the introduction of electromagnetic energy. Product recovery techniques have included steam leaching, chemically assisted or solvent leaching, and displacement by high-pressure gas or water injection. Some of these formation sweeping techniques also can be seen as aiding or promoting additional refining of the initial retorting products. It is beyond the scope of this summary to discuss in detail all or even a majority of the designs that have been developed; Lee (1991) has provided a comprehensive listing of the patents that have been issued for these designs.

Hydrocarbon products of successful in situ heating are similar in character to the products recovered from AGRs: petroleum gases, hydrocarbon liquids, and char. Field experiences with the first generation in situ retorts indicate that the petroleum gases tend to be of lesser quality than gases recovered by AGRs. The condensable liquid fraction, however, tends to be of generally better quality than the liquid hydrocarbon fractions recovered from AGRs with higher degrees of cracking of the kerogen macromolecules and elimination of substantial portions of the higher boiling fractions typically produced in AGRs. Overall yields with any in situ retorting tend to be lower than yields from equal amounts of oil shale of equivalent richness processed through AGR (EPRI 1981). Various explanations have been advanced for these observed differences. Some of the loss of quality for recovered gases may be the dilution effect when heat is introduced to the formation by injection of combustion gases and/or steam, by advancement of a flame front through combustion of some portion of the shale, or when high-pressure gases are used to sweep retorting products from the formation to recovery wells. The quality improvements for the liquid fraction may be due to the relatively slow and more even heating that can be attained in a properly designed and executed in situ retorting process. Such quality improvements also may be indicative of further refining of initial retorting products when sweep gases such as natural gas or hydrogen are used. Finally, and importantly from an environmental perspective, the char and the mineral fraction to which it is adsorbed are not recovered but remain in the formation, significantly reducing (but not completely eliminating) collateral environmental impacts from solid by-product wastes. Limited evidence collected by the EPA suggests that groundwater quality impacts may still result from in situ spent shale.

Experience with AGRs clearly demonstrated that the conditions maintained during pyrolysis significantly influence the composition, quality, and yield of recovered products, including unwanted by-products, much more so than does the initial composition of the oil shale. Establishing and maintaining such strict controls in situ is a significant engineering challenge. Overcoming this challenge requires significant effort, but the ultimate return is equally significant. There are unique and substantial operational and environmental advantages to in situ recovery, and even more and greater advantages result from successful in situ retorting, including the following:

- Simplified material handling requirements (only the retorted organic fraction, roughly less than 15% by weight of the parent oil shale, would need to be recovered from the formation);

- Greater portions of the deposit would be accessible for economical kerogen recovery (albeit at a lower overall recovery efficiency);

- Spent shale from conventional retorting, a significant solid waste issue, would be virtually eliminated;

- Overall energy efficiencies would increase over conventional retrieval and AGR methods;

- Air pollution potential would be significantly reduced;

- Noise pollution would be severely reduced;

- Impacts on ecosystems and fugitive dust potential would be reduced because of the smaller aerial extent of surface industrial activities and the reduced land area required for material stockpiles and solid waste disposal; and

- Surface water quality impacts would be reduced because of the reduced size of land disposal areas and the reduced potential for stormwater pollution from interim material and waste pile runoff.

In situ retorting also has some potential disadvantages. Intuitively, the overall success of any in situ retorting technology results from its ability to distribute heat evenly throughout the formation. Indiscriminate formation heating can result in technological problems, as well as the thermal decomposition of mineral carbonates and the release of CO_2. From an operational standpoint, such decompositions are endothermic, and will result in the energy demands of such uncontrolled in situ retorting quickly becoming insurmountable. As noted above, environmental consequences of carbonate decomposition during in situ retorting can be expected to be mitigated to a large extent by the natural CO_2 sequestrations that can also be anticipated. Nevertheless, the lack of precise heat control will devastate both the yields and the quality of recovered hydrocarbons and must be avoided.

Another potential disadvantage to in situ retorting involves the time that it takes to heat substantial masses of formation materials to retorting temperature (on the order of months or years) and the energy costs over that period. Field experiences are limited and, because every formation accepts heat differently, it is difficult to define a universal time line or perform precise, reliable energy balances except on a site-specific basis.

Other largely unanswered questions involve long-term impacts from retorted segments of oil shale formations. Questions regarding long-term impacts include:

- Will vacated pore spaces need to be filled to prevent surface subsidence?

- Will groundwater flow patterns change significantly?

- Will groundwater interactions with retorted shale minerals facilitate the leaching of heavy metals or other contaminants?

- Will water produced from in situ combustion become a conduit for delivery of contaminants to existing groundwater aquifers?

- Will CO_2 produced in situ be safely sequestered indefinitely within the formation?

While conceptual designs for in situ retorting are numerous, only limited field activities have been pursued, mostly undertaken as proof-of-concept exercises, but, in a few instances, with the intent of advancing the practical development and application of specific in situ retort designs. Field data on both the short- and long-term impacts of in situ retorting are therefore limited. Independent investigations were conducted as early as 1953. Government-sponsored research began in the 1960s. The following sections provide brief descriptions of the early research and a more extensive description of only the most prominent in situ retorting technology. Also included are brief descriptions of RD&D projects that have been recently proposed and approved by the BLM for further research and that also involve some form of in situ retorting.

A.3.2.2.1 Early In Situ Retorting Experiments. Lee (1991) has provided the following brief summaries of some of the earliest research into in situ technologies:

- ***Sinclair Oil and Gas.*** Sinclair's experiments investigated one of the earliest uses of high-pressure air injected into the formation to sweep retort products to recovery wells.

- ***Equity Oil Company.*** Equity's process used hot natural gas to both retort the shale and sweep the retort products to recovery wells.

- ***Laramie Energy Technology Center (LETC).*** LETC sponsored some early research into in situ retorting in the early 1960s at Rock Springs, Wyoming. The purposes of this research were twofold: (1) establish the best mechanisms for enhancing the fracturing of the formation to increase its permeability, and (2) investigate the process by which in situ combustion of shale and the subsequent movement of a heat front through the formation could be made self-sustaining.

- ***Dow Chemical.*** Dow Chemical's research was conducted on eastern United States shale in Michigan, but much of the experience is transferable to western shales. Dow's experiment was one of the earliest examples of TIS. It used explosives to enhance fracturing and electrical resistance heaters combined with propane-fired burners to effect in situ retorting.

- ***Geokinetics, Inc.*** The Geokinetics process was one of the earliest uses of horizontally oriented retort voids in an MIS process. This DOE-sponsored research occurred near Grand Junction, Colorado, in the Parachute Member of the Green River Formation and also in the Mahogany Zone. Importantly, this research proved the value of horizontal retort chambers in relatively thin shale deposits.

A.3.2.2.2 The Occidental Oil Shale MIS Retort Technology. OOSI conducted much of the pioneering investigations into in situ retorting under the auspices of a DOE contract, issuing its final report in January 1984. Although the operation was under the control of OOSI, personnel from DOE's Sandia National Laboratories provided consultation services throughout the project and were instrumental in development of the final report (Stevens et al. 1984). The project was conducted in two phases near Logan's Wash near Debeque, Colorado, and represents one of the most extensive research ventures into MIS vertical in situ retorting technology.

The OOSI experiment was conducted in two phases and was intended to provide demonstrations of mining, rubblizing, ignition, and simultaneous processing of commercial-sized MIS retorts. Although the primary thrust of the research involved the development of design and operating parameters for the MIS in situ retort, support systems, including surface processing of retort products, were also investigated.

The retorting technology involved creating a void in the oil shale formation using conventional underground mining techniques.[11] Explosives (ammonium nitrate and fuel oil [ANFO]) were then introduced to cause the "rubblizing" of some of the shale on the walls of the void and to expand existing fractures in the formation, improving its permeability.[12] Access to the void was sealed and a controlled mixture of air and fuel gas (or alternatively, commercial fuel such as propane or natural gas) was introduced to initiate controlled ignition of the rubblized shale. Combustion using this external fuel continued until the rubblized shale itself was ignited, after which external fuel additions were discontinued and combustion air continued to be provided to the void to sustain and control combustion of the shale.[13] The resulting heat expanded downward into the surrounding formation, heating and retorting the kerogen. Retort

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11 In commercial application, numerous voids would be created, spaced throughout the formation and collectively representing a removal of 15 to 20% of the formation volume of shale that would be brought to the surface for conventional AGR.

12 Although the original research utilized explosives, it can be anticipated that for some shale formations, sufficient alterations can be accomplished with the injection of high-pressure water (hydrofracturing).

13 Phase II experimented with the use of hot inert gas to preheat the rubblized shale, followed by air to initiate combustion.

products collected at the bottom of the retort void and were then recovered from conventional oil and gas wells installed adjacent to the void. Careful control of combustion air/fuel mixtures was the primary control over the rate of combustion occurring in the heavily instrumented and monitored void. Once recovery of retorted oil shale products equilibrated, a portion of the hydrocarbon gases was recycled back into the void to be used as fuel to sustain in situ combustion.[14] Two separate retorts were constructed and operated during Phase II of the project, with the last two retorts shutting down in February 1983.

Ultimately, oil recovery was equivalent to 70% of the yield predicted through Fisher Assay. Design of the experiment was directed toward potential future commercial applications so numerous that such in situ retorts were operated simultaneously to demonstrate the practicability of an approach that would likely have been desirable in commercial development ventures. Conceptual views of the OOSI in situ retort and the expected movement of the heat front through the formation are displayed in Figures A-5 and A-6, respectively.

From a technological perspective, the OOSI in situ retorting experiment was a success. Recovered crude shale oil has a specific gravity of 0.904 (American Petroleum Institute [API] Gravity of 25°[15]), a pour point of 70°F, a sulfur content of 0.71% (by weight), and a nitrogen content of 1.50% (by weight). OOSI believes that crude shale oil meeting those specifications would be available for use as a boiler fuel without further processing or would certainly constitute acceptable refinery feedstock for additional refining to other conventional fuels.

From an environmental perspective, many questions were raised regarding the type and scale of environmental impacts that would result from either the initial in situ retorting or from the subsequent use of the resulting shale oil in industrial boilers or furnaces, and some of those questions remain unanswered. As part of its development plan, OOSI identified as many as 48 separate activities associated with this technology for which there could be an environmental impact. Environmental monitoring throughout the project and beyond was scheduled to verify and quantify those impacts. However, the magnitudes of many of OOSI's anticipated impacts are disputed by the EPA.

First, the EPA disputes the OOSI claim of the magnitude of nitrogen oxides (NO_x) emissions that would result from combustion of the recovered crude shale oil in an industrial boiler, believing that the amount would be much greater than that claimed. Second, it has not

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[14] Hydrocarbon gases recovered from this process are of only moderate quality, having been diluted by gases of combustion as well as CO_2 from carbonate decomposition. Typically, the recovered gases had a heating value of less than 65 Btu/scf. In the OOSI design, the fraction of the gas that was not introduced back into the formation to support further combustion was used on-site for power and/or steam generation.

[15] The pour point is the temperature at which the petroleum liquid's viscosity is sufficiently low to allow pumping and transfer operations with conventional liquid handling equipment. American Petroleum Institute (API) gravity is an arbitrary scale for expressing the specific gravity or density of liquid petroleum products. Devised by the API and the National Bureau of Standards, API gravity is expressed as degrees API. API gravities are the inverse of specific gravity. Thus, heavier viscous petroleum liquids have the lower API values.

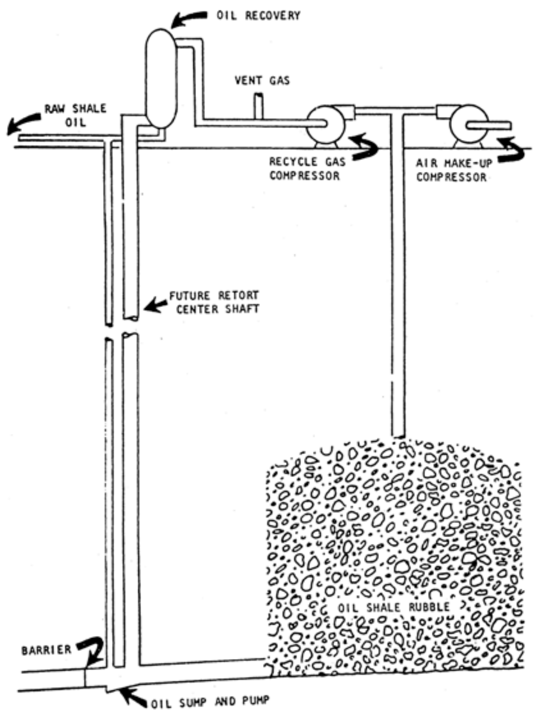

FIGURE A-5 Conceptual Design of the Occidental Oil Shale, Inc. MIS Retorting Process (Source: EPA 1979)

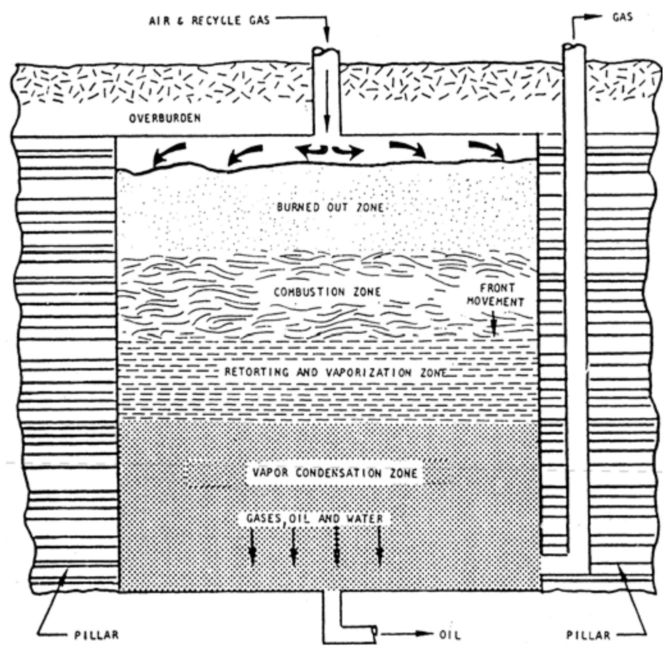

FIGURE A-6 Conceptual View of the Downward Movement of the Heat Front through the Formation in the Occidental Oil Shale, Inc., Vertical In Situ Retort (Source: EPA 1979)

been reliably demonstrated that all of the CO_2 generated during the retorting (from combustion sources as well as carbonate decomposition) would be successfully sequestered in the formation indefinitely. Thirdly, major water management problems exist. It was estimated that the volume of retort water created during retorting plus the amount of water used for surface processing (upgrading) of retort products and for fugitive dust control throughout the operational area is essentially equivalent to the volume of crude shale oil produced. Thus, a substantial volume of water may require treatment before discharge or recycling. Further, groundwater monitoring data appear to indicate that groundwater contamination had occurred, both during and after completion of retorting. The extent to which the retort water contains contaminants that would require proper treatment could not be reliably predicted, and it is not clear whether any or all of this water could be recycled for use in future processing.

Conclusions from a thorough analysis of water quality impacts from MIS retorts were summarized in the OOSI final report:

- Total alkalinity, NH_3, phenols, dissolved organic carbon, thiosulfate, and thiocyanide concentrations are significantly higher in retort water (i.e., waters recovered from retorts during operation) than in natural water;

- Aluminum, magnesium, and calcium concentrations are lower in retort water than in natural water;

- Monitoring data from wells near the retort operations showed no discernable trends that could be interpreted as contamination from the retorts; however,

- Trends over time indicate that concentrations of constituents thought to be leaching from the retired retorted areas initially increase significantly from natural waters, but also quickly equilibrated (in a matter of 2 years or less) to levels approximating the concentrations in natural waters without any intervention or remediation, suggesting that most leaching occurs from the initial flushing of retorted zones by infiltrating groundwater, but also that the amounts of leachable materials remaining in retorted zones appear to be limited.

A.3.3 Upgrading Oil Shale

Irrespective of the resource recovery and retorting technologies employed, kerogen pyrolysis products are likely to require further processing or upgrading before becoming attractive to oil refineries as feedstocks for conventional fuels. Upgrading crude shale oil to produce syncrude for delivery to refineries is analogous to the early steps of crude oil refining. The refining process is complex, but nevertheless well understood and well documented. The discussions that follow provide only a cursory review of those aspects of refining that are most relevant to mine site upgrading of crude shale oil.

Refining crude oil involves a great variety of reactions. Preliminary steps are taken to separate extraneous materials that may be present in the crude oil feedstock (e.g., water, suspended solids, etc.). Crude oil fractions are separated (fractionated) by their boiling points in atmospheric and/or vacuum distillations. Distillation fractions are subjected to heat, causing the thermal decomposition of large molecules into smaller ones (coking or cracking). Thermal cracking products are then subjected to a variety of chemical reactions designed to modify their chemical compositions either by removing hydrogen and other atoms to form compounds comprised largely of carbon (e.g., delayed coking, fluid coking), or by adding hydrogen while removing hetero atoms such as sulfur and nitrogen to form organic compounds composed exclusively of carbon and hydrogen (catalytic or thermal hydrocracking, hydrotreating, desulfurization, and hydrogenation). Finally, various treatment reactions are conducted to remove contaminants or modify chemicals that would be the source of air pollution when the petroleum product is later consumed by combustion. Numerous other specialized reactions are interspersed within this scheme, which is designed to reformulate organic molecules into chemicals that change the physical or chemical properties of the commercial fuel mixtures in which they are contained.

Upgrading crude shale oil at the mine site might consist of all of the above steps, although hydrogen-addition reactions generally predominate, and reactions to produce specialty chemicals are not likely to occur at all. Upgrading is typically directed only at the gaseous and liquid fractions of the retorting products and is rarely applied to the solid char that remains with the inorganic fraction of the oil shale, although coking of that solid fraction is possible. The most likely end products will be refinery feedstocks suitable for the production of middle distillates (kerosene, diesel fuel, jet fuel, No. 2 fuel oil), although lighter weight fuel components such as gasolines can also be produced. In general, hydrotreating followed by hydrocracking will produce jet fuel feedstocks, hydrotreating followed by fluid catalytic cracking is performed for production of gasoline feedstocks, and coking followed by hydrotreating is performed with the intention of producing diesel fuel feedstocks (Speight 1997).

Similar to the preliminary steps taken at refineries, prior to or coincident with crude shale oil upgrading reactions, there are also activities to separate water from both the gas and liquid fractions, to separate oily mists from the gaseous fraction, and to separate and further treat gases evolved during retorting to remove impurities and entrained solids and improve their combustion quality.[16] Actions to remove heavy metals and inorganic impurities from crude shale oils also take place.

Upgrading activities are dictated by factors such as the initial composition of the oil shale, the compositions of retorting products,[17] the composition and quality of desired petroleum feedstocks or petroleum end products of market quality, and the business decision to develop other by-products such as sulfur and NH_3 into saleable products.[18] Product variety and quality issues aside, there are other logistical factors that determine the extent to which upgrading activities are conducted at the mine site. Most prominent among these factors is the ready availability of electric power and process water. In especially remote locations, factors such as these represent the most significant parameters for mine site upgrading decisions.

The initial composition of the crude shale oil produced in the retorting step is the primary influence in the design of the subsequent upgrading operation. In particular, nitrogen compounds, sulfur compounds, and organometallic compounds dictate the upgrading process that is selected. In general, crude shale oil typically contains nitrogen compounds (throughout the total boiling range of shale oil) in concentrations that are 10 to 20 times the amounts found in typical crude oils (Griest et al. 1980). Removal of the nitrogen-bearing compounds is an essential requirement of the upgrading effort, since nitrogen is poisonous to most catalysts used in subsequent refining steps and creates unacceptable amounts of NO_x pollutants when nitrogen-containing fuels are burned.

Sulfur, also a poison to refinery catalysts, is typically present in much lower proportions as organic sulfides and sulfates. With respect to sulfur, crude shale oil compares favorably with

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[16] Removal of entrained solids is typically accomplished by simple gravity or centrifugal separation techniques such as cyclone separators. However, other techniques have been developed, including high-gradient magnetic separation (Lewis 1982).

[17] The composition of retort products is dictated by conditions during retorting. In general, pyrolysis of kerogen at the lowest temperature possible yields the highest proportion of saturates over olefinic and aromatic constituents. Higher retorting temperatures yield increasingly greater amounts of aromatic compounds until, at the retorting temperature of 871°C, Colorado Green River Formation shale can be expected to yield 100% aromatic compounds (Speight 1990).

[18] Elemental sulfur has widespread use in a wide variety of industry sectors: pulp and paper, rubber, pharmaceutical, detergents, insecticides, and explosives. Likewise, NH_3 enjoys widespread industrial applications, such as agricultural fertilizers, textiles, steel treatment, explosives, synthetic fibers, and refrigerants.

most low-sulfur crude oils, which are preferred feedstocks for low-sulfur fuels that are often required by local air pollution regulations. Hydrotreating to the extent necessary to convert nitrogen compounds to NH_3 is sufficient in most instances to simultaneously convert sulfur to H_2S. Crude shale oil additionally contains much higher amounts of organometallic compounds than conventional crude oils. The presence of these organometallic compounds complicates the mine site upgrading, since they can readily foul the catalysts used in hydrotreating, causing interruptions in production and increased volumes of solid wastes requiring disposal, sometimes even requiring specialized disposal as hazardous wastes because of the presence of spoiled heavy-metal catalysts.

Desired end products for mine site upgrading are typically limited to mixtures of organic compounds that are acceptable for use as conventional refinery feedstock; however, it is possible to produce feedstocks that are of higher quality and value to refineries than even crude oils having the most desirable properties. Since crude shale oils are typically more viscous than conventional crude oils, their yields of lighter distillate fractions such as gasolines, kerosene, jet fuel, and diesel fuel are typically low. However, additional hydrotreating can markedly increase the typical yields of these distillate fractions.

Given the high capital costs involved in constructing and operating more sophisticated refining operations at remote mine sites, there is little incentive for mine operators to duplicate existing refinery capabilities, and most oil shale development business models will likely include only the upgrading that is minimally necessary for the end products to be acceptable to conventional refineries and capable of being transported to those refineries by existing conveyance technologies (i.e., sufficiently improved API gravities and pour points). Such a business model was endorsed by the Committee on Production Technologies for Liquid Transportation Fuels of the National Research Council in 1990 and is believed to still be applicable today (National Research Council 1990).

All of the factors controlling upgrading are very site- and project-specific. At the PEIS level, it is not possible to precisely describe all of the actions that may be undertaken for the purposes of upgrading retorting products; however, a general overview of the nature of those reactions is provided below. An example of an explicitly defined upgrading scheme is provided in the BLM’s *Final Environmental Impact Statement for the Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Volume I* (BLM 1977).

Upgrading is designed to increase the relative proportion of saturated hydrocarbons over unsaturated hydrocarbons in the crude shale oil recovered from retorting and to eliminate the other compounds present that can interfere with further refining of the crude shale oil into conventional middle distillate fuels (primarily, compounds containing nitrogen or sulfur atoms). Hydrogen at high temperatures and pressures is used to create a reducing atmosphere in which olefinic or aromatic hydrocarbons are converted to alkanes (or saturates), and organic compounds containing sulfur or nitrogen are destroyed with the sulfur and nitrogen being converted to H_2S and NH_3, respectively, which are then captured and removed. As upgrading converts crude shale oil to syncrude, the physical properties change significantly. As a practical matter, the pour point and API gravity of the liquid fraction are substantially reduced, making syncrude much easier to handle and transport than crude shale oil (typically another stated goal of mine site upgrading). Gaseous components are converted to fuel gas, LPG, and butanes,[19] all becoming available for use as fuels to support further oil shale processing or as marketable materials for sale at the wholesale or retail level. Most probably, gases such as propane and propylene would be stored and receive an appropriate odorant gas (e.g., methyl mercaptan) for eventual sale as LPG, while any hydrogen produced as well as the butane/butylene fraction are more likely to be returned to the retorting process and consumed as supplemental fuel.

A.4 SPENT SHALE MANAGEMENT

An important component of surface mining and underground mining projects is spent shale management. Either surface mining or underground mining projects may opt to dispose of spent shale in surface impoundments or as fill in graded areas; for surface mining projects it may be disposed of in previously mined areas. Disadvantages of surface disposal include the use of large land areas; labor-intensive requirements to revegetate the disposal area; dust-control prior to revegetation; and potential impacts on surface water, particularly salinity, from runoff water containing residual hydrocarbons, salts, and trace metals from the spent shale.

While disposal of spent shale back into the underground oil shale mine or a preexisting mine appears initially attractive, various logistical issues may prevent or limit such disposals as well as potential problems unique to that disposal technique. For example, mine development design may prevent convenient access to retired portions while the mine is still active. Also, while the potential for leaching of toxic constituents from the spent shale as a result of precipitation or run-on surface water interactions is effectively eliminated, leaching as a result of interaction of groundwater can still be anticipated.[20]

Regardless of the disposal option selected, a number of issues need to be addressed, including the structural integrity of emplaced spent shale, an increase in volume (and decrease in density) over raw shale during the retorting process (this has become known as “the popcorn effect”), and the character of leachates from spent shale. Limited research has been conducted on each of these issues.

Studies on the structural properties of spent shale have been performed on the spent shale from the Paraho Retorting project at Anvil Points, Colorado, and summarized in a paper presented at the 13th Oil Shale Symposium held in Golden, Colorado, in 1980 (Heistand and Holtz 1980). The studies concluded that properly wetted and compacted spent shale could be quite stable, even exhibiting the properties of low-grade cements and exhibiting no problems

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[19] Butanes formed during upgrading of shale oil are typically mixtures of butane and butylenes. Although potentially saleable products, these mixtures are more typically used as fuel at the plant site.

[20] It is reasonable to expect that mine dewatering efforts will continue throughout the operational period of the mine, but will cease after the mine is shut down and natural groundwater flow patterns will reestablish, notwithstanding the alterations to flow caused by modifications to the formation. Thus, contact of groundwater with emplaced spent shale can be expected to occur.

with respect to leaching, autoignition, or fugitive dusting.[21] Average structural properties for spent shale from a Paraho AGR are shown in Table A-5.

The "popcorn effect" is the term used to describe the resulting volumetric expansion of oil shale rock after it has undergone retorting. As much as 30% expansion in volume can occur (DOE 1988). The exact reasons for this phenomenon are not fully understood. Certainly, some density changes could be expected after removal of the organic fractions. It may also be that CO_2 is being released from decomposing carbonate minerals as a gas expands the mineral structure as it escapes.

Density changes can be expected to be slightly different for each specific retorting technology, but in all cases, densities of spent shale have decreased over the density of the parent oil shale. A plant producing 50,000 bbl/day from 30 gal/ton oil shale using surface or subsurface mining and AGR may need to dispose of as much as approximately 450 million ft^3 of spent shale each year (DOE 1988). Regardless of the degree of compaction that can be accomplished during placement of spent shale, and assuming that the spent shale disposal strategy involves placement in retired mine areas to reestablish the original grades and topographies of those areas, as much as 30% of the volume of spent shale would be left once those original grades and topographies were reestablished and would need to be disposed of in virgin areas.

Field data evaluating the leachate character of spent shale have been collected by the EPA and others. Although the data are limited, there appears to be a clear indication that subjecting oil shale to retorting conditions can result in the mobilization of various ionic constituents contained in the mineral portion of the oil shale. Polar organic compounds with moderate-to-high water solubility formed during retorting and not successfully separated from

TABLE A-5 Structural Properties of Compacted Paraho AGR Spent Shale

Parameter	Ranges of Values Measured
Compaction (dry density)	1,400–1,600 kg/m^3 (87–106 lb/ft^3)
Permeability	1 x 10^{17} cm/sec (0.1 ft/yr)
Strength (unconfined, compressive)	1,480 kPa (215 psi)
Classifications	
Type	Silty-gravel
Size	30-50% > 4.76 mm (4 mesh)
	25-35% < 0.074 mm (200 mesh)
Leaching/autoignition/dusting	No problems identified

Source: Heistand and Holtz (1980).

21 Although the results of this study are encouraging with respect to the short- and long-term impacts of spent shale disposal, it is important to recognize that these results are specific to the spent shale, and specific conditions evaluated in this study and similar results of spent shale from other retorting technologies will not necessarily behave in the same manner.

the spent shale can also appear in spent shale leachates. Tables A-6 and A-7 show typical expected ranges of leachate constituents for spent shale from both in situ and aboveground retorting.

Independent leachate studies have also been carried out on both spent shale disposal piles and piles of raw shale, with emphasis on the potential leachability of arsenic, selenium, molybdenum, boron and fluorine (as the fluoride ion), all species that are relatively toxic to plants and can be expected to exist as soluble anions under the pH conditions normally encountered in waters interacting with spent shale disposal piles or raw shale stockpiles (i.e., $8 \leq pH \leq 12$) (Stollenwerk and Runnells 1981). The results of these studies supported the predictions regarding the character of typical leachates from spent shale piles presented in Table A-7.

Another study performed at the Anvil Points Oil Shale Facility in Rifle, Colorado, appeared to identify species that are unique to spent shale leachates, and thus, possibly useful for monitoring the movements of leachate from spent shale disposal areas (Riley 1981). Soil extracts, surface waters, and groundwaters were analyzed for the presence of water-soluble organic compounds in a drainage area adjacent to a spent shale disposal pile. The C3-C6 alkylpyridines[22] were identified in alluvial groundwater samples and in surface waters below a seep and in moist subsoils adjacent to the alluvial sampling well. Extracts of raw shale, crude shale oil and crude oil from Prudhoe Bay, Alaska, showed no alkylpyridines, however, suggesting that alkypyridines may be produced during oil shale retorting and become unique constituents of the char on the spent shale. Thus, alkylpyridines may serve as excellent agents for monitoring leachate movements from spent shale piles.

A.5 ONGOING AND EXPECTED FUTURE OIL SHALE DEVELOPMENT TECHNOLOGIES

Limited research into future oil shale development technologies is ongoing, but more is currently being planned. The clear trend established near the end of the last period of major oil shale development activities involved the move to in situ technologies.

A.5.1 Shell Oil Mahogany Ridge Project

Most of the in situ heating technologies have been in place since the mid-1980s, and early examples invariably involved the use of combustion strategies as sources of heat. There are, however, some novel ongoing research projects that are exploring alternative formation heating techniques. One project of particular potential importance is research being conducted by Shell Exploration and Production (hereafter, Shell), a subsidiary of Shell Oil Corporation, on Shell-owned property located southeast of Rangely, Colorado, in Rio Blanco County. Since

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[22] The parent compound, pyridine, is a cyclic polar hydrocarbon with the formula C5H5. It is a flammable liquid with moderate water solubility and a pungent odor. It is a severe eye irritant. Alkylpyridines are derivatives of the parent where one or more hydrogens is replaced by an alkyl group [$C_nH_{(n+1)}$].

TABLE A-6 Summary of the Range of Leachate Characteristics of Simulated Spent Shale from In Situ Retorting and from Three AGRs

Constituent	Simulated In-Situ Retorts	Surface Retorts[a]
General water quality measures		
pH	7.8–12.7	7.8–11.2
Total dissolved solids	80–>2,100	970–10,011
Major inorganics		
Bicarbonate	22–40	20–38
Carbonate	30–215	21
Hydroxide	22–40	–[b]
Chloride	5.5	5–33
Fluoride	1.2–4.2	3.4–60
Sulfate	50–130	600–6,230
Nitrate (NO_3)	0.2–2.6	5.1–5.6
Calcium	3.6–210	42–114
Magnesium	0.002–8.0	3.5–91
Sodium	8.8–235	165–2,100
Potassium	0.76–18	10–625
Organics		
Total organic carbon	0.9–38	–
Trace elements		
Aluminum	0.095–2.8	–
Arsenic	–	0.10
Boron	0.075–0.14	2–12
Barium	–	4.0
Chromium	0.002–1.8	–
Iron	0.0004–0.042	–
Lead	0.014–0.017	–
Lithium	0.020–0.42	–
Molybdenum	trace	2–8
Selenium	–	0.05
Silica	25–88	–
Strontium	0.004–8.7	
Zinc	0.001–0.025	–

[a] TOSCO, U.S. Bureau of Mines, and Union Oil Company processes.
[b] A dash indicates data not available.

TABLE A-7 Expected Characteristics of Leachates from Raw Shale Piles and Spent Shale Disposal Piles from Various AGRs[a]

Water Quality Parameter	Raw Shale	Spent Shale from Paraho Retort	Spent Shale from TOSCO II Retort
Total Dissolved Solids	18,000	28,000	55,000
Mo[b]	9	3	9
Boron[c]	32	3	18
Fluoride[d]	16	10	19

[a] Concentrations in milligrams per liter (mg/L); unless otherwise noted.

[b] Molybdenum predicted to be present as MoO_4^{-2}.

[c] Boron predicted to be present as $B(OH)_3^0$ and $B(OH)_4^{-1}$.

[d] Fluorine predicted to be present as free F^{-1}.

Source: Stollenwerk and Runnells (1981).

1996, Shell has been working in the Mahogany Ridge portion of the Piceance Basin, thought to be the richest portion of the Green River Formation, to develop and field-test a novel approach to in situ heating called the in situ conversion process (ICP). ICP involves creating an “ice curtain” or “freeze wall” to isolate a vertically oriented column of the oil shale formation. This is done by encircling the focus area of the formation with wells into which piping is installed for recirculation of a heat-exchange fluid.[23] The recirculating heat-exchange fluid removes latent heat energy from the formation immediately adjacent to each of the wells. Ultimately (over a period of years) sufficient heat will be removed from the formation immediately surrounding each of these refrigeration wells so that naturally occurring water in the formation will freeze, and form an ice curtain, thereby preventing the subsequent migration of groundwater into that portion of the formation. Then, after removal of any remaining liquid water within the bounded area, additional wells will be installed into which electric resistance heaters will be placed, and the formation will be slowly heated to 650 to 700°F (over the course of 2 years or more). As the process name implies, the intent is to cause a relatively complete chemical conversion of the kerogen to petroleum gases and liquids that will be subsequently recovered using conventional extraction technologies and that will require very little additional processing or modification before being delivered to conventional refineries. An initial review of this project was provided by DOE (2004a).

An artist’s conceptual drawing of the ICP is shown in Figure A-7. Figure A-8 is a photograph of the Shell Mahogany Research Project site.

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23 The initial research effort involved the use of a brine solution; however, future phases of research may use different heat exchange strategies, such as using aqueous NH_3 solutions coupled with secondary cooling provided by anhydrous NH_2.

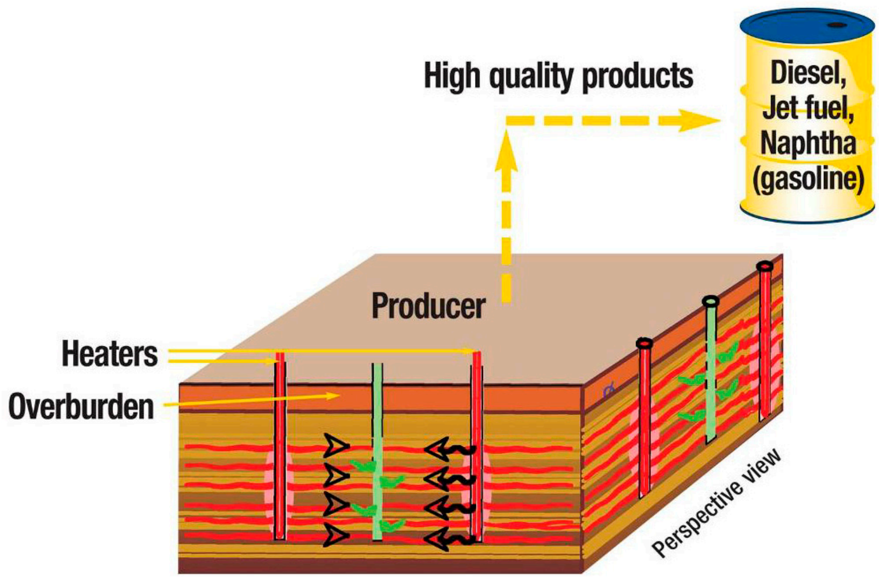

FIGURE A-7 Cross Section of Shell's Patented ICP Technology (Courtesy: Shell Exploration & Production; reprinted with permission)

FIGURE A-8 Shell's Field Research in Rio Blanco County, Colorado (Courtesy: Shell Exploration & Production; reprinted with permission.)

Initial results are very promising. Shell's fact sheet (Shell 2006) characterizes the attributes of this technology in the following manner:

- The process is more environmentally friendly than previous oil shale efforts that were based on mining and retorting.

- ICP has the potential to double the recovery efficiency, as it enables access to much deeper and thicker oil shale reserves.

- ICP can potentially generate transportation fuel products that require considerably less processing.

Early research data appear to support these claims. Recovered products have included gases (hydrogen, natural gas, other combustible gases) (approximately one-third by weight of the total amount recovered) as well as light oils (approximately two-thirds by weight) of relatively high quality (typically API 36°). Recovery rates as high as 62% (of recoverable oil) have been observed. Extrapolations from the test scale suggest potential yields (from oil shale deposits of equal richness) of as much as 1 million barrels per acre (i.e., heating of 1 acre of aerial extent of the formation throughout the entire depth of the formation present within that 1 acre footprint) (Boyd 2006).

Shell is currently preparing to integrate the research it has been conducting on the individual aspects of this technology (e.g., developing and maintaining a freeze wall, optimizing electric heater technology and rates of formation heating, optimizing product recovery techniques, etc.) into a larger-scale demonstration project under the auspices of an RD&D lease recently issued by the BLM. In 1996, Shell carried out a small field test on its Mahogany property, in Rio Blanco County, Colorado, using an in-ground heating process to recover oil and gas from the shale formation. Since then, Shell has carried out four additional field studies on private land near the towns of Rangely, Rifle, and Meeker, Colorado. The most recent test has produced 1,500 bbl of light oil plus associated gas from a relatively small plot. Shell's research is continuing, and Shell has nominated three separate projects under the BLM's oil shale RD&D program to further evaluate its process on public lands.

A.5.2 Oil Tech, Inc., AGR Research

Oil Tech, Inc., a small independent corporation, has been conducting research into aboveground retorting using electric resistance heating. The company maintains a small research site on approximately 2,600 acres of state-owned land approximately 20 mi east-northeast of Bonanza, Utah. This area is also underlain with Green River Formation shale at approximately a 1,000-ft depth, but has never been mined. Approximately 70,000 tons of Mahogany Ridge oil shale that had been previously mined from the U-a research tract more than 20 years ago has provided the feedstock for this AGR research and development effort to date. Truckload quantities of run-of-mine shale are delivered periodically to the research site and stockpiled there. The shale is crushed on-site to nominal 1/2-minus size before being introduced by a conveyor system to the vertical AGR. The AGR is of modular design, composed of a series of individual heating chambers, interconnected and stacked one upon the other, into which shale is loaded from the top. Heating rods extend into the centers of each of these chambers, transmitting heat to the shale in each chamber. Temperatures in each chamber are monitored and controlled by thermocouples. The temperature profile increases from top to bottom of the retort, culminating in the lowest heating chamber attaining a temperature of 1,000°F. An induced draft fan exerts a slight vacuum simultaneously on all of the chambers through a common plenum, providing the principal means of extracting and collecting the gases and volatilized organic products of kerogen pyrolysis released from the shale by the process of fractional vaporization. Pyrolysis products are collected, filtered, and condensed. Spent shale is dumped by gravity from the bottom chamber, allowed to cool, and stockpiled for disposal. Shale moves from the top of the retort to the lowest heating chamber by gravity displacement. The design basis for this retort is 500 tons/h shale input, resulting in a shale processing rate of approximately 24,000 yd^3/day.

The particular advantages of this retort include the following:

- The modular design allows for relative portability and adaptability.
- The process requires no water, yet produces approximately 200 lb of water (kerogen pyrolysis as well as free water present in the feedstock) for every ton of shale retorted.
- Heavily insulated enclosure and heating chambers maximize heating efficiency.
- Product separation is easily accomplished.
- Product quality is such that little additional upgrading is required.

Initial results are promising. Yet in these early phases of research, complementary data that are essential to evaluating the overall performance of this retort have not yet been collected in sufficient amounts or detail:

- Mass balances are incomplete to this point.
- Production curves and reaction kinetics have not yet been calculated.
- The fates of sulfur and nitrogen in the kerogen have not yet been investigated.
- Yields have not been precisely calculated; however, spent shale averages 10% residual carbon.
- Leachability, weathering characteristics, and structural features of the spent shale have not been fully investigated.
- No data have been collected regarding the extent to which carbonates are decomposing in the lower (hottest) sections of the retort; however, the acidic character of the pyrolysis water recovered suggests some carbonate decompositions may be occurring.
- Relationships between operating parameters and yield have not been fully explored.

The next phase of the research was scheduled to occur in the spring of 2006 and was to involve a 30-day continuous operation of the retort using the Mahogany Ridge shale that is still at the research site. Over this period, additional data will be collected that will be essential for optimizing operating parameters for the retort, establishing reaction kinetics and thermodynamics to optimize yields, and more precisely evaluating the environmental impacts of the operation, including disposal of spent shale.

As an aside, company representatives have indicated their intent to investigate the possible use of abandoned gilsonite mines for disposal of spent shale, and have calculated as much as 5 million ft^3 of disposal space to be available in abandoned mines in the immediate area that are located on private lands.[24]

A.5.3 Future R&D Projects on BLM-Administered Lands

On June 9, 2005, pursuant to its authority to lease federal lands for oil shale development under Section 21 of the Mineral Leasing Act (*United States Code*, Title 30, Section 241 [30 USC 241]), the BLM published a notice in the *Federal Register* (Volume 70, page 33753 [70 FR 33753]) announcing a program wherein companies or individuals could submit proposals to lease 160-acre tracts of BLM-managed land for a period of up to 10 years for the purpose of RD&D of oil shale development technologies. Potential lessees were required to submit a detailed Plan of Operation that addressed their proposed development scenario, including their approaches for complying with applicable laws and regulations and environmental protection.

The BLM reviewed each of the proposals that were submitted and selected six to receive further consideration. Upon successful completion of required environmental assessments (EAs), each of the six applicants was awarded a 160-acre lease on which to conduct RD&D of oil shale development technology for a period of up to 10 years, with the potential to extend the lease for another 5 years. Assuming that the RD&D efforts are successful, each RD&D leaseholder will be given the opportunity to exercise a preference right lease, expanding the aerial extent of its BLM lease to a maximum of 5,120 acres, thus facilitating transition from research-scale to commercial-scale operations. Figure A-9 shows the locations of the six RD&D tracts and the associated preference right lease areas. The following sections provide overviews of the six projects on the basis of information published in the EAs (BLM 2006a–c, 2007). Table A-8 lists the hazardous materials, hazardous wastes, and wastewater streams associated with these projects.

A.5.3.1 Chevron U.S.A., Inc. (Chevron)

The proposed Chevron project would be located in the Piceance Basin of Colorado; information presented here regarding this project is taken from the EA of the proposed activities (BLM 2006a). Chevron’s proposed methodology would be an in situ process for shale oil

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[24] Gilsonite is a natural asphalt deposit that occurs in the United States only in parts of Utah and Colorado. Tectonic movements in the past have resulted in gilsonite being present in vertically oriented fissures, many of which extend to the ground surface. These gilsonite seams were 20 ft or more across and hundreds of feet deep.

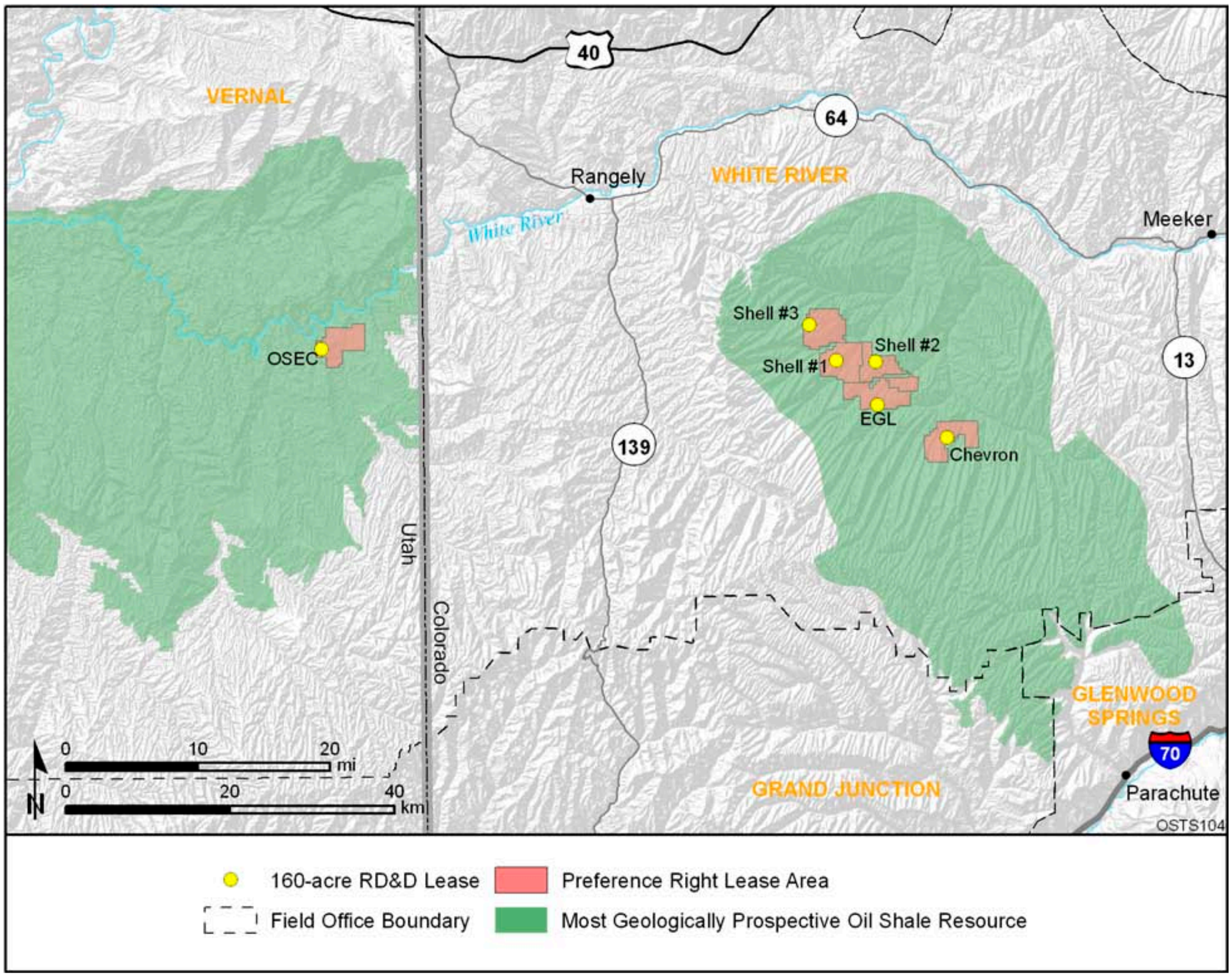

FIGURE A-9 Locations of Six RD&D Tracts and Associated Preference Right Lease Areas

recovery and production that would be facilitated by applying drilling, fracturing, and in situ heating technologies. This methodology would entail drilling wells into the oil shale formation and applying a series of horizontal fracturing technologies. The process would include the generation of hot gases via the in situ combustion of the remaining organic matter in previously heated and depleted zones. These hot gases would then be introduced into the fractured zone to decompose the kerogen into producible hydrocarbons.

The location of the 160-acre lease parcel nominated for Chevron's proposed R&D activities is shown in Figure A-9. Access to the proposed project area would be via Colorado State Highways 13 and/or 64 and County Roads 5 (Piceance Creek), 26, 29, and 69. The proposed lease parcel is situated adjacent to County Road 69 on Hunter Ridge at an elevation of 6,560 to 6,660 ft.

Chevron's proposed methodology for shale oil recovery would apply to an oil shale deposit that is approximately 200 ft thick. This methodology would entail drilling wells into the oil shale formation and applying a series of controlled horizontal fractures within the target

TABLE A-8 Hazardous Materials and Wastes, Other Wastes, and Wastewater Associated with the RD&D Projects

Hazardous Materials and Wastes in RD&D Operations

- Fuels and various working and maintenance fluids for vehicles and industrial equipment[a]
- Chemicals used in management, purification, and upgrading of gaseous and liquid products.
- Spent shale (at Oil Shale Exploration Company [OSEC] site)
- Sludges from purification and sanitary wastewater treatment
- Herbicides
- Containers, dunnage, packaging materials, miscellaneous wastes
- Office-related wastes
- Decommissioning wastes, including fluids for cleaning of industrial equipment, storage containers, and transfer piping
- Products from both in-situ and AGR retorting, including aqueous, gaseous, and organic liquid phases, and suspended solids.
- Caustic agents, flocculants, and other chemicals common to treatment of industrial wastewaters
- Ammonia chemicals used in the refrigeration system of the Shell sites
- Sulfur compounds generated during the retorting and during secondary processing (hydrotreating)
- Spent catalysts from the hydrotreatment process at the OSEC site

Wastewater from RD&D Initiatives

- Sanitary wastewater
- Formation water (for 5 sites using in situ retorting)
- Process water in the formation (a product of kerogen pyrolysis for 5 sites using in situ retorting)
- Spent drilling fluid and drill cuttings
- Pyrolysis water (or sour water) with suspended solids, sulfur, heavy metals and water-soluble organics from retort operation
- Equipment cleanout activities and boiler blowdown and steam condensate treatments (at those sites where boilers are operated)
- Wastewaters from well installations
- Water from mine dewatering (OSEC site)

[a] Fuels for vehicles and equipment (including diesel and possibly gasoline for emergency power generators), fuels for industrial and comfort heating furnaces, boilers, or other external combustion sources (diesel and/or propane stored in aboveground tanks, or natural gas delivered by pipeline), and vehicle and equipment maintenance fluids (lubricating oils, glycol-based antifreeze, battery electrolytes, hydraulic, transmission, and brake fluids). Fluids are those typically used for maintenance of vehicles and equipment. For on-road vehicles, on-site maintenance is expected to be limited to fluid level maintenance. More substantial maintenance activities (e.g., oil changes, repairs, etc.) would occur at off-site facilities. Also included are dielectric fluids, miscellaneous cleaning solvents, miscellaneous welding gases, and corrosion control coatings (e.g., exterior-grade oil-based paints, two-part epoxy coatings and sealants, etc.).

interval induced by injecting CO_2 gas into discrete areas of the target interval to effectively rubblize the production zone in a horizontal plane. If necessary, propellants and/or explosives might be directed into the specific horizontally and vertically limited area to facilitate further rubblization of the production zone in order to prepare it for heating and in-situ combustion.

The seven phases of the process would be as follows:

- *Phase 1.* A core would be extracted for use in developing a more comprehensive site-specific understanding of the geology, mineralogy, hydrogeology, and geophysical properties of the formation.

- *Phase 2.* Activity would be directed at identifying and avoiding the existing natural fracture network.

- *Phase 3.* One or more additional test wells would be drilled to confirm and verify the extent of the fracture network.

- *Phase 4.* Additional fracturing of the shale would be facilitated by subjecting the formation to thermal cycles using hot CO_2 gas brought in by CO_2 tanker trucks.

- *Phase 5.* The formation heating process would be initiated by circulating pressurized heated gas through the fractured interval of the formation.

- *Phase 6.* This phase would involve the decomposition of the kerogen and production of shale oil. Before the formation reached the kerogen decomposition temperature, equipment would be installed to collect and process the produced water, gas, and shale oil.

- *Phase 7.* After the recoverable kerogen was extracted from the initial wells, the proposed RD&D program would include integrating the heating process by drilling a new well pattern adjacent to the first and repeating the fracture process. Hot gases from in situ combustion of the residual organic material remaining in the oil shale would be used to heat the newly fractured zone.

Chevron believes that these fractured zones would have a predominantly horizontal component that would allow for the maintenance of barriers between the production zone and the upper and lower water-bearing units. The detection and avoidance of the natural vertical fractures within the formation is a key component of the proposed technology.

A.5.3.1.1 Groundwater and Surface Water Management. As many as 20 groundwater monitoring wells would be drilled into both the upper and lower water-bearing units as part of a comprehensive groundwater monitoring program incorporated into the design of the proposed process. Additional observation wells may be installed as necessary to further monitor the process.

A.5.3.1.2 Produced Shale Oil and Gas. Storage tanks and facilities would separate the produced gases from the shale oil and water, and liquid streams would then be trucked off-site to separate processing or disposal facilities. Preliminary estimates suggest production rates of 5 or more barrels per day after 1 year of initiating the heating process.

A.5.3.1.3 Storage and Disposal of Materials and Waste. The products used on-site would be typical of the products used in the oil and gas industry (lubricants, diesel fuel, gasoline, lubricating oils, solvents, and hydraulic fluid) and would be used, stored, and disposed of in accordance with all industry standards and practices, as well as in compliance with all federal, state, and local regulations. Smaller quantities of other materials, such as herbicides, paints, and other chemicals, would be used during facility operation and maintenance. Any produced water and/or flush water would be routed to 500-bbl storage tanks for transport off-site to an appropriate disposal facility. Spent caustic would be stored in 50-bbl tanks and transported off-site for disposal. No process wastewater is anticipated in the preliminary phases of the proposed project, but would be expected in the later phases of the program. Drilling fluid returns would be processed by a modularized solids control system to minimize spent drilling fluid generation. This system would produce relatively dry cuttings with minimal associated drilling fluid. The drilled cuttings and fluids would be collected in plastic-lined earthen pits approximately 100 ft by 100 ft with 6 ft of usable depth (8 ft deep). One pit for each of the four proposed well patterns (1 producer, 4 injectors, and 12 groundwater wells) would be anticipated. These pits would be kept clean and free of oil and other harmful constituents, constructed in accordance with industry regulations and BLM Gold Book standards (DOI and USDA 2006) and guidelines, and designed to meet BLM specifications to deter and/or prevent migratory birds and other wildlife from accessing the contents. Used oil would be handled in accordance with Title 40, Part 279 of the *Code of Federal Regulations* (40 CFR Part 279). A used oil recycler would be contracted to handle all used oil. The proposed in-situ process would not include any aboveground retort activities; therefore, no spent shale would be brought to the surface as a waste product.

The management, maintenance, and disposal of sanitary wastewaters would be contracted through local providers. Solid waste products would be stored in closed, animal-proof containers so as not to attract wildlife and to prevent trash from being blown off-site. All solid waste would be managed, collected, and disposed of in accordance with existing laws and regulations by a local contract provider. Other waste products would be collected and disposed of in accordance with existing laws, stipulations, and regulations.

The proposed in-situ process would not include any aboveground retort activities; therefore, no spent shale would be brought to the surface as a waste product.

Gas produced as a result of the proposed process would be burned as fuel or flared. Produced shale oil would be stored in 100-barrel tanks and transported off-site for processing and subsequent delivery to consumer markets.

A.5.3.1.4 Water Requirements. Table A-9 gives the amount of water consumed; water use would be limited to mixing additives and drilling mud, suppressing dust, and various purposes by personnel. The water required for construction and operation of the proposed process would be purchased from local permitted sources and trucked to the site.

TABLE A-9 Estimated Water Needs per Year for Chevron RD&D Site

	Estimated Water Needs per Year	
Year	bbl	ac-ft
2006	36,320	4.68
2007	134,725	17.36
2008	29,445	3.79
2009	254,410	32.79
2010	9,135	1.18
2011	2,135	0.28
2012	233,755	30.13
2013	3,890	0.5
Total	703,185	90.71

Source: BLM (2006a).

A.5.3.1.5 Staffing. The construction, drilling, and fracturing (Phases 1 through 4) of the proposed process would require from 10 to 100 contractors and employees.

A.5.3.1.6 Utilities. Portable diesel generators would be used to provide the needed power during the preliminary phases of Chevron's proposed RD&D project. Rights-of-way (ROWs) for power, communications, and natural gas would be constructed only if the fracturing phase was considered successful. The power line would be installed on elevated poles along with communication lines. The natural gas pipeline would be installed underground and would enter the proposed lease site by using the same 65-ft-wide combined ROW.

A.5.3.1.7 Noise. The noise generated by this technology would fluctuate with the alternate construction and operation phases of the project. The construction, well drilling, and fracturing phases would generate noise for 2 to 4 months or longer, depending on the success of initial operations. The active retorting phases of the proposed project would generate less noise, but that noise would occur 24 hours a day over the life of the project. The noise-generating equipment for this process would be diesel and gas generators.

Noise generated during the testing phase of the project would be from drill rigs installing monitoring wells and the heating/production wells. Equipment used would be designed to meet applicable Colorado Oil and Gas Conservation Commission allowable noise levels, which are expected to be 50 to 55 dbA for the tract in a rural/agricultural setting. Noise readings would be taken at the site during operations to verify noise levels.

A.5.3.1.8 Air Emissions. Air pollutant emissions would occur during construction (due to surface disturbance by earthmoving equipment, vehicle traffic fugitive dust, drilling activities, facility construction, and vehicle engine exhaust) and during production (including power generation, product and CO_2 processing, and engine exhausts).

The air pollution emission estimates were based on the best available engineering data assumptions and scientific judgment. However, where specific data or procedures were not available, reasonable but conservative assumptions were incorporated. For example, the air emission estimates assumed that project activities would operate at full production levels continuously (i.e., with no downtime).

A.5.3.1.9 Transportation. The proposed RD&D project would not create additional access onto BLM lands; it would, however, increase traffic on existing roadways and contribute to fugitive dust along the unpaved county roads necessary for access to the site.

A.5.3.2 EGL Resources, Inc. (EGL)

Information presented here regarding EGL's proposed project is taken from the EA of the proposed activities (BLM 2006b). The EGL project would use an in situ retorting technology to test a 300-ft-thick section of the Mahogany Zone of the Green River Formation in the Piceance Basin of Colorado. The EGL tract is located approximately 27 mi west-northwest of Rio Blanco, Colorado, on a ridge between Ryan Gulch and Black Sulphur Creek at elevations ranging from 6,795 to 6,965 ft (Figure A-9). Both streams are tributaries of Piceance Creek. Vegetation is 48% rolling loam sagebrush and 52% pinyon-juniper. Construction of the RD&D facilities would be accompanied by clearance of 28 acres of rolling loam vegetation and 8 acres of pinyon-juniper vegetation.

In the EGL oil shale process, heat would be introduced by using heated fluids and/or electric heaters near the bottom of the oil shale zones to be retorted. This would result in a gradual, relatively uniform heating of the shale to 650 to 750°F to convert kerogen to oil and gas. It is anticipated that once a sufficient amount of oil is released to surround the heating elements, a broad horizontal layer of boiling oil would continuously release hot hydrocarbon vapors upward and transfer heat to the oil shale above the heating elements.

The oil shale that would be tested at the EGL tract is a 300-ft-thick section composed of the Mahogany Zone (R-7) and the R-6 Zone of the Green River Formation, the top of which is at a depth of approximately 1,000 ft. The affected geologic unit would be approximately 1,000 ft long and 100 ft wide. At an estimated richness of 26 gal of oil per ton of shale, the potential amount of oil in the unit to be tested is more than 560,000 bbl per acre. For this test, however, the Mahogany and R-6 Zones would be retorted; the oil shale below these zones, however, could still be retorted at a later date on the 160-acre tract.

A number of heating fluids could be used. It is expected that steam would be used during the initial heating phase of the development. During the later stages of processing, a high-temperature, hot-oil heat-transfer medium, such as Dowtherm, Syltherm, and/or Paratherm, might be used.

To introduce the heating fluids into the oil shale deposit, EGL's technology would involve drilling five cased wells that would vertically penetrate nearly the full length of the oil shale deposit to be tested. Once near the bottom of the oil shale zone, the wells would be drilled horizontally for a distance of about 1,000 ft to the opposite side of the pattern. The wells would then be directed/connected vertically upward through the oil shale and overburden to the surface.

To minimize lost circulation problems in the Uinta Formation and to avoid contaminating any aquifers encountered, the wells would be drilled by using a flooded reverse-circulation method that uses a combination of fresh water and air drilling. Bentonite and polymer would be used to control viscosity and maintain the desired mud weight. Drilling would require about 80 bbl/day of fresh water that would likely be purchased from local sources.

For the RD&D phase of the project, a 25-million-Btu/h trailer or a skid-mounted, direct-fired, forced-circulation, steam-generation boiler would be used to heat the fluids. The boiler would initially be fired by natural gas or propane, but after retorting of the oil shale had begun, the boiler could be fired by gas and oil produced by the retorting process.

A.5.3.2.1 Groundwater Management. To reduce the amount of groundwater infiltrating into the oil shale zone that would be heated, EGL would establish a dewatered zone in the retorting zone. This would be accomplished with four to eight pumping wells surrounding the subsurface retort area. Extracted groundwater would be reinjected downgradient into the equivalent aquifer intervals in order to maintain the regional water table and avoid disturbing baseflow to nearby streams.

Upgradient and downgradient multilevel monitoring wells would be installed to characterize the structure and properties of local aquifers, establish predevelopment baseline groundwater conditions, better define the geology of the oil shale resource, and monitor water quality.

After project completion, pumping and treating of contaminated groundwater would continue until groundwater quality met applicable regulatory standards.

A.5.3.2.2 Produced Shale Oil and Gas. During sustained operation, it is expected that the product would be about 30% gas and 70% light oil, on the basis of heating value. Shale oil produced during test operations would be separated from the gas and water produced with it and stored in tanks at the test site. The shale oil would be trucked to markets in Colorado, Utah, and Wyoming.

A.5.3.2.3 Storage and Disposal of Materials and Waste. Wastewater from the site, including retort water (up to 50 bbl/day), boiler blowdown, and drilling waste, would be trucked to a licensed disposal facility.

A variety of materials typical of the oil and gas drilling and production operations prevalent in the Piceance Basin could be on-site during construction and operations, including lubricants, diesel fuel, gasoline, lubricating oils, solvents, and hydraulic fluid. Smaller quantities of other materials, such as herbicides, paints, and other chemicals, would be used during facility operation and maintenance. These materials would be used to control noxious weeds, facilitate revegetation on disturbed areas, and operate and maintain the facility during the life of the project.

Solid waste (human waste, garbage, etc.) would be generated during construction activities and during operation of the oil shale RD&D facility. Trash would be collected in animal-proof containers and periodically hauled to a sanitary landfill in Rio Blanco County. All other wastes would be collected and disposed of in a manner consistent with existing laws and regulations.

A.5.3.2.4 Water Requirements. Little water would be required for the test facility. Start-up, dust suppression, personnel requirements, and drilling operations would require limited amounts of water (approximately 80 bbl/day for drilling) that would be purchased and trucked to the site from local sources. Makeup water would be required for the boiler to compensate for minor steam losses and to maintain dissolved solids in the boiler at an appropriate level. Water needed for sustained operations would likewise be so acquired or taken from wells on-site if possible. The total volume of water required from outside sources for sustained operation would be approximately 27 bbl/day.

A.5.3.2.5 Staffing. It is estimated that a total of 10 to 40 employees would be required during test operations; most employees would work during daylight hours. During construction of the test facilities and drilling of the test wells, more workers would be needed, and their numbers would vary from 10 to 100, depending on the phase of construction.

A.5.3.2.6 Utilities. A new power line would interconnect an existing power line southwest of the tract and project facilities. The power line would extend approximately 1,760 ft from the southwestern corner of the tract to the existing power line and have a 25-ft-wide ROW. Construction of the power line could disturb as much as 1.0 acre outside the 160-acre tract boundary.

A.5.3.2.7 Noise. Noise generated during the testing phase of the project would be from drill rigs installing monitoring wells and the heating/production wells. Equipment used would be designed to meet applicable Colorado Oil and Gas Conservation Commission allowable noise levels, which are expected to be 50 to 55 A-weighted decibels (dbA) for the tract in a rural/agricultural setting. Noise readings would be taken at the site during operations to verify noise levels.

A.5.3.2.8 Air Emissions. Air pollution emissions were estimated on the basis of the best available engineering data assumptions and scientific judgment. However, where specific data or procedures were not available, reasonable but conservative assumptions were incorporated. For example, the air emission estimates assumed that project activities would operate at full production levels continuously (i.e., with no downtime).

Table A-10 gives the estimated NO_x, carbon monoxide (CO), sulfur dioxide (SO_2), PM_{10}, and $PM_{2.5}$[25] emissions associated with EGL's project for both construction and RD&D operation scenarios. The emission estimates include both an anticipated maximum daily basis and an annual basis. The construction sources include fugitive dust from road traffic, surface preparation and trenching construction activities, and combustion emissions from drill rig operations. Operation sources include combustion emissions from EGL's boiler and fugitive dust from road traffic. Construction and road traffic were modeled by assuming activities would occur during the 7 a.m. to 7 p.m. 12-hour period 5 days per week. The drill rig and boiler were modeled assuming that these activities would occur continuously.

A.5.3.2.9 Transportation. Workers and contractors would commute to the job site during the test phase. Most traffic would be from Rifle, Meeker, and Rangely on Piceance Creek Road and State Highways 13 and 64. Employer-provided housing is not contemplated for the test phase, but workers whose presence would be required for extended nonroutine testing might be temporarily housed in trailers.

EGL estimates that 10 light and 6 heavy vehicles would travel to the tract each day for a 4- to 6-month duration. During the well drilling and facility construction period, 16 light and 10 heavy vehicles per day would travel back and forth for a duration of 12 to 18 months. During the 3 to 4 years that the facility would be operating, approximately 15 light and 9 heavy vehicles per day would travel back and forth. During shale oil production, 3 tanker trucks would transload railcars at Lacy Siding west of Rifle each day. During reclamation, 2 light vehicles and 1 heavy vehicle would travel to and from the site each day, for a duration of 3 to 4 years. Heavy vehicles would include drill rigs, water trucks, and tanker trucks. Light vehicles would include passenger vehicles, trucks, and vans. Equipment would be obtained locally depending on equipment/drill rig availability, and local services would be used whenever possible. Tankers would be of the standard weight, size, and axle arrangements normally used in the State of Colorado without special permits.

A.5.3.3 Shell Frontier Oil and Gas

Shell is to conduct RD&D projects on three separate 160-acre sites in the northern part of the Piceance Basin in Rio Blanco County, Colorado (Figure A-9); information presented here regarding these projects is taken from the EA of the proposed activities (BLM 2006c). The elevation of the sites ranges between 6,580 and 7,060 ft. The sites would be used to test different methods of shale oil extraction, all of which are based on Shell's proprietary ICP that converts kerogen contained in oil shale into ultraclean petroleum liquids and gas that require less processing to become finished transportation fuels (e.g., gasoline and jet and diesel fuels). The majority of the 160 acres for each of the sites would be impacted through ground disturbance and the construction of buildings and associated infrastructure.

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[25] PM_{10} = particulate matter with a mean aerodynamic diameter of 10 micrometers (μm) or less; $PM_{2.5}$ = particulate matter with a mean aerodynamic diameter of 2.5 μm or less.

TABLE A-10 EGL RD&D Project Air Emissions Summary

		Emissions	
Source	Constituent	lb/day	tons/yr
Construction			
Surface preparation	PM_{10}	22.95	2.625
	$PM_{2.5}$	2.08	0.245
Trenching	PM_{10}	22.90	2.004
	$PM_{2.5}$	9.8	1.024
Road traffic	PM_{10}	20.00	2.600
	$PM_{2.5}$	3.10	0.403
Drill rig engine	PM_{10}	7.12	1.300
	$PM_{2.5}$	1.10	0.200
	NO_x	124.40	22.700
	CO	152.90	27.900
Operations			
Boiler	NO_x	222.92	40.500
	CO	40.55	7.400
	SO_2	832.88	152.000
Road traffic	PM_{10}	20.00	2.600
	$PM_{2.5}$	3.10	0.403

Source: BLM (2006b).

The three sites have the following variations:

- Site 1: ICP—implemented by recovering hydrocarbons from kerogen using self-contained heaters that heat the shale rock.

- Site 2: Two-Step ICP—implemented by initially extracting nahcolite by injecting hot water into the shale and then recovering hydrocarbons through ICP once the nahcolite is removed.

- Site 3: Electric-ICP (E-ICP)—implemented by recovering hydrocarbons from kerogen using bare-wire heaters to heat the rock; some of the heating is created by the flow of electricity through the shale formation.

Site 1 Technology: ICP. For Shell Oil Shale Test Site 1, a freeze wall would be installed to prevent groundwater from flowing into areas where ICP was being used. A series of 150 holes approximately 8 ft apart would be drilled where the freeze wall would be created. The freeze holes would be drilled to a depth of approximately 1,850 ft. A chilled fluid (–45°F) would be circulated inside a closed-loop piping system and into the holes. The cold fluid would freeze the nearby rock and groundwater, and in 6 to 12 months, it would create a wall of frozen ground. The freeze wall would be maintained during both the production and reclamation phases of the ICP project.

After the freeze wall was established, 10 producer holes would be drilled inside the freeze wall and used to remove the groundwater trapped inside the wall. These holes would later be converted to producer holes that would remove the hydrocarbon products. The producer holes would be completed to a depth of approximately 1,675 ft. Pumps would be installed in each hole to bring the product to the surface.

Approximately 30 heater holes would be drilled in the interior of the containment zones, spaced 25 ft apart, and electric heaters would be installed to uniformly heat the otherwise undisturbed hydrocarbon-bearing shale to between 550° and 750°F for a period of several years.

Additional holes would be used to monitor subsurface conditions (e.g., temperatures, pressures, and water levels). The monitoring holes would be placed inside and outside the freeze wall.

After ICP treatment, pumping water into the heated zone would allow recovery of the remaining hydrocarbons. This process, followed by a pump-and-treat process with water and possibly bioremediation, would reduce the amount of hydrocarbons in the heated shale to acceptable levels. Then the freeze wall would be allowed to thaw.

Site 2 Technology: Two-Step ICP. Although significant areas of the Piceance Basin are amenable to ICP technology, the presence of excessive amounts of nahcolite limits the applicability of ICP in portions of the Piceance Basin. Nahcolite, also known as baking soda or sodium bicarbonate, occurs naturally within shale. The process to be used at this test site would be nearly the same as the process to be used in Site 1, with the exception of the extraction of nahcolite prior to removal of hydrocarbon material. The drilling for the freeze walls, heater holes, and extraction would be the same. Removal of the nahcolite prior to implementation of ICP would be required for efficient recovery of both the nahcolite and the petroleum products in the kerogen. Shell has demonstrated that nahcolite can be solution mined by circulating hot water through the shale. The nahcolite, which is dissolved into the hot water and recovered from the hot water after it is pumped back to the surface, is a product of this process. Removal of the nahcolite increases the permeability and porosity of the remaining rock matrix and significantly improves the thermal efficiency in recovering petroleum from the oil shale when the ICP process is used.

This two-step ICP technology would have a number of energy-saving benefits. The hot water used for nahcolite decomposition could be heated by using waste heat from previous areas where ICP had been implemented. Solution mining would preheat the oil shale in the mined zone to at least 250°F using otherwise wasted heat. The water used for cooling the ICP-treated oil shale would pass through a surface heat exchanger to heat the water used for nahcolite solution mining, providing additional energy savings.

Removing the nahcolite and then dewatering would reduce the mass within the formation that must be heated to ICP temperatures, ultimately reducing the ICP energy requirements. Solution mining the nahcolite would increase the speed at which a heat front would move within the formation, thus reducing the time and energy requirements to produce oil and complete the project.

A freeze wall would be created before initiating nahcolite solution mining and would be maintained through implementation of ICP to contain groundwater. Following the solution mining of the nahcolite, electric heaters would be installed to heat the shale to ICP temperatures, and the solution mining holes would be converted to hydrocarbon production wells. The boundary between the solution-mined nahcolite-ICP region and the remaining nahcolite-bearing strata would provide an impermeable wall, in addition to the freeze wall, to prevent hydrocarbons from migrating out of, and water coming into the heated area.

After ICP treatment occurred, the pumping of water into the heated zone would allow recovery of the remaining hydrocarbons. This process, followed by a pump-and-treat process with water and possibly bioremediation, would reduce the amount of hydrocarbons in the heated shale to acceptable levels. Then the freeze wall would be allowed to thaw.

The Colorado State University revegetation test plot (approximately 50 acres) would remain fenced and undisturbed.

Site 3 Technology: Advanced Heater Test Site (E-ICP). The process used at Site 3 would be nearly the same as that used for Site 1 in terms of the amount and type of drilling and the extraction process. However, the technology for heating would be different. The economics of the ICP process could be improved dramatically if bare electrode heaters were installed that combined both thermal conduction and some heating generated by electricity flow through the shale formation. The bare electrode process is called E-ICP and is a patented in situ heating technology. The project would include about 70 to 100 vertical heaters spaced 20 to 40 ft apart. The bare electrode heaters are about 1,950 ft long and are designed to concentrate most of their heat output in the bottom 1,000 ft. With lower heater well capital costs and greater energy efficiency, E-ICP might increase the oil shale target resource by making much more of the Piceance Basin commercially attractive. Other than the difference in heater technology, the remainder of this process is comparable to the Oil Shale Test (Site 1).

A.5.3.3.1 Groundwater and Surface Water Management. Groundwater monitoring would be conducted at each site to assure compliance with groundwater regulations during and after the project.

Water requirements would vary throughout the life of each project. Water would be trucked to the sites for initial construction and drilling activities. Potable water would be trucked to the sites throughout the life of the facilities.

Once a freeze wall was formed, the water inside the wall would be removed by pumping prior to heating. The groundwater pumped from inside the freeze wall would be injected into wells located outside the freeze wall. The injection wells would be permitted per the requirements of the EPA Underground Injection Control Program.

During heating, water removed from within the freeze wall, along with the hydrocarbon products, would be treated in the processing facilities and recycled or discharged. Water used to recover nahcolite would be recycled into the process. Water that could not be recycled or otherwise used would be treated to appropriate discharge standards in a process water treatment plant and released to surface drainage in a manner consistent with the requirements of a Colorado Department of Public Health and Environment discharge permit.

Groundwater would be used only after state approvals were received. Water wells would be drilled to provide additional water required by the operations, especially during reclamation following completion of hydrocarbon recovery. Reclamation would include flushing and cooling of the shale inside the freeze wall.

During dewatering operations, water from the dewatered zone would be reinjected into the same zone or potentially a different zone at another location on the property.

The pyrolysis process occurring within the approximately 130-ft by 100-ft test area would likely increase the porosity of the oil shale intervals because of the removal of kerogen, resulting in an increase in horizontal hydraulic conductivity. Shell’s testing to date, using its heating process on oil shale materials, suggests that the porosity of the rock would increase by about 30% as a result of the pyrolysis of kerogen and removal of oil. There would likely be a minimal increase in the vertical hydraulic conductivity associated with the heating effect on the rock mass. The removal of kerogen is not anticipated to affect the aperture widths of preexisting joints or fractures.

Heating of the oil shale during the pyrolysis phase could increase the vertical permeability of the confining units by enlarging preexisting joints or fractures. The potential consequence of the increased fracture apertures is that groundwater could flow more easily between the Upper and Lower Parachute Creek Units.

Produced Shale Oil and Gas. For Sites 1 and 3, oil and gas production is expected to be approximately 600 bbl/day of oil or 1,000 bbl/day of oil equivalent (oil and gas) at full production. Oil and gas coming to the surface via the previously installed producer holes would be collected for further processing by traditional processing techniques. Full oil and gas production for the Nahcolite Test Site 2 would be approximately 1,500 bbl/day of oil in the form of untreated synthetic condensate.

The recovered product would include a mixture of liquid hydrocarbons, gas, and water that would be processed further to remove impurities and ready the products for transport off-site or reuse in the recovery process. This recovery process is a typical process used in the oil and gas industry.

The initial processing would separate the recovered product into three streams: liquid hydrocarbons, sour gas, and sour water. The term sour refers to the presence of sulfur compounds and CO_2. Once the three streams were separated, each stream would be further processed to remove impurities. The waste streams generated during much of the processing would be recycled for further treatment.

Nahcolite Recovery (Site 2). The nahcolite mining solution would be pumped to a processing building where the mineral would be removed. The process would remove the mineral from the water in a series of steps; the product would then be dried, stored, and loaded for market. Hot solution would be cooled; because the mineral is less soluble, it would crystallize. Centrifuges would drive off water to concentrate the crystallized material. The water would be reheated and recycled as barren solution. CO_2 would be used to make a final product (sodium bicarbonate).

To minimize disturbance, the groundwater reclamation facilities would be built at the same location as the nahcolite processing facility. Additional engineering evaluations would optimize the site arrangements for these facilities.

Refrigeration System. Appropriate procedures for storage, handling, and emergency response for ammonia chemicals used in the refrigeration system would be included in the Process Safety Management Manual to be developed in accordance with Occupational Safety and Health Administration regulations prior to operation. Emergency response procedures, including procedures for cleanup of spills and notification requirements, would be included in the Emergency Response Plan to be developed prior to operation.

A.5.3.3.2 Storage and Disposal of Materials and Waste. During the course of construction and operation, a variety of by-products and waste materials would be generated at each of the three sites. They would include construction waste, drill hole cuttings, garbage, and miscellaneous solid and sanitary wastes.

Surface construction operations would result in a variety of small waste products that might include paper, wood, scrap metal, refuse, or garbage. These materials would be collected in appropriate containers and recycled or disposed of off-site in accordance with applicable regulations.

Approximately 200,000 ft^3 of earth and rock materials would be generated at each test site during drilling operations for the project. Drill cuttings removed from the drilled holes would be dewatered so that the water could be recycled back to the drill rigs. The dewatered cuttings would be placed into a cutting pit. These nontoxic, non-acid-forming drill cuttings would be separated from free water and buried below grade. Burial depth and soil coverage would be sufficient such that the materials would not impede revegetation.

During operation, garbage from the site would be collected in appropriate containers and disposed of off-site. Waste oils, reagents, and laboratory chemicals that were not collected in sumps and treated at the water treatment plants would be recycled or disposed of off-site in accordance with applicable regulations.

The process of producing hydrocarbons from the oil shale would require processing and treating multiple materials. The production complex would include a refrigeration facility, nahcolite recovery process (at Site 2), groundwater reclamation facility, and hydrocarbon processing facility. Spill prevention, control, and countermeasure plans and best management practices would need to be implemented for each stage of production and for all processing facilities. In addition, all waste by-products from the site would need to be properly transported and disposed of according to all rules and regulations regarding the specific waste by-product. These waste by-products would include but not be limited to biosolids effluent and reverse-osmosis reject effluent.

A combination of sanitary waste handling methods would be employed. Some sanitary waste, such as that collected in temporary toilet facilities, might be shipped to an approved facility for off-site treatment and disposal. Any gray water or black water disposed of on-site would be treated in an appropriate sewage processing unit or disposed of according to standards via an approved septic system with a clarifier and drain field.

A.5.3.3.3 Water Requirements. Water requirements would vary throughout the project life. Water uses would include construction, potable water, dust control, drilling, processing, filling, and cooling of the heated interval for reclamation, and rinsing of the zone inside the freeze wall.

Water would be trucked to the site for initial construction and drilling activities. Potable water for personnel consumption would be trucked to the site throughout the life of the facilities.

On-site water would be used for most operational uses and would be supplied from water wells drilled for that purpose. The well would supply water needed for processing and reclamation. Peak pumping demand (250 to 300 gpm, approximately 400 to 480 ac-ft/yr) would occur during the cooling and resaturation phase of the reclamation cycle. If the water well is available during construction and drilling, then this water would supplement or replace construction and drilling water trucked to the site.

Water needs for each phase of the operation are outlined below and summarized in Table A-11. The projected water needs are estimates and are subject to change as additional information becomes available and facility designs are finalized. The current estimate of the amount of water needed for process water is 10 gpm. This water would be supplied from groundwater extracted from either the Uinta or Upper Parachute Creek Units. Water rights

TABLE A-11 Anticipated Water Usage for the Proposed Shell RD&D Projects[a]

Water Requirements	Water Source	Estimated Water Usage: Site 1	Site 2[b]	Site 3[b]
Potable water	Trucked in	Unknown	Unknown	Unknown
Drilling	Trucked in or groundwater	5 gpm (8 ac-ft/yr)	5 gpm (8 ac-ft/yr)	5 gpm (8 ac-ft/yr)
Construction water	Trucked in	6 gpm (10 ac-ft/yr)	6 gpm (10 ac-ft/yr)	6 gpm (10 ac-ft/yr)
Process water[c]	Groundwater	10 gpm (16 ac-ft/yr)	10 gpm (16 ac-ft/yr)	10 gpm (16 ac-ft/yr)
Nahcolite recovery[d]	Groundwater	NA	7.8 million gal (24 ac-ft/yr)[e]	NA
Reclamation[f]	Groundwater	300 gpm max (480 ac-ft/yr)	300 gpm max (480 ac-ft/yr)	300 gpm max (480 ac-ft/yr)

Source: BLM (2006c).

[a] Abbreviations: max = maximum anticipated or estimated; NA = not applicable.

[b] Estimated quantities of water usage for Sites 2 and 3 are based on the Plan of Operations for Site 1.

[c] Initially, groundwater would be obtained from extraction wells inside the freeze wall (initial dewatering); subsequent process water would come from water wells completed in the Upper Parachute Creek Unit. Process water is treated and recycled again for process operations.

[d] Groundwater for nahcolite solution mining would largely originate from dewatering of the freeze wall interior area, with additional water from extraction wells in the Upper Parachute Creek Unit located outside of the freeze wall. Water used would be treated and reused.

[e] Volume estimated is for nahcolite solution mining of a 130-ft by 100-ft pyrolyzed zone footprint. Water would be treated and reused.

[f] Reclamation includes quenching, cooling, and reclamation of the pyrolyzed zone. Groundwater would originate from extraction wells in the Upper Parachute Creek Unit located outside the freeze wall, and it would be treated and reused.

required for the project would be acquired prior to start-up of the operation. The combined annual volume of water required for all three sites is unknown at this time and would vary on the basis of when each project started and how each project progressed. On the basis of the assumption that all three sites would operate at the same time for at least 1 year, the combined process water needs would be a minimum of 30 gpm. This flow rate equates to an annual volume of almost 48 ac-ft/yr.

Construction water would be trucked to the sites as necessary to meet needs for compaction, dust control, and miscellaneous uses. Potable water needed during construction would be brought to the sites. Water required for drilling would be trucked to the sites until water from the on-site water supply well was available to supplement or replace trucked water.

Water would be needed for various processing and operating needs. Water removed with the hydrocarbon products would be treated in the processing facilities and recycled or discharged at a permitted discharge point. The locations of discharge points have not been determined. It is currently anticipated that excess water would be available during the initial processing period as a result of dewatering operations from within the freeze wall containment area and that there would be no need for the water supply well to provide water for processing during this initial period. As processing progressed, there would be a need for additional water.

Water would also be needed to conduct reclamation filling and cooling of the heated interval within the freeze wall containment barrier as well as for rinsing the heated interval. This water would be a combination of recycle water and makeup water from the water supply well, as needed. During reclamation, a water supply would be needed for initial stages of flushing and cooling. Two wells would be completed in the upper Parachute Creek Unit to serve as reclamation water supply wells. However, only one well would be used at a time.

A.5.3.3.4 Staffing. Employment of the maximum number of people at the sites would occur during construction and drilling. An estimated maximum of approximately 720 individuals would be employed at Sites 1 and 3 during the construction and drilling period. At Site 2, an estimated maximum of approximately 700 individuals would be employed during the construction and drilling period. However, because the three test sites would not be developed at the same time, the number of workers employed during construction and drilling would not be cumulative. Once construction was completed, the maximum expected employment would be approximately 155 individuals at Sites 1 and 3 and 150 individuals at Site 2.

A.5.3.3.5 Utilities. Estimates of electricity and gas requirements were not provided in the EA.

A.5.3.3.6 Noise. Noise generated during the testing phase of the project would be from drill rigs installing monitoring wells and from the heating/production wells. Equipment used would be designed to meet applicable Colorado Oil and Gas Conservation Commission allowable noise levels, which are expected to be 50 to 55 dbA for the tract in a rural/agricultural setting. Noise readings would be taken at the site during operations to verify noise levels.

A.5.3.3.7 Air Emissions. The air pollution emission estimates for each of the three Shell sites were based on the best available engineering data assumptions and scientific judgment. However, when specific data or procedures were not available, reasonable but conservative assumptions were incorporated. For example, the air emission estimates assumed that project activities would operate at full production levels continuously (i.e., with no downtime).

A.5.3.3.8 Transportation. Access to each of the three sites would be provided by constructing an access road to connect the site to existing county roads. Initial construction activities would include development of the site access road to a running width of approximately 24 ft to allow heavy equipment to travel in two directions. The access road would be paved with asphalt for the 24-ft width and include appropriate ditches and culverts to maintain drainage control. Access to the sites from public roads would be restricted by an entry gate. An estimated 300 to 650 vehicles per day would access the sites during construction.

A.5.3.4 Oil Shale Exploration Company (OSEC)

OSEC proposes to lease the White River Mine site (160 acres) in Uintah County, Utah (Figure A-9), in order to conduct a three-phase RD&D project to test shale oil recovery by using the ATP retort technology and by providing incoming natural gas via a pipeline through the "western" ROW alignment. Information presented here regarding this project is taken from the EA of the proposed activities (BLM 2007). The ATP system is a thermal process for pyrolyzing oil shale. The primary unit is the ATP Processor, which is a modified horizontal rotary kiln. The ATP Processor has four internal zones in which the four stages of ore processing occur: (1) preheating of the feedstock, (2) pyrolysis of the oil shale under anaerobic conditions, (3) combustion of coked solids to provide the process heat requirements, and (4) cooling of the combustion products by heat transfer to the incoming feed.

Phase 1 of the project is expected to last approximately 11 months. During this time, OSEC would remove approximately 1,000 tons of oil shale from the White River Mine's on-site surface stockpile for processing at the existing ATP pilot plant unit in Calgary, Alberta, Canada.

The 1,000 tons of shale would be transported by truck from the 160-acre lease out of the project area to a gravel pit in Uintah County, where it would be crushed to design specifications (–3/8 in.). The crushed shale (total 1,000 tons) would be trucked to Calgary for testing by UMATAC in its 4-ton/h ATP Processor pilot plant. During Phase 1, no crushing of oil shale would be performed within the White River Mine lease area.

It is expected that about 650 bbl of raw shale oil would be produced from the 1,000 tons of oil shale processed. Approximately 800 tons of non-Resource Conservation and Recovery Act (RCRA) hazardous spent shale would be produced from the processing of the 1,000 tons of feed shale. Samples of this material would be retained for testing and analysis in Canada and the United States. The remaining spent shale would be disposed of in a licensed landfill in Alberta, or it would be stored on-site in Alberta pending identification of a beneficial reuse.

No fuel storage, office facilities, overnight accommodations, toilets, or drinking water supply would be established at the White River Mine lease area during Phase 1. Although the loading and trucking operation is not expected to be dusty, some minor amounts of water might be required to control dust during the loading of the shale feed into the trucks at the White River Mine. All water required for this phase would be trucked in by a local supplier and dispensed from a water truck. No water rights would be needed for this phase of work. The fugitive dust emissions associated with loading the oil shale from the existing surface stockpile, road dust, and exhaust emissions from the front-end loader and trucks (short-term activities) would be the only air emissions associated with the Phase 1 operations within the 160-acre leasehold.

Phase 2 of the RD&D project would last about 14 months and involve the mobilization of the UMATAC 4-ton/h ATP Processor pilot plant and associated equipment from Calgary to the White River Mine lease area. Shale for processing would initially come from the existing surface stockpiles. OSEC would reopen the White River Mine and begin mining fresh oil shale for use as feed to the plant during the latter stage of Phase 2.

It is currently anticipated that Phase 2 construction would involve a relatively small amount of new construction work on-site. The trailer-mounted ATP pilot plant would be mobilized from Calgary and set up on-site on an impervious base pad. A fuel tank area would be constructed with a liner and an embankment surrounding it. An additional aboveground storage tank area would be established for shale oil product storage and load out; these tanks would sit on a liner within an embankment. There would also be a facility for on-site crushing, stockpiling, and ore handling.

The major Phase 2 construction activity would involve reopening the mine and constructing a spent-shale disposal area. Approximately 10,000 tons of oil shale would be processed through the ATP Processor pilot plant during Phase 2.

Phase 3 of the RD&D project would involve the design, permitting, and fabrication of a 250-ton/h ATP Processor demonstration plant and construction of that plant within the 160-acre lease area. OSEC plans on 2 years to permit, engineer, and construct the plant. Also, the mine would be developed sufficiently to support the mining of 1.5 million tons/yr of oil shale, which would be used as feed for the operation of the demonstration plant. Following commissioning, the plant would operate for 2 years so enough operational, technical, environmental, and financial information could be compiled to make an informed decision on whether to proceed to a commercial project.

Preparation for Phase 3 operations would involve significant on-site construction activity, particularly related to the new 250-ton/h ATP demonstration plant and all the ancillary equipment. Many of the demonstration plant components would be fabricated elsewhere and transported to the site for final assembly and erection. This would lessen the amount of laydown space required during construction and the number of construction workers needed at the site. The most significant permanent surface feature constructed during Phase 3 would be the 38-acre storage area for containing the 2.2 million tons of spent shale that could be generated during this phase of work.

Approximately 2.7 million tons of oil shale would be processed through the ATP Processor demonstration plant during Phase 3. The source of the shale feed would be the reopened mine. All mined shale would be stockpiled and crushed/blended at the surface within the 160-acre lease area. It is expected that all shale mined would be processed (i.e., there would be no fines rejects produced during the shale crushing activities).

In addition to the construction of the ATP Processor plant and ancillary equipment on the 160-acre lease, it would be necessary to construct/install natural gas, electric power, and water lines along the proposed ROWs.

A.5.3.4.1 Storage and Disposal of Materials and Waste. During Phase 2, approximately 8,000 tons of spent shale would be generated and placed in a small valley impoundment, less than 2 acres in size. The impoundment would be bermed, and surface water runoff would be directed around the impoundment to prevent stormwater runoff from other areas of the lease from contacting the pile of spent shale. Overall, flow would be directed to the gully near the dam.

During Phase 3, 2.2 million tons of spent shale would be produced and disposed of at a 38-acre storage area. Minor amounts of construction-related wastes would also be generated during the rehabilitation of existing structures and the construction of new facilities and structures associated with the Phase 3 250-ton/h demonstration work. Such wastes could include scrap metal or wood, concrete, and miscellaneous trash from the packaging of the construction materials. These materials would be temporarily staged in roll-offs and trucked to an off-site solid waste facility.

Shale oil typically contains 0.5 to 0.75% sulfur (OTA 1980b). Sulfur compounds generated during retorting and secondary processing (hydrotreating) are primarily in the form of H_2S, with lesser amounts of mercaptans. Through the treatment train process (i.e., air emission control devices and/or wastewater treatment), sulfur-bearing solid wastes would be generated.

The hydrotreatment process would generate a variety of waste products, including sulfur-containing residuum and spent catalysts. Spent catalyst, which is considered a listed RCRA hazardous waste (K071), would consist of aluminum silicate and various metals (typically cobalt, molybdenum, nickel, and/or tungsten). These waste materials would be disposed of at an appropriate off-site disposal facility. Prior to disposal, the wastes would be contained in waste storage areas built with appropriate spill containment features.

Occasionally, waste oils would be generated from equipment maintenance activities during Phases 2 and 3. In addition, the hydrotreatment process and wastewater treatment of the process waters would produce large volumes of oily sludges. (Since the exact nature of the hydrotreatment has not been finalized, it is not possible to reasonably predict the volume of such materials that would be produced during Phase 3.) All such materials would be temporarily stored on the 160-acre lease site and trucked off-site to a licensed facility for treatment and disposal.

Mine Water. During Phase 2, the mine would be dewatered as part of the reopening process. Mine water of good quality would be discharged to the existing retention dam area. The exact volume of such water is not known, but it would amount to more than 2 million gal if the water was pooled to the top of the Birds Nest Aquifer. Mine water below the bulkhead might contain levels of petroleum-based compounds that would have resulted from contact with the oil shale and the bitumen seep in the lower portion of the mine. This water would likely be trucked off-site for treatment and disposal at an approved facility.

During mining operations, water from dewatering of the mine could contain petroleum-based compounds. During Phase 2 operations, this water would be temporarily stored in tanks. Depending on test results, it would then either be discharged to an on-lease drainage channel to flow toward the retention dam area (if the test showed that it met agreed-upon discharge criteria) or trucked off-site. The appropriate frequency of testing the water would be stipulated on the basis of the results from the initial test of mine water conducted prior to the reopening of the mine.

During Phase 3, mine water that did not meet water quality standards would be treated through the process wastewater treatment system, along with wastewater from the air treatment and hydrotreatment processes.

Connate and Retort Water. Approximately 150 tons (35,700 gal) of connate water (water trapped in shale pore spaces) would be generated during Phase 2, and 40,000 tons (9.5 million gal) would be generated during Phase 3. The connate water might be suitable for use in remoistening and cooling the spent shale without treatment. If the connate water did not meet appropriate criteria, it would be trucked off-site for treatment and disposal during Phase 2 RD&D activities and would be treated in a wastewater treatment system on the 160-acre lease site during Phase 3.

Approximately 200 tons (48,000 gal) of retort water (chemically bound moisture in the shale) would be generated during Phase 2, and approximately 55,000 tons (13.2 million gal) would be generated during Phase 3. Retort water often contains phenols, H_2S, or trace levels of petroleum constituents that might require treatment before they could be used for cooling and moistening spent shale or discharged to an existing retention dam. During Phase 2, all retort water would be temporarily stored on the lease site, tested, and, if it met appropriate water quality criteria, used to cool the spent shale or trucked off-site for treatment and disposal. During Phase 3, a wastewater treatment facility on the 160-acre lease site would be used to treat the retort water to remove H_2S, NH_3, phenols, and other constituents of concern. It is anticipated that following treatment, nearly all of the water would be used to cool and moisten the spent shale or otherwise reused in the process. Small amounts of water not needed for cooling and moistening the spent shale might be discharged to a drainage feature leading to the retention dam area.

Process washdown is water that is regularly used to clean the retort and other equipment during the on-site operations. Such water might contain high levels of sediment, and it might also contain oily residues from the equipment.

All the sour water generated during Phase 3 would be stored and treated on-site prior to being used for controlling dust or moistening the spent shale. Depending on chemical analysis results, the sour water treatment might include stripping of NH_3 and H_2S, followed by biological aeration.

Sanitary Sewage Effluent. During routine daily operations in Phase 2 and Phase 3, workers would generate sanitary wastes. These, along with other wash water, would be processed in an existing closed sanitary wastewater treatment system on the 160-acre lease site. Any sanitary sewage generated before the repair and testing of the on-site system would be collected and trucked to an off-site wastewater treatment plant.

A.5.3.4.2 Produced Shale Oil and Gas. Approximately 6,000 bbl of raw shale oil would be produced during Phase 2. All oil produced would be temporarily stored in aboveground tanks located within the 160-acre lease area before being trucked to an off-site facility for sale.

Approximately 1.8 million bbl of raw shale oil is expected to be produced during Phase 3. It is anticipated that this oil would be hydrotreated on-site to produce a synthetic crude oil product. The synthetic crude oil would be temporarily stored in aboveground tanks on-site. The product would be trucked off-site to a refinery or delivered to a nearby pipeline that would have the capacity and specifications to accept this upgraded shale oil.

A.5.3.4.3 Water Requirements. The amount of makeup water required in Phase 2 for processing the oil shale is estimated to be approximately 2 bbl (84 gal) per ton of shale feed, half of which would be needed to cool and moisten the spent shale. This means that the total makeup water requirement for Phase 2 would be 20,000 bbl of water. Small amounts of additional water might be required on-site for drinking, cooking, laundry, and toilet facilities for the Phase 2 workforce. All Phase 2 water needs (potable and process) would be trucked to the site by a local supplier that had the appropriate water rights. The water would be stored in aboveground tanks within the 160-acre lease area. No water rights would be needed by OSEC for this phase of work.

The total amount of Phase 3 water needed to process the oil shale (i.e., makeup water) is estimated to be on the order of 4.1 million bbl. This is equivalent to a peak water demand of 380,000 gal/day while the processing plant is operating. Currently, it is proposed that the makeup water be supplied from water wells established in the Birds Nest Aquifer (two to three wells located in the northwestern portion of the 160-acre lease site), from wells in the White River alluvial deposits (wells installed as part of the earlier mine development activities that are north of the 160-acre lease), or from a direct intake in the White River. Water pumped from these sources would be stored in aboveground tanks on-site.

A potable water tank would be placed near the trailers to supply domestic needs; the potable water would be trucked to the site. A process water tank with a capacity of about 750 bbl would be installed next to the plant.

A.5.3.4.4 Staffing. It is estimated that the operational workforce at the site during Phase 3 operations would be composed of approximately 120 individuals. Offices and shower and toilet blocks would be provided on-site.

A.5.3.4.5 Utilities. Electricity required for the mine, pilot plant, and on-site accommodations would be provided by diesel generators established within the 160-acre lease area (1-MW total capacity). Propane would be used to provide heat to the process during start-up periods as well as heat for office and field trailers. Also, diesel fuel would be used to run surface and underground mine vehicles and equipment on-site. All diesel and propane fuel would be trucked in and stored on-site in aboveground tanks. The diesel tanks would be placed in lined and bermed containment areas.

Up to 14 MW of electric power could be required at the site during Phase 3, and it is assumed that electric power to the site would be provided from the grid via a new 138-kV transmission line. Emergency diesel generator capacity would also be provided on-site to meet both plant backup and mine operational and safety requirements.

Natural gas or propane would be required for the operation of the ATP Processor demonstration plant. Further studies are required to assess whether it would be feasible to truck in propane gas or whether a pipeline connection to a natural gas supply would be required.

A.5.3.4.6 Air Emissions. The sources of air emissions would vary during the three phases of RD&D activities on the site. These sources are listed by phase in Tables A-12 through A-16. The ATP unit and the hydrotreatment unit would be fully permitted under the Clean Air Act and have all the emission control equipment required by the Act.

Greenhouse gas emissions would be generated on-site during both Phase 2 and Phase 3 operations. They would originate mostly from the retorting of the shale feed (see Tables A-15 and A-16). Additional greenhouse gas emissions would be produced from the burning of coal at the Bonanza Power Plant to generate electric power.

A.5.3.5 Syntec Energy

Syntec Energy is a small, privately held R&D company. The Syntec process uses a rotary kiln in conjunction with syngas derived from coal gasification to pyrolize the shale and produce shale oil. Successful bench tests of this technology have been conducted by the University of Utah.

TABLE A-12 Phase 1 Estimated Emissions

	Estimated Emissions (tons during Phase I)					
Emission Point	NO_x	SO_2	CO	VOC[b]	PM_{10}	HAPs
Diesel vehicle emissions[a]	3.17	0.50	0.78	0.22	0.11	0.00
Truck loading/unloading[c]	–[d]	–	–	–	0.000008	–
Storage pile[c]	–	–	–	–	0.06	–
Total	3.17	0.50	0.78	0.22	0.17	0.00

[a] Emission factors are from South Coast Air Quality Management District (2006).

[b] VOC = volatile organic compound.

[c] Emission factors for truck unloading of fragmented stone are from EPA AP-42 (EPA 2004a). It was assumed that emissions would be controlled by using wet suppression. The aggregate storage emission factor is from EPA FIRE 6.25 (EPA 2004b).

[d] A dash indicates that these emissions are not significant to overall air quality.

Source: BLM (2007).

TABLE A-13 Phase 2 Estimated Emissions

	Estimated Emissions (tons during Phase 2)					
Emission Point	NO_x	SO_2	CO	VOC	PM_{10}	HAPs
ATP Processor operation[a]	0.55	1.23	8.21	0.14	0.55	–[b]
Start-up burner[c]	0.086	0.000072	0.014	0.0023	0.0027	0.000033
Flaring of flue gas[d]	–	–	0.26	5.98	–	–
Diesel generator[e]	7.73	1.44	0.86	0.91	1.44	0.27
Diesel storage tank[f]	–	–	–	0.0062	–	–
Shale crushing/screening[g]	–	–	–	–	0.026	–
Truck loading/unloading[g]	–	–	–	–	0.00008	–
Stockpiled shale[h]	–	–	–	–	0.48	–
ANFO blasting	0.032	0.004	0.126	–	–	–
Shale oil storage tank[i]	–	–	–	0.73	–	–
Unpaved on-site roads[j]	–	–	–	–	0.000018	–
Total	8.40	2.67	9.47	7.77	2.49	0.27

[a] Estimated concentration data were provided by UMATAC and based on a pilot project in Canada. It was assumed that there would be 95% control on CO, VOCs, and SO_2 and that a filter bag would be used for PM control. The CO_2 that would form during oxidation of CO, assuming 100% conversion, was added to the total amount of CO_2. Hazardous air pollutant (HAP) emissions are not known at this time. A portion of these emissions would be due to the start-up burner; to be conservative, however, it was assumed that the start-up burner emissions would be separate.

[b] A dash indicates that these emissions are not significant to overall air quality.

[c] It was assumed that a 24-hour start-up period would be required 15 times over the course of the phase. It also was assumed that a natural gas burner would consume 48 MMBtu per start-up. A portion of these emissions could be included in the ATP process data; to be conservative, however, it was assumed that the start-up burner emissions would be separate. Emission factors are from EPA AP-42 (EPA 1996a). HAP emissions were taken from EPA (1998).

[d] Estimate is based on flare gas data from a previous pilot study conducted at a similar ATP plant. A 98% destruction efficiency was assumed based on EPA AP-42 (EPA 1991). The amount of CO that gets converted to CO_2 in the flare is included in the CO_2 emission value.

[e] Estimated by assuming that 592,000 gal of diesel would be needed for the duration of Phase 2. To be conservative, it was assumed that all diesel fuel would be used in diesel-fired generators; however, some (~22,000 gal) would be used in the haul trucks and other unknown underground equipment. To comply with concentration thresholds, a CO and NO_x air pollution control device might need to be installed; therefore, 85% and 90% control efficiencies for NO_x and CO were assumed. Emission factors were obtained from typical Cummins 1-MW diesel generator specifications. The CO_2 emission factor is from EPA AP-42 (EPA 1996b).

[f] Working and breathing losses for 15,000-gal tanks with a total throughput of 592,000 gal (570,000 gal for power generation, 22,000 gal for the mine work) were estimated for Phase 2 by using the EPA Tanks 4.0 Program (EPA 2005).

Footnotes continued on next page.

TABLE A-13 (Cont.)

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[g] Emission factors are from EPA (2004a). It was assumed that emissions would be controlled by using wet suppression. It also was assumed that there would be two intermediate conveying transfer points between one primary crusher, one secondary crusher, and one screener. The aggregate storage emission factor is from EPA FIRE 6.25 (EPA 2004b).

[h] Emission factors are from EPA AP-42 (EPA 1980).

[i] Working and breathing losses for a 31,500-gal tank used to store the produced shale oil with a total project throughput of 6,400 gal were estimated by using the EPA Tanks 4.0 Program (EPA 2005).

[j] PM_{10} emissions from unpaved vehicle traffic on-site were estimated by using EPA AP-42 (EPA 2003). It was assumed that a 200-ton truck would travel a total of 50 mi during Phase 2 to gather 10,000 tons of shale oil (200 tons at a time) and transport it to the ATP plant.

Source: BLM (2007).

TABLE A-14 Phase 3 Estimated Emissions

	Estimated Emissions (tons during Phase 3)					
Emission Point	NO_x	SO_2	CO	VOC	PM_{10}	HAPs
ATP Processor operation[a]	126.97	285.67	1,904.49	31.74	13.34	–[b]
Start-up burner[c]	17.75	0.015	2.99	0.47	0.56	0.0068
Electrical needs (14 MW)[d]	207.79	34.94	–	–	–	–
Hydrogen plant reformer[e]	5.15	0.06	8.64	0.57	0.78	0.00
Flaring of flue gas[f]	–	–	8.19	186.94	–	–
Diesel storage tank[g]	–	–	–	0.024	–	–
Shale crushing/screening[h]	–	–	–	–	7.14	–
Stockpiled shale[h]	–	–	–	–	132.00	–
Truck loading/unloading[h]	–	–	–	–	0.02	–
ANFO blasting[i]	14.88	1.75	58.63	–	–	–
Diesel combustion[j]	870.81	24.25	145.50	15.43	24.25	4.52
Shale oil storage tank[k]	–	–	–	9.19	–	–
Unpaved on-site roads[l]	–	–	–	–	0.0065	–
Total	12,43.34	346.69	2,128.44	244.36	178.10	4.52

a Estimated concentration data were provided by UMATAC and based on a pilot project in Canada. It was assumed that there would be 95% control on CO, VOCs, and SO_2 and that a filter bag would be used for PM control. The CO_2 that would form during oxidation of CO, assuming 100% conversion, was added to the total amount of CO_2. HAP emissions are not known at this time. A portion of these emissions would be due to the start-up burner; to be conservative, however, it was assumed that the start-up burner emissions would be separate.

b A dash indicates that these emissions are not significant to overall air quality.

c It was assumed that a 24-hour start-up period would be required 50 times over the course of the phase. It also was assumed that a natural gas burner would consume 3,000 MMBtu per start-up. A portion of these emissions could be included in the ATP process data; to be conservative, however, it was assumed that the start-up burner emissions would be separate. Emission factors are from EPA AP-42 (EPA 1996a). HAP emissions were taken from EPA AP-42 (EPA 1998).

d Emissions were estimated based on the average 2000 to 2005 Bonanza I Power Plant emissions data from the EPA Clean Air Markets Web site (EPA 2006). Between 2000 and 2005, the power plant required an average of 4,996 MMBtu/h. The additional power needed for Phase 3 would result in a maximum increase in usage of 3%. It was assumed that 3% of the average power plant emissions as given on the Clean Air Markets Web site would be emitted due to operations in Phase 3. The Web site did not provide data on CO, VOCs, PM_{10}, and HAPs.

e Emissions were estimated by assuming that a 5.8-MW reformer would be fueled with natural gas and are based on EPA AP-42 (EPA 1998). These emissions are only for the hydrogen reformer. Additional combustion devices that might be needed are not included or known at this time. The hydrotreating process is not anticipated to result in emissions not already accounted for in the ATP Processor emissions estimate.

f Estimate is based on a previous test run conducted at a similar ATP plant scaled up for the 250-ton/yr processor and the assumption that only 50% of the off-gas is flared. This value is highly conservative, given that flaring might occur only during emergency situations and/or that the off-gas might be used instead to further fuel the ATP plant.

Footnotes continued on next page.

TABLE A-14 (Cont.)

[g] Working and breathing losses for 15,000-gal tanks with a total throughput of 10 million gal were estimated for Phase 3 by using the EPA Tanks 4.0 Program (EPA 2005).

[h] Emission factors are from EPA AP-42 (EPA 2004a). It was assumed that emissions would be controlled by using wet suppression. It also was assumed that there would be two conveying transfer points. The aggregate storage emission factor is from EPA FIRE 6.25 (EPA 2004b).

[i] Emission factors are from EPA AP-42 (EPA 1980).

[j] Diesel fuel would be used mostly in underground haul trucks and other mining equipment. Some surface equipment or a standby emergency generator might be used. To be conservative, it was assumed that the estimated 10 million gal of diesel fuel would be burned in a generator.

[k] Working and breathing losses for shale oil storage tanks with a project throughput of 75,348,000 gal were estimated by using the EPA Tanks 4.0 Program (EPA 2005).

[l] PM_{10} emissions from unpaved vehicle traffic on-site were estimated by using EPA AP-42 (EPA 2003). It was assumed that a 200-ton truck would travel a total of 18,100 mi during Phase 3 to gather 2.7 million tons of shale oil (200 tons at a time) and transport it to the ATP plant.

Source: BLM (2007).

TABLE A-15 Phase 4 Greenhouse Gas Emissions

	Phase 2 (tons during Phase 2)		
Emission Point	CO_2	Methane	Carbon Equivalent
ATP Processor operation[a]	2,296.86	–[b]	626.42
Start-up burner[c]	56.56	–	15.42
Flaring of flue gas[d]	128.16	–	34.95
Diesel generator[e]	6,807.48	–	1,856.58
Mine opening methane[f]	–	10.52	7.89
Total	9,289.05	10.52	2,541.27

[a] Estimated concentration data were provided by UMATAC and based on a pilot project in Canada. The CO_2 that would form during oxidation of CO, assuming 100% conversion, was added to the total amount of CO_2. A portion of these emissions would be due to the start-up burner; to be conservative, however, it was assumed that the start-up burner emissions would be separate.

[b] A dash indicates that these emissions are not significant to overall air quality.

[c] It was assumed that a 24-hour start-up period would be required 15 times over the course of the phase. It also was assumed that a natural gas burner would consume 48 MMBtu per start-up. A portion of these emissions might be included in the ATP process data; to be conservative, however, it was assumed that the start-up burner emissions would be separate.

[d] Estimate is based on flare gas data from a previous pilot study conducted at a similar ATP plant. A 98% destruction efficiency was assumed based on EPA AP-42 (EPA 1991). The amount of CO that gets converted to CO_2 in the flare is included in the CO_2 emission value.

[e] Estimated by assuming that 592,000 gal of diesel would be needed for the duration of Phase 2. To be conservative, it was assumed that all diesel fuel would be used in diesel-fired generators; however, some (~22,000 gal) would be used in the haul trucks and other unknown underground equipment. The CO_2 emission factor is from EPA AP-42 (EPA 1996b).

[f] Estimated value was provided by OSEC; it assumes that 5,000 ft^3 of CH_4 per day is emitted over the course of Phase 2.

Source: BLM (2007).

TABLE A-16 Phase 5 Greenhouse Gas Emissions

	Phase 3 (tons during Phase 3)		
Emission Point	CO_2	Methane	Carbon Equivalence
ATP Processor operation[a]	532,985.79	–[b]	145,359.76
Start-up burner[c]	11,680.33	–	3,185.54
Electrical needs (14 MW)[d]	126,049.52	–	34,377.14
Hydrogen plant reformer[e]	12,349.23	–	3,367.97
Flaring of flue gas[f]	4,004.99	–	1,092.27
Diesel combustion[g]	114,991.18	–	31,361.23
Mine opening methane[h]	–	472.73	354.55
Total	802,061.04	472.73	219,098.46

a Estimated concentration data were provided by UMATAC and based on a pilot project in Canada. The CO_2 that would form during oxidation of CO, assuming 100% conversion, was added to the total amount of CO_2. A portion of these emissions would be due to the start-up burner; to be conservative, however, it was assumed that the start-up burner emissions would be separate.

b A dash indicates that these emissions are not significant to overall air quality.

c It was assumed that a 24-hour start-up period would be required 50 times over the course of the phase. It also was assumed that a natural gas burner would consume 3,000 MMBtu per start-up. A portion of these emissions might be included in the ATP process data; to be conservative, however, it was assumed that the start-up burner emissions would be separate.

d Emissions were estimated based on the average 2000 to 2005 Bonanza I Power Plant emissions data from the EPA Clean Air Markets Web site (EPA 2006). Between 2000 and 2005, the power plant required an average of 4,996 MMBtu/h. The additional power needed for Phase 3 would result in a maximum increase in usage of 3%. It was assumed that 3% of the average power plant emissions as given on the Clean Air Markets Web site would be emitted due to operations in Phase 3. The Web site did not provide data on CO, VOCs, PM_{10}, and HAPs.

e Emissions were estimated by assuming that a 5.8-MW reformer would be fueled with natural gas and are based on EPA AP-42 (EPA 1998). These emissions are only for the hydrogen reformer. Additional combustion devices that might be needed are not included or known at this time. The hydrotreating process is not anticipated to result in emissions not already accounted for in the ATP Processor emissions estimate.

f Estimate is based on a previous test run conducted at a similar ATP plant scaled up for the 250-ton/yr processor and the assumption that only 50% of the off-gas is flared. This value is highly conservative, given that flaring might occur only during emergency situations and/or that the off-gas might be used instead to further fuel the ATP plant.

g Diesel fuel would be used mostly in underground haul trucks and other mining equipment. Some surface equipment or a standby emergency generator might be used. To be conservative, it was assumed that the estimated 10 million gal of diesel fuel would be burned in a generator.

h Estimated value was provided by OSEC; it assumes that 5,000 ft^3 of CH_4 per day is emitted over the course of Phase 2.

Source: BLM (2007).

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ATTACHMENT A1:

ANTICIPATED REFINERY MARKET REPONSE TO FUTURE OIL SHALE PRODUCTION

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ATTACHMENT A1:

ANTICIPATED REFINERY MARKET REPONSE TO FUTURE OIL SHALE PRODUCTION

1 INTRODUCTION

Ultimately, crude shale oil's acceptance into the U.S. refinery market will be based on a number of factors. While some of these factors are well understood and can be used to make reliable forecasts, others are difficult to precisely define at this time. This brief overview of the manner in which the U.S. petroleum refining market may react to new crude oil sources from shale oil identifies some of the major factors that will influence decisions regarding construction or expansion of refineries. Among the factors that predominate in supporting refinery market adjustments are the following:

- The investment into and expansion of refining capacity are solely determined by the investor's long-term expectation of refining margins. Only those crude oil sources that can demonstrate long-term availability and consistent quality factors are likely to be considered as expansion or displacement candidates.

- New crude oil sources displace sources in existing markets based on how well their quality parameters align with existing or expanding refining capability; the market will take proportionally longer to accept new sources with quality factors substantially different from existing or alternatively available sources.

- Indicators of potential new incremental markets include forecasted refining capacity expansion in existing facilities or in proposed new refineries. Currently, only a few small facilities are in the planning or permitting stages, and no large-scale integrated fuels refineries have been publicly proposed.

- Incremental expansion at existing facilities is the expected way in which crude oil shale will be introduced into the refinery market in the short term, especially considering the time it has historically taken to plan, permit, design, and build new refineries (> 10 years).

- Identification of the most probable markets for the shale oil crude is dependent upon the phase of its growth. Early adopters could displace existing sources in geographically local markets with shale oil of comparable quality. Subsequent phases of oil shale industry development will require the development of logistical capacity and transport to larger markets to accommodate the higher production levels with the Midwest and Gulf Coast markets becoming available first, followed by the West and East Coast markets.

- Intuitively, domestic sources of crude shale oil are more desirable than foreign sources of crude oil simply because of their inherently more secure status. However, to retain their advantage, such domestic sources must also compare favorably with imported feedstocks with respect to overall product yield and other quality parameters (e.g., high-sulfur, high-acid content, etc.). Crude shale oil has great potential for replacing equivalent amounts of imported crude oil with comparable quality factors.

- Of the imported crude sources likely to be displaced by crude shale oil, the most likely are those currently being delivered to refiners in the Midwest and Gulf Coast, the two geographic areas composing the largest and most flexible markets for crude. Imported crude oil supplies most similar in quality to crude shale oil would be the first to be replaced since that replacement would require little to no change in refining capability.

- Pipelines do not drive refinery market investments; pipeline operators react to committed emerging markets and provide transportation linkage between the source and the refiner.

The U.S. refining market is not geographically equally distributed, and it has evolved into concentrations of refining capacity. The volume and types of crude that each of these refining concentrations consume have also evolved given their economic and logistical access to various sources of crude. In addition, the economics of processing crude oil possessing particular characteristics (e.g., heavy crude oil) has driven the type of processing capability and subsequently investments. For example, the Gulf Coast, with easy waterborne access to traditionally cheaper foreign crude imports, has emerged with a large share of the U.S. refining capacity. The increased availability of heavy foreign crude at a price discount has spurred increased heavy crude processing capacity in this region. Subsequently, extensive logistical capacity to transport refined products to larger consumer markets, such as the Northeast, has evolved. In contrast, inland refining centers, such as the Rocky Mountains, have expanded only to serve their regional markets. The inland centers originally were configured to process primarily lighter domestic crude. Only relatively recently, with the growth of heavy Canadian crude oil imports, have they invested in increased refining capacity to process heavy crude.

The growth of total refining capacity has tended to result from the expansion of existing facilities rather than from the construction of totally new facilities. The lower risk to capital investment afforded by incremental expansion and economies of scale has supported this approach. While incremental expansion is the norm, it does occur in significant overall quantities and does have associated incremental environmental impacts.

Refinery capacity growth and the location of this growth is determined by a complex mix of economics, acceptance of all environmental impacts, and in some situations, availability of basic resources, such as water, electricity, and logistical access. The same synergies of local markets for workers and equipment, logistical access, and markets for feedstock and product trading that created the existing concentrations of refining capacities have directed continued growth to these same areas.

This paper reviews some of these issues to identify the inherent drivers in the marketplace that could show the likely market placement of increased production of U.S. crude shale oil. The relatively recent entry of Canadian syncrude and bitumen into the U.S. refinery market provides a good example of how U.S. oil shale production might enter the refining market.[1] Volumetrically, the amount of Canadian syncrude and bitumen currently entering the U.S. market is of the same general order of magnitude as an estimate of anticipated commercial production levels for U.S. oil shale facilities (i.e., about 2 million bbl/day).[2] The Canadian crude experience can help anticipate logistical infrastructure changes, the economic factors that control inflow into existing refining centers, the probability of refinery expansions, and the possible crude sources that may be displaced. It is important to note, however, that recent trends in refining demand for Canadian crude are economically favoring the nonupgraded raw bitumen, which is sold at a substantial discount, thus providing the refiners with more margin potential. This ultraheavy bitumen is analogous to other foreign heavy crudes, which are in abundant supply in the marketplace and are also sold at a steep discount. The increased utilization of these ultraheavy crudes has required extensive investments in the "bottom-of-the-barrel processing" coker capacities. The shale oil and upgraded synthetic portions of Canadian crude have very little "bottoms" or residual; therefore, not only can they be processed in refineries without significant capital investment, they can serve as a complementary blending component with the ultraheavy crudes to balance the overall feedstock pool to the refinery. They must be produced, however, at an economically attractive price to compete with these steeply discounted heavy crudes

2 OVERVIEW OF THE CRITICAL PARAMETERS IN THE CRUDE OIL REFINERY PROCESS

Crude oil is a mixture of hydrocarbons formed from organic matter. It varies in chemical and physical composition, including differences in sulfur content, acidity, density, etc. At the most fundamental level, the refining process involves actions in any of the following categories:

- Separation—Distillation,
- Conversion—Changing the size and/or shape of molecules, and
- Treatment/Blending—Making products to desired specifications.

The first step in the refining process is crude distillation. Crude distillation breaks a full barrel of crude into intermediate feedstocks through the application of heat and pressure. A small portion of the yield of a distillation tower can be recovered and marketed as a finished product.

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1 The organic fraction of Canadian tar sands is what is referred to here as bitumen. Syncrude is that which results from the mine site upgrading of bitumen. Both raw bitumen and syncrude are currently being delivered to U.S. markets.

2 To facilitate discussion of the potential effects of oil shale development, the BLM assumed a commercial production level of approximately 2 million bbl/day.

Most distillate fractions, however, must be further processed in downstream conversion units into blend components, petrochemical feedstocks, and finished petroleum products. The distillation process is merely a separation process, while other downstream conversion processes actually involve chemical reactions that modify the molecular structures of the hydrocarbon distillate fractions to produce products with desirable physical and chemical qualities. Figure 1 shows a generic refinery flow. The initial crude oil composition dictates the relative proportions of initial distillate fractions.

Crude oil sources are typically classified by density. By industry convention, density is expressed as American Petroleum Institute (API) gravity: light (API>34), medium (API 26–24), or heavy (API < 24).[3] Density, in turn, is reflective of fundamental differences in underlying chemical compositions. The lighter the crude source, the greater the relative percentage of small- to moderate-sized organic molecules with high degrees of saturation, making it more amenable to conversion into high-value products such as gasoline and other low-boiling fuels and products.

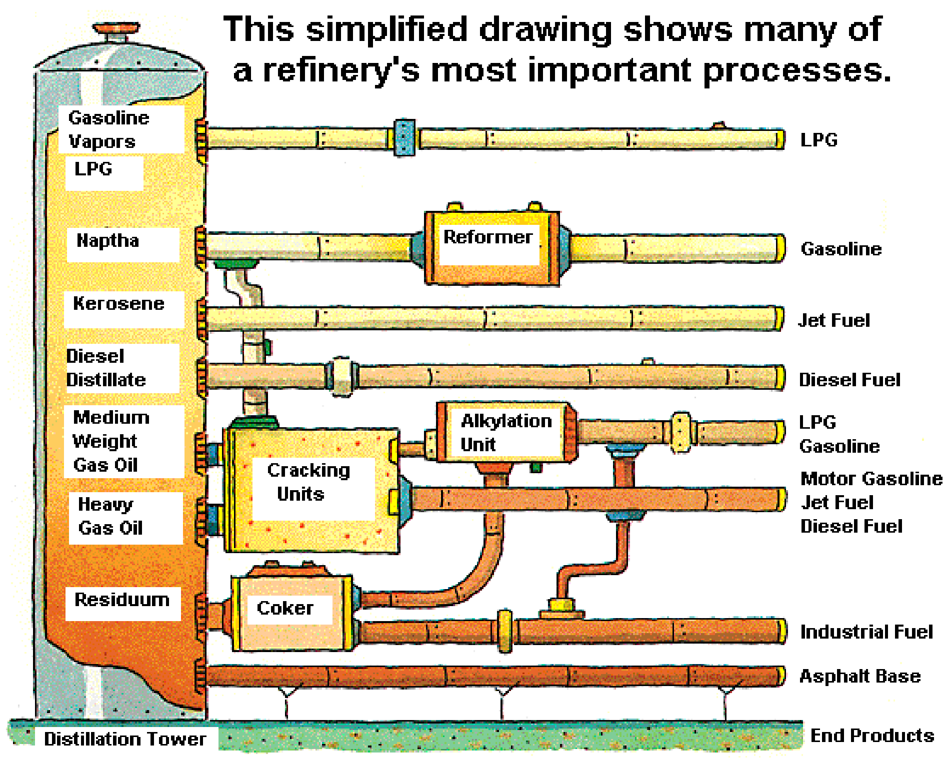

FIGURE 1 Generic Refinery Configuration (Source: EIA 2006a) (LPG stands for liquefied petroleum gas.)

3 API gravity is an arbitrary scale for expressing the specific gravity or density of liquid petroleum products. Devised by the API and the National Bureau of Standards, API gravity is expressed as degrees API. API gravities are the inverse of specific gravity. Thus, heavier viscous petroleum liquids have the lower API values.

Heavier crude will have greater relative concentrations of heavier components with higher degrees of unsaturation. Such compositions lend themselves more readily to conversion into heavier distillate products such as various grades of fuel oils, lubricating oils, asphalts, and similar products, as shown in Figure 2.

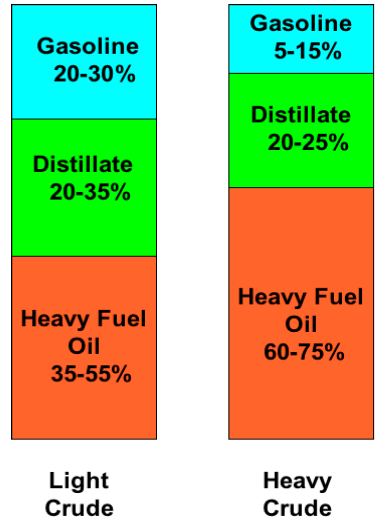

FIGURE 2 Comparison of Conversion Products Based on Crude Composition (Adapted from Day 2005)

While it is chemically possible to convert any quality crude to a wide range of final products, to convert heavier crude feedstock into high-value products requires substantial amounts of energy and results in reduced yields. Consequently, crude oil density (and, more specifically, chemical composition) dictates the refining pathway and the relative proportion of distillate products in most instances. This is the case for any crude source, including crude shale oil. The maximization of a refinery's total production value is derived by optimizing each component of the refinery, such as impurity removal and each type of processing capacity. Consequently, for existing refineries considering replacement of an existing feedstock, the desirability of a crude shale oil source as a replacement will be as dependent on the shale oil's quality and how well it aligns with the preferred refining pathway and intended final products for that refinery, as it is on outright market price. On the other hand, when the pending decision is to create a new refinery or to expand an existing refinery to produce different products, long-term availability, supply logistics, and cost become more influential but still do not displace the long-term refining margin returns as the primary basis for the decision.

As the above discussion suggests, many factors ultimately determine the extent of crude shale oil's penetration into the existing petroleum refinery market; however, the crude shale oil's overall quality (chemical composition as well as critical physical properties) would be the primary factor on which refineries base their decisions to pursue shale oil feedstocks. Unfortunately, the quality of crude shale oil produced at commercial scale is currently one of the areas of greatest uncertainty. Empirical evidence suggests that, together with the intrinsic variability in the composition of the parent oil shale, the quality of recovered shale oil ultimately offered to the refinery market will be highly dependent on the extraction and retorting technologies selected and the nature and extent of mine site upgrading. That being said, there is very little experience related to commercial-scale shale oil development. The newest in situ retorting technologies undergoing research and development (R&D) hold the promise of recovered shale oil of exceptional quality. (For example, Shell Oil anticipates that its in situ heating/retorting technology may yield crude shale oil of roughly 30% fractions each of raw naphtha, jet fuel, and diesel fuel and 10% residual. Shell further believes that relatively minor adjustments to field conditions could allow a change in composition of recovered product in response to extant refinery market conditions.). At this point in time, however, neither legacy technologies nor cutting edge technologies have amassed sufficient evidence on which to safely predict the quality factors that would result from their implementation at commercial scales. Long-term reliability of quality factors is absolutely critical to refinery acceptance, more so than the absolute values of those quality factors.

3 MARKET RESPONSES TO FEEDSTOCK VALUE PARAMETERS

Because heavier crude sources produce fewer high-value products, or produce higher-value products only with additional processing costs, markets compensate by trading heavier crude at a price discount relative to lighter crude. Heavier crude stocks are further discounted to offset the higher processing costs of using cokers to convert this low-value residual into higher-value gasoline and distillate components rather than less valuable heating fuels and asphalts, lubricating oils, and road oils. Transportation fuels, for example, gasoline and distillates, are the highest demanded products. Without upgrading capacity, there would be an excess of fuel oils and asphalts, and refiners would process lighter crudes rather than the economically desirable heavier crude. Figure 3 shows the refining margins associated with processing light and heavy crudes. The green line highlighted at the top represents the difference between processing the benchmark light (e.g., West Texas Intermediate) and heavy (Mexican Maya) crudes. As can be seen on the left axis, this reached a peak of an approximately $40 per barrel advantage of heavy crude over light crude this year. The Canadian crudes referenced in this paper are in the heavy category. While the expected composition of U.S. crude shale oil is not known precisely, it will probably be more comparable to the light crude in value than to the heavier crude stocks now available on the market. Mine site upgrading could further improve this equivalency.

The second element critical to the desirability of crude oil supplies is sulfur content. New specifications on gasoline and diesel are increasingly requiring lower and lower sulfur content. Sellers of high-sulfur crudes have to discount them enough to account for the required sulfur extraction process in the refinery. From a sulfur content perspective, some U.S. shale oil

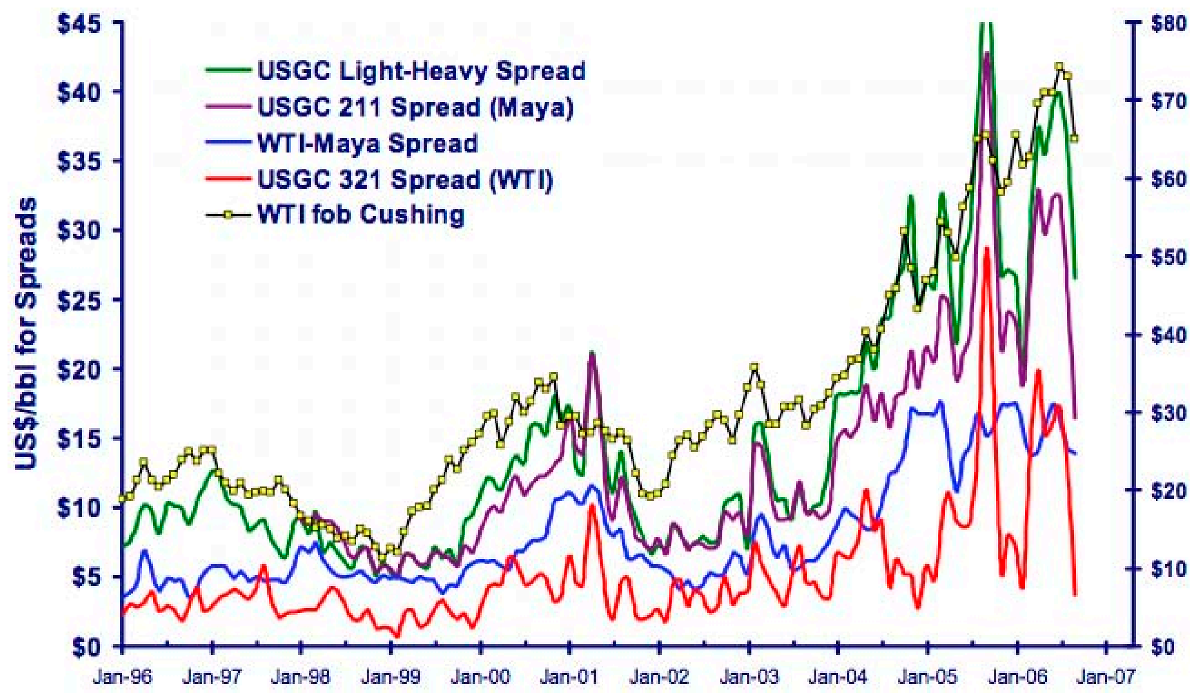

FIGURE 3 Heavy vs. Light Crude Refining Margins (Source: Arnold 2006)

products could be more attractive than conventional domestic crudes and Canadian imports. Green River oil shale sulfur content ranges from 0.46 to 1.1% (by weight), approximately 30% organic sulfur compounds, with sulfur content increasing as the richness of oil shale deposits increase.

Because of the high investment capital required to modify a refinery to process heavy crudes, refiners electing to do this have typically signed 7- to 10-year crude supply agreements. These long-term crude supply agreements shrink the near-term market available for heavy crude displacement by new crude shale oil supplies.

Given the uncertainty of quality factors that can be expected for commercially developed shale oil, it is difficult for refinery operators to determine the relative attractiveness of future crude shale oil sources against currently available sources. Frequently, operational adjustments and sometimes equipment investments have to be made to adapt to a significant change in a crude oil source. This could be related to process upgrading, impurity removal, or accommodation of other metallurgy, heating, cooling, or pumping capacities. Even without major structural changes, the normal unit variations created with introductions of new sources typically result in a refinery repeatedly testing small volumes of a new feedstock over a period of time to better understand the impacts on operations. Until long-term quality factors are established for crude shale oil, it is reasonable to expect a lag between initial commercialization of oil shale facilities and the development of refineries to accept it. Such an initial lag may be shortened to some extent by interim decisions on the part of refineries to accept crude shale oils of lesser quality with the intent of blending them with existing stocks to produce averaged quality factors in the blend that can still be managed economically in existing refining units with little to no modifications.

Shale oil facility operators also have opportunities to influence their potential place in the refinery market and to reduce the hesitancy of refineries to accept their product by the degree of upgrading they perform on their products. Since demand for low-sulfur distillate fuels is currently high and expected to increase (especially given the additional influence of recent lowering of sulfur limits in diesel fuel by the U.S. Environmental Protection Agency [EPA]), upgrading to align shale oil more directly with the high-quality conventional crude sources that now support that refinery market segment is the most likely objective. Thus, if shale oil developers pursue this option, upgrading actions at the mine site would be designed to remove sulfur and nitrogen and increase hydrogen to carbon ratios with reactions such as hydrocracking to improve the quality of initially recovered crude shale oil and make it more competitive with higher-quality conventional crude oil feedstocks.

However, given that shale oil production sites will be located in generally arid or semiarid regions with limited sources of power, fuel, and water for processing, extensive treatment and upgrading of crude shale oil could be limited in the early years of industry development by the availability and costs of required resources and may, therefore, occur only to the extent necessary for safe and economical pipeline transport to an off-site refinery. Should this be the case, early market penetration of shale oil would more likely be the result of the pursuit of blending options rather than displacement of high-value conventional crude feedstocks.

4 REFINERY UTILIZATION FACTORS

The refining process is a continuous liquid process. During normal operation, a refinery operates 24 hours per day, 7 days per week; however, maintenance on various units is periodically required. Individual (or groups of) units are typically shut down every 1 to 5 years, depending upon the unit type, and for 1 to 3 weeks for a unit “turnaround.” A turnaround involves a major maintenance overhaul of the unit, including replacing catalysts, performing upgrades, and replacing worn-out components. In addition, feedstock variation or unit upsets can cause feed preheating, pumping, overhead cooling capacity, sulfur recovery, etc., to become constraints, further lowering the overall utilization of the plant. Therefore, the overall utilization of the refinery is reduced by the amount of time the units are down. Thus, most data sources account for the realities of refinery operation by representing refinery capacity in two ways: barrels per stream day (BSD) and barrels per calendar day (BCD):

BSD represents the absolute maximum rate at which a unit can operate during any single day. This rate is a function of unit design and the capacity of supporting systems, but cannot be sustained for extended periods of time.

BCD represents the maximum rate of production a unit can sustain over the course of a year given maintenance downtime and operating limits due to varying feed qualities. As such, the BCD value is the only reliable representation of a refinery’s long-term production capacity.

The differences between BSD and BCD are unique for each refinery and reflect the types and ages of individual refining units and their respective repair and maintenance demands. The quality of the incoming feedstock also affects the difference between BSD and BCD capacities, since the amounts and types of impurities that must be removed during processing can greatly affect maintenance and overhaul schedules of individual units. Such factors explain the reported utilization rates for refineries being typically less than 100%. U.S. refineries run as much as is operationally feasible over the long term. However, because of these maintenance turnarounds, operational upsets, and unforeseen breakdowns, their overall utilization average nationwide is about 90 to 93%. Utilization rates for refineries in the closest vicinity to Green River oil shale deposits currently range from 91 to 95%. This, however, is still the maximum operating rate that can be reliably anticipated.

The difference between BCD and BSD, or between either rate and 100%, does not reflect spare capacity that can be utilized when desired to accommodate a new feedstock source, however. Unless otherwise specified, refinery capacities referenced in the remainder of this analysis mean BCD.

5 CURRENT STATE OF PETROLEUM REFINING IN THE UNITED STATES

The 149 operable refineries in the United States range in size from very small and specialized individual processing units with a capacity of 1,500 BCD, to large integrated refineries with capacities exceeding 550,000 BCD.

For the purpose of data collection, refineries are arranged in geographic regions known as Petroleum Administration for Defense Districts (PADDs). This system of categorization dates back to World War II and was devised to administer the distribution of petroleum products. PADDs also reflect the natural boundaries and flows of petroleum feedstocks and refined products. Figure 4 shows the geographic boundaries of the PADDs.[4]

Figure 5 shows the histograms of refinery sizes by PADD. PADD 4—Rockies has a disproportionate number of small refineries in comparison with the other PADDs, and these small refineries only serve regionally local markets and are configured to produce a limited array of products. The PADD 4 refineries originally were almost exclusively supplied with domestically produced crude from fields within the PADD. Now, additional pipeline investments have been made bringing Canadian crude into the region. In most cases, additional upgrading capacity was added at the refineries to process the heavier Canadian crude. A relatively high

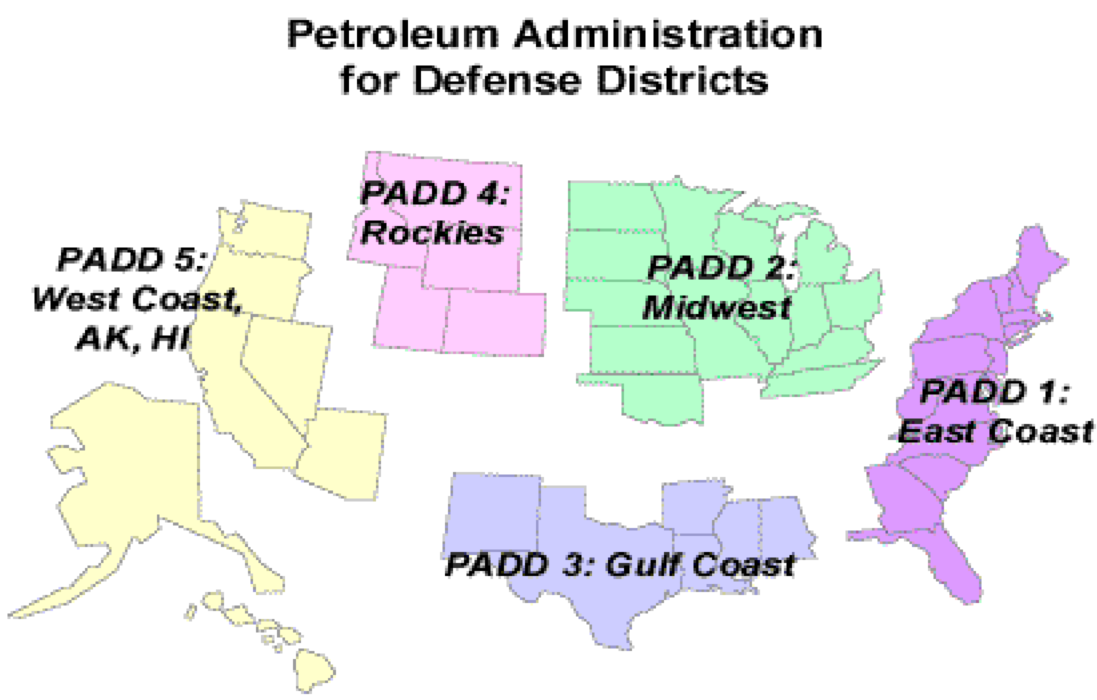

FIGURE 4 Petroleum Administration for Defense Districts Map (Source: EIA 2006b)

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[4] The U.S. Department of Energy (DOE) Energy Administration Agency (EIA) collects and provides reporting on energy data. Considerable information can easily be obtained at the EIA Web site: http://www.eia.doe.gov/. Much of this data reporting is aggregated on a regional basis, and the data are organized by PADDs.

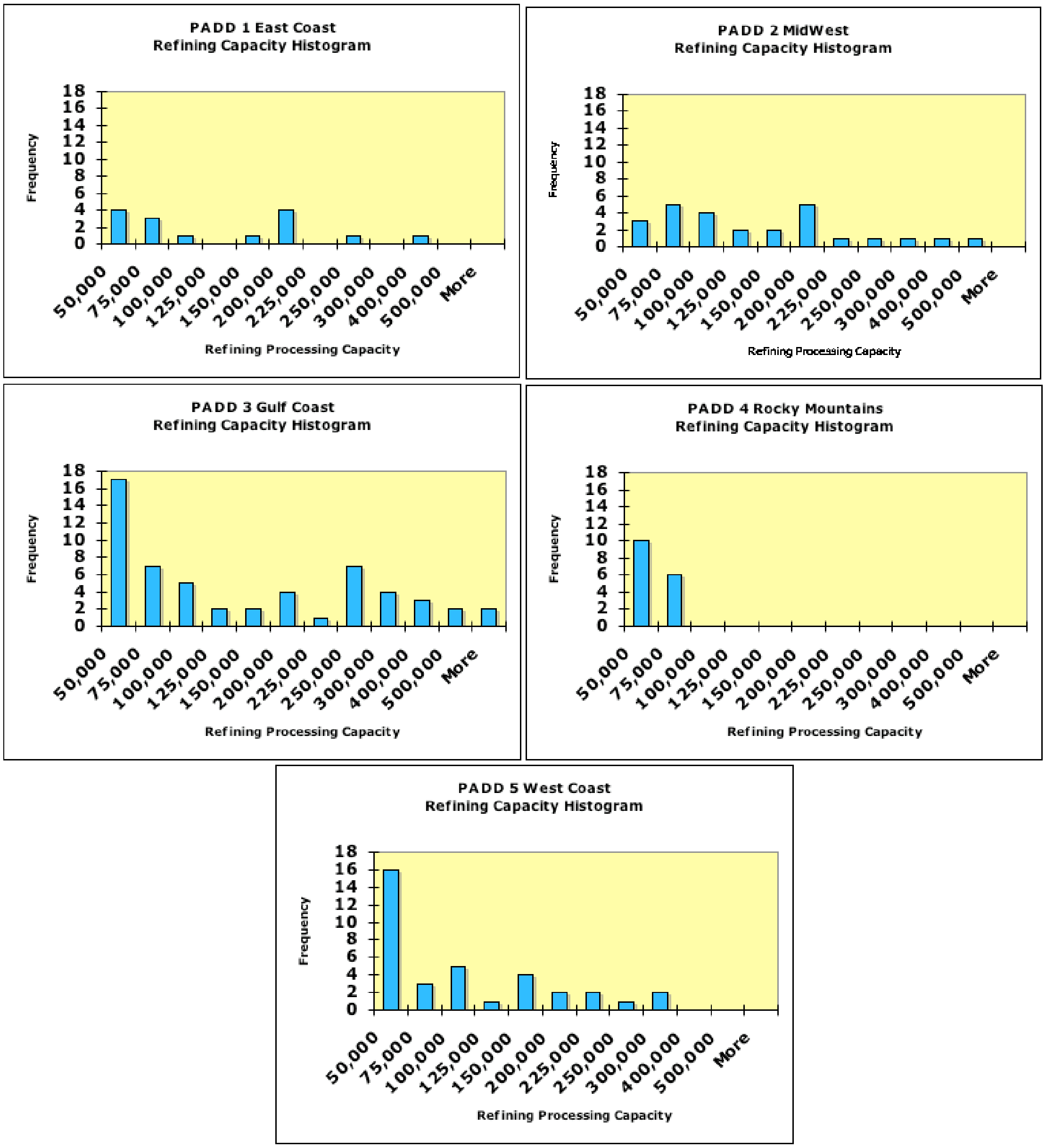

FIGURE 5 Distribution of Refining Capacities (Source: EIA 2006c)

sulfur concentration characterizes the remaining domestic crude production in the region. Key producing states in PADD 4, such as Wyoming and Montana, currently have an excess capacity of domestic crude production. In addition to pipeline logistical constraints, the consistent expanding price differential between light crude over heavy crude has kept this domestic production of light crude noncompetitive outside of this region. This was the first market with logistical connections with Canada and was the first market penetrated by Canada, although in relatively small volumes compared with Canada's current production.

Figure 5 shows the refinery production capacity and its variation arranged by PADD or regional basis. This is an important view for broader and longer range analysis. Figure 6 shows individual refining capacities by state for the production region of interest. This view defines the current maximum potential volume penetration for crude shale oil in PADD 4. Such market penetration could occur without the significant transportation infrastructure expansion that would be required before shale oil market penetration into any other PADD could take place. Thus, penetration into these "local" refinery markets is the most likely scenario in the early years of commercial oil shale production.

As shown in Figure 7, U.S. refining capacity increased a total of 3.6 million bbl/day between 1985 and 2004, and refinery utilization rates have been stable at near maximum achievable levels. The last refinery built in the United States was in Garyville, Louisiana, in 1976. Current conservative estimates for construction of a new refinery are about $2.4 billion for a 150,000-bbl/day capacity ($16,000/bbl/day of processing capacity). The most expensive sale of an existing refinery asset was Valero's recent purchase of Premcor, which sold for approximately $10,000/bbl/day of processing capacity. With existing assets selling for well under construction costs, there is little incentive to develop a new grass roots facility. Nevertheless, between 1985 and 2004, U.S. refineries increased their total capacity to refine crude oil by 7.8%, from 15.7 million BSD in 1986, to 16.9 million BSD day in 2004, but only maintaining a consumption rate of 15.7 million BCD, reflecting a utilization rate of operating capacity equivalent to 93%. This increase in operating capacity is equivalent to adding several mid-size refineries, but it occurred, instead, as a result of expansions of production capacities at existing refining facilities to take advantage of economies of scale (Slaughter 2005). Much of the current capital investment is going to environmentally related processing capability. Over the last 10 years, U.S. refiners have spent approximately $47 billion (Slaughter 2005) to reduce sulfur levels in transportation

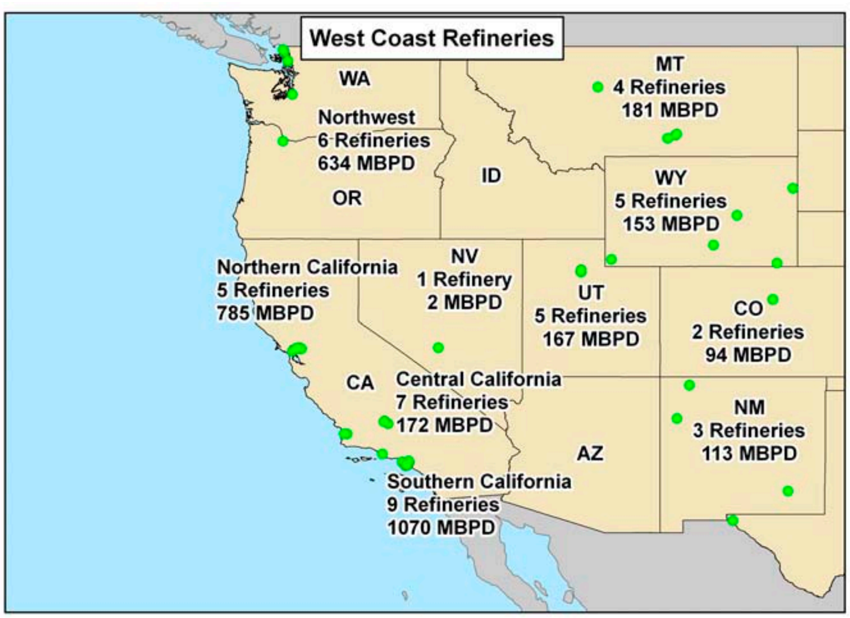

FIGURE 6 Western States Refining Capacity (Source: EIA 2006c)

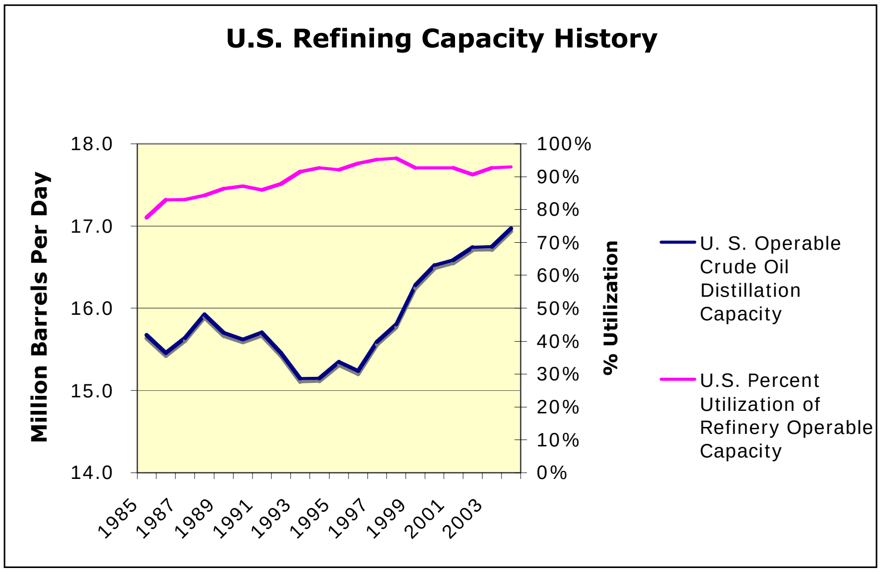

FIGURE 7 U.S. Refining Capacity (Source: EIA 2006d)

fuels and to comply with 14 new environmental regulations that come into place this decade (Wall Street Journal 2006). Of the 60 refinery expansion projects identified by the *Oil and Gas Journal*, 38 are environmentally related, 14 are for conversion units, and only 8 are related to expanding or retrofitting crude distillation capacity. Approximately 300,000 bbl of crude distillation capacity are committed to refinery expansion through 2010. However, despite the overall increase in production capacity that would result, utilization rates for refineries overall are not expected to change substantially.[5] However, refinery expansion is a continuous process of capital project evaluation so it does not represent a true forecast for refinery capacity. Because of the industry's tendency to expand existing assets, initial new market growth for shale crude oil is most likely to be at existing areas of refining concentration.

U.S. demand for refined products has grown steadily, and growth is expected to continue into the foreseeable future. Similarly, increased refining capacity has followed a parallel growth path to meet the rising demand. Current margins and announced refinery projects suggest that refinery growth will continue into the foreseeable future. The distinction of whether or not such growth occurs at a new location or whether it comes through expansion of existing facilities is not critical in evaluating the foreseeable potential of crude shale oil. If the market drives the crude shale oil to be delivered to the Gulf Coast, expansion of existing large refinery facilities to take advantage of associated economies of scale would be the probable response. If a new facility was constructed to take specific advantage of crude shale oil economics and logistical availability, it would not necessarily be located within the immediate vicinity of the crude shale oil sources. Ultimately, increase in refining capacity, whether through expansions or new facilities, will occur to the extent necessary to serve the ultimate markets for the end products.

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5 Since these expansions would involve new processing units utilizing state-of-the-art technologies, some minor improvements of utilization rates may result, but such increases are likely to be insignificant when averaged over the entire U.S. refining capacity.

Whether the crude shale oil is transported to existing refining centers for processing or whether a new facility is constructed to refine the crude closer to the point of production is a function of economics and market balance and is not an inherent constraint on the viability of crude shale oil production. In either scenario, there is a positive realization of the crude shale oil market and an associated environmental impact wherever refinery expansion occurs.

Refinery expansion occurs to profitably meet growing demand. Feedstock selection is a secondary process of optimizing refinery economics. Given the complexity of the dynamics of meeting increasing refinery demand and/or displacing existing crude supplies, attribution of refinery expansion to the introduction of crude shale oil is difficult. A further complication arises with the realization that over a period of as long as 20 years, production rates of some current feedstock sources may fall dramatically, therefore "freeing up" refining capacity without the need for refinery expansions

6 CURRENT CRUDE SOURCES

Any new crude source has to find a market in either expanded refinery production or by competitively displacing other crude supplies in the market (including through the adoption of feedstock blending strategies by refineries). This section describes the existing sources of crude feedstock that are supplying U.S. refineries.

In 2005, the United States processed 15.8 million bbl of crude per day. Of this, 2.4 million bbl/day comes from domestic production, 2.1 million bbl/day is imported from Canada, and 11.3 million bbl/day comes from other international sources. Crude is produced domestically in 28 states and in state and federal offshore waters on the West Coast and the Gulf of Mexico. Figure 8 shows domestic production by state.

The most likely market for new domestic crude sources is the displacement of comparable foreign crude. Figure 9 shows the percent of crude processed in each state that is imported as well as the volume that percentage represents. States in the extreme North and some in the Midwest are processing Canadian imports, which are less likely to be displaced because of the capital investment in upgrading already made or committed to by refineries to process these heavy crude supplies. The Canadian producers are developing crude pipelines to the Gulf Coast and are looking to the Gulf Coast PADD as their next incremental market. Any substantial shale oil production would likely follow this same market pattern. Summary information describing each of the PADDs is provided below:

- PADD 1—East Coast has primarily waterborne crude receipts. It is net short of refining capacity and is a large importer of refined products from within the United States and internationally. It is the least likely market for crude shale oil. It receives refined products through the Colonial and Plantation pipelines and refined imports from the Caribbean and Europe.

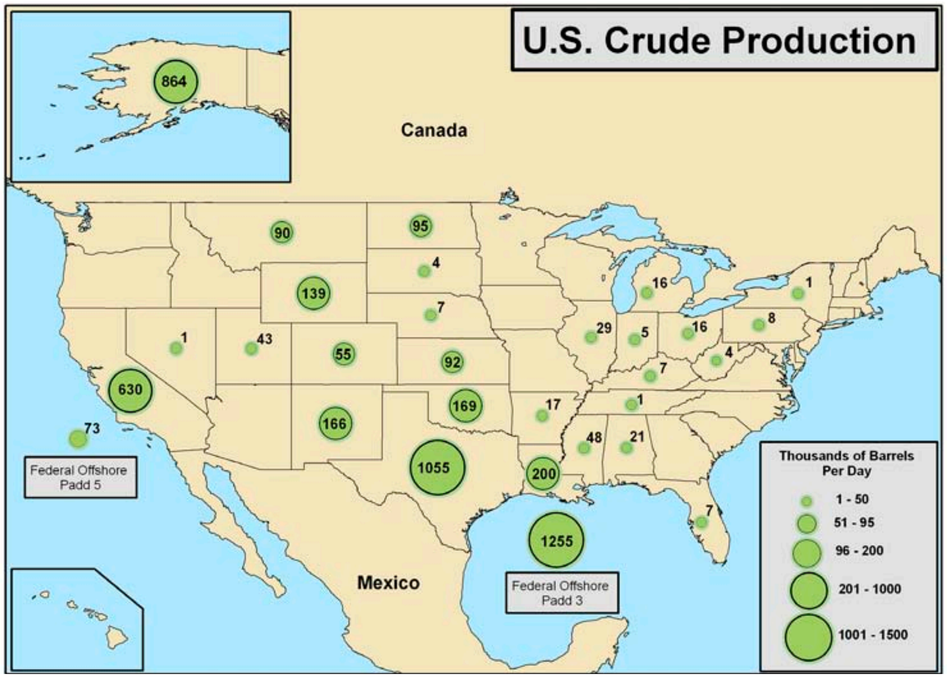

FIGURE 8 Domestic Crude Production (Source: EIA 2006e)

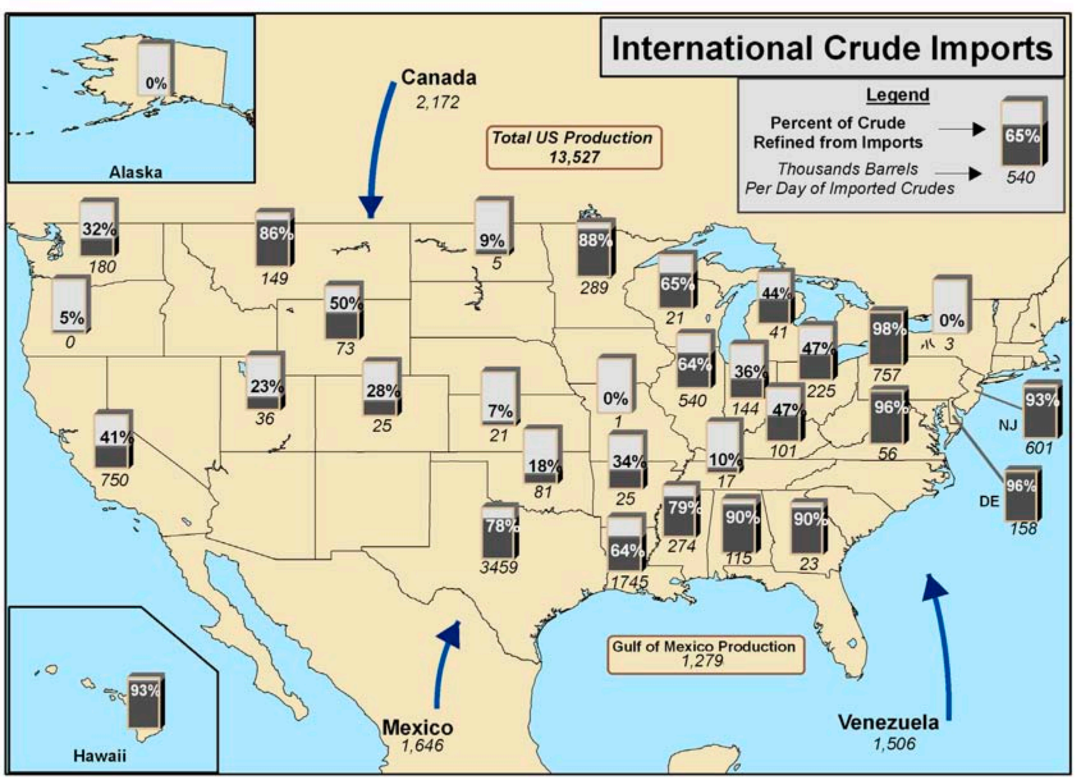

FIGURE 9 International Crude Imports (Source: EIA 2007)

- PADD 2—Midwest is geographically constrained from the primarily waterborne receipts in the Gulf Coast and offshore domestic Gulf Coast production. Its access via crude pipelines from the Gulf adds additional expense. Therefore, it was a natural secondary market for Canadian penetration. It is a very diverse PADD with a wide range of refinery sizes and configurations and serves a wide range of product specifications, including heavy integration of ethanol (for use in gasoline blending). PADD 2 has been the largest regional recipient of Canadian crudes entering the market. This is because of its large total refining capacity and its relatively closer proximity to the Canadian sources than other refining center markets. Its proximity to Canada and associated crude pipelines and the relatively higher cost to ship foreign crudes from the Gulf Coast to Midwest refineries makes PADD 2 a naturally attractive and economic recipient of Canadian crudes. Without some unexpected extensive logistical expansion of crude shale oil to other markets, such as the West Coast, these same factors will make PADD 2 the most likely recipient of any substantial volumes of shale oil.

- PADD 3—Gulf Coast is the heart of the U.S. refining concentration. It not only contains the most diverse refinery sizes and configurations, it is also the most integrated, with exchanges of secondary feedstocks with refineries and petrochemical plants. The first step in refining is distillation, which breaks crude into components such as naphtha, distillates, etc. These are considered secondary feedstocks in that they feed conversion process units downstream of the initial crude distillation. Secondary feedstocks are routinely sold to other refineries or to petrochemical plants. If a secondary market for this is readily available, such as in the Gulf Coast, then a refiner has to be less concerned with balancing the composition of the crude with the individual unit capacities. They can sell or purchase additional intermediates to make up for crude mismatch. The extensive number of petrochemical plants within the immediate vicinity of PADD 3 refineries further expands market flexibility for secondary feedstocks. This makes a much more competitive crude environment and lowers the premium on crude qualities, since there is more freedom to correct poor quality feeds. The Gulf Coast also was the original recipient of foreign heavy crude and, therefore, has extensive upgrading and sulfur extraction processing capacity for these supplies. Having access to a wide variety of world crude supplies, these refiners present a more competitive landscape for producers of crude oil and also establish a lower barrier to market entry for any feedstock that has differentiating economics. Pipeline reversals and new pipeline construction are underway to transport Canadian crudes to PADD 3. The large market is certainly an alternative for larger volumes of shale oil, but again, is the most competitive on price.

- PADD 4—Rockies is the region in which crude shale oil would be produced. Its refineries are relatively smaller than those in other PADDs. Its crude market is primarily domestic light sour production and imported Canadian crude. Canadian crude imports have increased substantially. It was one of the first markets to be exploited by Canada until further logistical capacity could be built to the Midwest and then later connections with other pipelines to the Gulf Coast. The markets for the refined products are also very localized, with the exception of the product pipeline from Salt Lake City, Utah, to eastern Washington and Oregon. Environmental considerations, such as water availability, could be a larger issue to refinery expansion in PADD 4 than in other PADDs. PADD 4 refiners are implementing improved wastewater recovery and water conservation projects in existing refineries in this region. PADD 4 would be the most likely early adopter, and refineries would be available with little pipeline capacity increase but, collectively, refineries in this PADD are very limited in the total volume of new feedstock that they can accept. Full realization of the shale oil potential will require significant displacement of current crude sources to PADD 4 refineries or crude shale oil sales in other PADDs.

- PADD 5—West Coast is a complex, but isolated market. The product requirements of the California Air Resources Board (CARB) are very challenging for refiners. Access to European and Gulf Coast products is constrained logistically by the transit time and ship availability to transit the Panama Canal (including the size limitation imposed on ships by the Canal). Even within the PADD, interchanges of supply and distribution are complex. Many of the San Francisco area refiners cannot produce CARB-approved gasoline and, therefore, export the entirety of their gasoline production to Washington and Oregon. Washington refiners can make CARB-approved gasolines and, therefore, produce for this higher profit market segment and supply gasoline to Southern California, which is net short of all products. Washington refiners produce some high-sulfur distillates, which exceed U.S. specifications, and these distillates are exported to both Latin America and South America. PADD 5 processes approximately two-thirds of domestic crude, including Alaska North Slope crude. Both California and Alaskan domestic crude sources are expected to decline within the 20-year time frame for this shale oil forecast horizon. The Southern California refiners, representing more than 1 million bbl/day of processing capacity, are particularly short of crude, and any domestic declines will only further disadvantage them. While there are currently no crude pipelines to carry shale oil crude from the Rocky Mountain area to the West Coast, PADD 5 represents a sufficiently attractive market for consideration in that pipeline infrastructure investments are likely over the long term.

7 CANADIAN CRUDE PRODUCTION

Canada is one of the largest crude exporters into the United States and is becoming of greater strategic importance given the increasing uncertainties associated with other foreign crude sources. It is enlightening to review the history of Canadian syncrude oil's entry into the U.S. refining market since this has been a relatively recent injection of a significant volume of crude feedstock into the U.S. market and may be representative of the pathway that U.S.-produced crude shale oil may follow. The source for the information presented in this section is *Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006–2015*, published in 2006 by the Alberta Energy and Utilities Board (EUB 2006).

The majority of Canadian syncrude is produced in Alberta Province, which is geographically closest to and competes with Western U.S. crude production. Most syncrude is now produced either by mining tar sands or by various in situ techniques using wells to extract crude bitumen. The product is generally classified as "heavy crude." Raw bitumen production has been increasing in recent years and accounts for more than 60% of Alberta's 1995 total crude feedstock production. A large portion of Alberta's bitumen production is upgraded to syncrude. Upgraders chemically add hydrogen to bitumen; subtract carbon from it, or both. In upgrading processes the sulfur contained in bitumen may be removed. Bitumen crude must be diluted with some lighter viscosity product (called a diluent) in order to be transported in pipelines. Use of heated and insulated pipelines can decrease the amount of diluent required; however, such techniques are not feasible for transport over long distances.

Canada has accomplished a dramatic increase in overall crude production and is forecasted to continue increasing at a large rate. Figure 10 shows the historical growth and forecast of Canadian crude oil by source. At the rate of anticipated production growth displayed in Figure 10, Canadian syncrude could represent a substantial percentage of total crude volume consumed by U.S. refineries within the near future. For example, by 2015, a forecasted Canadian syncrude production volume of approximately 4.5 million bbl/day could represent as much as 28% of the U.S. refinery industry's crude consumption.[6]

Canadian exports to the United States have grown approximately 15% since 2000. By 2015, 3.5 million bbl/day are expected to be exported to the United States, which would be an increase of 1.5 million bbl/day over current levels. Figure 11 shows the disposition of the Canadian exports to the United States by state.

In the United States, PADD 4—Rockies, although small in overall refining capacity, and PADD 2—Midwest have been the traditional markets for Canadian crude. However, several announced pipeline projects constructing new pipelines and reversing the direction of flows in existing pipelines are currently planned or under construction. The most significant is the planned construction of the Keystone pipeline and the reversals of the Spearhead and ExxonMobil line targeting significant new pathways to the PADD 3—Gulf Coast market. Significant increases in U.S. crude shale oil production in PADD 4 also would likely target similar markets of existing refinery capacity. As noted earlier, there are similar drivers between

6 The EIA forecasts that, by 2015, the total volume of crude actually consumed by all U.S. refineries will be 16.3 million bbl/day. For clarification against refinery capacities discussed earlier, assuming continuing refinery utilization rates of 93%, this volume infers 17.5 million BSD refinery distillation capacity, which can be reasonably expected to come from incremental expansions of existing facilities. For EIA crude volume consumption forecasts see EIA (2005).

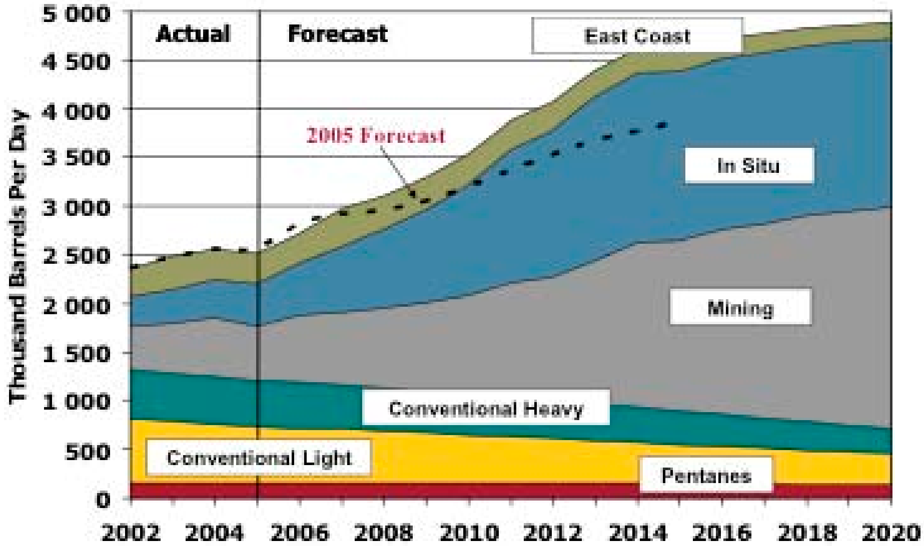

FIGURE 10 Canadian Crude Supply Forecast (Source: CAPP 2006)

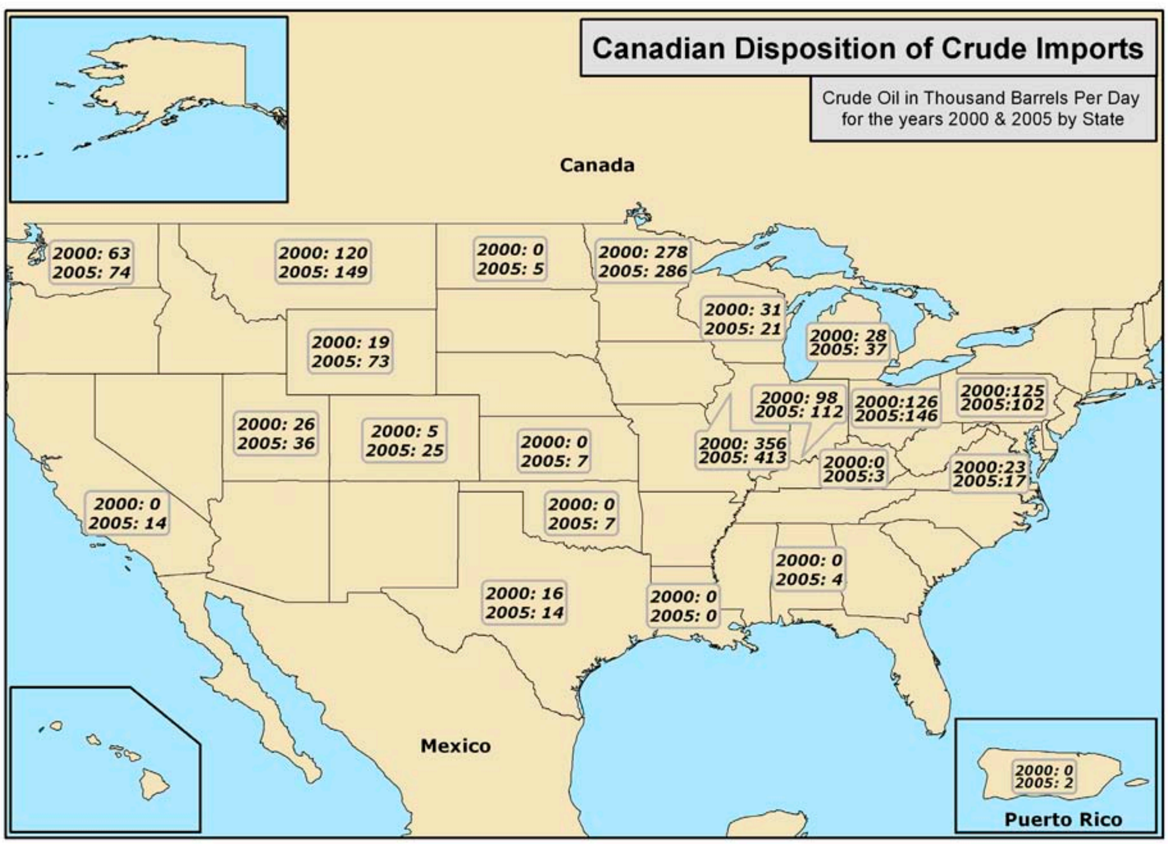

FIGURE 11 Canadian Crude Oil Disposition (Source: EIA 2007)

U.S. crude shale oil and Canadian crude because of geographical location and associated transportation capacities and costs. However, they do differ in chemical composition. Expected higher production costs as well as heavy subsidization of Canadian synthetic crude oil by the Alberta government suggest that the U.S. crude shale oil will not be offered at the lower cost that enables higher refining margins for the Canadian heavy crude. However, because commercially produced crude shale oil can be expected to be lighter than Canadian synthetic crude oil, its acceptance into refineries will not require incremental investment in heavy crude processing capacity.

Figure 12 shows the refining locations and the associated volumes of gasoline production in thousands of metric tons per year. This shows the concentration of refining assets in the Gulf Coast and West Coast markets and the lack of them in the Rocky Mountain source region.

To accomplish logistical movements of existing and planned import volumes, a series of pipeline construction projects, reversals of existing pipelines, and pipeline capacity expansions are underway. Figure 13 shows the current and projected Canadian and U.S. pipeline projects.

8 THE EVOLVING MARKET FOR SHALE OIL CRUDE

It is useful to consider the development of shale oil markets in phases. On the basis of historical precedent, in the early years of initial commercial production (1 to 5 years after the start of commercial development) there is likely to be a relatively small volume of shale oil available on the local commercial market, and this volume may be of varying quality as various methods of shale oil recovery and processing are introduced, fine-tuned, and combined. In addition, over this period, the shale oil producers may shift the degree to which they upgrade the raw recovered crude shale oil to match evolving market conditions and to improve their market penetration potential. If these initial volumes of commercial shale oil are differentiated economically, they are most likely to find a market within PADD 4 to the extent allowed by existing transportation infrastructure. As was noted earlier, there will likely be some hesitancy on the part of refiners to use these crudes until their qualities are consistent and predictable.

In a second phase (probably in years 5 to 10), the volume of shale oil available will have exhausted refiner's opportunities to displace existing feedstocks, saturate local refining capacities, and exceed existing pipeline transport capacity within the immediate region. This is likely to focus additional growth to either PADD 2—Midwest or PADD 3—Gulf Coast, depending upon which region has the greatest new (and unclaimed) pipeline transport capacity. In this time frame, it is possible that PADD 2 already could be saturated with existing Canadian capacity, and PADD 3 would be the more likely incremental market for greater volumes of crude shale oil. By this point in time, the quality of commercially available shale oil should have stabilized so that the true determining factor would be a market-driven valuation of the crude composition and qualities versus its transportation and processing economics. Either PADD 2 or PADD 3 could absorb up to 2 million bbl/day additional shale oil with little refinery configuration restructuring required if the market determines it is economically advantageous to do so.

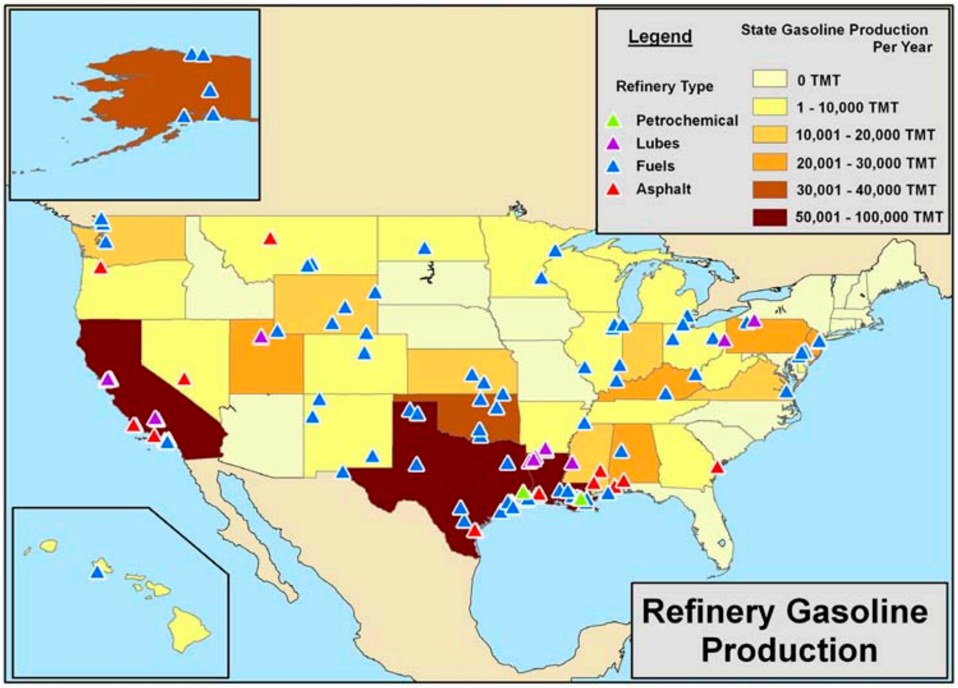

FIGURE 12 Refinery Locations and Gasoline Production (Source: EIA 2006c)

FIGURE 13 Canadian and U.S. Crude Oil Pipelines (Source: CAPP 2005)

In the long-term (probably 10+ years), other markets such as PADD 5—West Coast could also become viable. The potential decreases in California and Alaskan North Slope crude production and/or increased insecurity in foreign crude availability could provide the motivation to construct high-capacity pipelines to supply that market.

Uncertainty as to the exact quality of commercially produced shale oil prevents a precise determination of the feedstock market segment in which it would be most competitive. Current in situ technologies under evaluation show the promise of partial upgrading of crude oil prior to recovery from the oil shale formation as well as the conversion of sulfur and nitrogen-bearing compounds to hydrogen sulfide and ammonia compounds, respectively, either of which can be easily removed from the product stream. Although this hypothesis remains unproven at commercial scales, if it is realized, the resulting crude shale oil could be both light weight and low in sulfur content (relative to many current conventional feedstocks), which could give it a distinct advantage over both the high-sulfur conventional domestic crude production and the Canadian synthetic crude oil. This may influence both the rate and extent of market penetration for shale oil.

Refinery expansion and operations will also be influenced by environmental factors, which contribute to the overall market picture. Issues such as air quality (attainment status for each of the primary ambient air quality criteria pollutants as well as source-specific emission limitations) and water availability could constrain or preempt significant expansions of existing refineries or the construction of new refineries in certain geographic areas. It is intuitive that refinery growth occurring in the immediate vicinity of a crude oil source would minimize transportation costs; however, other factors, such as ambient air quality and water availability, could be key constraining factors in refinery expansion that could overwhelm any concerns for transportation costs. In addition to the high water requirement of typical refineries of 1 to 3 bbl of water per barrel of processed crude, the degree of impurities present in crude shale oil could create increased wastewater and waste disposal issues. In the final economic models that are typically employed, transportation costs are nominal and have very little influence over the ultimate decision regarding the location of the refinery relative to the crude oil source. Of a more critical influence is the existing pipeline capacity that links the market areas under consideration. However, as has been suggested in the introduction, pipeline operators will expand their capacities and build pipelines linking new locations once markets are reliably established.

Environmental controls aimed not at refineries but at some distillate fuel products may also influence the overall market. New low-sulfur fuel requirements will put high-sulfur feedstocks at a disadvantage or will require expensive expanded sulfur control capabilities at refineries currently receiving such feedstocks. The intrinsically lower sulfur content of crude shale oil over some conventional crude feedstocks, as well as the ability of crude producers to further reduce sulfur content through in situ retorting techniques and/or mine site upgrading, could greatly increase shale oil’s attractiveness to refineries producing such distillate fuels.

9 OTHER POSSIBLE MARKET DRIVERS

Declines in supply from existing major exporters (e.g., Venezuela and Mexico), domestic sources (North Slope of Alaska), and geopolitical events could create an increasing demand for domestic crude production in the future. Venezuela and Mexico have been primary sources of crude oil, with each providing approximately 1.5 to 1.7 million bbl/day into the United States, but concern for these sources is growing. Venezuela has been unable to return to the level of production in 2001, and the government has become increasingly antagonistic to U.S. interests. Also, there is growing industry concern in the decline of Mexican production because of the lack of investment, which could dramatically impact production levels in the next few years. With two major Western Hemisphere producers facing uncertain futures and continuing concerns in the Middle East and Africa, the medium-term potential for increased demand for domestic crude production could improve the market viability for production and processing of crude shale oil.

Alaska North Slope production has been in decline and is currently supplying approximately half of its historic peak. Although there are considerable logistical challenges to moving crude to the West Coast, future declines in supply from Alaska could create increased demands on the West Coast that could improve what is currently considered a nonviable market for moving feedstock from the Rocky Mountain region to the West Coast.

While nearby crude sources are likely declining, world demand of crude oil is expected to increase by 47% by 2030. China and India are expected to account for more than 40% of this increase (EIA 2006f). These forecasts of increasing demand and diminishing resources are creating an international competition, which is being acted on now. China began the process of constructing a Strategic Petroleum Reserve in 2004 and is increasing its relations with oil producers, such as Angola, Central Asia, Indonesia, the Middle East (including Iran), Russia, Sudan, and Venezuela (Office of the Secretary of Defense 2005). Further international energy risk could provide additional incentive for utilization of domestic resources.

Legislation could also play a role in driving the advancement of shale oil. The Energy Policy Act of 2005 extends the Title VII, National Oil Heat Research Alliance Act of 2000, providing for research for use of distillates as home heating oil. Heating oil equipment is found to "operate at efficiencies among the highest of any space heating energy source." Further support of this could drive additional demand for the types of distillates that can be produced from upgraded shale oil. The same act also directs the Secretary of Energy to select sites necessary to procure the fully authorized Strategic Petroleum Reserve (SPR) storage volumes. Although additional segregation would be required from the current SPR storage, shale oil could be upgraded to meet additional SPR storage acquisition or even displace existing barrels of conventional oil. The need to extend the physical storage capacity affords an opportunity to evaluate alternative locations, from the existing Gulf Coast-centric storage to support production in the Rocky Mountain region, or storage and consumption in Southern California or the upper Midwest. In addition, Section 369 of the Act directs the Secretary of Defense to procure fuel derived from coal, shale oil, and tar sands. This could also stimulate a demand, especially in the western United States. While the precise nature of future actions implementing these statutory directives is unknown at this time, impacts on the oil shale industry are easily anticipated.

10 CONCLUSIONS

The unknowns regarding the quality and availability of crude shale oil, the extent to which it may be upgraded at the site of production, and the time frames for expansions of pipeline capacity for movements outside the immediate production area, introduce considerable uncertainty with respect to the timing and specifics of refinery market development. As a result, it is difficult to predict with certainty how the refinery market will respond to oil shale development on public lands over the next 20 years (2007 to 2027). It is likely that during the first 10 years of the study period (2007 to 2017), there will be no commercial oil shale production; activities during this period will be focused on R&D and demonstration only. Commercial-scale production may start around 2017 at some project sites and reach a level of about 1 million bbl/day from those sites within a few years. Additional production from other project sites could start in a similar time frame, and a production rate of approximately 2 million bbl/day could be reached around the end of the study period.

The information presented in this paper defines the factors that will likely impact the incorporation of shale oil into the market. In addition, information from the relatively recent introduction of Canadian synthetic crude can be used to define a possible path for crude shale oil market infusion. To make any projections about the refinery market response to oil shale production, it is necessary to make certain assumptions. It is assumed that the U.S. refinery market will respond in a fashion consistent with past behavior. It is further assumed that both the Canadian crude and other foreign crude will continue at their current levels of availability. This analysis of potential markets for shale oil does not depend upon any reduction in available global supply typically referred to as the peak oil argument. The expected build-out of shale oil production will enter at the beginning of the peak oil argument. Any international decline in crude oil production will only create greater demand for alternative crude production sources. An exception to the assumption that all existing crude supplies remain relatively stable is the Alaskan North Slope crude supply where, as noted, current projections forecast a significantly reduced production in the 10-year time frame. In the Alaska projection, the Alaska National Wildlife Refuge is not assumed to be in production.

Because of the many uncertainties that still exist, it is probable that market development will proceed in different directions during different growth phases of the crude shale oil market. Initially, the market is likely to respond to new crude shale oil production through displacements of similar or complementary quality crude supplies from the refinery stream rather than expansions of refinery capacity. Such displacements, however, will be tempered by conditions in the market, including the relative price of crude oil of similar quality and existing crude oil supply contracts (as in the case of existing contracts for heavy Canadian crude oil).

On the basis of historic patterns of expansion in refining capacity, refinery expansions to incorporate new crude shale oil supplies will occur incrementally, largely within areas of existing concentrated refining capacity, and only after refiners have identified a long-term profit margin for expanded facilities. The availability of new supplies alone is not sufficient to drive new refining capacity (as seen in the current oversupply of light crude in Wyoming). Only long-term profit potential will provide that incentive.

The scenario described below reflects the suppositions and constraints discussed in this paper. There is no historic precedent for production increases of this magnitude in such a short period of time; therefore, this scenario may not be accurate. It does not represent the only pathway by which shale oil refining markets will develop, but can nevertheless be justified on a number of critical levels.

Development will likely occur in three phases:

1. Early adoption and geographically local market penetration within PADD 4,

2. Market expansion outside of PADD 4 with increased logistical capability (for both oil shale production facilities and transportation infrastructure), and

3. High-volume production and multimarket penetration of a mature shale oil industry.

Successful market penetration is a balance of crude shale oil availability, logistical availability (i.e., pipeline transportation), and market demand. Each phase of market maturity for shale oil will confront constraints in one or more of these areas. The relative significance of these constraints will shift during the various phases of maturity.

Phase 1, early adoption and local market penetration, will likely occur during the first 5 years of commercial development. If approximately 1,000,000 bbl/day of oil shale were produced in Colorado during this time, the abundance of shale oil supply will be placed into a refinery market that already is experiencing excess domestic production. Transportation capacity will be the limiting factor during this phase. Until reliable product definition and consistent quality of the crude shale oil are established, refineries will have a slow adoption rate and are more likely to only replace existing sources of crude of comparable quality. While it is unlikely that new refineries will be constructed during this period in response to this new production, the crude transport connections and overall refinery capacities within the PADD 4—Rocky Mountain region will need to be improved in order for these refineries to be early adopters. This could translate into the construction of new pipelines in the PADD 4 region. Demand in PADD 4 is not expected to increase dramatically during this time, but refineries could potentially reconfigure their processes or create new blends of crude stocks to better align their feeds with desired products. The potential qualities of crude shale oil could be similar to domestic light crudes and if market conditions allow, could compete with an already oversupplied local domestic crude market in the immediate vicinity. Alternatively, Phase 1 could be very short-lived, or skipped entirely, and Phase 2 conditions could prevail.

Phase 2, market expansion beyond PADD 4, is likely to involve expansion of the transportation network allowing distribution of crude shale oil outside of PADD 4. At the point in time that PADD 4 reaches a saturation point, thus presenting a growth-limiting factor, Phase 2 expansions beyond PADD 4 will need to occur. This could occur starting around 2022 (or sooner) and extend until 2027 or beyond. To accomplish this, expansion of pipeline capacities to multiple markets outside of PADD 4 will be required. As addressed above, the most likely markets are the Midwest and Gulf Coast, although some potential growth could occur in the local markets. Because of the limited forecasted refinery expansion over this time period, new market penetration will require displacement of alternative sources of crude oil. The overall cost of production, the final qualities of the crude shale oil, and the availability of out-of-region transport will determine the economics and subsequently, its economic viability. During this period, it is also unlikely that new refineries will be constructed in any of the PADDs; more likely, the transportation network will expand and there could be some expansions at existing refineries.

Phase 3 represents multimarket penetration and the maturation of the shale oil industry where the market is at equilibrium and crude shale oil availability is the limiting factor rather than transportation or refinery capacity. This phase assumes large volumes of crude shale oil would be produced (approximately 2 million bbl/day). By this time, it is realistic to expect that PADD 5—West Coast refineries that have been utilizing California and Alaskan North Slope crude will be searching for alternative sources of supply, which may bring these refineries into the shale oil market equation. The market viability of these levels of production is probably dependent upon integration with multiple regional markets and assumes ongoing economic viability versus alternative sources. Even in this long-range projection, neither demand or refining capacity in the PADD 4 local markets is expected to increase to a level that could utilize the expected shale oil production, thus development of markets in other regions will be necessary to sustain the industry or allow it to reach its full projected production capacity.

The long-term view for the potential for the oil shale industry beyond 2027 with an expected production capacity of 2.1 million bbl/day could be realistic. On the basis of recent experience with the development and penetration of U.S. markets by Canadian syncrude, however, the early and mid-phase development scenarios are aggressive, especially given some of the unknowns regarding the final reliable quality of crude shale oil produced at commercial scale and the extended time lines required for market acceptance and development of both transportation and refining infrastructures. Assuming that the chemical characteristics of the crude shale oil product are desirable (and assuming no revolutionary development of refining technology that would make feedstocks of marginal quality more desirable), market manipulation, including possible subsidization or facilitation of development of logistical infrastructure (e.g., designated pipeline corridors), could speed up market acceptance and make the overall scenario more likely.

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APPENDIX B:

TAR SANDS DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW

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APPENDIX B:

TAR SANDS DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW

This appendix describes the geology of the tar sands resource area, the resource, the history of tar sands development in the western United States, and provides an overview of the technologies that have been applied to tar sands development. It introduces technologies that may be employed in future developments on U.S. Department of the Interior, Bureau of Land Management (BLM)-administered lands. The technologies that are addressed include those used for recovery (i.e., mining), processing (i.e., separation and pyrolysis of the hydrocarbon fraction), and upgrading of tar sands resources.

Tar sands deposits occur throughout the world except in Australia and Antarctica (Han and Chang 1994). The largest deposits occur in Alberta, Canada (the Athabasca, Wabasha, Cold Lake, and Peace River areas), and in Venezuela. Smaller deposits occur in the United States, with the larger individual deposits in Utah, California, New Mexico, and Kentucky.

Accurate estimates of the reserves of hydrocarbon liquids in tar sands deposits have not been made, but worldwide demonstrated deposits (excluding inferred deposits) may total about 320×10^9 m^3 ($2{,}000 \times 10^9$ bbl), with the largest share in Alberta, Canada, at about 270×10^9 m^3 ($1{,}700 \times 10^9$ bbl). There are about 546 occurrences of tar sands in 22 states in the United States in deposits that may have more than 4.5×10^9 m^3 (28×10^9 bbl) of hydrocarbons. About 60% of this potential resource is located in Utah (Spencer et al. 1969; Meyer 1995).

The term tar sands, also known as oil sands (in Canada), or bituminous sands, commonly describes sandstones or friable sand (quartz) impregnated with a viscous, extra-heavy crude oil known as bitumen (a hydrocarbon soluble in carbon disulfide). Significant amounts of fine material, usually largely or completely clay, are also present. The degree of porosity varies from deposit to deposit and is an important characteristic in terms of recovery processes. The bitumen makes up the desirable fraction of the tar sands from which liquid fuels can be derived. However, the bitumen is usually not recoverable by conventional petroleum production techniques (Oblad et al. 1987; Meyer 1995; Speight 1997).

The properties and composition of the tar sands and the bitumen significantly influence the selection of recovery and treatment processes and vary among deposits. In the so-called “wet sands” or “water-wet sands” of the Athabasca deposit, a layer of water surrounds the sand grain, and the bitumen partially fills the voids between the wet grains. Utah tar sands lack the water layer; the bitumen is directly in contact with the sand grains without any intervening water (Speight 1997); such tar sands are sometimes referred to as “oil-wet sands.” Typically, more than 99% of mineral matter is composed of quartz and clays. The general composition of typical deposits at the P.R. Spring Special Tar Sand Area (STSA) showed a porosity of 8.4 vol% with the solid/liquid fraction being 90.5% sand, 1.5% fines, 7.5% bitumen, and 0.5% water by weight (Grosse and McGowan 1984). Utah deposits range from largely consolidated sands with low porosity and permeability to, in some cases, unconsolidated sands (Speight 1997). High concentrations of heteroatoms tend to increase viscosity, increase the bonding of bitumen with minerals, reduce yields, and make processing more difficult (Oblad et al. 1987).

To utilize a tar sands resource in a mining operation, the bitumen must be recovered from its natural setting, extracted from the inorganic matrix (largely sand and silt) in which it occurs, and upgraded to produce a synthetic crude oil suitable as a feedstock for a conventional refinery. In general, it takes about 2.0 tonnes (2.2 tons) of surface-mined Athabasca tar sands to produce 159 L or 1 barrel (42 gal) of synthetic oil (Oil Sands Discovery Center 2006a). Nonmining operations recover the bitumen already free of the matrix (sand and clays) in which it originally occurred. Preparation may require removal of bitumen or vaporized bitumen from steam, other gases, water, or solvents. Depending on the end product required, upgrading may not be required.

At this time, there are no commercial tar sands operations on public lands in Utah. Commercial development could occur on lands with existing combined hydrocarbon leases (CHLs). The BLM does predict some commercial development on public lands under the new tar sands leasing program that would be established with this *Draft Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement (PEIS)* and the accompanying Record of Decision (ROD). It is also likely that additional development would proceed on private and/or state lands. The impacts being evaluated in the PEIS could occur under either a CHL or under a tar sands lease; however, the decisions that may result from this PEIS and its accompanying ROD are not applicable to CHLs.

The following discussion includes general information on the geology, development history, and technologies for tar sands development that are being considered in this PEIS. Chapter 9 of the PEIS provides a glossary of technical terms used in the PEIS and its appendices, including geologic terms.

B.1 DESCRIPTION OF GEOLOGY

Tar sands are sedimentary rocks containing bitumen, a heavy hydrocarbon compound. Tar sands deposits may be divided into two major types. The first type is a breached petroleum reservoir where erosion has removed the capping layers from a reservoir of relatively heavy petroleum, allowing the more volatile petroleum hydrocarbons to escape. The second type of tar sands deposit forms when liquid petroleum seeps into a near-surface reservoir from which the more volatile petroleum hydrocarbons escape. In either type of deposit, the lighter, more volatile hydrocarbons have escaped to the environment, leaving the heavier, less volatile hydrocarbons in place. The material left in place is altered by contact with air, bacteria, and groundwater. Because of the very viscous nature of the bitumen in tar sands, tar sands cannot be processed by normal petroleum production techniques.

Tar sands deposits are not uniform. Differences in the permeability and porosity of the reservoir rock and varying degrees of alteration by contact with air, bacteria, and groundwater mean that there is a large degree of uncertainty in the estimates of the bitumen content of a given tar sands deposit. Estimates may be off by an order of magnitude (a factor of 10) (USGS 1980a–k).

More than 50 tar sands deposits occur in Utah. Limited data are available on many of these deposits, and the sizes of the deposits are based on estimates. Most of the known bitumen occurs in just a few deposits. The deposits that are being evaluated in this PEIS are those deposits classified in the 11 sets of geologic reports (minutes) prepared by the U.S. Geological Survey (USGS) in 1980 (USGS 1980a–k) and formalized by Congress in the Combined Hydrocarbon Leasing Act of 1981 (Public Law [P.L]. 97-78).[1] While there are 11 sets of minutes, in some cases, the geologic report refers to more than one deposit. For example, the minutes titled *Asphalt Ridge–Whiterocks and Vicinity* discuss the Asphalt Ridge deposit, the Whiterocks deposit, the Asphalt Ridge Northwest deposit, the Littlewater Hills deposit, and the Spring Hollow deposit. All of these deposits are included in the designated STSA and in this analysis for the PEIS. For the sake of convenience, the deposits are often combined and referred to on maps, and otherwise, as the Asphalt Ridge STSA.

Tar sands deposits outside the areas designated by the Secretary of the Interior in the 11 sets of minutes are not available for leasing under the tar sands program, but would be available for development under a conventional oil and gas lease. Figure B-1 shows the locations of the STSAs in Utah, as defined by the 11 sets of minutes from the USGS. Figure B-2 shows the generalized stratigraphy of the areas in Utah where the STSAs are present.

Table B-1 provides estimates of the heavy oil resources for the 11 STSAs as published by Ritzma (1979). Additional resource estimates have been published in an Interstate Oil Compact Commission report titled, *Major Tar Sand and Heavy Oil Deposits of the United States* (Lewin and Associates 1983). The data indicate that a large percentage of the tar sands bitumen in Utah is located within just a few of the STSAs. The following sections summarize the information that is available for each of the STSAs. The level of detail varies between the STSAs because significant amounts of information have been compiled only for those STSAs with the largest resource base.

B.1.1 Argyle Canyon–Willow Creek STSA

The Argyle Canyon–Willow Creek STSA, hereafter referred to as the Argyle Canyon STSA, is located in the southwestern portion of the Uinta Basin and includes deposits in two areas. These deposits are sometimes referred to independently as the Argyle Canyon deposits, which are located in the Bad Land Cliffs area, and the Willow Creek deposits, which are located along the western end of the Roan Cliffs. For the purposes of this PEIS, the Argyle Canyon

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[1] The boundaries of the designated STSAs were determined by the Secretary of the Interior's orders of November 20, 1980 (Volume 45, pages 76800–76801 of the *Federal Register* [45 FR 76800–76801]) and January 21, 1981 (46 FR 6077–6078).

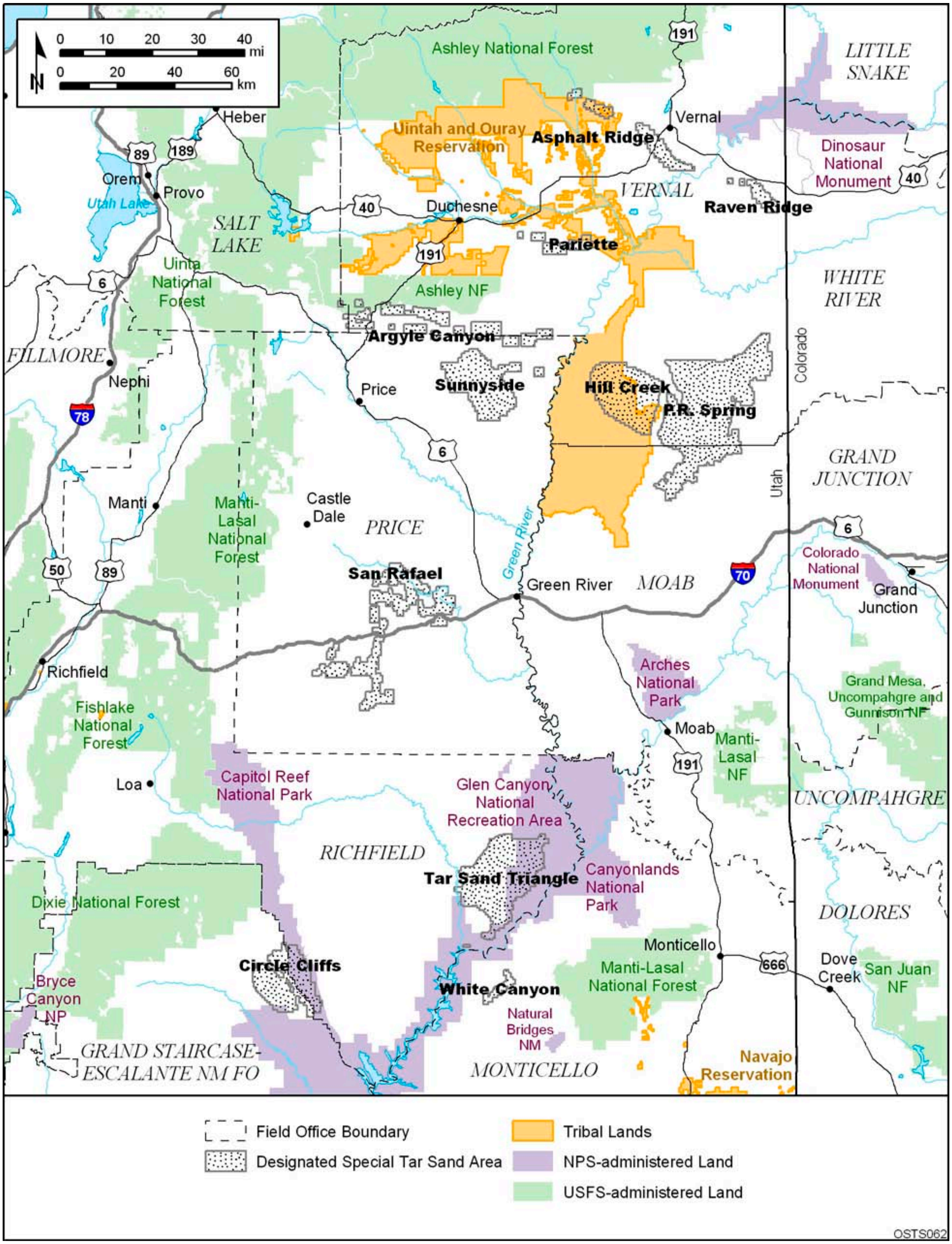

FIGURE B-1 Special Tar Sand Areas in Utah

STSA includes both areas. All information presented in this section is from Blackett (1996) unless otherwise noted.

The Argyle Canyon portion of the STSA is highly dissected by a north-south trellis-type drainage. The rocks present in this deposit are the Parachute Creek Member and the Deltaic facies of the Eocene Green River Formation, which is overlain by the Eocene Uinta Formation. The Parachute Creek Member is regularly bedded and contains siltstone, mudstone, and oil shale. The Deltaic facies is irregularly bedded, lenticular micaceous sandstone and interbedded mudstone.

The Willow Creek portion of the area is characterized by high plateaus dissected by deep, steep-walled canyons. Rocks present in the Willow Creek deposit are the upper part of the Garden Gulch Member and the lower part of the Parachute Creek Member of the Green River Formation (Eocene). The Garden Gulch Member consists of interbedded thin sandstone, siltstone, shale, and limestone. The Parachute Creek Member is composed of massive beds, thinning upward, of fine-grained sandstone, interbedded with siltstone and shale.

Within the Argyle Canyon deposit, most of the bitumen is contained in the sandstones of the Deltaic facies. Within the Willow Creek deposit, channel sandstones contain most of the bitumen. Recovery of the bitumen in areas near outcrops, with gentle dips, would be amenable to surface mining. The remainder of the area would have to be developed by in situ methods (BLM 1984).

B.1.2 Asphalt Ridge–Whiterocks and Vicinity STSA

The Asphalt Ridge–Whiterocks and Vicinity STSA, hereafter referred to as the Asphalt Ridge STSA, is located along Asphalt Ridge, on the north-northeast flank of the Uinta Basin. Asphalt Ridge is a northwest-southeast trending cuesta, with dips to the southwest. All information presented in this section is from Blackett (1996) unless otherwise noted.

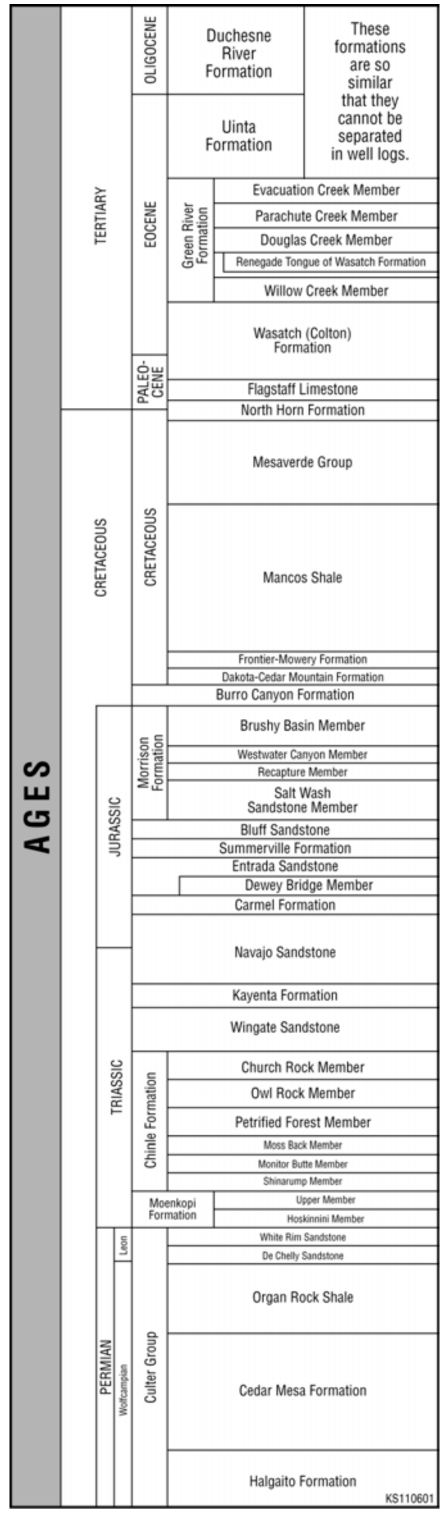

FIGURE B-2 Generalized Stratigraphy of the Areas in Utah Where the STSAs Are Present

TABLE B-1 Estimated Resources in Place in Utah Tar Sands Deposits

	Measured (million bbl)[a]	Speculative (million bbl)
Major Deposits		
Uintah Basin		
P.R. Spring	2,140	2,230
Hill Creek	320	560
Sunnyside	4,400	1,700
Whiterocks	60	60
Asphalt Ridge	830	310
Paradox Basin		
Tar Sand Triangle	2,500	420
Nequoia Arch	730	160
Circle Cliffs Uplift		
Circle Cliffs	590	1,140
San Rafael Uplift		
San Rafael Swell	300	250
Subtotal:	11,870	6,830
Minor Deposits		
Uinta Basin		
Argyle Canyon	–[b]	50–75
Raven Ridge	–	75–100
Rimrock	–	25–30
Cottonwood–Jacks Canyon	–	20–25
Littlewater Hills	–	10–12
Minnie Maud Creek	–	10–15
Pariette	–	12–15
Willow Creek	–	10–15
San Rafael Uplift		
Black Dragon	–	100–125
Chute Canyon	–	50–60
Cottonwood Draw	–	75–80
Red Canyon	–	60–80
Wickiup	–	60–75
Subtotal:		557–707
Total	11,870	7,387–7,537

[a] bbl =barrel; 1 bbl syncrude = 42 gal.

[b] A dash indicates no formal quantification available.

Source: Ritzma (1979).

The rock units present at Asphalt Ridge, in order of decreasing age, are the Mesaverde Group (Asphalt Ridge Sandstone, Mancos Shale, and Rim Rock Sandstone; all Cretaceous), possibly the Uinta Formation (Eocene), and the Duchesne River Formation (Eocene-Oligocene). The Uinta Formation may or may not be present as the contact between the Mesaverde Group and the Duchesne River Formation; it is gradational and difficult to recognize. The Duchesne River Formation unconformably overlies the Rim Rock Sandstone. Both the Duchesne River Formation and the Rim Rock Sandstone dip to the south-southwest at gradients ranging from 8° to 30°; the Rim Rock Sandstone generally has the steeper dips.

The White Rocks tar sands deposit is found in the Navajo sandstone, which dips from 70° to near vertical due to a major regional uplift and folding. Severe faulting has caused a large offset of the Navajo and other formations in the subsurface. However, within the limits of the deposit as seen at the surface, local faulting is small. The over- and underlying strata are impervious shales of the adjacent Chinle and Carmel Formations, which have sealed the bitumen in the Navajo.

Several faults are known to have cut across the trend of the ridge. One has 150 ft of vertical displacement. At least one fault acted as a barrier to hydrocarbon migration, as the Asphalt Ridge Sandstone is bitumen saturated to the northwest of the fault and unsaturated to the southeast.

The Rim Rock Sandstone, the Uinta Formation (where present), and the Duchesne River Formation all contain bitumen in the Asphalt Ridge area. The Rim Rock Sandstone is generally bitumen saturated for its entire outcrop length in the Asphalt Ridge area. The Uinta Formation generally contains bitumen only in sandy beds near the southern part of Asphalt Ridge. The bitumen saturation of the Duchesne River Formation varies both laterally and vertically. Rock composition of the Duchesne River Formation ranges from shale to conglomerate. The rocks with the greatest porosity, coarse sandstones, tend to have the highest bitumen saturations.

It has been suggested that the bitumen in the White Rocks deposit is Tertiary and has migrated across joints and unconformities to the Jurassic Navajo. However, original paths of migration are not clear and Paleozoic source rocks have been suggested as an alternate hypothesis for the source of hydrocarbons. In the subsurface, the bitumen extends down to the water/oil contact in the steeply dipping Navajo sandstone.

Recovery of the bitumen at this STSA would be amenable to surface mining along the outcrop on Asphalt Ridge. However, the surface minable portion of the deposit is primarily on state and private lands. In the remainder of the area, the deposits would have to be recovered by in situ methods (BLM 1984).

B.1.3 Circle Cliffs East and West Flanks STSA

The Circle Cliffs East and West Flanks STSA, hereafter referred to as the Circle Cliffs STSA, is located in south-central Utah, along the Circle Cliffs anticline. All information presented in this section is from BLM (1984) unless otherwise noted.

Rocks exposed at the surface in the vicinity of the Circle Cliffs anticline, in decreasing age order, are the Kaibab Limestone (Permian), Moenkopi Formation (Torrey Member and Moody Creek Member; Triassic), Chinle Formation (including the Shinarump Conglomerate; Triassic), Wingate Sandstone (Triassic/Jurassic), Kayenta Formation (Jurassic), Navajo Sandstone (Jurassic), Carmel Formation (Jurassic), Entrada Sandstone (Jurassic), and several younger units (Short 2006). The beds on the eastern side of the anticline dip from a few degrees to more than 25°. The beds on the western side of the anticline dip from 2° to 3° to the west.

The bitumen is contained in shoreface and fluvial-deltaic sandstones of the Torrey and Moody Creek Members of the Moenkopi Formation (Schamel and Baza 2003). Recovery of the bitumen would only be amenable to surface mining in very limited areas. In most of the area, the deposits would have to be recovered by in situ methods (BLM 1984; Kohler 2006).

B.1.4 Hill Creek STSA

The Hill Creek STSA is located along the Book Cliffs, on the south flank of the Uinta Basin. It lies to the west of the P.R. Spring STSA and east of the Sunnyside and Vicinity STSA. All information presented in this section is from Blackett (1996) unless otherwise noted.

The Hill Creek STSA tar sands deposits are contained entirely within the Eocene Green River Formation. The composition of the Green River Formation includes oil shale, marlstone, shale, siltstone, sandstone, limestone, and tuff. The three mappable units of the Green River Formation in the vicinity of the Hill Creek deposit, in order of decreasing age, are the Douglas Creek Member, the Parachute Creek Member, and the Evacuation Creek Member. The Mahogany Bed, an important oil shale resource, lies between the Douglas Creek and Parachute Creek Members.

There are five bitumen-impregnated zones in the Hill Creek STSA. Four of these zones are in the upper portions of the Douglas Creek Member, and one is in the lower part of the Parachute Creek Member. In ascending order, these zones have been designated A, B, C, D, and E. The zones can be correlated throughout the deposit.

The extent of bitumen saturation varies laterally and vertically throughout each of the zones. Overburden thicknesses are too great throughout most of the deposit for surface mining to be feasible, and it is likely that recovery of the bitumen would require in situ methods (BLM 1984).

B.1.5 Pariette STSA

The Pariette STSA is located on the southern flank of the Uinta Basin in an area of low relief near the topographic center of the basin. All information presented in this section is from Blackett (1996) unless otherwise noted.

Rocks of the Uinta Formation (Eocene) are present within the Pariette STSA. The Uinta Formation rocks in the STSA are overlain by Quaternary surficial deposits. The Uinta Formation is nearly flat in the STSA, dipping 1° to 4° to the north.

The bitumen-saturated zones are typically lenticular, fluvial sandstones. There is a large amount of horizontal and vertical variability in bitumen saturation levels within the Pariette STSA deposits. The small size and discontinuous nature of the individual areas of rock saturated with bitumen would tend to limit in situ production to a few of the larger bitumen-saturated areas. Development is limited by the small size, the lean quality (saturation is low), and the discontinuous lenticular occurring nature of the deposits (USGS 1980e).

B.1.6 P.R. Spring STSA

The P.R. Spring STSA is located along the Book Cliffs in the southeastern part of the Uinta Basin, to the east of the Hill Creek STSA. The topography in the area is relatively flat, with narrow plateaus and mesas incised by intermittent and perennial streams. All information presented in this section is from Blackett (1996) unless otherwise noted.

The geology of the Hill Creek STSA and the P.R. Spring STSA is essentially identical. The P.R. Spring STSA tar sands are contained entirely within the Eocene Green River Formation. The composition of the Green River Formation includes oil shale, marlstone, shale, siltstone, sandstone, limestone, and tuff. The three mappable units of the Green River Formation in the vicinity of the P.R. Spring deposit, in order of decreasing age, are the Douglas Creek Member, the Parachute Creek Member, and the Evacuation Creek Member. The Mahogany Bed, an important oil shale resource, lies between the Douglas Creek and the Parachute Creek Members.

There are five bitumen-impregnated zones in the P.R. Spring STSA. Four of these zones are in the upper portions of the Douglas Creek Member, and one is in the lower part of the Parachute Creek Member. In ascending order, these zones have been designated A, B, C, D, and E. The zones can be correlated throughout the deposit.

The extent of bitumen saturation varies laterally and vertically throughout each of the zones. Numerous tar seeps occur along the outcrop of the bitumen-impregnated areas within the STSA. They tend to be active during periods of wet weather and inactive during drier periods.

Overburden thicknesses are too great throughout most of the deposit for surface mining to be feasible, except in the southern part of the STSA. It is likely that recovery of the bitumen would require in situ methods, except in the southern part of the STSA where these deposits are considered among the most valuable for surface mining (USGS 1980f).

B.1.7 Raven Ridge–Rim Rock and Vicinity STSA

The Raven Ridge–Rim Rock and Vicinity STSA, hereafter referred to as the Raven Ridge STSA, is located on the north flank of the Uinta Basin and includes deposits in two areas. These deposits are sometimes referred to independently as the Raven Ridge deposits, which are located along a series of northwest-trending hogbacks known as Raven Ridge, and the Rim Rock deposits, which lie at the east end of a series of low, west-northwest-trending hogbacks called the Rim Rock. The Raven Ridge portion of the STSA is east of Asphalt Ridge. The Rim Rock portion lies between Raven Ridge and Asphalt Ridge. All information presented in this section is from Blackett (1996) unless otherwise noted.

Rocks present within the Raven Ridge deposit include, in order of decreasing age, the Paleocene/Eocene Green River Formation (Douglas Creek Member, Parachute Creek Member, and Evacuation Creek Member) and the Eocene Uinta Formation. The Mahogany oil shale zone occurs above the Raven Ridge tar sands deposit. Rocks in the Raven Ridge area dip from 10° to 85° southwest, with an average dip of 30°. They are composed of shoreline and deltaic facies sandstone, limestone, and shale in the Green River Formation, and fluvial-deltaic shale, sandstone, and pebble conglomerate in the Uinta Formation. All four of the rock units present in the Raven Ridge area contain some bitumen. Saturation levels vary greatly between units, as well as in lateral and vertical extent.

The Wasatch Formation (Paleocene) and the Douglas Creek and Parachute Creek Members of the Green River Formation are present in the Rim Rock part of the STSA. Rocks in the Rim Rock area dip as much as 76° to the southwest. Each successively younger unit overlaps and truncates the next older unit. Bitumen is located within the Wasatch Formation sandstones and in Green River sandstones that truncate older Wasatch Formation rocks.

Recovery of the bitumen by surface mining would be possible in the Raven Ridge STSA only along the outcrops on Raven Ridge. In situ methods would be needed elsewhere (BLM 1984).

B.1.8 San Rafael Swell STSA

The San Rafael Swell STSA is located in the southwester portion of Utah. The San Rafael Swell is a breached dome, with the core of older rocks exposed in the middle of the dome. The rocks dip away from the geographic center of the dome, in all directions. Schamel and Baza (2003) report that the White Rim Sandstone, within the San Rafael Swell deposit, contains bitumen. The White Rim Sandstone is present only on the eastern most edge of the San Rafael Swell. All information presented in this section is from BLM (1984) unless otherwise noted.

Rocks exposed at the surface in the vicinity of the San Rafael Swell, in order of decreasing age, are the Cutler Group (White Rim Sandstone; Permian), Kaibab Limestone (Permian), Moenkopi Formation (Sinbad Limestone Member and Black Dragon Member; Triassic), Chinle Formation (Triassic), Wingate Sandstone (Triassic/Jurassic), Kayenta

Formation (Jurassic), Navajo Sandstone (Jurassic), and San Rafael Group (Carmel Formation, Entrada Sandstone, Curtis Formation, and Summerville Formation; Jurassic) (USGS 2006).

All of the rock units in the San Rafael Swell area contain bitumen in some areas. (Schamel and Baza 2003). Within the deposit, most of the bitumen occurs within the lower and middle portions of the Black Dragon Member of the Moenkopi Formation. The other units contain lesser amounts of bitumen, with some such as the Sinbad Limestone containing only isolated spots of bitumen.

In situ methods would be the preferred methods of production for the San Rafael Swell STSA. The overburden is too great for recovery of the bitumen by surface mining (BLM 1984).

B.1.9 Sunnyside and Vicinity STSA

The Sunnyside and Vicinity STSA, hereafter referred to as the Sunnyside STSA, is located along the Roan Cliffs on the southwestern flank of the Uinta Basin. The topography of this area is characterized by high relief and rugged terrain. All information presented in this section is from Blackett (1996) unless otherwise noted.

The rock units present at Sunnyside, in order of decreasing age, are Colton Formation (Paleocene/Eocene) and the Lower Green River Formation (Eocene). Colton Formation rocks are shale, siltstone, and sandstone, which were deposited in a fluvial-deltaic environment. The Green River rocks were deposited in a lacustrine environment and are composed of shale, marlstone, siltstone, sandstone, limestone, and tuff. Bitumen in the deposit is typically contained in sandstone. The bitumen content is typically inversely proportional to the distance from the deltaic complex.

The rocks in the Sunnyside area dip to the northeast at 3° to 12°. Small-scale faulting and fracturing occur in the area but do not appear to have affected bitumen emplacement.

The depositional environments in this area have resulted in a complex stratigraphy. Bitumen saturation may vary greatly within just a few feet, with bitumen-saturated rock and barren rock occurring within a few feet of each other. Surface mapping has identified as many as 32 bitumen saturated beds.

Recovery of the bitumen by both surface mining and in situ methods would be needed to fully develop the Sunnyside deposit (BLM 1984).

B.1.10 Tar Sand Triangle STSA

The Tar Sand Triangle STSA is located in southeastern Utah along the western edge of the Monument Upwarp. The topography of the area is a dissected plateau. The margins of the plateau have stair-step topography, and mesas and buttes occur as outliers from the plateau

(BLM 1984). All information presented in this section is from Glassett and Glassett (1976) unless otherwise noted.

The rocks present in the Tar Sand Triangle STSA, in order of decreasing age, include the Cutler Group (Cedar Mesa Sandstone and White Rim Sandstone; Permian), Moenkopi Formation (Triassic), and Chinle Formation (Shinarump Conglomerate; Triassic). The Monument Upwarp is a westward-dipping monocline, and the Permian and Triassic rocks of central Utah pinch out against the upwarp. The bitumen in the Tar Sand Triangle STSA appears to be the residue of a gigantic oil field located in the stratigraphic trap formed by this pinch out. The oil field was breached by erosion allowing the more volatile components to escape, leaving the less volatile components behind.

Although bitumen is found in the Cedar Mesa Sandstone, White Rim Sandstone, Moenkopi Formation, and Shinarump Conglomerate, most of the bitumen is located in shoreface and eolian deposits of the Permian White Rim Sandstone near its southeastern extent, as it pinches out against the Monument Upwarp (Schamel and Baza 2003).

The Tar Sand Triangle deposit may be technically suitable for surface mining; however, the remoteness of the area and other considerations could limit this potential (BLM 1984).

B.1.11 White Canyon STSA

The White Canyon STSA is located south of the Tar Sand Triangle STSA, in the White Canyon area of southeastern Utah. The topography in the area is that of one large mesa with bench and slope topography along its margins. The ground below the mesa is incised by White Canyon. All information presented in this section is from BLM (1984) unless otherwise noted.

Rocks present in the White Canyon area, in order of decreasing age, include DeChelly and/or White Rim Sandstones (these two sandstones are coeval; Permian), Moenkopi Formation (Hoskinnini Member; Triassic), and Chinle Formation (Shinarup Member; Triassic) (Beer 2005). Other rock units may be present but are not relevant to the tar sands. The Hoskinnini Member, which hosts all of the bitumen in the White Canyon STSA, pinches out toward the northwestern part of the STSA.

The lack of site-specific data precludes any consideration of mining methods for the White Canyon deposit. The data available on the quality of the deposit suggest that it is not of commercial grade. It may be too heavily jointed for in situ methods, and heavy overburden appears to be unfavorable for surface mining (USGS 1980k).

B.2 PAST EXPLORATION AND DEVELOPMENT ACTIVITY

The mining of petroleum-bearing materials from tar sands has been practiced for thousands of years. Petroleum and bitumen were mined in the Sinai Peninsula before 5,000 B.C.

The bitumen was used as an adhesive, brick binder, and waterproofing agent and, somewhat later, it was used to produce petroleum as a fuel. However, the distillation process was lost and not used again until the middle of the nineteenth century with the advent of drilling for oil. Underground oil mining was practiced in the Alsace region of France from about 1735 to 1866. The mined sand was treated on the surface with boiling water to release the oil. After 1866, oil was obtained by letting it drain into mine shafts where it was recovered as a liquid (National Academy of Sciences 1980; Meyer 1995; Speight 1995).

Natural bitumen (or natural asphalt) has been used throughout the world, primarily in the last 200 years, during which time it was widely used as a paving material. This use has largely been replaced by the use of manufactured asphalt. In the 1890s, the Canadian government became interested in tar sands deposits. Research on recovery mining from the Athabasca tar sands began in the 1920s. Three extensive pilot-scale operations were conducted between 1957 and 1967, and commercial operations began in 1967 when the Great Canadian Oil Sands Company (now Suncor) started open-pit mining using bucket-wheel excavators, conveyor belts, and hot water extraction (Oblad et al. 1987; Meyers 1995; Speight 1995, 1997; Woynillowicz et al. 2005). By 1976, cyclic steam recovery had been piloted by Imperial Oil Limited at Cold Lake. Syncrude Canada Ltd. opened the Athabasca deposits in 1978 using draglines, bucket-wheel reclaimers, and conveyor belts. By 1986, steam-assisted gravity drainage (SAGD) had been piloted, and in situ combustion was being researched in Canada. Suncor and Syncrude were in commercial operation as was Imperial Oil’s cyclic steam facility. By 1996, both Suncor and Syncrude had converted their extractions to truck and shovel operations. For surface mining, hydrotransport (the transport of mined sand as a slurry of warm water and sand in pipes) rather than conveyor belts was used to transport mined sand to the extraction plant for cold-water extraction, mechanical separation, and by-product recovery. Several new in situ projects were also in commercial operation (Oil Sands Discovery Center 2006). By 2004, about two-thirds of the recovered tar sands in Alberta were mined; about one-third was recovered by in situ operations (Alberta Economic Development 2006).

In Utah, the amount of exploration and development for tar sands resources has varied from location to location. No known exploration or development activities have occurred at the Argyle Canyon, Circle Cliffs, Hill Creek, Pariette, San Rafael Swell, Tar Sand Triangle, or White Canyon STSAs. A brief description of previous activities at the other STSAs is provided below (from Blackett 1996).

- *Asphalt Ridge STSA.* The Asphalt Ridge deposit has been the target of many exploration and development efforts. It was mined at least as early as the 1920s when the town of Vernal, Utah, paved its streets with material from the deposit. Between 1910 and 1950, a number of shallow wells were drilled in the area in an attempt to locate liquid hydrocarbons below the bitumen cap. During the 1930s, a hot-water extraction plant was built to extract tar from the deposit. Knickerbocker Investment Company and W.M. Barnes Engineering Company conducted a comprehensive evaluation program on Asphalt Ridge in the early 1950s. Sohio Petroleum Company then leased Asphalt Ridge and conducted its own evaluation program. In 1970 or 1971, Major Oil Company obtained a working agreement with Sohio to strip-mine the tar sands and build and operate an extraction plant. Hot water was used to strip the bitumen from the crushed run-of-mine material, and the bitumen was shipped to a refinery in Roosevelt, Utah. Arizona Fuels Corporation and Fairbrim Company acquired the operation in 1972. In the 1970s, Sun Oil Company, Texaco, Phillips Petroleum Company, and Shell Oil Company conducted exploratory drilling at Asphalt Ridge. The U.S. Department of Energy (DOE) conducted extensive field experiments on the deposit between 1971 and 1982.

- *P.R. Spring STSA.* In 1900, John Pope drilled an oil test well in the P.R. Spring deposit. During the early twentieth century (the exact date is unknown), a 50-ft-long adit was driven into a tar sands outcrop in the P.R. Spring area. A steel pipe was run from the adit to a metal trough to collect the gravity-drained oil. In the 1970s and 1980s, the P.R. Spring deposit was the target of intense exploration and research activity by several companies and government agencies. The U-tar Division, Bighorn Oil Company, operated a 100-bbl/day pilot plant in the area. Although several other companies proposed development operations for the P.R. Spring deposit, no viable commercial production has occurred.

- *Raven Ridge STSA.* Sporadic attempts to develop the Raven Ridge deposit were made before 1964. Western Tar Sands, Inc., conducted test mining activities on the deposit during the summer of 1980 and planned to build a 100-bbl/day production facility. This plant was not built, and there have been no other exploration or development activities at the STSA since.

- *Sunnyside STSA.* The Sunnyside deposit was mined, primarily for road construction, from 1892 to the late 1940s. The mined material was transported over a 3-mi-long aerial tram and then trucked to the railhead at Sunnyside, where it was shipped to five other western states. A large number of companies, including Shell Oil Company, Signal Oil and Gas Company, Texaco, Gulf Oil Corporation, Pan-American Petroleum Corporation, Phillips Petroleum, Sabine Resources, Cities Service, Amoco, Chevron Resource Company, Great National Corporation, and Mono Power Company, conducted activities in the Sunnyside deposit from 1963 through 1985. Shell Oil Company, Signal Oil and Gas Company, Pan-American Petroleum Corporation, Mono Power Company, and Great National Corporation all conducted pilot operations on the deposit. Sunnyside sandstone was mined as a road-paving material as early as 1892 through 1948. These deposits were also the site of Shell Oil’s steam flood pilot plant from 1964 to 1967 and a mining and bitumen extraction operation from 1982 to 1985.

B.3 PRESENT EXPLORATION AND DEVELOPMENT ACTIVITY

Currently, no tar sands development activities are underway on public lands in Utah. According to the Utah Office of Energy Policy (Wright 2006), the only ongoing tar sands operations in Utah are small pilot-scale and exploration operations and a few small mining operations by counties to recover road materials (including operations by Uintah County to excavate materials at Asphalt Ridge for road surfacing). The Utah Division of Oil, Gas and Mining expects to see several of the pilot operations expand to large mines ranging from 5 to possibly 80 acres in size. Specifically, the Division projects three large mines (two on private and one on state lands) and eight small mines (one on private and seven on state lands) in the future.

For several years, Nevtah Capital Management Corp. and its joint venture partner, Black Sands Energy (formerly known as Cassandra Energy, Inc.), have been working to develop an oil extraction technology for commercial tar sands development. Initial tests were conducted at the Asphalt Ridge STSA. On August 1, 2006, the companies announced the completion of construction of their first commercial production unit, which was built off-site and has a production capacity of 400 to 500 bbl/day of syncrude. The companies hold a total of 13 leases covering 11,000 acres within the Asphalt Ridge, Sunnyside, and P.R. Spring STSAs (Nevtah Capital Management Corp. 2006).

B.4 RECOVERY OF TAR SANDS

Recovery methods can be categorized as either mining activities or in situ processes. Mining consists of using surface or subsurface mining techniques to excavate the tar sands with subsequent recovery of the bitumen by washing, flotation, or retorting. In situ techniques recover the bitumen without physically excavating the tar sands. Some techniques combine mining techniques and in situ techniques. In situ recovery is sometimes further categorized as true in situ or modified in situ. True in situ methods generally involve either heating the tar sands or injecting fluids into them to mobilize the bitumen for recovery (Speight 1990, 1995, 1997). There are at least two types of modified in situ methods. The first involves fracturing the tar sands with explosives to increase the permeability of the deposit (National Academy of Sciences 1980); the second process combines true in situ processes with mining techniques (Speight 1990).

Potential Tar Sands Recovery Processes

Mining
- Surface
- Subsurface

In Situ
- Thermal
  - Steam and hot water
    - Stimulation
    - Flood
  - Combustion
    - Forward
    - Reverse: wet, dry
  - Electrical
  - Nuclear
- Nonthermal
  - Diluents
    - Miscible displacement: hydrocarbons, inert gases, carbon dioxide
    - Solvent
    - Chemical: polymer, caustic, surfactant polymer
  - Emulsification
  - Bacterial

Source: Based on Speight (1997).

Depending on production costs and the price of the synthetic crude produced, surface mining operations are generally cost-effective only where the overburden is no more than about

45 m (150 ft) (Meyer 1995). In situ processes requiring high pressures are generally considered to require a thick overburden of about 150 m (500 ft) to contain the pressure. Between these depths, bitumen must be extracted by other means.

B.4.1 Direct Recovery Mining Technologies

Surface mining methods can be used to mine the tar sands for subsequent recovery of bitumen. Subsurface mining has been proposed but has not been applied because of the fear of collapse of the sand deposits (Speight 1990). For this reason, only surface mining is discussed below. However, subsurface mining techniques are employed in some modified in situ recovery methods.

Surface mining requires conventional earthmoving and mining equipment (BLM 1984). Development begins with the construction of access roads and support facilities. Major mining activities during extraction include the following:

- Removing vegetation;
- Stripping, stockpiling, and disposal of topsoil;
- Removing and disposing of overburden;
- Excavating of tar sands; and
- Reclamation of the mined area.

Operations begin with the removal of topsoil and overburden. Topsoil is stockpiled, protected from erosion, and used for reclamation. Erosion and runoff can be reduced by depositing overburden in layers beginning in the bottoms of valleys and building upwards. Later, the deposited overburden can be used for backfilling the pit. It is likely that ultimately the entire area would be disturbed because of actual mining and ancillary activities. Reclamation can proceed as mining progresses and initially mined areas are retired (BLM 1984).

Disposing of waste sand after extraction of the bitumen is a major concern in any surface mining operation (BLM 1984). Although variable, the bitumen content of waste sand can be a high as 5%. Waste sand can be disposed of by (1) backfilling the mined area, (2) filling valleys, or (3) using tailings ponds. Tailings ponds need to be constructed to keep tailings from sliding, to preclude outside runoff from entering the ponds, and to control seepage from the ponds.

In Utah, less than 15% of the tar sands may be shallow enough for strip mining; the deposits at the Asphalt Ridge, P.R. Spring, and Sunnyside STSAs appearing to be most suitable (BLM 1984; National Academy of Sciences 1980). The Athabasca deposits are currently being recovered by surface mining.

The equipment used for surface recovery includes a combination of excavation equipment, to remove the sands from their original location, and conveying equipment, to move the excavated sand to another location. Depending upon the approach chosen, tar sands removal equipment can include draglines, bucketwheel excavators, power shovels, scrappers, bulldozers and front-end loaders. Conveying equipment can include belt conveyors, large trucks, (typically 150–400 tons), trains, scrapers, and hydraulic systems (Speight 1995).

Surface excavation is conducted by using two basic approaches. The first uses a small number of large, custom-made, expensive bucketwheel excavators and drag lines along with belt conveyors. The second uses a large number of smaller, conventional, less expensive equipment. Initially, the major developers of the Athabasca tar sands in Canada used bucketwheels or draglines, they now use a truck and shovel approach. Truck and shovel mining is more mobile, can be moved more easily to the richest deposits, and requires less maintenance than the custom bucketwheels and draglines. The larger number of units in operation also means that equipment breakdown has much less impact on overall production.

Today, hydrotransport provides an alternative to the use of belt conveyors between the mining pit and the extraction plant (Oil Sands Discovery Center 2006b). The tar sands are crushed at the mine site, mixed with warm water, and moved by pipeline to the extraction plant. Hydrotransport improves efficiency by initiating the extraction of bitumen while the tar sands are being transported to the extraction plant. However, its application in arid areas such as Utah may be problematic.

Speight 1995 identifies the following possible problems that may be encountered when mining tar sands deposits:

- The clay shale overburden and sand may swell when exposed to fresh water,
- Pit wall slopes may slough off and may need to be controlled by preblasting or excluding heavy equipment form slope crests,
- The abrasive sands cause a high rate of equipment wear, and
- The large quantity of tailings from the extraction process require disposal.

Table B-2 provides available data describing potential impact producing factors that could be associated with a tar sands surface mine. These data were derived from information published by Daniels et al. (1981) on the basis of a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah. The table presents the original numbers estimated for the McKittrick project and extrapolated numbers for larger operations. It should be noted that the numbers were

TABLE B-2 Potential Impact Producing Factors Associated with a Tar Sands Surface Mine Operating at a Diatomaceous Earth Tar Sands Deposit

	Production Capacity (bbl/day syncrude)[b,c]			
Impact Producing Factor[a]	20,000	25,000	50,000	100,000
Total land disturbance (acres)	1,000	1,250	2,500	5,000
Water use (bbl/day)[d]	25,160	31,450	62,900	125,800
Noise (dBA at 500 ft)	61	–[e]	–	–
Processed sand (tons/day)	52,000	65,000	130,000	260,000
Air emissions (tons/yr)[f]				
Mining equipment				
TSP	70	87	174	348
SO_x	70	87	174	348
NO_x	905	1,131	2,262	4,524
CO	383	479	957	1,914
THC	104	131	261	522
Crushing apparatus[g]				
TSP	7	9	17	35
Mine pit and storage[h]				
TSP	1,009	1,262	2,523	5,046
THC	35	44	87	174

a CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; THC = total hydrocarbons (includes methane and photochemically nonreactive compounds); TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter).

b bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

c Data taken from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

d Approximately 3.5% of the process water would need to be fresh water (Daniels et al. 1981).

e A dash indicates noise level determined by modeling, not by extrapolation.

f The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

g Assumes 99.5% emissions control via the baghouse.

h Assumes 80% dust suppression by virtue of the natural oil in the tar sands combined with water application.

extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

Table B-3 provides available data describing potential air emissions from a tar sands surface mine on the basis of data published by Aerocomp, Inc. (1984), for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA. These data may more accurately reflect emissions from a surface mine excavating sandstone-based tar sands deposits as opposed to the emissions presented in Table B-2 for the diatomaceous earth tar sands deposit.

B.4.2 In Situ Methods

Given the environmental problems associated with mining and the fact that the majority of tar sands lie under an overburden too thick to permit their economic removal, nonmining recovery of bitumen may be a practical alternative. This is especially true in U.S. deposits where the terrain and the character of the tar sands may not be favorable for mining. However, the

TABLE B-3 Potential Air Emissions from a Surface Mine Operating at a Sandstone-Based Tar Sands Deposit[a]

Impact Producing Factor[b]	Production Capacity (bbl/day syncrude)[c,d]			
	20,000	32,500	50,000	100,000
TSP	2,814	4,573	7,035	14,071
SO_x	335	544	837	1,674
NO_x	5,276	8,573	13,189	26,378
CO	1,047	1,701	2,617	5,234
VOC	338	549	322	1,689

[a] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

[b] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter); VOC = volatile organic compound.

[c] bbl = barrel; 1 bbl syncrude = 42 gal.

[d] The air emissions data were derived from information published by Aerocomp, Inc. (1984) for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

physical properties of Utah tar sands and the bitumen may constrain application of nonmining methods; Utah sands tend to be low-porosity, low-permeability, consolidated to unconsolidated sands, and the bitumen does not flow under reservoir conditions. Low permeability and porosity require fluids to be injected at pressures sufficient to cause fracturing, which can result in undesirable flow pathways (e.g., direct communication between the injection well and the production well) (Speight 1990).

In situ or nonmining methods are basically enhanced or tertiary oil recovery techniques that require injecting a “heating” and “driver” substance into the tar sands formation through injection wells to reduce the viscosity of and displace the bitumen so that it can be recovered through conventional liquid production wells (Speight 1997). For a given technique, there could be considerable variation in the efficiency of extracting bitumen between different sites, for example, between water-wet Athabasca sands and oil-wet Utah sands (BLM 1984).

All in situ recovery processes must perform the following:

- Establish fluid flow between injection and production wells;
- Reduce the viscosity of the bitumen by heating it or dissolving it in a solvent so that it will flow to the production well; and
- Maintain the flow of bitumen after it has started.

Heat could be supplied either from steam from surface boilers or by combustion of part of the bitumen in situ. In addition, the deposit should be permeable or susceptible to fracturing to make it permeable and reasonably stable so that it does not compact structurally (i.e., collapse) and lose permeability as bitumen is removed (BLM 1984).

Briefly, development of an in situ facility would include the following processes:

- Exploration to characterize the formation hydrogeologically;
- Drilling of injection and production wells;
- Installation of production equipment;
- Recovery, processing, and upgrading of bitumen to produce synthetic crude oil;
- Removal of equipment at the close of operations; and
- Reclamation.

Numerous, closely spaced holes would be required for injection and production wells, with production wells probably spaced within 150 m (500 ft) of each other. The exact number and the spacing of the wells would be governed by the characteristics of the formation. Surface equipment would vary by the method used but would include drilling rigs, compressors, pumps, piping, storage tanks, waste pits, and pits or tanks for drilling fluids and process water storage and recycling. For most processes, especially those involving steam injection, boilers and steam pipes would also be required. Facilities for treating condensate and water for recycling would also be needed. Ancillary facilities could include shops, warehouses, offices, outside storage areas, fuel storage, housing, and roads (BLM 1984).

Over time, different parts of the site would be developed, and production equipment would be moved from one area to another as the recoverable bitumen was exhausted. Upgrading equipment would be centrally located and would probably not be moved over the life of the site. After the production equipment had been moved, the depleted site could be reclaimed. The amount of surface disturbance from development of in situ recovery facilities would depend on topography and the characteristics of the bitumen and the surrounding rock. Estimates of surface disturbance range from 10 to 60% of the site and are expected to be similar for most in situ methods. The use of directional drilling techniques tends to reduce the amount of surface disturbance (BLM 1984). In addition to the disturbances resulting directly from surface activities, subsidence may also occur and require remediation.

B.4.2.1 Combustion Processes and Modifications

In combustion processes, the bitumen itself is ignited. Once ignition has been achieved, partial or complete combustion must be maintained for a period of about 30 to 90 days. Temperatures can range from about 600 to 1,200°F. Control of the amount of air injected regulates the rate at which bitumen is burned and hence the temperature. Several regions exist within the reservoir. Just ahead of the fire front, heat breaks the oil down (by cracking and distillation). The cracking provides a partial upgrading of the bitumen recovered from the production wells. Lighter fractions of the bitumen vaporize and move toward cooler portions of the formation and exchange their heat with it, displacing some of the bitumen and increasing recovery efficiency. As the vapors move into cooler parts of the deposit, they condense and can be pumped out of production wells. Condensation could cause a problem by plugging the deposit. Heavier fractions remain behind as coke that includes heavy hydrocarbons containing oxygen, sulfur, nitrogen, and trace metals. Coke may account for up to 20% of the oil and provides most of the combustion fuel. The burned region consists mostly of sand (Schumacher 1978; Speight 1990, 1997).

The use of combustion or fire flooding to stimulate bitumen production may be attractive for deep reservoirs because little heat is lost. Conversely, heat loss limits the use of steam injection in deep reservoirs. The high pressures involved in injecting combustion air preclude the use of combustion in shallow deposits. Another advantage of combustion over steam-based processes is the reduction of carbon dioxide (CO_2) emissions from aboveground steam generators. However, CO_2 from in situ combustion will be present in the produced gases recovered from production wells. Combustion has been effective in the recovery of heavy oils from thick reservoirs where the dip and continuity of the formation may assist gravity flow of bitumen or where wells can be closely spaced (Schumacher 1978; Speight 1990, 1997; Isaacs 1998)

With the exception of the fuel needed to initiate combustion, there is no need to buy fuel to produce heat in the well (Schumacher 1978). However, any bitumen in the combusted coke cannot be recovered as product. Some of the advantage also is lost by the need to compress the injection air and the increased loss of heat to the formation at the elevated temperatures associated with burning. This loss can be reduced by injecting water at the same time or alternatively with the combustion air.

Far less experience and information are available for in situ combustion than for steam processes, and process control is more difficult. Some considerations include:

- Sufficient bitumen must be consumed to raise the temperature enough to mobilize the remaining bitumen,

- Sufficient oxygen must be supplied to support and control combustion,

- Overburden and underburden must provide effective seals for injected air and mobilized bitumen and serve as effective barriers to heat loss (Speight 1990).

The combustion in in situ processes can be categorized as either forward, reverse, or a combination of forward and reverse. In forward combustion (Figure B-3), the fire front is ignited at the injection well and moves toward the production well. As the bitumen moves toward the production well, it moves from the zone of combustion into a colder, unheated portion of the formation. Because the bitumen is generally less mobile when it is colder, the forward combustion process has an upper limit on the viscosity of liquids that can be recovered. Up to 80% of the combustion heat remains behind the advancing fire front and is lost. However, because the air passes through the hot formation behind the flame front prior to reaching the combustion zone, combustion efficiencies are enhanced and more unburned hydrocarbons are recovered. Heavier components are left on the sand grains and consumed as fuel. Deposits with relatively high permeability and relatively low bitumen saturation (45–65 vol%) are most amenable to this process. Forward combustion has been used with some success in the Orinoco deposits in Venezuela and in Kentucky sands (Schumacher 1978; Speight 1990, 1997; Meyer 1995).

In reverse combustion (Figure B-3), the fire front is ignited at the production well and moves toward the injection well. Combustion air introduced at the injection well helps drive the volatile organics toward the production well. Because combustion products and product move into the hot zone behind the fire front, there should be less of a viscosity limitation. Residual coke would remain on the sand grains. This process is most applicable to deposits with lower permeability because movement of mobilized fluids would be into a hot zone with a consequent reduction in plugging (Speight 1990, 1997; Meyer 1995).

In a combination of reverse and forward combustion, the initial phase uses a low-temperature reverse combustion to increase the permeability of the formation and increase the mobility of the bitumen. The subsequent forward combustion phase supplies the heat and energy to distill and mobilize the bitumen and move it to the production wells (Marchant and Westhoff 1985).

Modifications of the in situ combustion process include fracturing by either pneumatic or hydraulic means to increase permeability of reservoirs so that combustion air can flow more freely. In another modification, oxygen or oxygen-enriched air rather than atmospheric air is injected under certain conditions. Cost savings accrue because of the reduced compression costs and the reduction in the gas-to-oil ratio in the recovered product.

In the wet combustion modification, water and air are injected alternatively into the formation. The water flows through the fire, vaporizes, and then condenses, thereby heating the unburned deposit and reducing the viscosity of the bitumen. Wet combustion can move heavier oils and operate at lower pressures than dry combustion and may burn less bitumen, resulting in a reduced need for injected air (Schumacher 1978; Speight 1990, 1997).

A combination of forward combustion and waterflooding has also been tried at Athabasca. It involved a heating phase followed by a production or blowdown phase followed by a displacement phase using a fire-water flood, over a period of 18 months (8 months heating, 4 months blowdown, and 6 months displacement) (Speight 1990).

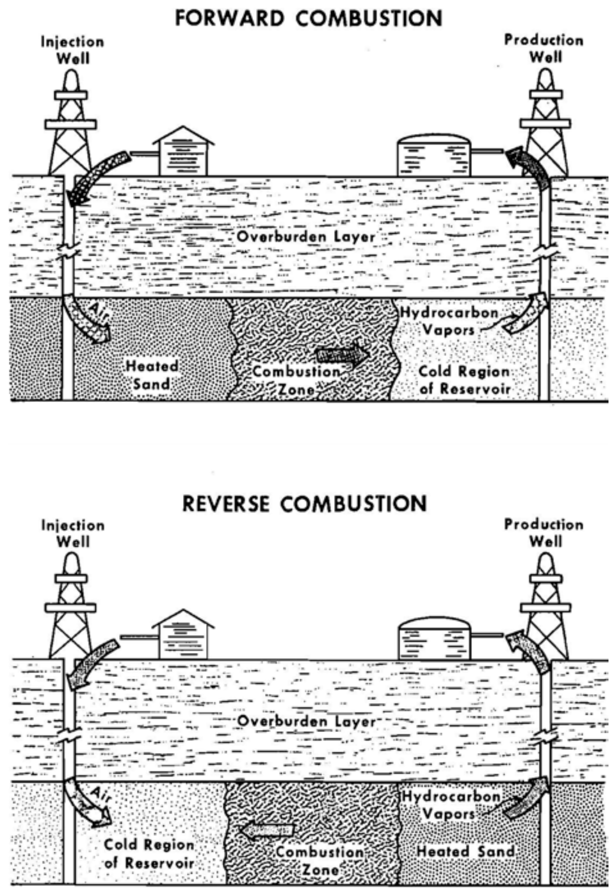

FIGURE B-3 Simplified Diagrams of Forward and Reverse Combustion Processes (Speight 1990) (Copyright 1990 from Fuel Science and Technology Handbook edited by James G. Speight. Reproduced by the permission of Routledge/Taylor & Francis Group, LLC.)

Table B-4 provides available data describing potential impact producing factors that could be associated with in situ combustion processes. The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 20,000-bbl/day-capacity project in the Circle Cliffs STSA (based upon parameters for an oil shale processing facility) and include emissions from upgrading processes. The nonair emissions data were derived from information published by Daniels et al. (1981) on the basis of the proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The table presents the original numbers estimated for each project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

TABLE B-4 Potential Impact Producing Factors Associated with In Situ Combustion Processes

	Production Capacity (bbl/day syncrude)[b,c]			
Impact Producing Factor[a]	20,000	25,000	50,000	100,000
Total land disturbance (acres)	4,000	5,000	10,000	20,000
Produced wastewater (bbl/day)[d]	40,000	50,000	100,000	200,000
Air emissions (tons/yr)				
Stack emissions[e]				
TSP	438	548	1,095	2,190
SO_x	4,960	6,200	12,400	24,800
NO_x	2,052	2,565	5,130	10,260
CO	60	75	150	300
VOC	110	138	275	550
Fugitive emissions[f]				
TSP	409	511	1,022	2,045
SO_x	4	5	10	20
NO_x	7	9	18	35
CO	48	60	120	240
VOC	2	3	5	10

a CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 µm in diameter); VOC = volatile organic compound.

b The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 20,000-bbl/day-capacity project in the Circle Cliffs STSA (based upon parameters for an oil shale processing facility). Nonair emissions data were derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

c bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

d Based upon an estimated generation rate of 1 to 2 bbl of wastewater per bbl of syncrude produced.

e Modeled on the basis of the following: stack height = 76 m (249.3 ft), stack diameter = 3 m (9.8 ft), velocity = 10 m/s (32.8 ft/s), and temperature = 311K (100.1°F).

f Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

B.4.2.2 Noncombustion Processes

The noncombustion processes discussed in this subsection involve the injection of liquid or gas into the reservoir to effect the mobilization and recovery of the bitumen. For steam injection processes, the cost of generating steam is the most significant expense. Also, the feedwater must be of relatively high quality (Speight 1990), which could prove to be an obstacle to using steam injection processes in the arid and semiarid regions of Utah.

Steam drive (steam flood) processes (Figure B-4) involve the injection of steam from surface boilers into at least one injection well with the recovery of the mobilized bitumen and condensed steam from at least one production well. The wells could be placed either in parallel rows or in a ring around a central well. Heat released by condensing steam reduces the viscosity of the bitumen, which is forced to the production well by the flow of steam and hot water. In situ distillation (upgrading) and improved gas drive are side benefits of this steam drive. This process may be used following cyclic steam injection. The permeability of the reservoir must be sufficient to permit the injection of steam at rates high enough to raise the temperature to the point at which the bitumen will flow. Permeability will decrease as the process proceeds and water and steam saturate the reservoir; as permeability decreases, the amount of injected steam required to produce a unit of oil increases sharply. Establishing communication between the injection and production wells presents a problem for this technique, but it has been successfully utilized by Shell Canada in the Peace River deposit in Alberta. Bitumen-to-water ratios could be as high as 1 to 10 but are generally around 1 to 5. The use of steam has been demonstrated with some success in Utah sands. The large amount of energy required to generate, compress, and

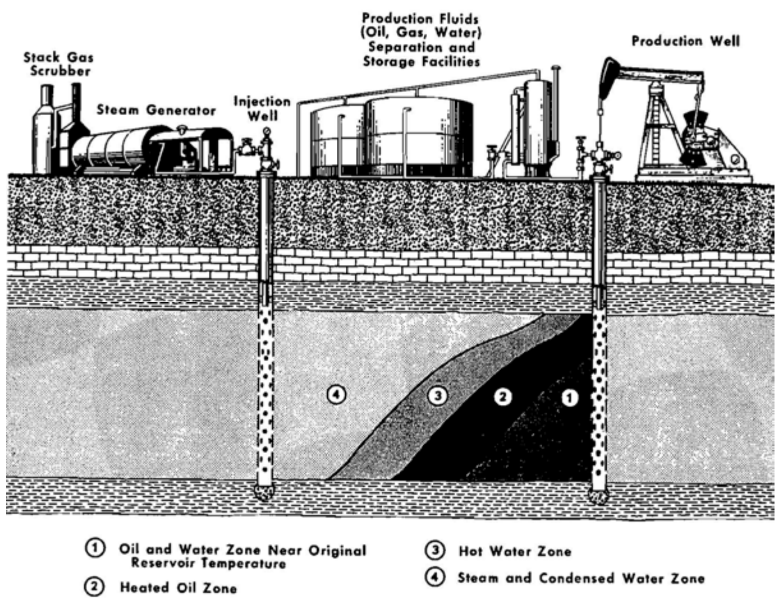

FIGURE B-4 Simplified Steam Drive Process (Speight 1990) (Copyright 1990 from *Fuel Science and Technology Handbook* edited by James G. Speight. Reproduced by the permission of Routledge/Taylor & Francis Group, LLC.)

pump steam presents an important technical requirement for steam drive (Spencer et al. 1969; Schumacher 1978; National Academy of Sciences 1980; BLM 1984; Speight 1995; Isaacs 1998).

The alternative cyclical steam stimulation, also known as “huff and puff,” involves injecting high-temperature (about 350ºC [660ºF]) steam from surface boilers at higher than fracturing pressure into the deposit over a period ranging from days to months, followed by a “soak” period of variable length, followed by production for up to a year. Initial production relies on the pressure created by injection followed by pumping (Speight 1990, 1997; Oils Sands Discovery Center 2006b). Cyclic steam has more effect on increasing the rate of production than on increasing the ultimate recovery (Schumacher 1978).

Another steam injection approach, SAGD, is most suitable for reservoirs with immobile bitumen. It involves drilling two horizontal wells at the bottom of a thick unconsolidated sandstone reservoir. Steam is injected continuously through the upper well at pressures much lower than the fracture pressure. Heat and steam rise and condensed water and mobilized oil flow down by gravity into the lower or production well. As the process proceeds, a “steam chamber” develops laterally and upwards. SAGD seems to be insensitive to horizontal barriers to flow such as shale intrusions that fracture from thermal shock. Recovery ratios of 50 to 75% may be achievable; however, the initial oil recovery rate is low.

The uses of hot fluids, steam, water, and gas, for injection are similar. Hot water is more efficient than hot gas but less efficient than steam mainly because of the relative heat-carrying capacities of the fluids. Nonsteam techniques have been applied to bitumen recovery in conjunction with other techniques (Spencer et al. 1969; BLM 1984).

Solvent extraction involves the injection of solvent into the formation to dissolve the bitumen and carry it to a production well for pumping to the surface. At the surface, the bitumen is separated from the solvent and the solvent is recovered. When applied in situ, large losses of solvent and bitumen have always presented major problems that must be controlled. In addition, the only useful solvents, at least for Athabasca bitumen, are relatively expensive naphthenic and aromatic substances. Solvent extraction has not generally been economical compared with steam injection.

Two aqueous emulsifying systems have been developed for use in the Athabasca sands (Spencer et al. 1969). One employs an alkaline surfactant solution, the other a dilute sodium hydroxide solution. Field tests showed that bitumen was completely removed from the contacted portion of the reservoir but that the contacted portion was very limited because of the low permeability of the reservoir.

Several variations of steam heating and emulsification have been tried (Speight 1990). These include the use of steam with various solvents to reduce the viscosity of the oil through a combination of heating and dissolution. A technique involving fracturing by using dilute aqueous alkaline solutions followed by emulsification with hot caustic and production of an emulsion by using steam injection at the production wellhead was used in the Athabasca sands. It was estimated that more oil had leaked away from the recovery zone than had been recovered.

Many additional processes are in the concept or early development phase or for which patents have been sought or issued. Some of those that potentially could be applied within the 20-year planning horizon of this PEIS include the following:

- *Top-Down Combustion*, in which combustion would be initiated and maintained by the injection of air at the top of the reservoir with the heated, mobilized oil draining into horizontal wells by gravity (Isaacs 1998).
- *Cyclic Steam Combined with Steam-Assisted Gravity Drainage Gravity* (Isaacs 1998).
- *Warm Vapor Extraction*, which involves the injection of vaporized solvents to create a vapor chamber through which mobilized hydrocarbons flow because of gravity drainage.
- *Toe-to-Heel Air Injection*, which combines a vertical air injection well with a horizontal production well. A combustion front is created and combusts part of the hydrocarbon in the reservoir. The heat generated reduces the viscosity of the hydrocarbon that is pulled to the horizontal production well by gravity. The combustion front moves from the “toe,” the underground end of the horizontal production well to the “heel,” where the production well transitions from horizontal to vertical.
- *Pressure Pulse Flow Enhancement Technology*, which is based on the recent discovery that large-amplitude, low-frequency energy waves can enhance flow rates in porous media (Dusseault 2001).
- *Nuclear Energy*, which has been proposed as an energy source for producing a combination of steam and electricity for tar sands recovery while reducing CO_2 emissions (Donnelly and Pendergast 1999; Dunbar and Sloan 2003).

Table B-5 provides available data describing potential impact producing factors that could be associated with in situ steam injection processes. The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 50,000-bbl/day-capacity project in the P.R. Spring STSA and a proposed 20,000-bbl/day-capacity project in the San Rafael Swell STSA and include emissions from upgrading processes. The nonair emissions data were derived from information published by Daniels et al. (1981) on the basis of the proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The table presents the original numbers estimated for each project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

TABLE B-5 Potential Impact Producing Factors Associated with In Situ Steam Injection Processes

	Production Capacity (bbl/day syncrude)[b,c]		
Impact Producing Factor[a]	20,000	50,000	100,000
Total land disturbance (acres)	4,000	10,000	20,000
Water use (bbl/day)[d]	100,000	250,000	500,000
Air emissions (tons/yr)			
Stack emissions[e]			
TSP	358	1,155	2,310
SO_x	6,758	16,896	33,792
NO_x	5,332	13,332	26,664
CO	712	1,782	3,564
VOC	356	889	1,778
Fugitive emissions[f]			
TSP	615	895	1,790
SO_x	0	1	2
NO_x	1	2	4
CO	4	11	22
VOC	0.4	1	2

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 µm in diameter); VOC = volatile organic compound.

[b] The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 50,000-bbl/day-capacity project in the P.R. Spring STSA and a proposed 20,000-bbl/day-capacity project in the San Rafael Swell STSA. Nonair emissions data were derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Based upon an estimated use rate of 5 bbl of water per bbl of syncrude produced.

[e] Modeled on the basis of the following: for the 20,000-bbl/day facility, stack height = 76 m (249.3 ft); stack diameter = 5 m (16.4 ft); velocity = 12 m/s (39.4 ft/s); and temperature = 493°K (427.7°F). Modeled on the basis of the following: for the 50,000-bbl/day facility, stack height = 76 m (249.3 ft); stack diameter = 7 m (23 ft); velocity = 12 m/s (39.4 ft/s); and temperature = 473 K (391.7°F).

[f] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

B.4.3 Modified In Situ

The use of explosives to disaggregate the tar sands and increase permeability is similar to the process used for oil shale (see Appendix A) and is not discussed further here.

As noted above, methods for recovering bitumen from formations located at depths between about 45 and 150 m (150 and 500 ft) are limited. In comparison with surface mining, subsurface mining reduces the need for raw tar sands handling and storage; the need for handling and disposal of spent sand (tailings); and the need for reclamation of a mined out pit, room, or shaft. One potential extraction method applicable at these depths involves combining in situ and subsurface mining techniques. This process, referred to as oil mining, has been used in the past in France, Germany, and Russia and entails underground mining of some of the tar sands deposit so that in situ methods can be used on the remaining deposit. Most commonly, a vertical shaft is sunk and horizontal drifts are excavated from the bottom of the shaft. Horizontal injection and production wells are drilled from the drifts. The drifts can be above or below the tar sands formation and are typically used to permit low-pressure steam to be injected into the formation to heat the sands so that the bitumen will flow (Meyer 1995; Isaacs 1998).

B.5 PROCESSING RECOVERED BITUMEN

The choice of recovery method affects which processing operations are used. In mining operations, the mined bitumen must be processed to recover or separate it from the inorganic matrix (largely sand, silt, and clay) in which it occurs. Nonmining extraction produces bitumen mixed with water, steam, other gases, or solvent from which it must be separated. If combustion recovery is used, the viscosity of the recovered bitumen may need to be reduced prior to further processing. If steam, water, or gas injection is used, the injection fluid would need to be separated from the bitumen. In all cases, the viscosity of the bitumen might need to be changed prior to further processing and upgrading (BLM 1984). Depending on the recovery method, mining operations may also need to perform similar separations.

B.5.1 Hot Water Process

The hot water process has been applied with commercial success to mined water-wet Athabasca sands (see Figure B-5). As of 1997, it was the only process to have been applied with commercial success to mined tar sands in North America (Speight 1997). There are three main steps: conditioning, separation, and scavenging.

There are two methods of conditioning. In the first, mined tar sands are pumped with water and caustic into a conditioning drum at 180 to 220°F to reduce particle size and digest the bitumen. The resulting slurry is screened to remove undigested material, and lumps are sent to a separation cell. In the newer hydrotransport method, the tar sands are crushed at the mine site and moved by pipeline in a water slurry to the extraction plant (Marchant and Westhoff 1985; Speight 1997; Oil Sands Discovery Center 2006b).

The separation cell operates like a settling vessel. Sand settles downward to be removed, as tailings and bitumen float to the top where they are skimmed off. Most of the middlings, an emulsion for bitumen and water, are sent to scavenger cells for additional bitumen removal by froth flotation (Marchant and Westhoff 1985; Speight 1997).

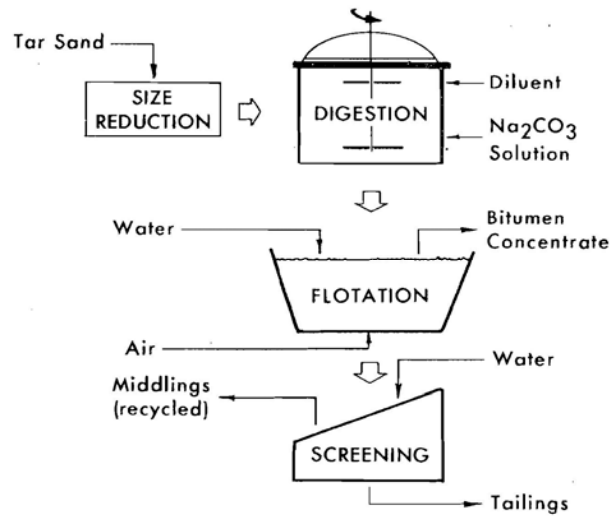

FIGURE B-5 Simplified Diagram of Hot Water Recovery Process (Marchant and Westhoff 1985)

Experiments have been conducted to develop a hot water process for the oil-wet tar sands deposits in Utah (Speight 1997; Marchant and Westhoff 1985). The absence of a sheath of water around the tar sands particles and the strong bonding directly between the sand and the bitumen suggest that more energy would be required to separate sand and bitumen in the Utah tar sands than would be required in the Athabasca tar sands. After size reduction, digestion is accomplished using a high shear energy digester stirred at about 750 rpm at 200°F. Next, bitumen is separated by modified froth flotation. Middlings are screened and recycled (Oblad et al. 1987). This process has been developed to the pilot plant stage (Figure B-5), processing 125 tons/day of tar sands to produce 50 to 100 bbl/day of oil (Speight 1990).

Disposal of tailings presents a problem for hot water recovery processes (Speight 1997). The volume of material expands during processing. A ton of in situ tar sands has a volume of about 16 ft^3 and produces about 22 ft^3 of tailings, a volume increase of almost 40%. The tailings stream contains about 49 to 50 wt% sand, about 1 wt% bitumen, and about 50 wt% water (Speight 1990). Regulations preclude dumping these tailings in streams or rivers or in areas from which runoff may enter rivers or contaminate groundwater. Reclamation of the tailings must also be accomplished upon site closure.

In some operations, recovery of bitumen from the middlings in scavenger cells may be economical, the goal being an additional 2 to 4% bitumen recovery. This process generally involves injecting air in a froth flotation process. Froth containing bitumen rises to the surface of the cell and is skimmed off.

The froths from the separation vessel and the scavenger cells are combined and sent for further processing. The froth stream is usually diluted with naphtha and centrifuged. At this stage, the bitumen contains 1 to 2 wt% minerals and 5 to 15 wt% water and is ready for upgrading.

B.5.2 Cold Water Process

Operations in the Athabasca tar sands have changed from hot water processing to cold water processing, which uses less energy. This change was made possible by using slurry pipelines rather than belt conveyors to transport ore from the mine to the extraction facility. Mined sand is crushed at the mine site, mixed with warm water to form a slurry, and moved by pipeline to the extraction plant. Partial separation of the bitumen from the sand occurs in the pipeline (Singh et al. 2005; Oil Sands Discovery Center 2006b).

Experiments with cold water extraction of Utah tar sands showed a removal of more than 60% of the sand with easily accomplished water removal. Calculations indicated that for 90% recovery of the bitumen, hot water processing would require at least 45 kWh/ton, while cold water processing would require only 13 kWh/ton (Oblad et al. 1987).

Bench-scale cold water processes have also been developed. The sand reduction process uses cold water and no solvent to provide a feed for a fluid coking upgrading process. Tar sands are mixed with water in a screw conveyor and discharged to a screen of appropriate mesh in a water-filled settling vessel. Bitumen agglomerates on the screen and is removed while the sand passes through and is removed as waste.

In the spherical agglomeration process, water is added to the tar sands and the mixture is sent to a ball mill. The bitumen agglomerates to particles with at least 75 wt% bitumen (Speight 1990, 1997).

B.5.3 Processes Involving Solvents

Solvent extraction without water has been attempted. It generally uses a low boiling point hydrocarbon (such as heptane, cyclohexane, or ethanol) and involves four main steps. Fresh tar sands are mixed with recycled solvent containing some bitumen, water, and minerals. Next, a three-stage countercurrent wash is used with settling and draining of about 30 minutes after each stage forming a bed of sand through which the bitumen containing solvent is drained. The last two steps recover the solvent from the sand. Solvent extraction has been demonstrated for Athabasca, Utah, and Kentucky sands, but the cost of solvent losses has kept the process from going commercial (Speight 1997).

Experiments have been carried out on various tar sands deposits, including those at the Asphalt Ridge and Sunnyside STSAs, by using kerosene to control the viscosity of the bitumen to improve bitumen recovery and tailings sedimentation. The temperatures involved have been lowered from near the boiling point of water 100°C (212°F) to around 50 to 55°C (120–130°F). More than 92% of the bitumen in the concentrate was recovered (Oblad et al. 1987).

The cold water bitumen separation process using a combination of cold water and a solvent has been used in a small-scale pilot plant (Speight 1997). The tar sands are first mixed with water, reagents, and a diluent, which may be a petroleum fraction such as kerosene. The solution is maintained in an alkaline condition. Then sand is removed by settling in a clarifier from which the water and oil overflow is sent to thickeners to concentrate the oil. Clay in the feed emulsifies and carries off some of the bitumen as waste from the thickeners.

Table B-6 provides available data describing potential impact producing factors that could be associated with solvent extraction processes. The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA and include emissions from upgrading processes. The nonair emissions data were derived from information published by Daniels et al. (1981) on the basis of the proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth

TABLE B-6 Potential Impact Producing Factors Associated with a Solvent Extraction Facility

	Production Capacity (bbl/day syncrude)[b,c]			
Impact Producing Factor[a]	20,000	32,500	50,000	100,000
Total land disturbance (acres)	2,600	4,225	6,500	13,000
Water use (bbl/day)[c]	106,930	173,760	267,330	534,650
Noise (dBA at 500 ft)	73–88	–[d]	–	–
Air emissions (tons/yr)				
Extraction plant[e]				
TSP	422	686	1,055	2,110
SO_x	632	1,027	1,580	3,161
NO_x	4,990	8,109	12,475	24,950
CO	239	389	598	1,196
VOC	118	193	296	592
Upgrading plant[f]				
TSP	139	225	346	693
SO_x	94	153	235	470
NO_x	4,522	7,348	11,305	22,610
CO	217	352	542	1,084
VOC	107	174	268	537
Spent tar sands[g]				
TSP	825	1,340	2,062	4,123
SO_x	46	75	115	231
NO_x	750	1,218	1,874	3,748
CO	129	209	322	643
VOC	39	63	97	194

a CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter); VOC = volatile organic compound.

b The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA. Nonair emissions data were derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant

Footnotes continued on next page.

TABLE B-6 (Cont.)

designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Approximately 22% of the process water would need to be fresh water (Daniels et al. 1981).

[e] A dash indicates noise level determined by modeling, not by extrapolation.

[f] Modeled on the basis of the following: stack height = 33 m (108.3 ft), stack diameter = 5 m (16.4 ft), velocity = 12 m/s (39.4 ft/s), and temperature = 393 K (247.7°F). Values derived from the original source on basis of relative emission rates provided (see Table 5-5, Aerocomp, Inc. 1984).

[g] Modeled on the basis of the following: stack height = 55 m (180.4 ft), stack diameter = 6 m (19.7 ft), velocity = 12 m/s (39.4 ft/s), and temperature = 393K (247.7°F). Values derived from the original source on the basis of relative emission rates provided (see Table 5-5, Aerocomp, Inc. 1984).

[h] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

tar sands deposit near McKittrick, California. The table presents the original numbers estimated for each project and extrapolated numbers for larger or smaller operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

B.5.4 Thermal Recovery Processes

Various schemes have been proposed as alternatives to the hot water process to remove bitumen from mined tar sands by applying heat. Direct coking or thermal recovery processes appeared promising but the success of hydrotransport in making cold water extraction commercially successful in Athabasca has helped reduce the attractiveness of thermal recovery, which can require consumption of a substantial amount of heat (Marchant and Westhoff 1985).

In most processes, the tar sands are pyrolyzed (heated in an inert or nonoxidizing atmosphere) by heating at 900°F to effect chemical changes, including:

- Volatilization of low molecular weight components,
- Cracking of some heavier components, and
- Conversion of part of the bitumen to coke.

The volatile materials exit the reaction vessel, are cooled, and separated into gases and condensed liquids while the coke remains behind adhering to the sand, which is transferred to a combustion vessel for burning to provide heat for the process. In general, the oil obtained by a thermal process would require upgrading before it is acceptable as a refinery grade synthetic crude. The sulfur- and nitrogen-containing compounds must be eliminated, the nitrogen and/or sulfur converted to compounds that are subsequently removed (typically ammonia and hydrogen sulfide, respectively) and further processed into saleable commodities or disposed of as waste, the average molecular weight lowered, and the carbon-to-hydrogen ratio reduced (Marchant and Westhoff 1985; Speight 1990).

About a dozen other thermal processes have been described in the literature. Experiments utilizing fluidized bed pyrolysis have been conducted on Utah tar sands at the University of Utah (Marchant and Westhoff 1985; Speight 1997).

Table B-7 provides available data describing potential impact producing factors that could be associated with a surface retort facility. These data were derived from information published by Daniels et al. (1981) on the basis of a proposed 20,000-bbl/day-capacity plant designed for the recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The proposed retort facility was a Lurgi-Ruhrgas retort. The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah. The table presents the original numbers estimated for the McKittrick project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

B.6 UPGRADING

Upgrading recovers the light components from the recovered bitumen and changes the heavy components into synthetic crude oil. By-products, which can be used directly or as raw materials for other processes, are also produced. Bitumen has a higher carbon-to-hydrogen ratio than crude oil. Some upgrading processes remove carbon (e.g., a coking operation) and others add hydrogen (e.g., a hydrogenation that converts unsaturated hydrocarbons in the saturated analogs) to reduce this ratio. Upgrading also decreases the specific gravity (density) of the synthetic crude oil to a level suitable for a refinery feedstock. Although there are variations between different production operations, four main processes are used to upgrade bitumen:

TABLE B-7 Potential Impact Producing Factors Associated with a Surface Retort Facility

	Production Capacity (bbl/day syncrude)[b,c]			
Impact Producing Factor[a]	20,000	25,000	50,000	100,000
Total land disturbance (acres)	2,600	3,250	6,500	13,000
Water use (bbl/day)[d]	11,950	14,940	29,880	59,760
Noise (dBA at 500 ft)	73–88	–[e]	–	–
Air emissions (tons/yr)				
Retort[f]				
TSP	954	1,192	2,384	4,768
SO_x	1,002	1,253	2,506	5,011
NO_x	393	492	983	1,966
Fuel burning equipment[g]				
TSP	21	26	52	104
SO_x	24	30	61	122
NO_x	104	131	261	522
CO	17	22	44	87
THC	3	4	9	17
Storage tanks[h]				
THC	28	35	70	140
Valves, pumps, compressors[i]				
THC	3	4	9	17

a CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; THC = total hydrocarbons (includes methane and photochemically nonreactive compounds); TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter).

b Data derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

c bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

d Approximately 100% of the process water would need to be fresh water (Daniels et al. 1981).

e A dash indicates noise level determined by modeling, not by extrapolation.

f These data are based upon a Lurgi-Ruhrgas retort operating with a 97% efficient lime injection and scrubbing system to control SO_x emissions and a 99.5% efficient electrostatic precipitator to control TSP emissions. These data were modeled on the basis of the following: stack height = 76 m (249.3 ft), volume = 193.4 m^3/s (2,081.7 ft^3/s), and temperature = 88°C (190.4°F). The particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

Footnotes continued on next page.

TABLE B-7 (Cont.)

[g] The fuel burning equipment includes a distillation furnace, hydrogen plant, and hydrogenation unit and is equipped with a 50% efficient ammonia injection system to control NO_x emissions. These data were modeled on the basis of the following: stack height = 76 m (249.3 ft), volume = 22 m^3/s (236.8 ft^3/s), and temperature = 88°C (500°F). The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

[h] Equipped with a double-sealed floating roof.

[i] Assumes equipment is subjected to a strict maintenance program.

coking (thermal conversion), catalytic conversion, distillation (fractionation), and hydrotreating (Speight 1990, 1997; Meyer 1995; Oil Sands Discovery Center 2006c).

The recovery process has a determining influence on the ancillary processes associated with upgrading. If combustion recovery were used, the viscosity of the bitumen might need to be reduced prior to upgrading. If a steam, hot water, or hot gas injection were used, the injected fluids would probably need to be separated from the recovered bitumen/fluid mixture. In addition, the viscosity of the bitumen might need to be reduced. Similarly, if solvent recovery were used, the solvent and bitumen would need to be separated and the viscosity of the bitumen might need to be reduced (BLM 1984).

Limited data are available to describe the potential impact producing factors that could be associated strictly with upgrading processes; usually, the data are provided for an entire plant, including extraction and upgrading facilities. Table B-8 provides data describing potential impact producing factors that could be associated with the upgrading facilities used for processing oil shale—specifically, The Oil Shale Corporation (TOSCO) II aboveground retort facility. Given that kerogen oil (raw shale oil) derived from oil shale requires more extensive upgrading than bitumen recovered from tar sands, these data are likely to result in conservative overestimates of potential impacts. These data were derived from information published by the DOE (1983) on the basis of a 47,000-bbl/day syncrude facility, including hydrogenation and hydrotreating units.

B.6.1 Coking (Thermal Conversion)

The molecules in recovered bitumen must be reduced in average molecular weight. If heated to high temperatures, long, heavy hydrocarbon molecules break apart into shorter, lighter molecules. This process is called cracking and proceeds faster at higher temperatures (Meyer 1995; Oil Sands Discovery Center 2006c). There are two types of coking: delayed

TABLE B-8 Potential Impact Producing Factors Associated with Upgrading Facilities

	Production Capacity (bbl/day syncrude)[b,c]			
Impact Producing Factor[a]	25,000	47,000	50,000	100,000
Water use (bbl/day)[d]	481,910	906,000	963,830	1,927,660
Air emissions (tons/yr)				
Particulates	31	58	62	123
SO_x[e]	271	510	542	1,085
NO_x	221	416	442	885
CO	27	51	54	108
Hydrocarbons	5	9	10	19

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides.

[b] Data derived from DOE (1983) for a proposed 47,000-bbl/day-capacity TOSCO II aboveground retort (indirect mode) for production of syncrude from oil shale. Numbers for larger and smaller production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Represents evaporative losses from the coker unit.

[e] Includes emissions from tail gas incinerator.

coking and fluid coking. Suncor uses delayed coking, and Syncrude uses fluid coking in its Athabasca operations.

Delayed coking is a batch process. Recovered bitumen is heated to 925°F and pumped into one side of a double-sided coker where it cracks into vapor and coke. The vapors escape from the vessel for condensation and further processing, and the coke remains behind. In about 12 hours, the first side is full of coke and the cracking operation shifts to the other side. The solid coke is cut out by use of a water drill (Oil Sands Discovery Center 2006c).

Fluid coking is a continuous process. Bitumen is heated to 925°F (500°C) and blown into a vessel containing small spheres of coke suspended in an upward flow of steam. The large molecules in the bitumen are cracked, and the resulting smaller molecules are carried out of the top of the vessel as a vapor for condensation and further processing. The remaining coke agglomerates with the coke spheres, which eventually become large enough to settle to the bottom of the vessel from which they are removed. At the Syncrude operation, the process recovers about 86 bbl of synthetic crude for every 100 bbl of recovered bitumen. In another variation, the heated bitumen is sprayed into the entire height and circumference of the vessel and cracks into a gas that is removed from the top of the vessel and a fine coke powder that is removed from the bottom (Meyer 1995; Oil Sands Discovery Center 2006c).

Both fluid and delayed coking produce coke, distillate oils, and light gases. Upwards of 75% of the bitumen is converted to liquids, with fluid coking giving 1 to 5% more than delayed coking. Most of the coke is used to produce heat for the upgrading operations. More is produced than is needed and is stockpiled for storage. Sulfur occurs throughout the distillates from both processes. Nitrogen occurs in all fractions but is concentrated in the higher boiling point fractions. Naphtha and gas oil require the addition of hydrogen to be suitable as refinery feeds (Speight 1997; Oil Sands Discovery Center 2006c).

B.6.2 Catalytic Conversion

Catalytic conversion is really a thermal conversion enhanced by using catalysts. Catalysts help chemical reactions occur but are not themselves chemically changed by the reactions. For a catalyst to be effective, the hydrocarbon molecules in the bitumen must contact the so-called active sites on the catalyst. When large hydrocarbon molecules contact the active sites, they crack into smaller molecules. The catalyst also impedes the progress of larger hydrocarbon molecules so that they can continue to crack into smaller pieces. In hydroprocessing, hydrogen is added to the process to improve the carbon-to-hydrogen ratio (Oil Sands Discovery Center 2006c).

B.6.3 Distillation (Fractionation)

Distillation is a very common refinery process. The functioning of a distillation tower depends on the fact that different substances boil at different temperatures. The tower is essentially kept hotter at the bottom and cooler at the top. Vapors collected from the coker are introduced at the bottom and rise up through the tower. Heavier hydrocarbons with higher boiling points condense near the bottom of the tower. Lighter hydrocarbons with lower boiling points move upward and condense at different levels depending on their boiling points. The condensed liquids are removed from the tower (Oil Sands Discovery Center 2006c).

An efficiency gain is realized in processing bitumen if the output of the coker is separated into several streams for additional processing. In particular, the naphtha component requires special processing. At Suncor, the coker distillate is distilled into three fractions: naphtha, kerosene, and gas oil. At Syncrude, the coker distillate is distilled into two fractions: naphtha and mixed gas oil. The products of additional processing, including hydrotreating, are blended to produce synthetic crude oil (Speight 1997).

B.6.4 Hydrotreating

Hydrotreating is used on the gas oils, kerosene, and naphtha resulting from the upgrading of bitumen. It is one of the most commonly used chemical processes for adding hydrogen to organic molecules. In hydrotreating, the feedstock is mixed with excess hydrogen at high pressure and temperatures of 300 to 400°C (570 to 750°F) in the presence of catalysts. The process can also remove sulfur, nitrogen, and metals as well as undesirable organics from the feedstock. The addition of hydrogen also helps stabilize the produced synthetic crude so that its chemical composition does not change in transit between the syncrude plant and the refinery. In the production of synthetic crude oil, the gases from hydrotreating (all of which are typically flammable) are usually desulfurized and used as fuels on-site (Meyer 1995; Speight 1997; Oil Sands Discovery Center 2006c).

B.6.5 Other Upgrading Processes

Hydrocracking is an upgrading process that cracks the bitumen in the presence of hydrogen and produces higher liquid yields than coking (up to 104 bbl of synthetic fuel per 100 bbl of raw bitumen) because of the uptake of hydrogen. Products from hydrocracking have lower contents of sulfur- and nitrogen-containing compounds than products from coking. Despite the need to consume hydrogen and operate at high pressures, hydrocracking has been chosen for use in two projects in Canada (Meyer 1995; Speight 1997).

In partial coking, the froth from the hot water recovery process is distilled at atmospheric pressure, thereby removing water and minerals.

Flexicoking uses a gasifier to gasify excess solid coke with a mixture of gas and air. The product is a low-heating-value gas that can be used on-site. This process produces a heavy pitch rather than coke as a by-product by using steam stripping in a delayed coking process. The yield of liquids is also increased.

The Alberta Oil Sands Technology and Research Authority Taciuk Processor simultaneously extracts and upgrades the bitumen from tar sands to produce a distillate oil (Meyer 1995). Heat alone is used to separate bitumen from sand, crack it, and drive off the hydrocarbons. Much of the heat for the process is obtained from the separated sand, which contains residual coke. The sand-coke is burned, and the heated sand is used to preheat unprocessed tar sands and then discarded. The Taciuk process has several advantages over the combination recovery-upgrading procedure described above. These include increased product yield, a simplified process flow, reduction of bitumen losses to tailings, elimination of the need for tailings ponds, improvement in energy efficiency compared with the hot water extraction process, and elimination of requirements for chemical and other additives.

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ATTACHMENT B1:

ANTICIPATED REFINERY MARKET RESPONSE TO FUTURE TAR SANDS PRODUCTION

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ATTACHMENT B1:

ANTICIPATED REFINERY MARKET RESPONSE TO FUTURE TAR SANDS PRODUCTION

1 INTRODUCTION

As noted in the discussion in Attachment A1 to Appendix A regarding refinery market response to future oil shale production, crude feedstocks, regardless of their provenance, all compete for acceptance into the U.S. refinery market based on a number of factors. These include value factors of the feedstock itself (i.e., critical chemical and physical parameters of the feedstock), reliability and consistency of supply, the logistics of transporting the feedstocks from points of recovery or generation to refining facilities, the extent to which existing refinery processing configurations align with feedstock parameters and their processing demands, and how efficiently those feedstocks can be converted to products currently in high demand. Collectively, all such factors contribute to a "refining margin" that is unique for every refinery and that is constantly changing on the basis of the availability of crude feedstocks as well as changing market demands for refinery products (e.g., distillate fuels, feedstock intermediates delivered to other refineries for further processing, and petrochemical feedstocks). While oil shale and tar sands are fundamentally different resources with respect to their depositional environments, their chemical compositions, their extraction and production technologies, and their marketable products, many of the same factors influencing penetration of oil shale–derived crude feedstocks into the refining market can be seen to be in effect for tar sands–derived feedstocks.

Attachment A1 of Appendix A of this PEIS gives an overview of the U.S. refinery market, including discussions of critical parameters in the crude oil refinery process, market responses to feedstock value parameters, refinery utilization factors, current refinery capacity, the Petroleum Administration for Defense District (PADD) system, current crude sources (including Canadian syncrude production), and other possible market drivers. This brief overview discusses how tar sands–derived crude feedstocks might be incorporated into the U.S. refinery market and how the availability of these new crude feedstocks may influence decisions regarding construction, expansion, or reconfiguration of processing capabilities.

In a manner very similar to the anticipated market development pathways for oil shale–derived crude feedstocks, the following factors predominate in supporting refinery market adjustments to tar sands–derived crude feedstock:

- The investment into and expansion of refining capacity are solely determined by the investor's long-term expectation of refining margins. Only those crude feedstock sources that can demonstrate long-term availability and consistent quality factors are likely to be considered as drivers for refinery processing capacity expansions or crude feedstock displacements.

- New crude feedstock sources displace sources in existing markets based on how well their quality parameters align with existing or expanding refining capability; the market will take proportionately longer to accept new sources with quality factors substantially different from existing or alternatively available sources; conversely, refineries will more readily consider an expansion in capacity within their current processing configurations if new feedstock sources become available and can be seen to result in satisfactory refining margins.

- Incremental expansion at existing facilities is the expected primary way in which tar sands–derived crude feedstock will be introduced into the refinery market. Given the modest ultimate production levels forecasted both collectively and at individual facilities, there will be little to no impetus to build new refineries solely in response to this U.S. tar sands–derived feedstock's newly established availability.

- Only high-volume feedstock streams of proven reliability and consistency will precipitate major refinery expansions and/or displacements, or major expansions and/or construction of long-distance pipelines to link the feedstock to distant refineries.

- Pipelines do not drive refinery market investments. Pipeline operators react to emerging markets and provide transportation linkage between the source and refiner.

- Intuitively, domestic sources of crude feedstocks are more desirable than foreign sources simply because of their inherently more secure status. However, to retain their advantage, such domestic sources must also compare favorably with imported feedstocks with respect to overall product yield and other quality parameters (e.g., contaminant and acid content).

2 IMPORTANT CHARACTERISTICS OF TAR SANDS RESOURCES AND RESULTING MARKETABLE PRODUCTS

Production of crude feedstock and/or asphalt from many facilities producing from tar sands deposits in Utah may approach a total of about 300,000 bbl/day over the next 20 years (2007–2027).[1] It is anticipated that most of the tar sands–derived feedstocks will be crude feedstock, with a smaller portion being produced as asphalt. Table 1 provides a comparison of some critical chemical and physical parameters of various tar sands deposits within selected Special Tar Sand Areas (STSAs) in Utah.

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[1] To facilitate discussion of potential effects of tar sands development, the BLM assumed a commercial production level of approximately 300,000 bbl/day.

TABLE 1 Critical Chemical and Physical Properties of Selected Tar Sands Deposits

PROPERTIES OF SELECT UTAH TAR-SAND BITUMENS

PROPERTY	Tar Sand Triangle	P.R. Spring Rainbow I	P.R. Spring Rainbow II	P.R. Spring South	Sunnyside	Whiterocks	Asphalt Ridge
Bitumen content, wt%	4.5	14.1	8.5	6.5	8.5	8	10.9
Specific gravity	1.01	1.0157	0.9872	1.0083	1.0328	0.9979	0.97
Gravity, °API	8.6	7.8	11.8	8.8	5.5	10.3	14.4
Conradson carbon, wt%	16.7	14	17.4	24	14.8	13	ND
Ash, wt%	0.2	3.3	1.4	1.9	2.4	0.8	0.04
Pour point, °F	94	210	320	320	ND	ND	ND
Viscosity, cps	42638	8269	2900	7031	7373	29245	2015
Simulated distillation							
IBP, °F	316	279	316	308	ND	307	ND
Volatility, wt%	34.4	39.9	22.8	14.3	32.4	22.1	ND
IBP-400 °F, wt5	0.7	1.3	0.5	0.7	0.9	0.9	ND
400-650 °F	7.6	5.1	2.2	1.3	7.3	3.3	ND
650-1000 °F	26.2	25.6	20.1	12.3	24	18.8	ND
>1000 °F residue, wt%	65.61	68.1	77.2	85.1	67.6	77.9	ND
Elemental Analysis							
C, wt%	84.3	84.7	81.41	81.7	83.3	85	85.2
H, wt%	10.3	11.2	10.3	9.3	10.8	11.4	11.7
N, wt%	0.4	1.3	1.4	1.4	0.7	1.3	1
S, wt%	4	0.5	0.4	0.4	0.6	0.4	0.6
O, wt%	1	1.8	6.3	7.2	4.4	1.6	1.1
Atomic H/C ratio	1.47	1.6	1.51	1.36	1.56	1.61	1.65
M_n, g/mol	571	702	1381	1561	1024	ND	668
Gradient elution chromatography							
Saturates, wt%	13.3	9.5	15.8	4.1	13.2	15.3	10
MNA/DNA oils, wt%	9.7	10.2	3.5	5.3	21	8.5	11.4
PNA oils, wt%	11.7	11.4	9	0.9	5.9	11.9	4.4
Soft resins, wt%	25.9	13.9	5.8	4	13.9	16.7	18.4
Hard resins, wt%	1.9	1.1	2.3	1.8	5.6	2.6	1.2
Polar resins, wt%	3.5	2	3.6	1.1	1.7	2.7	3.7
Asphaltenes, wt%	30.6	31.3	35.9	55.7	29.8	31.2	39.9
Non-eluted asphaltenes, wt%	3.5	20.6	24.1	27.1	8.9	11.1	11.1

Source: On-line poster by Steve Schamel and John Baza

Source: Gwynn (2006).

Although it can be anticipated that development of each of the STSA deposits will follow very different cost and logistical schedules to generate marketable product, the refining market is generally insensitive to resource development costs and logistical demands and impediments. Therefore, for the purposes of this analysis, all tar sands developers are considered to be in the same starting position with respect to finding markets for their products, irrespective of the overall costs each developer has incurred in getting to that point.

Although the cost of resource development is outside the scope of determining the competitiveness of the resulting products to the refinery market, critical chemical and physical parameters of those products are not. Thus, for example, the Sunnyside deposit that would produce raw bitumen with an American Petroleum Institute (API) gravity of 5.5°,[2] puts the

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2 API gravity is an arbitrary scale for expressing the specific gravity or density of liquid petroleum products. Devised by the API and the National Bureau of Standards, API gravity is expressed as degrees API. API gravities are the inverse of specific gravity. Thus, heavier viscous petroleum liquids have the lower API values.

developer at a distinct disadvantage compared with developers of other deposits whose raw bitumen API gravities are higher since the Sunnyside developer would need to invest greater effort to improve the gravity of his product for economical pipeline transport. However, as can be seen from Table 1, API gravities for any U.S. tar sands bitumen can range from a low of 5.5° to a high of 14.4°. Consequently, even the bitumen with the highest API gravity is still not acceptable for pipeline transport, suggesting that all developers would be faced with the requirement to improve on the quality of the raw bitumen they recovered before having any realistic opportunity of finding both a refining market and an economical way of getting their product to that market.

Likewise, developers whose raw bitumen has the lowest percentages of refining catalysts-fouling contaminants, such as sulfur and nitrogen, would have an initial competitive edge over sources where the amounts of these contaminants are higher. In addition to threatening the safe operation of refinery processing units, adding to the cost of operation by reducing the life of expensive catalysts and adding to processing unit downtime for catalyst replacement, the presence of both nitrogen and sulfur contaminants may cause a refinery to incur heavier regulatory burdens in the form of severe limitations placed on resulting processing emissions that would require significant investments in pollution control devices before necessary operating permits could be secured. Even without emission limitations, the recently promulgated standards for low-sulfur diesel fuels for on-road vehicles further increases the costs of processing by requiring additional expensive sulfur removal steps to meet product specifications. Premature catalyst replacements, increased regulatory controls, and more rigorous product specifications can each severely impact refining margins and thus reduce the attractiveness of the feedstock. To remain competitive with intrinsically higher quality feedstocks, purveyors of high-sulfur, high-nitrogen, and low API gravity feedstocks must consider discounting or, alternatively, carrying the costs themselves of improving on these parameters before offering their product to refineries.

Crude feedstock quality is among the most critical of factors affecting refinery market penetration. Because there has been very little commercial development of U.S. tar sands deposits, there is virtually no empirical evidence on which to base any presumptions of the quality factors for U.S. tar sands–derived products; however, irrespective of the recovery technology employed, recovery of bitumen from its natural setting is simply a physical separation process and is not expected to substantially change its chemical composition. Consequently, it is safe to assume that the quality factors displayed by bitumen in its natural setting will survive virtually unchanged throughout any separation processes (see Table 1).

Tar sands deposits in Canada are fundamentally different from tar sands in the United States. The presence of a free water sheath surrounding the inorganic sand and separating it from the bitumen in Canadian deposits (known as “water-wet tar sand”) facilitates the separation of the bitumen from the sand using relatively inexpensive and highly effective (but water-intensive) separation technologies. Those same technologies, while technically available to developers of U.S. tar sands, will not produce the same efficiencies of separation as they do for Canadian developers and would be executed at a higher cost in U.S. development or not at all because of the unavailability of the required volumes of water. Amended technologies to those practiced in Canada, as well as alternative technologies, are nonetheless available for U.S. tar sands, although at higher overall costs and/or reduced recovery efficiencies. As noted above, however, such development costs are not of particular concern to refiners; decisions regarding acceptance of new feedstocks are based on the quality, availability, and cost of the feedstocks and the refining margins of the resulting products, and disregard the difficulty or efficiency of resource recovery. In this sense, raw bitumen recovered from U.S. deposits can be expected to be generally equivalent to Canadian bitumen in critical quality factors, despite expected higher recovery costs. Likewise, synthetic crude resulting from upgrading of U.S. tar sands–derived bitumen is expected to be generally equivalent to synthetic crude that results from upgrading Canadian-derived bitumen to an equivalent extent, again, costs notwithstanding. Consequently, those same refineries that now are configured to receive significant quantities of Canadian syncrude or raw bitumen can be expected to find U.S. tar sands–derived feedstocks equally attractive from a quality perspective. Other factors of attractiveness, such as reliability and consistency of supply over time, have not been established for U.S. tar sands–derived feedstocks, however, and are not likely to be equivalent to Canadian analogs, based on the relative magnitudes, accessibility, and quality of the respective tar sands resources and the maturity of the Canadian tar sands industry and its supporting transportation infrastructures.

3 ISSUES ASSOCIATED WITH UPGRADING

As discussed above, all tar sands deposits are not equal with respect to the products they might potentially offer to refineries. Obtaining equality by improving upon or eliminating unattractive chemical and physical properties of the raw bitumen involves upgrading of the raw bitumen by either removing carbon (coking reactions) or adding hydrogen (hydrogenation) Reacting bitumen with hydrogen results in two distinct types of reactions: hydrocracking (adding hydrogen to complex, unsaturated molecules to make smaller, more desirable saturated hydrocarbons) and hydrotreating (converting sulfur- and nitrogen-bearing constituents to hydrogen sulfide and ammonia, respectively, both of which can be subsequently easily removed from the product stream). Upgrading can be performed to whatever extent is desired, yielding ever-increasing quality of resulting products with proportionally increasing costs. Upgraded products are generally referred to as synthetic crude, regardless of the extent of upgrading. Even modest degrees of upgrading would require a substantial investment in resources (e.g., electric power, natural gas, and water), expensive reactants such as hydrogen, processing equipment, and related infrastructure. Developers of tar sands deposits that exist in relatively remote, arid areas with limited access to required resources and other logistical constraints would be at a disadvantage in pursuing this strategy. Consequently, any upgrading performed at the tar sands development site would be expensive and impossible without significant investment in supporting infrastructures. Nonetheless, the analyses in this PEIS anticipate that some modest amount of upgrading of raw bitumen would occur at U.S. tar sands developments.

An additional strategic option exists that is unique to tar sands. The raw bitumen itself is a legitimate constituent of conventional crude oil and, without further chemical alteration, can serve as a feedstock for properly configured refineries. Some logistical impediments still exist for this development path, however. The relatively low API gravity of raw bitumen (see Table 1, e.g.) preempts its transport by pipeline. However, diluents such as raw naphtha, raw gas oil, or other crude oil distillation condensates, any of which would be in abundance in integrated refineries, can be shipped to the tar sands development and mixed with the raw bitumen to form a solution (known in the industry as “dil-bit” or “dilbit”) that can be transported by conventional pipeline. Once arriving at the refinery, the diluent can be separated and used again for pipelining subsequent batches of raw bitumen. However, dilution ratios as high as 30% by volume diluent may be necessary (Brierley et al. 2006), and transporting the diluent to the mine site in requisite volumes by truck would ensure that any strategy involving dilbit would be expensive. Nevertheless, as will be discussed later, evolution in processing capabilities in the refining industry to add greater coking capacity is compatible with this strategic option, and production and shipment of diluted bitumen are already being pursued by many Canadian tar sands developers. Of the more than 2.17 million bbl/day of crude feedstocks imported into the United States from Canada, approximately 400,000 bbl/day consists of un-upgraded bitumen (transported as dilbit), sold primarily to refineries configured to process heavy crudes.[3] Finally, a smaller fraction of Canadian crude imports is transported as “Syn-dil-bit,” a blend of synthetic crude, distillation condensates, and bitumen. Such mixtures, however, are typically sold to refineries configured to process light to medium crudes. Each of the bitumen mixtures described above commands its own unique processing scheme, and major challenges remain for refiners of such bitumen mixtures. Bitumen dilutions typically are assembled to meet a target API gravity of 20°; however, most will still contain significant volumes of residuum and have a high sulfur content. By comparison, the synthetic crudes resulting from upgrading of raw bitumens would be characterized by virtually no residual and relatively low sulfur content.[4] Distillates yielded in their subsequent refining, however, would have high aromatic character, which would necessitate greater degrees of subsequent hydrotreating to produce rigorously specified transportation fuels. Further, distillate suites also would typically include relatively high volumes of polyaromatic gas oil, which would reduce the yields in subsequent downstream fluid catalytic cracking (FCC) units.

4 EVOLVING CRUDE FEEDSTOCK MARKETS

Currently, light crude (API gravity of 34° or higher) represents approximately 50% of the crude oil available on the world market. Much of the availability and thus more rapid depletion of light crudes are due to the Organization of Petroleum Exporting Countries (OPEC) quota system. This quota on total production volumes provides incentives to OPEC producers to sell the higher margin light crudes. Production of light sour crude is expected to increase by 9 million bbl/day by 2015, but the production of light sweet crude is expected to increase by only 1 to 2 million bbl/day over the same period (Phillips et al. 2003). Availability of light sweet crude is expected to continue to decline as production in key areas declines. At the same time, availability of heavier synthetics and bitumen blends is increasing and is expected to reach almost 3 million bbl/day by the year 2015 (Brierley et al. 2006). Concurrently, demand for

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3 To facilitate import of bitumen, pipelines specifically designed to deliver diluent to Canadian tar sands mine sites are also now being constructed.

4 Although synthetic crudes are typically low in overall sulfur content, the specific sulfur-bearing species that remain are difficult to treat. Significant effort is required to hydrotreat synthetic crude distillate fractions to meet the recently promulgated ultra-low-sulfur on-road diesel fuel specifications.

lighter distillate fuels continues to increase, and specifications for such fuels become more rigorous. Consequently, refiners throughout the country are focusing their attention on expanding their capacity for "bottom of the barrel" processing and seeking out heavier crude feedstocks, including synthetics. Traditionally, heavier crude feedstocks were converted to low-value fuel oils, asphalts, and lube stocks, with these relatively low-value products commanding severe discounting of the parent feedstock. However, reconfiguration to add coking, delayed coking, FCC, and hydrocracking capacities allows refineries to switch to heavier crude stocks and still meet market demands for lighter, more rigorously specified fuels.[5] Deep discounting of heavier crudes allows refineries to obtain amortization of their reconfiguration costs over a reasonable period while still maintaining adequate refining margins. Increased "bottom of the barrel" processing capacity is driven not only by "upstream" factors, such as crude source availability, but also by "downstream" factors such as increased markets for transportation fuels with a coincident decline in the market for heavier residuals, an increasing demand for anode-grade coke,[6] and a continued inclination by the refinery industry to meet changing processing and product demands by reconfiguring or expanding capacities at existing refineries rather than building new grass roots crude processing capacity.

Crude feedstocks from Canadian tar sands production can be seen as significant competition for U.S. tar sands–derived synthetics and bitumen. In addition to the Canadian tar sands resource being substantially larger, more contiguous, and more homogeneous than the U.S. resource, the Canadian tar sands industry is mature, and the volumes of Canadian imports are expected to grow significantly in the near term. For example, by 2015, a forecasted Canadian syncrude import volume of approximately 4.5 million bbl/day could represent as much as 28% of the U.S. refinery industry's crude consumption nationwide.[7]

Canadian imports into PADD 4 refiners, the region in which the Utah tar sands deposits are located, has increased from 2000 to 2005 by approximately 40%, as shown in Table 2. The majority of this was upgraded synthetic crudes. These crudes (after upgrading) are being offered at prices roughly equivalent to domestic conventional crudes in the region. The attractiveness of the synthetic crudes over conventional domestic crudes is based on the lack of light ends, such as butane and propane, and the lack of the bottoms or residual. Both of these fractions are of less value than the "middle of the barrel" transportation fuel progenitors and sometimes even below the cost of the crude, thereby destroying overall value. In addition, the domestic crude in the area

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5 Phillips et al. (2003) reports that approximately 50% of the worldwide coking capacity is concentrated in the Untied States and totaled more than 2,000,000 bbl/day of installed capacity in 2003. In the 15 years previous to 2003, delayed coking capacity had grown by 56% in the United States, followed by hydrocracking (37%) and FCC (14%).

6 Anode grade coke is used in aluminum smelting and generally requires a crude feedstock that is low in sulfur and low in metals but that typically commands a high price, guaranteeing high refining margins even with the purchase of more expensive crude.

7 The Energy Information Administration (EIA) forecasts that by 2015, the total volume of crude actually consumed by all U.S. refineries will be 16.3 million bbl/day. For clarification against refinery capacities discussed earlier, assuming continuing refinery utilization rates of 93%, this volume infers 17.5 million bbl per stream day refinery distillation capacity, which can be reasonably expected to come from incremental expansions of existing facilities. EIA crude volume consumption forecasts can be downloaded from http://www.eia.doe.gov/oiaf/aeo/pdf/aeotab_11.pdf.

TABLE 2 PADD 4 Crude Imports by Mode of Transportation

Thousands of Barrels per Day	2000	2001	2002	2003	2004	2005
Total	505	501	522	527	555	559
Pipeline	474	468	488	489	510	508
Domestic	287	263	257	253	248	247
Canadian	187	205	230	236	261	260
Trucks	31	33	34	38	45	52
Domestic	31	33	34	38	45	52
Canadian	0	50	0	0	0	0

Source: EIA (2006a).

has a higher sulfur content, which requires additional capital investment and operating expense to meet low-sulfur fuel specifications.

The overall markets for residual fuel oils have diminished over time. The key remaining market is heavy, relatively high-sulfur “bunker fuels” used primarily in ocean-going vessels. PADD 4 refineries do not have ready access to this market, primarily because of their geographic location. Therefore, there has been an incentive to import upgraded synthetic crudes, which lack a residual cut. Aside from acquiring a synthetically derived crude, which lacks a bottoms or residual product, it must either be sold as lower value asphalts and fuel oils or be upgraded into transportation fuels. The most common process technologies in the upgrading of bottoms (as found in bitumen, but not in upgraded synthetic crudes) are forms of thermal cracking called cokers. They produce roughly 65% transportation fuels and 35% petroleum coke from the residual portion of a full crude barrel. PADD 4 thermal cracking capacity has been relatively flat since 2001 (except for normal capacity creep through normal maintenance and debottlenecking) as shown in Table 3. This represents coking capacity at only 4 of the 16 PADD 4 refineries. This leaves a significant portion of the market with available options to invest in this heavy upgrading utilizing this new crude resource. Currently, two coker projects are under construction in PADD 4, with one more announced. In addition, there is one coker being constructed adjacent to, but outside PADD 4 at Borger, Texas, which is to be supplied as part of a new strategic partnership between Encana and ConocoPhillips.

Because of the Canadian tar sands industry’s maturity and other important circumstantial factors such as resource availability, many Canadian developers have begun extensively upgrading their products to eliminate problematic characteristics of earlier products and enhance more desirable characteristics without proportional increases in costs. For example, Brierley et al. (2006) report that Suncor markets a light sweet crude, Suncor Oil Sands Blends A (OSA), that is the product of hydrotreating the products of delayed coking performed at the Suncor mine site. Suncrude Canada Ltd. markets a fully hydrogenated blend, Syncrude Sweet Blend (SSB), utilizing fluidized bed coking technology. Husky Oil now operates a heavy crude upgrading system consisting of a combination of ebullated-bed hydroprocessing and delayed

TABLE 3 PADD 4 Thermal Cracking Downstream Refining Capacity

(Thousands of Barrels/ Stream Day)	2001	2002	2003	2004	2005	2006
Total coking	45,700	45,700	46,850	47,250	47,950	48,850
Delayed coking	36,800	36,800	37,950	37,950	37,950	38,450
Fluid coking	8,900	8,900	8,900	9,300	10,000	10,400

Source: EIA (2006b).

coking to produce Husky Sweet Blend (HSB). The Athabasca Oil Sands Project uses ebullated bed hydroprocessing to produce Premium Albian Synthetic (PAS). Upgraded Canadian synthetics display very favorable characteristics over un-upgraded bitumens, with API gravities as high as 38.6° and sulfur contents as low as 0.1% by weight (Brierley et al. 2006). Light sweet synthetic crudes produced at mine site upgrading facilities command a premium price on the market (but still discounted relative to conventional light sweet crudes) and are comparable to conventional light sweet crudes in many respects. However, because of the high aromatic character of the parent bitumen, even these upgraded light sweet synthetic crudes are attractive only to refineries configured specifically to handle them.

In recent years, strategic mine site upgrading decisions have not been made unilaterally by Canadian developers, but, instead, are the products of extensive collaboration with individual refineries. The result has been the production of synthetic feedstocks uniquely suited to a particular refinery's processing capabilities and, at the same time, reconfiguration strategies undertaken by the refineries to ensure full compatibility with particular synthetic crude sources. The highly integrated agreements between feedstock supplier and refiner that result from such collaborations are not easily overturned or displaced. However, while such one-on-one collaborations can yield both increased overall efficiencies and maximum refining yields, it is generally acknowledged that, as the Canadian tar sands industry continues to grow, there will be an increasing need to direct synthetic crude production into a few "marker" categories in consultation with major refining market centers as opposed to individual refineries, rather than allow a continuing expansion in the number of "boutique feedstocks" (OSEW/SPP 2006).

Irrespective of any controls being placed on the variety of synthetic crudes being developed, it will continue to be the case that Canadian tar sands developers will have much greater opportunities to undertake bitumen upgrading at their mine sites than will U.S. developers. The ability to upgrade at the mine site, together with purchasing agreements already in place for synthetic crudes with specific properties, gives a distinct advantage to Canadian developers over their U.S. counterparts in the competition for refinery market share, especially in the near term.

Notwithstanding the extensive mine site upgrading discussed previously, the potential refinery market for raw bitumen would be only incrementally different from the market available to producers of relatively heavy conventional or synthetic crudes, including synthetic crudes from tar sands. Refineries configured to accept heavier crude feedstocks, including Canadian synthetics upgraded to various degrees, would be in an ideal position with respect to processing capability to accept the raw bitumen. However, processing schemes are established against the characteristics of a particular crude feedstock or feedstock blend, and myriad process modifications are required before even modest changes in feedstock character are made. Thus, simple replacements of feedstocks are not necessarily straightforward operations even if the required processing units are in place. In addition to the unique processing requirements of each feedstock, available processing capacity for new sources is likely to be very limited. This is especially the case for refineries that have recently reconfigured to accept products from Canadian sources that currently import both synthetic crude and dil-bit into the United States as heavy crude feedstocks. All of the above being said, it is the case that PADD 4 refineries in closest proximity to the STSAs were some of the first U.S. refineries to reconfigure to accept Canadian synthetic crude. Refineries in Denver, Salt Lake City, and Cheyenne, among others, have reconfigured to accept Canadian feedstocks, including raw bitumens, and would be the most likely candidates for receipt of U.S. tar sands–derived crude feedstocks and/or raw bitumen.

The evolution of the refining industry toward heavier feedstocks bodes well for the tar sands industry in a general sense; however, there are still substantial supplies of conventional crude oils of equivalent densities and qualities against which unconventional or synthetic crudes such as those from tar sands must still compete. Those other conventional sources aside, however, of more immediate interest and concern to U.S. tar sands developers are the current and anticipated productions of Canadian tar sands–derived synthetic crudes, and especially the upgraded synthetic crudes that are now being offered.

5 CONCLUSIONS

Bitumen and synthetic crude oil derived from Canadian tar sands represent the most immediate and direct competition to U.S. tar sands–derived feedstocks for refinery market share. The enormous size of the Canadian tar sands resources, the maturity of the Canadian tar sands industry, the proven reliability and consistency of Canadian products, the ever expanding pipeline infrastructure devoted to delivering Canadian tar sands to U.S. refineries, and the ability of Canadian developers to undertake extensive upgrading of recovered bitumen at their mine sites to remove unfavorable characteristics all give Canadian developers substantial market advantages over U.S. developers.

Refineries in PADD 4 are geographically closest to each of the STSAs and have also already undertaken reconfiguration of their processing streams to accept heavy synthetic crude feedstocks, making them the most likely candidates to receive U.S. tar sands–derived feedstocks. However, Canadian imports of bitumen and synthetic crude are already being received at these refineries, and unused processing capacity is not expected to be available in any appreciable amount. It is possible that the current investment rate of transportation of Canadian crudes to alternative markets, such as the Gulf Coast (PADD 3), the West Coast (PADD 5), and international export to China and Asia could produce more competition for Canadian crudes over the long run and provide more economic room for tar sands–derived crude feedstock in PADD 4.

With a projected maximum collective production rate approaching only a total of about 300,000 bbl/day, the U.S. tar sands developments would not be large enough to single-handedly or collectively motivate significant expansions in either long-range crude pipeline transportation networks or refinery expansions, suggesting that penetration into the refinery market would be limited to refineries in the immediate vicinity of the STSAs, primarily the properly configured PADD 4 refineries. Only modest expansions of crude oil pipeline networks already in place in PADD 4 would be required to connect STSAs to PADD 4 refineries.

The market for PADD 4 refinery products is geographically constrained, thus even if additional processing capacity were to be made available by PADD 4 refinery expansions, construction and/or expansion of product pipelines to distant markets would need to occur before that additional processing capacity could be utilized.

6 REFERENCES

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APPENDIX C:

PROPOSED LAND USE PLAN AMENDMENTS ASSOCIATED WITH ALTERNATIVES B AND C FOR OIL SHALE AND TAR SANDS

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APPENDIX C:

PROPOSED LAND USE PLAN AMENDMENTS ASSOCIATED WITH ALTERNATIVES B AND C FOR OIL SHALE AND TAR SANDS

The U.S. Department of the Interior, Bureau of Land Management (BLM), develops land use plans to guide activities, establish management goals and approaches, and establish land use allocations within a planning area. Current land use plans are called Resource Management Plans (RMPs); in the past, such plans were called Management Framework Plans (MFPs), and some MFPs are still in use. Analyses conducted in this programmatic environmental impact statement (PEIS) support the amendment of specific land use plans in those field offices where oil shale and tar sands resources are located, as discussed in Chapters 2 and 6 of the PEIS. For oil shale, nine land use plans would be amended:

- Colorado
  – Glenwood Springs RMP (BLM 1988, as amended by the 2006 Roan Plateau Plan Amendment [BLM 2006a, 2007])
  – Grand Junction RMP (BLM 1987)
  – White River RMP (BLM 1997a, as amended by the 2006 Roan Plateau Plan Amendment [BLM 2006a, 2007])

- Utah
  – Book Cliffs RMP (BLM 1985)
  – Diamond Mountain RMP (BLM 1994)
  – Price River Resource Area MFP, as amended (BLM 1989)

- Wyoming
  – Great Divide RMP (BLM 1990)
  – Green River RMP (BLM 1997b, as amended by the Jack Morrow Hills Coordinated Activity Plan [BLM 2006b])
  – Kemmerer RMP (BLM 1986).

For tar sands, six land use plans would be amended:

- Book Cliffs RMP

- Diamond Mountain RMP

- Henry Mountain MFP, issued 1982

- Price River Resource Area MFP, as amended

- San Rafael Resource Area RMP (BLM 1991a)

- San Juan Resource Area RMP (BLM 1991b).

Table C-1 presents specific information regarding the proposed amendments for each land use plan that would be associated with Alternatives B and C for oil shale, and Table C-2 presents the same information for amendments associated with Alternatives B and C for tar sands. These tables describe the individual amendments for each plan, along with the rationale for the amendment. Some of the proposed amendments are common to all land use plans; these amendments are presented first in each table. Amendments specific to individual plans are presented in the latter section of each table.

TABLE C-1 Proposed Changes and Rationales for Land Use Plan Amendments Associated with Alternatives B and C for Oil Shale[a]

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Common to All Land Use Plans	
Identify the most geologically prospective oil shale areas within the planning unit. *Rationale:* In accordance with the requirements of Section 369(d)(1) of the Energy Policy Act of 2005, the BLM has identified the most geologically prospective oil shale resources in Colorado and Utah as those deposits that yield 25 gal of shale oil per ton of rock (gal/ton) or more and are 25 ft thick or greater. The most geologically prospective oil shale resources in Wyoming are defined as those deposits that yield 15 gal/ton of shale oil or more and are 15 ft thick or greater.[b]	Same as Alternative B.
Specify that commercial leasing will occur utilizing a lease by application process described in Section 2.2.3. The process will require that additional NEPA analysis be conducted prior to lease issuance. Information collected as part of the lease application process will be incorporated into the NEPA analysis. *Rationale:* The BLM has concluded that, at this time, it does not have adequate information on the (1) potential magnitude and pace of commercial development, (2) potential locations for commercial leases, (3) technologies that will be employed, (4) size or production level of individual commercial projects, and (5) development time lines for individual projects to support decisions about lease issuance. As a result, the BLM is deferring decisions regarding lease issuance into the future and specifying that prior to processing applications for commercial leases for oil shale development, applicants will be required to identify key information regarding aspects of the proposed development needed to support a complete NEPA review (e.g., technologies to be employed, level of planned development, anticipated	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
off-site impacts, strategies to comply with regulatory requirements, and so forth). During this NEPA review, the BLM will identify and establish appropriate lease stipulations to mitigate anticipated impacts.	
Specify that approval of the project-specific plan of operation will require NEPA review to consider site-specific and project-specific factors. The NEPA review for the plan of operations may be incorporated into NEPA for the lease application if adequate operational data are provided by the applicant(s).	Same as Alternative B.
Rationale: Conducting additional NEPA review prior to approval of project-specific plans of operation will allow the BLM to identify and require appropriate mitigation measures as needed to control impacts beyond those established in the lease stipulations.	
Specify that the BLM will consider and give priority to the use of land exchanges, where appropriate and feasible, to consolidate land ownership and mineral interests within the oil shale basins.	Same as Alternative B.
Rationale: Section 369(n) of the Energy Policy Act of 2005 requires the Secretary of the Interior (the "Secretary") to consider and give priority to the use of land exchanges to facilitate the recovery of unconventional fuels. The Act states "…to facilitate the recovery of oil shale and tar sands, especially in areas where Federal, State, and private lands are intermingled, the Secretary shall consider the use of land exchanges where appropriate and feasible to consolidate land ownership and mineral interests into manageable areas." The Act also dictates that any land exchange undertaken shall be implemented in accordance with Section 206 of FLPMA.	

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans	
Colorado	
Glenwood Springs RMP, Glenwood Springs Field Office	
Designate 12,424 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies.	Designate 3,532 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies.
Rationale: As discussed in Section 2.2.3.1, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	*Rationale:* As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
Specify that applications for commercial leases using surface mining technologies will not be accepted in the planning area.	Same as Alternative B.
Rationale: As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically, using today's technologies. Within the most geologically prospective oil shale area defined in the Piceance Basin in Colorado, the areas where the overburden is 0 to 500 ft thick are very limited, and it would be difficult to assemble a logical mining unit (see Figure 2.2-1).[c]	

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Grand Junction RMP, Grand Junction Field Office Designate 4,024 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. *Rationale:* As discussed in Section 2.2.3, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	Designate 4,014 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. *Rationale:* As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
Specify that applications for commercial leases using surface mining technologies will not be accepted in the planning area. *Rationale:* As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically, using today's technologies. Within the most geologically prospective oil shale area defined in the Piceance Basin in Colorado, the areas where the overburden is 0 to 500 ft thick are very limited, and it would be difficult to assemble a logical mining unit (see Figure 2.2-1).[b]	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
<u>White River RMP, White River Field Office</u> Designate 343,358 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. In addition, the existing decision in the White River RMP regarding the prohibition of oil shale leasing within the Piceance Creek Dome area would be eliminated, and the carrying-capacity thresholds for air quality, socioeconomic impacts, big game, and water quality would also be removed. Rationale: As discussed in Section 2.2.3, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	Designate 32,780 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. In addition, the existing decision in the White River RMP regarding the prohibition of oil shale leasing within the Piceance Creek Dome area would be eliminated, and the carrying-capacity thresholds for air quality, socioeconomic impacts, big game, and water quality would also be removed. Rationale: As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
Specify that applications for commercial leases using surface mining technologies will not be accepted in the planning area. *Rationale:* As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically using today's technologies. Within the most geologically prospective oil shale area defined in the Piceance Basin in Colorado, the areas where the overburden is 0 to 500 ft thick are very limited, and it would be difficult to assemble a logical mining unit (see Figure 2.2-1).[c]	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Specify that certain decisions regarding oil shale leasing and development contained in the current RMP will be removed from the RMP. Specifically, the decisions that will be removed include those designating (1) 223,860 acres of land as available for oil shale leases, of which 39,140 acres are available for surface mining, and (2) that lands within the “Piceance dome area” are currently closed to leasing for oil shale development. The RMP amendments will not reverse the existing decision regarding the 70,820-acre Multimineral Zone (see Figure 3.2.2-3) that requires that the commercial development of oil shale, nahcolite, and dawsonite will only be allowed in this area if recovery technologies are implemented to ensure that each of these minerals can be recovered without preventing recovery of the others. *Rationale:* The BLM has determined that it will make all lands within the most geologically prospective oil shale area available for application for leasing, except that surface mining lease applications will not be accepted (see above). The BLM also has determined that it will not preclude commercial oil shale leasing in areas, such as the Piceance dome area, where extensive oil and gas leases exist. Decisions about commercial mineral development will be driven by primary lease holders. The decision to maintain the restrictions associated with the Multimineral Zone will continue protection of the potential commercial value of all mineral resources within this area.	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Utah	
<u>Book Cliffs RMP, Vernal Field Office</u> Designate 473,936 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies.	Designate 423,434 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies.
Rationale: As discussed in Section 2.2.3, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	*Rationale:* As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
Specify that applications for commercial leases using surface mining technologies will only be accepted within an area of 85,640 acres within the most geologically prospective oil shale area where the overburden is 0 to 500 ft thick (see Figure 2.2-1). Applications for commercial leasing using surface mining technologies will not be accepted in any other areas.	Specify that applications for commercial leases using surface mining technologies will only be accepted within an area of 46,900 acres within the most geologically prospective oil shale area where the overburden is 0 to 500 ft thick (see Figure 2.2-1). Applications for commercial leasing using surface mining technologies will not be accepted in any other areas.
Rationale: As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where, surface mining can occur economically using today's technologies.	*Rationale:* As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically using today's technologies.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Specify that the Ute Indian Tribe will be consulted regarding potential leasing for commercial oil shale development on split estate lands located in the Hill Creek Extension of the Uintah and Ouray Reservation prior to considering any parcel for leasing; *Rationale:* During the tribal consultation process conducted in conjunction with this PEIS, the Ute Indian Tribe requested that such consultation be conducted.	No comparable amendment because the split estate lands in the Hill Creek Extension of the Uintah and Ouray Reservation are not available for application for leasing under Alternative C.
<u>Diamond Mountain RMP, Vernal Field Office</u> Designate 100,556 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. *Rationale:* As discussed in Section 2.2.3, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	Designate 74,359 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. *Rationale:* As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Specify that applications for commercial leases using surface mining technologies will not be accepted in the planning area. *Rationale:* As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically using today's technologies. Within the Diamond Mountain RMP planning area, there are no areas where the overburden is 0 to 500 ft thick (see Figure 2.2-1).[c]	Same as Alternative B.
<u>Price River Resource Area MFP, Price Field Office</u> Designate 107 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. *Rationale:* As discussed in Section 2.2.3, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	Designate 87 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. *Rationale:* As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
Specify that applications for commercial leases using surface mining technologies will not be accepted in the planning area.	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Rationale: As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically using today's technologies. Within the Price River Resource Area MFP planning area, there are no areas where the overburden is 0 to 500 ft thick (see Figure 2.2-1).[c]	
Wyoming	
<u>Great Divide RMP, Rawlins Field Office</u> Designate 68,405 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies.	Designate 40,376 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies.
Rationale: As discussed in Section 2.2.3, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	*Rationale:* As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Specify that applications for commercial leases using surface mining technologies will not be accepted in the planning area. *Rationale:* As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically using today's technologies. Within the Great Divide RMP planning area, there are no areas where the overburden is 0 to 500 ft thick (see Figure 2.2-1).[c]	Same as Alternative B.
Green River RMP, Rock Springs Field Office Designate 788,230 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. *Rationale:* As discussed in Section 2.2.3, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	Designate 209,616 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies. *Rationale:* As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
Specify that applications for commercial leases using surface mining technologies will only be accepted within an area of 248,000 acres within the most geologically prospective oil shale area where the overburden is 0 to 500 ft thick (see Figure 2.2-1). Applications for commercial leasing using surface mining technologies will not be accepted in any other areas.	Specify that applications for commercial leases using surface mining technologies will only be accepted within an area of 68,200 acres within the most geologically prospective oil shale area where the overburden is 0 to 500 ft thick (see Figure 2.2-1). Applications for commercial leasing using surface mining technologies will not be accepted in any other areas.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Rationale: As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically using today's technologies.	*Rationale:* As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically using today's technologies.
<u>Kemmerer RMP, Kemmerer Field Office</u> Designate 143,987 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies.	Designate 49,544 acres of land within the most geologically prospective oil shale area as available for application for leasing for commercial oil shale development in accordance with applicable federal and state regulations and BLM policies.
Rationale: As discussed in Section 2.2.3, all lands within the most geologically prospective oil shale area that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	*Rationale:* As discussed in Section 2.2.3.2, all lands within the most geologically prospective oil shale area that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
Specify that applications for commercial leases using surface mining technologies will not be accepted in the planning area.	Same as Alternative B.
Rationale: As discussed in Section 2.2.1, surface mining will only be allowed in areas where the overburden is 0 to 500 ft thick, because 500 ft is assumed to be the maximum amount of overburden where surface mining can occur economically using today's technologies. Within the Kemmerer RMP planning area, there are no areas where the overburden is 0 to 500 ft thick (see Figure 2.2-1).[c]	

Footnotes on following page.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C

[a] Abbreviations: BLM = Bureau of Land Management; FLPMA = Federal Land Policy and Management Act; MFP = Management Framework Plan; NEPA = National Environmental Policy Act; PEIS = programmatic environmental impact statement; RMP = Resource Management Plan.

[b] The most geologically prospective oil shale resources in Colorado were defined on the basis of digital data provided by the U.S. Geological Survey taken from Pitman and Johnson (1978), Pitman (1979), and Pitman et al. (1989). In Utah, the most geologically prospective oil shale resources were defined by digital data provided by the BLM Utah State Office. In Wyoming, the most geologically prospective oil shale resources were defined on the basis of detailed analyses of available oil shale assay data (Wiig 2006a,b). As discussed in Section 1.2, the oil shale resource is not of as high a quality in Wyoming as it is in Colorado and Utah; therefore, the most geologically prospective oil shale resources were defined on the basis of a lower yield and thickness.

[c] The areas within the most geologically prospective oil shale areas where the overburden is 0 to 500 ft thick were mapped on the basis of a variety of sources of information. In Colorado, the area was defined on the basis of data published in Donnell (1987). In Utah, the area was mapped on the basis of data provided by the Utah Geological Survey (Tabet 2007). In Wyoming, the area was mapped on the basis of data provided by Wiig (2006a,b).

TABLE C-2 Proposed Changes and Rationales for Land Use Plan Amendments Associated with Alternatives B and C for Tar Sands[a]

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Common to All Land Use Plans	
Specify that commercial leasing will occur utilizing a lease by application process described in Section 2.3.3. The process will require that additional NEPA analysis be conducted prior to lease issuance. Information collected as part of the lease application process will be incorporated into the NEPA analysis. *Rationale:* The BLM has concluded that, at this time, it does not have adequate information on the (1) potential magnitude and pace of commercial development, (2) potential locations for commercial leases, (3) technologies that will be employed, (4) size or production level of individual commercial projects, and (5) development time lines for individual projects to support decisions about lease issuance. As a result, the BLM is deferring decisions regarding lease issuance into the future and specifying that prior to processing applications for commercial leases for tar sands development, applicants will be required to identify key information regarding aspects of the proposed development needed to support a complete NEPA review (e.g., technologies to be employed, level of planned development, anticipated off-site impacts, strategies to comply with regulatory requirements, etc.). During this NEPA review, the BLM will identify and establish appropriate lease stipulations to mitigate anticipated impacts.	Same as Alternative B.
Specify that approval of the project-specific plan of operation will require NEPA review to consider site-specific and project-specific factors. The NEPA review for the plan of operations may be incorporated into NEPA for the lease application if adequate operational data are provided by the applicant(s). *Rationale:* Conducting additional NEPA review prior to approval of project-specific plans of operation will allow the BLM to identify and require appropriate mitigation measures as needed to control impacts beyond those established in the lease stipulations.	Same as Alternative B.

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Specify that the BLM will consider and give priority to the use of land exchanges, where appropriate and feasible, to consolidate land ownership and mineral interests within the STSAs. *Rationale:* Section 369(n) of the Energy Policy Act of 2005 requires the Secretary of the Interior (the "Secretary") to consider and give priority to the use of land exchanges to facilitate the recovery of unconventional fuels. The Act states "…to facilitate the recovery of oil shale and tar sands, especially in areas where Federal, State, and private lands are intermingled, the Secretary shall consider the use of land exchanges where appropriate and feasible to consolidate land ownership and mineral interests into manageable areas." The Act also dictates that any land exchange undertaken shall be implemented in accordance with Section 206 of FLPMA.	Same as Alternative B.
Amendments Specific to Individual Plans	
Book Cliffs RMP, Vernal Field Office Designate the following amounts of land within the specific STSAs as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies: Hill Creek STSA: 56,506 acres P.R. Spring STSA: 153,003 acres[c] Raven Ridge STSA: 14,364 acres *Rationale:* As discussed in Section 2.3.3, all lands within the designated STSAs that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimates presented here represent those lands not excluded from commercial leasing under Alternative B.	Designate the following amounts of land within the specific STSAs as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies: Hill Creek STSA: 19,934 acres P.R. Spring STSA: 56,728 acres[c] Raven Ridge STSA: 9,950 acres *Rationale:* As discussed in Section 2.3.3.2, all lands within the designated STSAs that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimates presented here represent those lands not excluded from commercial leasing under Alternative C.

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Specify that the Ute Indian Tribe will be consulted regarding potential leasing for commercial tar sands development on split estate lands located in the Hill Creek Extension of the Uintah and Ouray Reservation prior to considering any parcel for leasing. These lands fall entirely within the Hill Creek STSA. *Rationale:* During the tribal consultation process conducted in conjunction with this PEIS, the Ute Indian Tribe requested that such consultation be conducted.	No comparable amendment because the split estate lands in the Hill Creek Extension of the Uintah and Ouray Reservation are not available for application for leasing under Alternative C.
<u>Diamond Mountain RMP, Vernal Field Office</u> Designate the following amounts of land within the specific STSAs as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies: Argyle Canyon STSA: 11,226 acres Asphalt Ridge STSA: 5,435 acres Sunnyside STSA: 16,101 acres *Rationale:* As discussed in Section 2.3.3, all lands within the designated STSAs that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimates presented here represent those lands not excluded from commercial leasing under Alternative B.	Designate the following amounts of land within the specific STSAs as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies: Argyle Canyon STSA: 0 acres Asphalt Ridge STSA: 1,464 acres Sunnyside STSA: 1,199 acres *Rationale:* As discussed in Section 2.3.3.2, all lands within the designated STSAs that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimates presented here represent those lands not excluded from commercial leasing under Alternative C.

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
<u>Henry Mountain MFP, Richfield Field Office</u> Designate 24,938 acres of land within the Tar Sand Triangle STSA as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies.	Designate 22,511 acres of land within the Tar Sand Triangle STSA as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies.
Rationale: As discussed in Section 2.3.3, all lands within the designated STSAs that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	*Rationale:* As discussed in Section 2.3.3.2, all lands within the designated STSAs that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
<u>Price River Resource Area MFP, Price Field Office</u> Designate the following amounts of land within the specific STSAs as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies:	Designate the following amounts of land within the specific STSAs as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies:
San Rafael STSA: 125 acres Sunnyside STSA: 62,076 acres	San Rafael STSA: 30 acres Sunnyside STSA: 61,602 acres
Rationale: As discussed in Section 2.3.3, all lands within the designated STSAs that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimates presented here represent those lands not excluded from commercial leasing under Alternative B.	*Rationale:* As discussed in Section 2.3.3.2, all lands within the designated STSAs that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimates presented here represent those lands not excluded from commercial leasing under Alternative C.

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
<u>San Rafael Resource Area RMP, Price Field Office</u> Designate 70,348 acres of land within the San Rafael STSA as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies.	Designate 54,460 acres of land within the San Rafael STSA as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies.
Rationale: As discussed in Section 2.3.3, all lands within the designated STSAs that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	*Rationale:* As discussed in Section 2.3.3.2, all lands within the designated STSAs that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.
<u>San Juan Resource Area RMP, Monticello Field Office</u> Designate 7,001 acres of land within the White Canyon STSA as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies.	Designate 386 acres of land within the White Canyon STSA as available for application for leasing for commercial tar sands development in accordance with applicable federal and state regulations and BLM policies.
Rationale: As discussed in Section 2.3.3, all lands within the designated STSAs that are not excluded from commercial leasing by existing laws and regulations, Executive Orders, or administrative land use plan designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative B.	*Rationale:* As discussed in Section 2.3.3.2, all lands within the designated STSAs that are excluded from commercial leasing under Alternative B, also will be excluded under Alternative C. In addition, lands that are identified as requiring special management or resource protection in existing land use plans also will be excluded in order to provide maximum protection to the resources present in those areas. The acreage estimate presented here represents those lands not excluded from commercial leasing under Alternative C.

Footnotes on following page.

TABLE C-2 (Cont.)

[a] Abbreviations: BLM = Bureau of Land Management, FLPMA = Federal Land Policy and Management Act; MFP = Management Framework Plan; NEPA = National Environmental Policy Act; PEIS = programmatic environmental impact statement; RMP = Resource Management Plan; STSA = Special Tar Sand Area.

[b] The tar sands resources available for application for leasing under Alternatives B and C include deposits located in the designated STSAs described in the geologic reports (minutes) prepared by the U.S. Geological Survey (USGS) in 1980 (USGS 1980a–k) and formalized by Congress in the Combined Hydrocarbon Leasing Act of 1981 (Public Law 97-78). The boundaries of the designated STSAs were determined by the Secretary of the Interior's orders of November 20, 1980 (Volume 45, pages 76800–76801 [45 FR 76800–76801]), and January 21, 1981 (46 FR 6077–6078).

[c] A portion of the P.R. Spring STSA extends south from the Vernal Field Office boundary into the Moab Field Office boundary; however, this area is administered by the Vernal Field Office under a Memorandum of Understanding with the Moab Field Office. Under this agreement, the Vernal Field Office administers all resources and programs, including land use planning, for the entire P.R. Spring STSA. Therefore, the Moab Field Office plan is not impacted by this PEIS. Under Alternative B, the acreage in the P.R. Spring STSA includes 14,406 acres of land within the Moab Field Office boundary. Under Alternative C, the acreage in the P.R. Spring STSA includes 1,874 acres of land within the Moab Field Office boundary.

APPENDIX C REFERENCES

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APPENDIX D:

FEDERAL, STATE, AND COUNTY REGULATORY REQUIREMENTS POTENTIALLY APPLICABLE TO OIL SHALE AND TAR SANDS DEVELOPMENT PROJECTS

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APPENDIX D:

FEDERAL, STATE, AND COUNTY REGULATORY REQUIREMENTS POTENTIALLY APPLICABLE TO OIL SHALE AND TAR SANDS DEVELOPMENT PROJECTS

D.1 REGULATORY CITATIONS AND STATUTORY AUTHORITIES

The tables that follow list the major federal, state, and county laws, Executive Orders, and other compliance instruments that establish permits, approvals, or consultations that may apply to the construction and operation of either an oil shale development project or development within a Special Tar Sand Area on public lands in Colorado, Utah, and Wyoming. The general application of these federal, state, and county authorities and other regulatory considerations associated with such construction and operation are discussed in Chapter 2.

Tables D-1 through D-14 are divided into general environmental impact categories. The citations in the tables are those of the general statutory authority that governs the indicated category of activities to be undertaken under the proposed action and alternatives. Under such statutory authority, the lead federal, state, or county agency may have promulgated implementing regulations that set forth the detailed procedures for permitting and compliance.

Definitions of abbreviations used in the tables are provided here.

App.	Appendix
BLM	Bureau of Land Management
CCDC	*Carbon County Development Code (Carbon County, Utah)*
CFR	*Code of Federal Regulations*
CRS	*Colorado Revised Statues*
DCC	*Duchesne County Code (Duchesne County, Utah)*
ECGP	Emery County General Plan (Emery County, Utah)
ECZO	Emery County Zoning Ordinance (Emery County, Utah)
GCLUC	*Grand County Land Use Code (Grand County, Utah)*
GCLUR	Garfield County Land Use Resolution (draft) (Garfield County, Colorado)
LCLUR	*Lincoln County Land Use Regulations (Lincoln County, Wyoming)*

MCMP	Moffat County Master Plan (Moffat County, Colorado)
NA	Not applicable
RBCLUR	*Rio Blanco County Land Use Resolution (Rio Blanco County, Colorado)*
SCDUDC	*Sweetwater County Draft Unified Development Code (Sweetwater County, Wyoming)*
SCZDRR	Sublette County Zoning and Development Regulations Resolutions (Sublette County, Wyoming)
SJCZO	San Juan County Zoning Ordinance (San Juan County, Utah)
UCA	*Utah Code Annotated (Grand County, Utah)*
UCC	*Utah County Code (Utah County, Utah)*
UCUC	*Unitah County Utah Code (Unitah County, Utah)*
USC	*United States Code*
WCC	*Wasatch County Code (Wasatch County, Utah)*
WS	*Wyoming Statutes*

TABLE D-1 Air Quality

Authority	Citation
Federal	• Clean Air Act (42 USC 7401 et seq.)
Colorado	• Air Quality Control (CRS 25-7-101 et seq.) – Garfield County: Air Quality (GCLUR 7-208) – Rio Blanco County: Air (RBCLUR 258)
Utah	• Air Conservation Act (UCA 19-2-101 et seq.) – Carbon County: NA – Duchesne County: Extraction of Earth Products (DCC 17.52.052) – Emery County: NA – Garfield County: NA – Grand County: NA – San Juan County: NA – Uintah County: NA – Utah County: NA – Wasatch County: Prohibition of Undesirable Emissions (WCC 16.28.02) – Wayne County: NA
Wyoming	• Air Quality (WS 35-11-201 et seq.) – Lincoln County: NA – Sublette County: Air Quality (SCZDRR 17) – Sweetwater County: NA – Uinta County: NA

TABLE D-2 Cultural Resources and Native Americans

Authority	Citation
Federal	• Native American Graves Protection and Repatriation Act (25 USC 3001 et seq.) • American Indian Religious Freedom Act (42 USC 1996 et seq.) • Archeological Resources Protection Act (16 USC 470(aa) et seq.) • Archeological and Historic Preservation Act (16 USC 469 et seq.) • Historic Sites, Buildings, and Antiquities Act (Historic Sites Act) (16 USC 461 et seq.) • Antiquities Act (16 USC 431 et seq.) • National Historic Preservation Act (16 USC 470 et seq.) • Theft and Destruction of Government Property (18 USC 641 et seq., 1361 et seq.) • Executive Order 11593, "Protection and Enhancement of the Cultural Environment," May 13, 1971 • Executive Order 13007, "Indian Sacred Sites," May 24, 1996 • Executive Order 13175, "Consultation and Coordination with Indian Tribal Governments," November 6, 2000 • Executive Order 13287, "Preserve America," March 3, 2003
Colorado	• Historical, Prehistorical, and Archeological Resources (CRS 24-80-401 et seq.) • Unmarked Human Graves (CRS 24-80-1301 et seq.) – Garfield County: NA – Rio Blanco County: NA
Utah	• History Development (UCA 9-8-102 et seq.) • Native American Graves Protection and Repatriation Act (UCA 9-9-102 et seq.) – Carbon County: HMC Historic Mining Camp Zone (CCDC 4.2.21) – Duchesne County: NA – Emery County: Position Statement—Preservation of Cultural and Historical Heritage Resources (ECGP p. 24) – Garfield County: NA – Grand County: NA – San Juan County: NA – Uintah County: Historic Preservation Commission (UCUC 2.24) – Utah County: Historic Preservation Commission (UCC 25) – Wasatch County: NA – Wayne County: NA
Wyoming	• Protection of Prehistoric Ruins (WS 36-1-114 et seq.) – Lincoln County: NA – Sublette County: NA – Sweetwater County: NA – Uinta County: NA

TABLE D-3 Energy Project Siting

Authority	Citation
Federal	• Natural Gas Act (15 USC 717 et seq.) • Natural Gas Policy Act (15 USC 3301 et seq.) • Federal Power Act (16 USC 791a et seq.) • Public Utilities Regulatory Policies Act (16 USC 2601 et seq.) • Energy Supply and Environmental Coordination Act (15 USC 791 et seq.) • Energy Policy and Conservation Act (42 USC 6201 et seq.) • Surface Mining Control and Reclamation Act (30 USC 1201 et seq.) • Accountable Pipeline Safety and Partnership Act of 1996 (49 USC 60101 et seq.) • Energy Policy Act of 2005 (Public Law 109-58) • Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," February 11, 1994
Colorado	• Local Government Regulation—Location, Construction, or Improvement of Major Electrical or Natural Gas Facilities—Legislative Declaration (CRS 29-20-108) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.) – Garfield County: Fiscal Impact Mitigation Program (GCLUR Article IV, Division 5) – Rio Blanco County: NA
Utah	• Electric Power Facilities Act (UCA 54-9-101 et seq.) • Natural Gas Pipeline Safety Act (UCA 54-13-1 et seq.) • Electricity Facility Review Board Act (UCA 54-14-101 et seq.) – Carbon County: Major Underground and Surface Mine Developments (CCDC 5.4); Major Utility Transmissions and Railroad Projects (CCDC 5.5) – Duchesne County: NA – Emery County: Mining, Grazing, and Recreation (MG &R-1) Zone (ECZO 9-4); Gas and Oil Wells (ECZO 11-2-1); Oil and Gas Operation (ECZO 11-3-5); and Position Statement—Oil and Gas Exploration and Production (ECGP p. 21) – Garfield County: NA – Grand County: Site Development Standards (GCLUC 4) – San Juan County: NA – Uintah County: NA – Utah County: NA – Wasatch County: NA – Wayne County: NA
Wyoming	• Industrial Development and Siting (WS 35-12-101 et seq.) • Electric Utilities (WS 37-16-101 et seq.) • Wyoming Energy Commission (WS 30-7-101) – Lincoln County: NA – Sublette County: NA – Sweetwater County: Commercial Wind Energy Conversion Systems (SCDUDC X.7) – Uinta County: NA

TABLE D-4 Floodplains and Wetlands

Authority	Citation
Federal	• Clean Water Act (33 USC 1344) • Rivers and Harbors Act of 1899 (33 USC 401 et seq.) • Executive Order 11988, "Floodplain Management," May 24, 1977 • Executive Order 11990, "Protection of Wetlands," May 24, 1977
Colorado	• Drainage of State Lands (CRS 37-30-101 et seq.) • Marsh Land (CRS 37-33-101 et seq.) – Garfield County: Protection of Wetlands and Waterbodies (GCLUR 7-203) – Rio Blanco County: Wetlands (RBCLUR 256)
Utah	• Plan Preparation (UCA 10-9a-403) • Plan Preparation (UCA 17-27a-403) – Carbon County: FPO (Floodplain Overlay Zone) (CCDC 4.2.22) – Duchesne County: NA – Emery County: Wetlands (ECGP p. 64) – Garfield County: NA – Grand County: Floodplains, Natural, and Historic Drainages (GCLUC 4.8) – San Juan County: Construction Subject to Geologic, Flood, or Other Natural Hazard (SJCZO 9-1) – Uintah County: Floodplain Regulations (UCUC 17.84); Flood Hazard Areas (UCUC 14.12) – Utah County: NA – Wasatch County: Stream Corridor/Wetland Development Standards (WCC 6.28.04) – Wayne County: NA
Wyoming	• Legislative Policy and Intent (WS 35-11-309 et seq.) • Application for Permit; Generally; Denial; Limitations (WS 35-11-406 (b)(v); (xv)) – Lincoln County: Flood Overlay (LCLUR App. I) – Sublette County: Flood Areas (SCZDRR 13) – Sweetwater County: Floodplain Areas (SCDUDC IX.4.2) – Uinta County: NA

TABLE D-5 Groundwater, Drinking Water, and Water Rights

Authority	Citation
Federal	• Safe Drinking Water Act (42 USC 300(f) et seq.)
Colorado	• Water Right Determination and Administration (CRS-37-92-101 et seq.) • Water Quality Control (CRS 25-8-101 et seq.) – Garfield County: NA – Rio Blanco County: NA
Utah	• Safe Drinking Water Act (UCA 19-4-101 et seq.) • Ground Water Recharge and Recovery Act (UCA 73-3b-101 et seq.) • Appropriation (UCA 73-3-1 et seq.) • Determination of Water Rights (UCA 73-4-1 et seq.) • Withdrawal of Unappropriated Water (UCA 73-6-1 et seq.) – Carbon County: Culinary Water (CCDC 6.7.2) – Duchesne County: NA – Emery County: Water Quality and Quantity (ECGP p. 57); Water Rights/Allocation (ECGP p. 59); and Groundwater (ECGP p. 61) – Garfield County: NA – Grand County: NA – San Juan County: NA – Uintah County: NA – Utah County: Potable Water (UCC 13-4-3-4); Wells (UCC 17-3-3-8) – Wasatch County: Adequate Water Rights Required (WCC 10.01.01) – Wayne County: NA
Wyoming	• Water Rights; Administration and Control (WS 41-3-101) • Board of Control; Adjudication of Water Rights (WS 41-4-101) • Prohibited Acts (WS 35-11-301 et seq.) • Protection of the Surface Owner (WS 35-11-416(b)) – Lincoln County: Wellhead and Surface Water Protection Standards (LCLUR 6.27) – Sublette County: Water Supply and Distribution Systems (SCZDRR 17); Easements for Public Water and Sewer, and Drainage and Other Utilities (SCDUDC IX.5.6) – Sweetwater County: Public Water Construction and Installation Requirements (SCDUDC IX.5.3); Private Wells and Water Systems (SCDUDC IX.5.4) – Uinta County: NA

TABLE D-6 Hazardous Materials

Authority	Citation
Federal	• Hazardous Materials Transportation Act (49 USC 5101 et seq.) • Emergency Planning and Community Right-to-Know Act of 1986 (42 USC 11001 et seq.) • Oil Pollution Control Act (33 USC 2701 et seq.) • Pollution Prevention Act of 1990 (42 USC 13101 et seq.) • Comprehensive Environmental Response, Compensation, and Liability Act (42 USC 9601 et seq.) • Executive Order 12856, "Federal Compliance with Right-to-Know Laws and Pollution Prevention Requirements," August 3, 1993
Colorado	• Implementation of Title III of Superfund Act (CRS 24-32-2601 et seq.) • Hazardous Substances (CRS 25-5-501 et seq.) • Pollution Prevention (CRS 25-16.5-101 et seq.) – Garfield County: Additional Standards Applicable to Storage Areas and Facilities (GCLUR 7-819) – Rio Blanco County: NA
Utah	• Hazardous Materials—Transportation Regulations (UCA 41-6a-1639) • Hazardous Materials Emergency—Recovery of Expenses (UCA 53-2-105) – Carbon County: NA – Duchesne County: (title not available) (DCC 8.16.040) – Emery County: NA – Garfield County: NA – Grand County: Waste Materials Management (GCLUC 3.3.2Z) – San Juan County: NA – Uintah County: NA – Utah County: Hazardous Materials (UCC 9-7) – Wasatch County: Hazardous Materials Planning (WCC 7.09) – Wayne County: NA
Wyoming	• Authority of Department to Adopt Rules and Regulations Governing Drivers, Equipment, and Hazardous Materials (WS 31-18-303) • Application for Permit; Generally; Denial; Limitations (WS 35-11-406 (b)(ix)) • Mineral Mining Permits and Testing Licenses (WS 35-11-426) – Lincoln County: NA – Sublette County: NA – Sweetwater County: NA – Uinta County: NA

TABLE D-7 Hazardous Waste and Polychlorinated Biphenyls

Authority	Citation
Federal	• Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act and the Hazardous Solid Waste Amendments of 1984 (42 USC 6901 et seq.) • Toxic Substances Control Act (15 USC 2605(e))
Colorado	• Hazardous Waste (CRS 25-15-101 et seq.) – Garfield County: NA – Rio Blanco County: NA
Utah	• Solid and Hazardous Waste Act (UCA 19-6-101 et seq.) – Carbon County: NA – Duchesne County: NA – Emery County: NA – Garfield County: NA – Grand County: Waste Transport and Transporters (GCLUC 3.3.2Z.1) – San Juan County: NA – Uintah County: NA – Utah County: NA – Wasatch County: Solid and Hazardous Waste (WCC 13) – Wayne County: NA
Wyoming	• Solid Waste Management (WS 35-11-501 et seq.) – Lincoln County: NA – Sublette County: NA – Sweetwater County: NA – Uinta County: NA

TABLE D-8 Land Use

Authority	Citation
Federal	• Federal Land Policy and Management Act of 1976 (43 USC 1701 et seq.) • Mineral Leasing Act (30 USC 181 et seq.) • Coastal Zone Management Act, as amended by Coastal Zone Reauthorization Amendments of 1990 (16 USC 1451 et seq.) • Wild and Scenic Rivers Act (16 USC 1271 et seq.) • National Trails System Act (16 USC 1241 et seq.) • National Park Service Organic Act (16 USC 1 et seq.) • Wilderness Act (16 USC 1311 et seq.) • Federal Land Exchange Facilitation Act (43 USC 1716) • Federal Land Transaction Facilitation Act (43 USC 2301 et seq.) • Farmland Protection and Policy Act (7 USC 4201) • Soil and Water Resources Conservation Act of 1977 (16 USC 2001 et seq.) • Oregon and California Grant Lands Act of 1937 (43 USC 1181 a, b, d–f) • An Act to Establish the Glen Canyons National Recreation Area in the States of Arizona and Utah (16 USC 460 dd)
Colorado	• Areas and Activities of State Interest (CRS 24-65.1-101 et seq.) • Local Government Land Use Control Enabling Act (CRS 29-20-101 et seq.) • County Planning (CRS 30-28-101 et seq.) • (Municipal) Planning and Zoning (CRS 31-23-101 et seq.) – Garfield County: Fiscal Impact Mitigation Program (GCLUR Article IV, Division 5) – Rio Blanco County: Process Generation, Collection, and Distribution Systems (RBCLUR 407); Special and Conditional-Use Permits (RBCLUR 54)
Utah	• Quality Growth Act (UCA 11-38-101 et seq.) • Environmental Institutional Control Act (UCA 19-10-101 et seq.) • Municipal Land Use, Development, and Management (UCA 10-9a-101 et seq.) • County Land Use, Development, and Management (UCA 17-27a-101 et seq.) • Critical Land Near State Prison: Definitions - Preservation as Open Land - Management and Use of Land - Restrictions on Transfer - Wetlands Development - Conservation Easement (UCA 23A-5-222) – Carbon County: Carbon County Development Code – Duchesne County: Conditional Use Permit (DCC 17.52) – Emery County: Zoning Ordinance for Emery County; Public Lands, Federal and State Agencies (ECGP p. 16) – Garfield County: Zoning Ordinance – Grand County: Zoning District Regulation (GCLUC 3) – San Juan County: San Juan County Zoning Ordinance – Uintah County: Mining and Grazing Zone (UCUC 17.60) – Utah County: Utah County Land Use Ordinance; Agriculture Protection Area (UCC 26) – Wasatch County: Land Use and Development Code (WCC 16) – Wayne County: NA

TABLE D-8 (Cont.)

Authority	Citation
Wyoming	• Land Quality (WS 35-11-401 et seq.) • Mineral Leases (WS 36-6-101 et seq.) • Carey Act Lands (WS 36-7-101 et seq.) • Sale of State Lands (WS 36-9-101 et seq.) • United States Lands (WS 36-10-101 et seq.) • State Control of Certain Land (WS 36-12-101 et seq.) • Counties Planning and Zoning (WS 18-5-101 et seq.) – Lincoln County: Lincoln County Land Use Regulations – Sublette County: Conformity with Development Standards (SCZDRR 1); Mining Operations (SCZDRR 21) – Sweetwater County: Sweetwater Draft Unified Development Code; Sweetwater County Zoning Resolution – Uinta County: Land Use Certificate

TABLE D-9 Noise

Authority	Citation
Federal	• Noise Control Act, as amended by Quiet Communities Act (42 USC 4901 et seq.)
Colorado	• Noise Abatement (CRS 25-12-101 et seq.) – Garfield County: Fiscal Impact Mitigation Program (GCLUR Article IV, Division 5) – Rio Blanco County: Noise (RBCLUR 260)
Utah	• No specific primary statutory authority – Carbon County: NA – Duchesne County: Nuisances (DCC 8.16.100) – Emery County: NA – Garfield County: NA – Grand County: Noise (GCLUC 4.11.3) – San Juan County: NA – Uintah County: NA – Utah County: Unreasonable Noise (UCC 12-3) – Wasatch County: Noise Ordinance (WCC 12.03) – Wayne County: NA
Wyoming	• No specific primary statutory authority – Lincoln County: NA – Sublette County: Noise (SCZDRR 14) – Sweetwater County: NA – Uinta County : NA

TABLE D-10 Pesticides and Noxious Weeds

Authority	Citation
Federal	• Federal Insecticide, Fungicide, and Rodenticide Act (7 USC 136 et seq.) • Noxious Weed Act of 1974, as amended by Section 15—Management of Undesirable Plants on Federal Lands, 1990 (7 USC 2801 et seq.)
Colorado	• Pesticide Act (CRS 35-9-101 et seq.) – Garfield County: Fiscal Impact Mitigation Program (GCLUR Article IV, Division 5) – Rio Blanco County: Weeds and Invasive Species (RBCLUR 261)
Utah	• Utah Pesticide Control Act (UCA 4-14-1 et seq.) – Carbon County: NA – Duchesne County: (no title available) (DCC 8.16.070) – Emery County: NA – Garfield County: NA – Grand County: Grading, Revegetation, and Restoration (GCLUC 4.9.9) – San Juan County: NA – Uintah County: NA – Utah County: Standards of Weed Control (UCC 12-2-9) – Wasatch County: Weed Control (WCC 12.02) – Wayne County: NA
Wyoming	• Weed and Pest Control (WS 11-5-101 et seq.) – Lincoln County: Wyoming Statutes, Weed Control and Agricultural Uses (LCLUR App. I) – Sublette County: NA – Sweetwater County: NA – Uinta County: NA

TABLE D-11 Solid Waste

Authority	Citation
Federal	• Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act and the Hazardous Solid Waste Amendments of 1984 (42 USC 6901 et seq.)
Colorado	• Solid Waste Disposal Sites and Facilities (CRS 30-20-100.5 et seq.) – Garfield County: Additional Standards Applicable to Solid Waste Disposal Sites (GCLUR 7-818) – Rio Blanco County: Waste Disposal (RBCLUR 257)
Utah	• Solid Waste Management Act (UCA 19-6-501 et seq.) – Carbon County: NA – Duchesne County: (no title available) (DCC 8.20) – Emery County: NA – Garfield County: NA – Grand County: Waste Materials Management (GCLUC 3.3.2Z) – San Juan County: NA – Uintah County: Sanitation—Management of Solid Waste (UCUC 8.24) – Utah County: Solid Waste (UCC 20) – Wasatch County: Solid and Hazardous Waste (WCC 13) – Wayne County: NA
Wyoming	• Solid Waste Management (WS 35-11-501 et seq.) • Solid Waste Disposal Districts (WS 18-11-101 et seq.) • Definitions (WS 35-11-103 (d)(ii)) – Lincoln County: Solid Waste Disposal (LCLUR Sec 6.24) – Sublette County: Sanitary Landfills (SCZDRR 24) – Sweetwater County: Debris and Waste (SCDUDC IX.2.6) – Uinta County: NA

TABLE D-12 Source Water Protection

Authority	Citation
Federal	• Safe Drinking Water Act (42 USC 300h et seq.)
Colorado	• Water Quality Control (CRS 25-8-101 et seq.) – Garfield County: Protection of Water Quality from Pollutants (GCLUR 7-204) – Rio Blanco County: NA
Utah	• Water Quality Act (UCA 19-5-101 et seq.) – Carbon County: Culinary Water (CCDC 6.7.2) – Duchesne County: NA – Emery County: Water Quality and Quantity (ECGP p. 57) – Garfield County: NA – Grand County: Water Supply (GCLUC 5.6) – San Juan County: NA – Uintah County: NA – Utah County: Water Systems Operated by Utah County (UCC 27); Emergency Water Supplies (UCC 9-6-4) – Wasatch County: Water Quality (WCC 16.28.03) – Wayne County: NA
Wyoming	• Protection of Public Water Supply (WS 35-4-201 et seq.) • Prohibited Acts (WS 35-11-301 et seq.) • Application for Permit; Generally; Denial; Limitations (WS 35-11-406 (b)(ix)) – Lincoln County: Wellhead and Source Water Protection Standards (LCLUR 6.27) – Sublette County: NA – Sweetwater County: Water Supply (SCDUDC IX.1.4.2) – Uinta County: NA

TABLE D-13 Water Bodies and Wastewater

Authority	Citation
Federal	• Clean Water Act (33 USC 1251 et seq.)
Colorado	• Water Quality Control (CRS 25-8-101 et seq.) • Water and Wastewater Treatment Plant Operations (CRS 25-9-101 et seq.) – Garfield County: Adequate Water Distribution and Wastewater Systems (GCLUR 7-105); Stormwater Run-Off (GCLUR 7-207) – Rio Blanco County: Water Quality, Stormwater, Drainage (RBCLUR 255)
Utah	• Water Quality Act (UCA 19-5-101 et seq.) – Carbon County: Sewers (CCDC 6.7.3); Storm Drains and Facilities (CCDC 6.7.2) – Duchesne County: NA – Emery County: Water Quality and Quantity (ECGP p. 57); Conveyance Systems (ECGO p. 63); In-Stream Flow (ECGP p. 63); and Salinity (ECGP p. 65) – Garfield County: NA – Grand County: Sewage Disposal (GCLUC 5.8) – San Juan County: NA – Uintah County: NA – Utah County: Location of Sewers (UCC 17-3-3-4); Ditches and Waterways (UCC 17-3-3-5); and Protection of Watercourses (UCC 17-5-3-7) – Wasatch County: Water Quality (WCC 16.28.03); Wastewater Disposal Systems (WCC 10.02) – Wayne County: NA
Wyoming	• Water Quality (WS 35-11-301 et seq.) • Application for Permit; Generally; Denial; Limitations (WS 35-11-406 (b)(ix)) – Lincoln County: Small Wastewater Facility Permit (LCLUR 2.5.C); Small Wastewater Design Regulations (LCLUR App. E) – Sublette County: Erosion Control (SCZDRR 11); Drainage (SCZDRR 12) – Sweetwater County: Wastewater and Sewage (SCDUDC IX.1.2.3); Storm Water Management (SCDUDC IX.1.2.4); Waterbodies and Watercourses (SCDUDC IX.2.7); Drainage and Storm Sewers (SCDUDC IX.4); and Water and Sewer Facilities (SCDUDC IX.5) – Uinta County: NA

TABLE D-14 Wildlife and Plants

Authority	Citation
Federal	• Fish and Wildlife Coordination Act (16 USC 661 et seq.) • Bald and Golden Eagle Protection Act (16 USC 668 et seq.) • National Wildlife Refuge System Administration Act (16 USC 668dd) • Migratory Bird Treaty Act (16 USC 703 et seq.) • Endangered Species Act (16 USC 1531 et seq.) • Wild Free-Roaming Horses and Burros Act (16 USC 1331 et seq.) • Executive Order 12996, "Management and General Public Use of the National Wildlife Refuge System," March 25, 1996 • Executive Order 13112, "Invasive Species," February 3, 1999 • Executive Order 13186, "Responsibilities of Federal Agencies to Protect Migratory Birds," January 10, 2001
Colorado	• Nongame and Endangered Species Conservation (CRS 33-2-101 et seq.) • Migratory Birds, Possession of Raptors, Reciprocal Agreements (CRS 33-1-115) • Protection of Fishing Streams (CRS 33-5-101 et seq.) • Nongame and Endangered Species Conservation (CRS 33-2-101 et seq.) • Colorado Natural Areas (CRS 33-33-101 et seq.) – Garfield County: Protection of Wildlife Habitat Areas (GCLUR 7-202); Additional Standards Applicable to Mining and Extraction Uses (GCLUR 7-813) – Rio Blanco County: Wildlife (RBCLUR 259)
Utah	• Wildlife Resources Code of Utah (UCA 23-13-1 et seq.) – Carbon County: NA – Duchesne County: NA – Emery County: Position Statement—Wilderness Designations and Other Public Lands Management Considerations (ECGP p. 19) – Garfield County: NA – Grand County: NA – San Juan County: NA – Uintah County: NA – Utah County: Wild Animals (UCC 5-2-10) – Wasatch County: Wildlife Habitat Protection (WCC 16.28.05) – Wayne County: NA
Wyoming	• Bird and Animal Provisions (WS 23-3-101 et seq.) • Predatory Animals—Control Generally (WS 11-6-101 et seq.) • Application for Permit; Generally; Denial; Limitations (WS 35-11-406 (a)(vii)) – Lincoln County: NA – Sublette County: NA – Sweetwater County: Preservation of Natural Features and Amenities (SCDUDC IX.9) – Uinta County: NA

D.2 ADDITIONAL INFORMATION REGARDING THE REGULATORY AND POLICY ENVIRONMENT

D.2.1 Air Quality

The U.S. Environmental Protection Agency (EPA) establishes and revises the National Ambient Air Quality Standards (NAAQS), as necessary, to protect public health and welfare, setting the absolute upper limits for specific air pollutant concentrations at all locations where the public has access. Although the EPA has revised both the ozone and $PM_{2.5}$ (particulate matter with a mean aerodynamic diameter of 2.5 μm or less) NAAQS, neither of these revised limits would be implemented by the states of Colorado, Utah, or Wyoming until their State Implementation Plans (SIPs) are formally approved by the EPA; until then, the EPA is responsible for implementing these revised standards.

Potential development impacts must demonstrate compliance with all applicable local, state, Tribal, and federal air quality regulations, standards, and implementation plans established under the Clean Air Act (CAA) and administered by the states (with EPA oversight). Air quality regulations require that proposed new or modified existing air pollutant emission sources (including potential future oil shale or tar sands projects) undergo a permitting review before their construction can begin. Therefore, the states have the primary authority and responsibility to review permit applications and to require emission permits, fees, and control devices prior to construction and/or operation.

In addition, the U.S. Congress (through CAA Section 116) authorized local, state, and Tribal air quality regulatory agencies to establish air pollution control requirements that are more (but not less) stringent than federal requirements (such as the Colorado and Wyoming sulfur dioxide [SO_2] ambient air quality standards). If future oil shale or tar sands projects are proposed, additional site-specific air quality analyses would be performed, and additional emission control measures (including emissions control technology analysis and determination) may be required by the applicable air quality regulatory agencies to ensure protection of air quality resources. In addition, under the federal CAA and Federal Land Policy and Management Act of 1976 (FLPMA), the Bureau of Land Management (BLM) cannot authorize any activity that does not conform to all applicable local, state, Tribal, and federal air quality laws, statutes, regulations, standards, and implementation plans.

Given the study area's current attainment status, future development projects that have the potential to emit more than 250 tons/yr (or certain listed sources that have the potential to emit more than 100 tons/yr) of any criteria pollutant would be required to submit a preconstruction Prevention of Significant Deterioration (PSD) permit application, including a regulatory PSD Increment Consumption Analysis under the federal New Source Review and permitting regulations. Development projects subject to the PSD regulations must also demonstrate the use of "Best Available Control Technology" (BACT) and show that the combined impacts of all applicable sources would not exceed the PSD increments for SO_2, nitrogen dioxide (NO_2), or PM_{10} (particulate matter with a mean aerodynamic diameter of 10 μm or less). The permit applicant must also demonstrate that cumulative impacts from all existing and proposed sources would comply with the applicable ambient air quality standards throughout the operational lifetime of the permit applicant's project.

In addition, a regulatory PSD Increment Consumption Analysis may be conducted at any time by the states or the EPA, in order to demonstrate that the applicable PSD increment has not been exceeded by all applicable major or minor increment-consuming emission sources. The determination of PSD increment consumption is a legal responsibility of the applicable air quality regulatory agency (with EPA oversight). National Environmental Policy Act of 1969 (NEPA) analyses may compare potential air quality impacts from a proposed project with applicable ambient air quality standards, PSD increments, and air quality related value (AQRV) impact threshold levels; this comparison, however, does not represent a regulatory air quality permit analysis. Comparisons with the PSD Class I and II increments are intended to evaluate a "threshold of concern" for potentially significant adverse impacts, but do not represent a regulatory PSD Increment Consumption Analysis.

D.2.2 Cultural Resources

Cultural resources that meet the eligibility criteria for listing on the *National Register of Historic Places* (NRHP) are considered "significant" resources and must be taken into consideration during the planning of federal projects (see text box). Federal agencies are also required to consider the effects of their actions on sites, areas, and other resources (e.g., plants) that are of religious significance to Native Americans[1] as established under the American Indian Religious Freedom Act (Public Law [P.L.] 95-341). Archaeological sites on public lands and Indian lands are protected by the Archaeological Resources Protection Act of 1979, as amended (P.L. 96–95), and Native American graves and burial grounds are protected by the Native American Graves Protection and Repatriation Act of 1990 (P.L. 101-601). Cultural resources on federal lands are further considered by laws penalizing the theft or degradation of property of the U.S. government (Theft of Government Property [62 Stat. 764, 18 USC 1361] and FLPMA). A list of these and other regulatory requirements pertaining to cultural properties is presented in Table D-15. These laws are applicable to any project undertaken on federal land or requiring federal permitting or funding.

Cultural resources on BLM-administered land are managed primarily through the application of the above-identified laws. As required by Section 106 of the National Historic Preservation Act (NHPA), BLM field offices work with land use applicants to inventory and evaluate cultural resources in areas that may be affected by proposed development. The BLM has established a cultural resource management program as identified in its 8100 Series manuals and handbooks (Table D-16). The goal of the program is to locate, evaluate, manage, and protect cultural resources on public lands. (See Section 3.1, Land Use, for a description of designated Areas of Critical Environmental Concern [ACECs], some of which are designated specifically to protect cultural resources.) Guidance on how to apply the NRHP criteria to evaluate the eligibility of sites located on public lands is provided in numerous documents prepared by the

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1 These acts refer specifically to Native Americans, Native Alaskans, and Native Hawaiians.

TABLE D-15 Cultural Resource Laws and Regulations

Law or Order Name	Intent
Antiquities Act of 1906	This law makes it illegal to remove cultural resources from federal land without permission. It also allows the President to establish historical monuments and landmarks.
National Historic Preservation Act of 1966, as amended (NHPA)	The NHPA creates the framework within which cultural resources are managed in the United States. The law requires that each state appoint a State Historic Preservation Officer (SHPO) to direct and conduct a comprehensive statewide survey of historic properties and maintain an inventory of such properties, and it created the Advisory Council on Historic Preservation, which provides national oversight and dispute resolution. Section 106 of the NHPA defines the process for identifying and evaluating cultural resources and determining whether a project will result in an adverse effect on the resource. It also addresses the appropriate process for mitigating adverse effects. Section 110 of the NHPA directs the heads of all federal agencies to assume responsibility for the preservation of listed or eligible historic properties owned or controlled by their agency. Federal agencies are directed to locate, inventory, and nominate properties to the NRHP, to exercise caution to protect such properties, and to use such properties to the maximum extent feasible. Additional provisions of Section 110 include documentation of properties adversely affected by federal undertakings, the establishment of trained federal preservation officers in each agency, and the inclusion of the costs of preservation activities as eligible agency project costs. The NHPA also establishes the processes for consultation among interested parties, the lead agency, and the SHPO, and for government-to-government consultation between U.S. government agencies and Native American Tribal governments.
E.O. 11593, Protection and Enhancement of the Cultural Environment (U.S. President 1971)	E.O. 11593 requires federal agencies to inventory their cultural resources and to record, to professional standards, any cultural resource that may be altered or destroyed.
Archaeological and Historic Preservation Act (1974) (AHPA)	The AHPA directly addresses impacts on cultural resources resulting from federal activities that would significantly alter the landscape. The focus of the law is data recovery and salvage of scientific, prehistoric, historic, and archaeological resources that could be damaged during the creation of dams and the impacts resulting from flooding, worker housing, creation of access roads, etc.; however, its requirements are applicable to any federal action.
Federal Land and Policy Management Act (1976)	The FLPMA requires the BLM to manage its lands for multiple use and sustained yield in a manner that will protect the quality of its environmental values, such as cultural resources.

TABLE D-15 (Cont.)

Law or Order Name	Intent
American Indian Religious Freedom Act of 1978 (AIRFA)	The AIRFA protects the right of Native Americans to have access to their sacred places. It requires consultation with Native American organizations if an agency action will affect a sacred site on federal lands.
Archaeological Resources Protection Act of 1979, as amended (ARPA)	The ARPA establishes civil and criminal penalties for the destruction or alteration of cultural resources and establishes professional standards for excavation.
Native American Graves Protection and Repatriation Act of 1990 (NAGPRA)	The NAGPRA requires federal agencies to consult with the appropriate Native American Tribes prior to the intentional excavation of human remains and funerary objects. It requires the repatriation of human remains found on the agencies' land.
E.O. 13006, Locating Federal Facilities on Historic Properties in our Nation's Central Cities (U.S. President 1996a)	E.O. 13006 encourages the reuse of historic downtown areas by federal agencies.
E.O. 13007, Indian Sacred Sites (U.S. President 1996b)	E.O. 13007 requires that an agency allow Native Americans to worship at sacred sites located on federal property.
E.O. 13175, Consultation and Coordination with Indian Tribal Governments (U.S. President 2000)	E.O. 13175 requires federal agencies to coordinate and consult with Indian Tribal governments whose interests might be directly and substantially affected by activities on federally administered lands.
E.O. 13287, Preserve America (U.S. President 2003)	E.O. 13287 encourages the promotion and improvement of historic structures and properties to encourage tourism.

TABLE D-16 BLM Guidance Regarding Cultural Resource Management

BLM 8100 Series Manuals and Handbooks
8100 Manual: *The Foundations for Managing Cultural Resources*
8110 Manual: *Identifying and Evaluating Cultural Resources*
8120 Manual: *Tribal Consultation under Cultural Resource Authorities*
H-8120-1: *General Procedural Guidance for Native American Consultation*
8130 Manual: *Planning for Uses of Cultural Resources*
8140 Manual: *Protecting Cultural Resources*
8150 Manual: *Permitting Uses of Cultural Resources*
8170 Manual: *Interpreting Cultural Resources for the Public*

National Park Service (NPS) and in the BLM 8100 Series manuals and handbooks. Further guidance on the application of cultural resource laws and regulations is provided through a national Programmatic Agreement (PA) developed among the BLM, the National Council of State Historic Preservation Officers (SHPOs), and the Advisory Council on Historic Preservation, and through state-specific PAs concerning cultural resources.

D.2.3 Noise

The Noise Control Act of 1972, as amended by the Quiet Communities Act of 1978 (42 USC 4901 et seq.), delegates the authority to regulate noise to the states and directs government agencies to comply with local noise regulations. Of the three states in the study area, only Colorado has a regulation specifying quantitative limits on noise. Table D-17 lists the noise limits in Colorado's Noise Abatement Law. Many local governments have enacted noise ordinances to manage community noise levels. These noise limits are typically applied to define noise sources and specify a maximum permissible noise level. They are commonly enforced by police but may also be enforced by the agency issuing development permits.

TABLE D-17 Colorado Limits on Maximum Permissible Noise Levels

Zone	Maximum Permissible Noise Level[a] (dBA) 7 a.m. to 7 p.m.[b]	7 p.m. to 7 a.m.
Residential	55	50
Commercial	60	55
Light industrial	70	65
Industrial	80	75

[a] At a distance of 25 ft from the property line. Periodic, impulsive, or shrill noises are considered a public nuisance at a level 5 dBA less than those tabulated.

[b] For a period not to exceed 15 minutes in any 1 hour, the tabulated noise levels may be exceeded by 10 dBA.

Source: CRS 25-12-101 et seq.

EPA guidelines recommend a day-night average sound level (L_{dn}) of 55 A-weighted decibels (dBA) as sufficient to protect the public from the effects of broadband environmental noise in quiet outdoor and residential neighborhoods (EPA 1974). The guidelines recommend an equivalent sound pressure level (L_{eq}) of 70 dBA or less over a 40-year period to protect the general population against hearing loss from nonimpulsive noise. The Federal Aviation Administration and the Federal Interagency Committee on Urban Noise have issued land use compatibility guidelines indicating that a yearly L_{dn} of less than 65 dBA is compatible with residential land uses and that, if a community determines it is necessary, levels up to 75 dBA may be compatible with residential uses and transient lodgings (but not mobile homes) if such structures incorporate noise reduction features (14 CFR Part 150, Appendix A).

Changes to ambient sound levels can interfere with wildlife, including predator/prey relationships, territory establishment, foraging, mating behavior, and reproductive success. Sections 4.8 and 5.8 discuss these impacts in more detail.

NPS policy states that "natural ambient" conditions (the sound levels that would occur in the absence of all noise caused by humans) are the baseline against which potential noise impacts should be judged. Site-specific environmental assessments would need to determine these levels and how development on adjacent BLM-administered lands might affect NPS-managed lands.

D.2.4 Paleontological Resources

As nonrenewable resources, no matter how common or rare they may be, fossils of scientific value are offered some protection through the Antiquities Act of 1906. Two other federal acts, the Archaeological Resources Protection Act of 1979 and the Federal Cave Resources Protection Act of 1988, protect fossils found in primary context and from significant caves, respectively. Fossils on federal lands (e.g., BLM-administered lands) are further protected by laws penalizing the theft or degradation of property of the U.S. Government (Theft of Government Property [62 Stat. 764, 18 USC 1361] and FLPMA).

D.3 REFERENCES

EPA (U.S. Environmental Protection Agency), 1974, *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety*, EPA 550/9-74-004, Office of Noise Abatement and Control, Washington, D.C., March.

U.S. President, 1971, "Protection and Enhancement of the Cultural Environment," Executive Order 11593, *Federal Register* 36:8921, May 13.

U.S. President, 1996a, "Locating Federal Facilities on Historic Properties in Our Nation's Central Cities," Executive Order 13006, *Federal Register* 61:26071, May 24.

U.S. President, 1996b, "Indian Sacred Sites," Executive Order 13007, *Federal Register* 61:26771, May 29.

U.S. President, 2000, "Consultation and Coordination with Indian Tribal Governments," *Federal Register* 65:67249, Nov. 9.

U.S. President, 2003, "Preserve America," Executive Order 13287, *Federal Register* 68:10635, March 5.

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APPENDIX E:

THREATENED AND ENDANGERED SPECIES WITHIN THE OIL SHALE AND TAR SANDS STUDY AREA

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TABLE E-1 Federally Listed and State-Listed Threatened, Endangered, Candidate Species, Species of Special Concern, and BLM-Designated Sensitive Species That Occur in the Study Area

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur[c]	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants						
Abies concolor	White fir	NL[f]	WY-SC	WY-Sweetwater	Green River	Foothills and lower slopes of mountains and in association with aspen woods and often on south-facing slopes on dry shallow soils. Only known record is from Little Mountain in Sweetwater County.
Achnatherum swallenii	Swallen mountain-ricegrass	NL	WY-SC	WY-Lincoln, Sublette	Green River	Calcareous sandy soils of rocky slopes and knobs at elevations between 6,600 and 7,100 ft.
Aliciella caespitosa	Wonderland Alice-flower	ESA-C	NL	UT-Wayne	Tar Sand Triangle STSA	Navajo and Wingate sandstone in crevices, Carmel Limestone formations, detrital slopes, and (infrequently) in sandy wash bottoms. Found within open pinyon-juniper communities, often mixed with mountain brush, sagebrush, or ponderosa pine, at elevations between 1,554 and 2,743 m.
Amsonia jonesii	Jones blue star	BLM	NL	UT-Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Uinta; all STSAs	Desert shrub, sagebrush, and pinyon-juniper communities, often on sandy or white shale soils; 6,000 to 7,000 ft.
Artemisia biennis var. *diffusa*	Mystery wormwood	BLM	WY-SC	WY-Sweetwater	Green River and Washakie	Clay flats and playas at approximately 6,500 ft.
Astragalus bisulcatus var. *haydenianus*	Hayden's milkvetch	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Clay or sandy soils near springs associated with sandstone rock outcrops on rims, upper slopes, and draws.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Astragalus calycosus var. *calycosus*	King's milkvetch	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Pinyon-juniper woodland; 4,900 to 12,000 ft.
Astragalus coltonii var. *moabensis*	Moab milkvetch	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Not available.
Astragalus debequaeus	Debeque milkvetch	BLM	NL	CO-Garfield	Piceance	Varicolored, fine-textured, seleniferous, saline soils of the Wasatch Formation-Atwell Gulch Member. Barren outcrops of dark clay interspersed with lenses of sandstone at elevations between 5,100 and 6,400 ft.
Astragalus detritalis	Debris milkvetch	BLM	NL	CO-Rio Blanco; UT-Duchesne, Uintah	Piceance and Uinta; Argyle Canyon, Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, and Sunnyside STSAs	Pinyon-juniper and mixed desert shrub communities; often rocky soils ranging from sandy clays to sandy loams. Alluvial terraces with cobbles. Elevations between 5,400 and 7,200 ft.
Astragalus lentiginosus var. *salinus*	Sodaville milkvetch	NL	WY-SC	WY-Lincoln, Uinta	Green River	Moist, open, alkaline hummocks and drainages near cool springs.
Astragalus musiniensis	Ferron milkvetch	BLM	NL	CO-Garfield; UT-Emery, Garfield, Grand, Wayne	Piceance; P.R. Spring, San Rafael, Sunnyside, Tar Sand Triangle, and White Canyon STSAs	Gullied bluffs, knolls, benches, and open hillsides; in pinyon-juniper woodlands or desert shrub communities, mostly on shale, sandstone, or alluvium derived from them at elevations between 4,700 and 7,000 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Astragalus naturitensis	Naturita milkvetch	BLM	NL	CO-Garfield; UT-San Juan	Piceance; White Canyon STSA	Sandstone mesas, ledges, crevices, and slopes in pinyon-juniper woodlands at elevations between 5,000 and 7,000 ft.
Astragalus piscator	Fisher Towers milkvetch	BLM	NL	UT-Garfield, Grand, San Juan, Wayne	Tar Sand Triangle and White Canyon STSAs	Sandy, sometimes gypsiferous soils of valley benches and gullied foothills at elevations between 4,300 and 5,600 ft.
Astragalus proimanthus	Precocious milkvetch	BLM	WY-SC	WY-Sweetwater	Green River and Washakie	Mainly in cushion plant communities on light-colored, somewhat calcareous clay soils where coarser cobbles are derived from shale on summits and upper slopes of low, windy ridges at about 2,130-m elevations.
Astragalus racemosus var. *treleasei*	Trelease's racemose milkvetch	BLM	WY-SC	WY-Sublette, Uinta	Green River	Silty loam soils derived from shales, primarily in sparsely vegetated outwash flats, outcrops of river valleys, and fluted badlands slopes within sagebrush-grassland communities and at elevations between 6,500 and 7,500 ft.
Astragalus rafaelensis	San Rafael milkvetch	BLM	NL	UT-Emery, Grand	P.R. Spring and San Rafael STSAs	Banks of sandy clay gulches, in pockets at the foot of sandstone outcrops, or among boulders along dry watercourses at elevations between 4,500 and 5,300 ft.
Atriplex falcata	Sickle saltbush	NL	WY-SC	WY-Sublette, Sweetwater, Uinta	Green River and Washakie	Sagebrush, shadscale, and greasewood communities in fine-textured saline substrates at elevations between 1,300 and 2,000 m.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Atriplex wolfii	Wolf's orache	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Alkaline flats.
Boechera crandallii	Crandall's rockcress	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Stony soils over limestone, often within sagebrush communities.
Boechera selbyi	Selby's rockcress	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Foothills and montane habitats.
Brickellia microphylla var. *scabra*	Little-leaved brickell-bush	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Dry rocky places, canyon walls, sand dunes, and washes at elevations between 1,200 and 2,400 m.
Carex specuicola	Navajo sedge	ESA-T	NL	UT-San Juan	None	Moist, sandy to silty soils of shady seep-spring pockets or alcoves with somewhat limited soil development, at elevations between 1,740 and 1,830 m.
Castilleja aquariensis	Aquarius paintbrush	ESA-C	NL	UT-Garfield, Wayne	None	Subalpine sagebrush-grass meadows and openings in spruce communities. Rocky/gravelly soils at elevations between 2,792 and 3,648 m.
Ceanothus martinii	Utah mountain lilac	NL	WY-SC	WY-Lincoln, Sweetwater	Green River and Washakie	Steep sagebrush slopes or mountain shrub communities on shallow-stony or hard clay soils at elevations between 7,600 and 8,100 ft.
Cercocarpus ledifolius var. *intricatus*	Dwarf mountain mahogany	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Pinyon juniper-woodland; 4,500 to 9,800 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Chamaechaenactis scaposa	Fullstem	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Dry, open, relatively barren silty or clay soils derived from shale, sandstone, marl, or limestone, and often with a rocky, sandy, or gravelly overburden, usually in pinyon-juniper woodlands at elevations between 1,400 and 2,600 m.
Chrysothamnus greenei	Greene rabbitbrush	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Sandy washes and dry open areas within desert habitats at elevations between 1,300 and 2,000 m.
Cirsium aridum	Cedar Rim thistle	BLM	WY-SC	WY-Sublette, Sweetwater	Green River and Washakie	Barren, chalk hills, fine-textured sandy and shaley draws, and gravelly slopes.
Cirsium ownbeyi	Ownbey's thistle	BLM	WY-SC	WY-Sweetwater	Green River and Washakie	Dry sites or sometimes in seeps on stony soils in sparsely vegetated areas of pinyon-juniper woodlands, sagebrush, arid grasslands, and riparian scrub at elevations between 1,500 and 2,400 m.
Cirsium perplexans	Adobe thistle	BLM	NL	CO-Garfield	Piceance	Almost exclusively on clay soils that are derived from shales of the Mancos or Wasatch Formations. Associated plant communities include pinyon-juniper woodlands and sagebrush, saltbrush, and mixed shrublands.
Collomia grandiflora	Large-flower collomia	NL	WY-SC	WY-Lincoln	Green River	Dry, open, or lightly wooded areas.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Cryptantha caespitosa	Caespitose cat's-eye	BLM	NL	CO-Rio Blanco; UT-Carbon, Duchesne, Uintah	Piceance and Uinta; Argyle Canyon, Asphalt Ridge, Hill Creek, Raven Ridge, Pariette, P.R. Spring, and Sunnyside STSAs	Sparsely vegetated shale knolls, with pinyon-juniper or sage-brush, usually with other cushion plants at elevations between 6,200 and 8,100 ft.
Cryptantha gracilis	Slender cryptantha	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Pinyon-juniper woodland between 2,900 and 7,000 ft.
Cryptantha osterhoutii	Osterhout cat's-eye	BLM	NL	UT-Emery, Garfield, Grand, San Juan, Wayne	P.R. Spring, San Rafael, Tar Sand Triangle, and White Canyon STSAs	Dry barren sites in reddish purple decomposed sandstone at elevations between 1,370 and 1,860 m, or in dry sandy soil in the desert, in blackbrush, mixed desert shrub, oak brush, salt bush, and pinyon-juniper communities at 1,520 to 2,000 m.
Cryptantha rollinsii	Rollins' cat's-eye	BLM	WY-SC	CO-Rio Blanco; UT-Duchesne, San Raphael, Uintah, Wayne; WY-Sweetwater	Green River, Piceance, Uinta, and Washakie; Argyle Canyon, Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, San Rafael, and Sunnyside STSAs	White shale slopes of the Green River Formation; in pinyon-juniper or cold desert shrubland communities at elevations between 5,300 and 5,800 ft.
Cycladenia humilis var. *jonesii*	Jones cycladenia	ESA-T	NL	UT-Emery, Garfield, Grand, Uintah	Hill Creek, Pariette, P.R. Spring, and San Rafael STSAs	Known from a few areas in and around the Canyonlands region of southeastern Utah.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Cymopterus duchesnensis	Uinta Basin spring-parsley	BLM	NL	CO-Rio Blanco; UT-Duchesne, Uintah	Piceance and Uinta; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	Cold desert shrub, sagebrush, and juniper communities; sandy clay and clay semibarrens of Mancos and Morrison shales; Morrison, Uintah, Wasatch, and Green River Formations at elevations between 4,700 and 6,800 ft.
Descurainia pinnata var. *paysonii*	Payson's tansy mustard	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Sandy flats and stabilized dunes with shrub cover.
Downingia laeta	Great Basin downingia	NL	WY-SC	WY-Uinta	Green River	Vernal pools, edge of ponds and lakes, and in roadside ditches.
Draba juniperina	Uinta draba	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Primarily on sandy-clay gravelly soils in juniper woodlands. May also occur in sagebrush-grasslands on sandstones at the edge of juniper woodlands, semibarren cushion plant communities on white clay-sandy rims, and mountain mahogany-juniper thickets.
Elymus simplex var. *luxurians*	Long-awned alkali wild-rye	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Sand dunes.
Ephedra viridis var. *viridis*	Green Mormon tea	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Sandy or rocky soils of upland desert habitats.
Eriastrum wilcoxii	Wilcox eriastrum	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Sagebrush scrub and pinyon-juniper woodland to 9,000 ft.
Erigeron compactus var. *consimilis*	San Rafael daisy	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Shale soils in pinyon-juniper woodland and desert scrub at elevations between 6,100 and 7,400 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Erigeron maguirei	Maguire daisy	ESA-T	NL	UT-Emery, Garfield, Wayne	San Rafael STSA	Cool, mesic wash bottoms and dry, partially shaded slopes of eroded sandstone cliffs of Wingate, Chinle, and Navajo Sandstone Formations in mountain shrub, Douglas-fir, ponderosa pine, and lower limits of juniper woodland communities at elevations between 5,400 and 7,100 ft.
Eriogonum contortum	Grand buckwheat	BLM	NL	CO-Garfield; UT-Grand	Piceance; P.R. Spring STSA	Mancos Shale badlands, with shadscale and other salt desert shrub communities at elevations between 4,500 and 5,100 ft.
Eriogonum corymbosum var. *corymbosum*	Crisp-leaf wild buckwheat	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Sandy, gravelly, and clayey flats, washes, slopes, outcrops, and cliffs in saltbush, blackbrush, and sagebrush communities, and pinyon-juniper and montane conifer woodlands at elevations between 1,200 and 2,700 m.
Eriogonum divaricatum	Divergent wild buckwheat	NL	WY-SC	WY-Lincoln, Sublette, Sweetwater, Uinta	Green River and Washakie	Clay flats and slopes in saltbush, greasewood, and sagebrush communities, and pinyon-juniper woodlands at elevations between 1,100 and 2,300 m.
Eriogonum ephedroides	Ephedra buckwheat	BLM	NL	CO-Rio Blanco; UT-Uintah	Piceance and Uinta; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	White shale soils of the Green River Formation, in a matrix of open pinyon-juniper woodlands and/or mixed desert shrublands.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Eriogonum hookeri	Hooker wild buckwheat	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Sandy washes, flats, and slopes in saltbush, greasewood, sagebrush, and mountain mahogany communities and pinyon-juniper woodlands at elevations between 1,300 and 2,500 m.
Galium coloradoense	Colorado bedstraw	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Shaded rocky or sandstone crevices and cliffs in desert scrub, sagebrush, and pinyon-juniper.
Gentianella tortuosa	Utah gentian	BLM	NL	CO-Rio Blanco; UT-Emery, Garfield	Piceance and Uinta	Green River Formation; barren shale knolls and slopes at elevations between 8,500 and 10,800 ft.
Gilia stenothyrsa	Narrow-stem gilia	BLM	NL	CO-Rio Blanco; UT-Carbon, Duchesne, Emery, Uintah	Piceance and Uinta; Argyle Canyon, Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, San Rafael, and Sunnyside STSAs	Silty to gravelly loam soils derived from the Green River or Uinta Formations. In grassland, sagebrush, mountain-mahogany, or pinyon-juniper communities at elevations between 5,000 and 6,000 ft.
Glossopetalon spinescens var. *meionandrum*	Utah greasebush	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Gypsiferous and calciferous soils.
Lathyrus lanszwertii var. *lanszwertii*	Nevada sweetpea	NL	WY-SC	WY-Uinta	Green River	Aspen and aspen-fir communities; 8,800 to 9,600 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Lepidium barnebyanum	Barneby ridge-cress	ESA-E	NL	UT-Duchesne	Uinta	Pinyon-juniper communities on poorly developed soils derived from white, marly shale outcrops of the Uinta Formation at elevations between 1,890 and 1,985 m. Mixed desert shrub and pinyon-juniper community.
Lepidium integrifolium var. *integrifolium*	Entire-leaved peppergrass	BLM	WY-SC	WY-Lincoln, Uinta	Green River	Moist meadows at lower elevations.
Lesquerella parviflora	Piceance bladderpod	BLM	NL	CO-Garfield, Rio Blanco	Piceance	Endemic to outcrops of the Green River Shale Formation in the Piceance Basin. It grows on ledges and slopes of canyons in open areas.
Lesquerella parvula	Narrow-leaved bladderpod	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Knolls, slopes, and ridges in open areas of sagebrush and mountain shrub communities at elevations between 1,830 and 2,700 m.
Lesquerella congesta	Dudley Bluffs bladderpod	ESA-T	NL	CO-Rio Blanco	Piceance	Barren, white shale outcrops of the Green River and Uinta Formations. Outcrops are exposed along drainages through erosion from downcutting of streams at elevations between 6,000 and 6,700 ft.
Lesquerella macrocarpa	Large-fruited bladderpod	BLM	WY-SC	WY-Lincoln, Sublette, Sweetwater	Green River and Washakie	Barren or sparsely vegetated gypsum-clay hills and benches and clay flats at elevations between 2,200 and 2,350 m.
Lesquerella prostrata	Prostrate bladderpod	NL	WY-SC	WY-Lincoln, Uinta	Green River	Plains, hills, and slopes in sagebrush, grass, and juniper communities at elevations between 6,000 and 8,000 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Listera borealis	Northern twayblade	BLM	NL	CO-Garfield; UT-Duchesne, San Juan; WY-Sublette	Green River, Piceance, and Uinta; Argyle Canyon, Pariette, and White Canyon STSAs	Moist, shady spruce forests at elevations between 8,700 and 10,800 ft.
Lomatium latilobum	Canyonlands lomatium	BLM	NL	UT-Grand, San Juan	None	Entrada Sandstone and Navajo Sandstone, between fins and in slot canyons, in sandy soil and in crevices. Surrounding plant communities are desert shrub, pinyon-juniper, or ponderosa pine-mountain brush at elevations between 1,237 and 2,207 m.
Lomatium triternatum var. *anomalum*	Ternate desert-parsley	NL	WY-SC	WY-Lincoln	Green River	Dry to moist open areas at low to mid-elevations.
Lygodesmia doloresensis	Dolores River skeletonplant	BLM	NL	UT-Grand	P.R. Spring STSA	Juniper-desert shrub or juniper-grassland communities on alluvial soils derived from sandstone outcrops associated with the undivided lower portion of the Cutler Group, which appears in the vicinity of Moab, Utah, at elevations between 1,341 and 1,441 m.
Mimulus eastwoodiae	Eastwood monkey-flower	BLM	NL	UT-Garfield, Grand, San Juan	Tar Sand Triangle and White Canyon STSAs	Seeps.
Minuartia nuttallii	Nuttall sandwort	BLM	NL	UT-Duchesne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Uinta, and Washakie; Argyle Canyon and Pariette STSAs	Sagebrush hills to alpine slopes, especially on gravelly benches or talus.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Monolepis pusilla	Red poverty-weed	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Saline or alkaline soils of deserts.
Opuntia polyacantha var. *juniperina*	Juniper prickly-pear	NL	WY-SC	WY-Sublette, Sweetwater	Green River and Washakie	Pinyon-juniper woodlands at elevations between 1,600 and 1,900 m.
Opuntia polyacantha var. *rufispina*	Rufous-spine prickly-pear	NL	WY-SC	WY-Lincoln, Sweetwater	Green River and Washakie	Sagebrush grasslands, salt desert shrublands, and vegetated sand dunes on slopes and buttes.
Oxytheca dendroidea	Tree-like oxytheca	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Desert hills and sandy roadsides.
Oxytropis besseyi var. *obnapiformis*	Maybell locoweed	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Found on steep, south-facing slopes of chalk badlands.
Packera crocata	Saffron groundsel	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Wet meadows, along trails, and rocky outcrops at elevations between 1,800 and 3,500 m.
Parthenium ligulatum	Ligulate feverfew	BLM	NL	CO-Rio Blanco; UT-Wayne	Piceance; Tar Sand Triangle STSA	Barren shale knolls at elevations between 5,400 and 6,500 ft.
Pediocactus despainii	San Rafael cactus	ESA-E	NL	UT-Emery, Wayne	San Rafael STSA	Hills, benches, and flats of open, semiarid grassland with scattered junipers and pinyon pines.
Pediocactus winkleri	Winkler cactus	ESA-T	NL	UT-Emery, Wayne	San Rafael STSA	Alkaline, fine-textured soils, primarily derived from the Dakota Formation. Associated with salt desert shrub communities at elevations between 1,450 and 1,600 m.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Pediomelum aromaticum	Paradox breadroot	BLM	NL	UT-Grand, San Juan	White Canyon STSA	Shallow rocky soils in open pinyon-juniper woodland with a sparse understory.
Penstemon acaulis var. *acaulis*	Stemless beardtongue	BLM	WY-SC	WY-Sweetwater	Green River and Washakie	Semibarren substrates in pinyon-juniper and sagebrush-grass communities at elevations between 5,500 and 8,200 ft.
Penstemon gibbensii	Gibbens' beardtongue	BLM	WY-SC	WY-Sweetwater	Green River and Washakie	Sparsely vegetated selenium-rich shale or sandy-clay slopes at elevations between 1,675 and 2,350 m. Surrounding vegetation is pinyon-juniper woodland, sagebrush, or greasewood-saltbush.
Penstemon harringtonii	Harrington beardtongue	BLM	NL	CO-Garfield	Piceance	Open sagebrush or, less commonly, pinyon-juniper habitats. Soils are typically rocky loams and rocky clay loams derived from coarse calcareous bedrock at elevations between 6,800 and 9,200 ft.
Penstemon scariosus var. *garrettii*	Garrett's beardtongue	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Rolling semibarren badlands on clay soils, on gentle clay slopes covered with small slate fragments, or on steep clay or talus slopes covered with slate chips below steep cliffs at elevations between 7,600 and 8,400 ft.
Penstemon debilis	Parachute beardtongue	ESA-C	NL	CO-Garfield	Piceance	Rocky clay loam soils of sagebrush hills and flats at elevations between 7,000 and 8,500 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Penstemon laricifolius ssp. *exilifolius*	White beardtongue	NL	WY-SC	WY-Sublette	Green River	Not available.
Penstemon scariosus var. *albifluvis*	White River beardtongue	ESA-C	NL	CO-Rio Blanco; UT-Uintah	Piceance; Uinta; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	Mixed desert shrub and pinyon-juniper communities on sparsely vegetated shale slopes of the Green River Formation at elevations between 5,000 and 7,200 ft.
Phacelia demissa	Intermountain phacelia	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Desert shrub often on clay barrens at elevations between 4,900 and 6,200 ft.
Phacelia glandulosa var. *deserta*	Desert glandular phacelia	NL	WY-SC	WY-Lincoln, Sublette, Sweetwater	Green River and Washakie	Desert scrub, sagebrush, mountain brush communities, and road cuts, usually on clay soils; 5,000 to 8,400 ft.
Phacelia incana	Western phacelia	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Rocky or sandy-clay slopes amid juniper, sagebrush, shadscale, kochia, and mountain mahogany stands at elevations between 6,000 and 7,000 ft.
Phacelia salina	Nelson phacelia	NL	WY-SC	WY-Lincoln, Sublette, Sweetwater, Uinta	Green River and Washakie	Alkaline flats and clay slopes.
Phacelia scopulina var. *submutica*	Debeque phacelia	ESA-C	NL	CO-Garfield	Piceance	Sparsely vegetated, steep slopes; in chocolate-brown or gray clay; on Atwell Gulch and Shire Members of the Wasatch Formation at elevations between 4,700 and 6,200 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Phacelia tetramera	Tiny phacelia	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Alkaline soils and in vernal pools in sagebrush-grassland communities at elevations between 1,200 and 2,210 ft.
Philadelphus microphyllus var. *occidentalis*	Little-leaf mock-orange	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Rocky canyon sides between 6,000 and 8,500 ft.
Phlox albomarginata	White-margined phlox	NL	WY-SC	WY-Lincoln	Green River	Not available.
Phlox pungens	Beaver Rim phlox	BLM	WY-SC	WY-Lincoln, Sublette	Green River	Sparsely vegetated slopes on clays and shales in the Green River Basin at elevations between 1,830 and 2,250 m.
Physaria condensata	Tufted twinpod	BLM	WY-SC	WY-Lincoln, Sublette, Uinta	Green River	Sparsely vegetated, shale slopes and ridges at elevations between 1,980 and 2,130 m.
Physaria dornii	Dorn's twinpod	BLM	WY-SC	WY-Lincoln, Uinta	Green River	Dry, sparsely vegetated, calcareous-shaley slopes and ridges dominated by mountain mahogany and rabbitbrush at elevations between 1,980 and 2,200 m.
Physocarpus alternans	Dwarf ninebark	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Pinyon-juniper woodland between 5,900 and 10,200 ft.
Physaria obcordata	Dudley Bluffs twinpod	ESA-T	NL	CO-Rio Blanco	Piceance	Barren white outcrops and steep slopes exposed by creek downcutting. Restricted to the Parachute Creek Member of the oil, shale–bearing Green River Formation at elevations between 5,900 and 7,500 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Populus deltoides var. wislizeni	Fremont cottonwood	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Stream banks, sandbars, and other riparian areas at elevations below 6,000 ft.
Potentilla multisecta	Deep Creek cinquefoil	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Rocky subalpine and alpine slopes.
Psilocarphus brevissimus	Dwarf woolly-heads	NL	WY-SC	WY-Sublette	Green River	Grasslands to 8,200 ft.
Ranunculus aestivalis	Autumn buttercup	ESA-E	NL	UT-Garfield	None	Sevier River Valley, where freshwater seeps and springs surface, creating marshy or bog-like conditions. The surrounding region is semiarid and sagebrush-dominated at elevations between 1,938 and 1,965 m.
Ranunculus flabellaris	Yellow water-crowfoot	NL	WY-SC	WY-Uinta	Green River	Ponds, mudflats, and slow-moving streams at elevations between 6,600 and 6,700 ft.
Rorippa calycina	Persistent sepal yellowcress	BLM	WY-SC	WY-Sweetwater	Green River and Washakie	Riverbanks and shorelines, usually on sandy soils near high water line at elevations between 4,300 and 6,800 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Sambucus cerulea	Blue elderberry	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Moist, well-drained sunny sites of early seral communities, or in openings in moist forest habitats (slopes, canyons, cliff bases, streamsides, stream banks, and riparian woodlands) and moist areas within drier, more open habitats (sagebrush, mountain brush, pinyon-juniper, ponderosa pine, and often along fence rows and roads); at elevations up to 10,000 ft.
Schoenocrambe argillacea	Clay reed-mustard	ESA-T	NL	UT-Uintah	Uinta; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	Mixed desert shrub communities on precipitous, typically north-facing slopes of the Evacuation Creek Member of the Green River Formation. These slopes consist of at-the-surface bedrock, scree, and fine-textured soils at elevations between 1,463 and 1,768 m.
Schoenocrambe barnebyi	Barneby reed-mustard	ESA-E	NL	UT-Emery, Wayne	San Rafael STSA	Mixed desert shrub communities on steep, typically north-facing slopes on red, selenium-rich, fine-textured soils of the Moenkopi and Chinle Formations at elevations between 1,705 and 1,985 m.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Schoenocrambe suffrutescens	Shrubby reed-mustard	ESA-E	NL	UT-Duchesne, Uintah	Uinta; Hill Creek, Pariette, P.R. Spring, and Sunnyside STSAs	Mixed desert shrub communities and, at some locations, in pinyon-juniper and desert shrub, on semibarren, white-shale layers of the Evacuation Creek Member of the Green River Formation. Commonly on level to moderately sloping ground surfaces. Soils are dry, shallow, and fine-textured and are usually overlain by shale fragments at elevations between 1,555 and 1,981 m.
Sclerocactus glaucus	Uinta Basin hookless cactus	ESA-T	NL	CO-Garfield; UT-Carbon, Duchesne, Uintah	Piceance and Uinta; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, and Sunnyside STSAs	Rocky hills, mesa slopes, and alluvial benches; in desert shrub communities at elevations between 4,500 and 6,000 ft.
Sclerocactus wrightiae	Wright fishhook cactus	ESA-E	NL	UT-Emery, Wayne	San Rafael and Tar Sand Triangle STSAs	Barren, alkaline soils with widely scattered shrubs, perennial herbs, bunch grasses, or scattered pinyon and juniper at elevations between 1,460 and 1,865 m. Soils vary from clay, to sandy silts, to fine sands that may have a high gypsum content or contain little or no gypsum. Soil crusts are usually present, and the ground surface is usually littered with sandstone or basalt gravels, cobbles, and boulders.
Senecio spartioides var. *multicapitatus*	Many-headed broom groundsel	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Plains, open slopes, valleys, arroyos, and dunes in pinyon-juniper woodlands, ponderosa pine forests, and desert areas; an early colonizer of disturbed soils.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Plants (Cont.)						
Silene douglasii	Douglas' campion	NL	WY-SC	WY-Lincoln	Green River	Sagebrush and lodgepole pine communities at elevations between 5,000 and 9,500 ft.
Spiranthes diluvialis	Ute ladies'-tresses	ESA-T	NL	UT-Duchesne, Garfield, Uintah, Wayne	Uinta; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	Moist to very wet meadows along streams or in abandoned stream meanders that still retain ample groundwater. Also near springs, seeps, and lakeshores at elevations between 1,300 and 1,600 m.
Thelesperma pubescens	Uinta greenthread	BLM	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Sparsely vegetated windy rims of coarse-cobble soils of the Bishop Conglomerate in grassland, sagebrush-grassland, or low prostrate forb communities, and at elevations between 2,470 and 2,710 m.
Townsendia aprica	Last chance townsendia	ESA-T	NL	UT-Emery, Wayne	San Rafael STSA	Pinyon-juniper and salt desert shrub communities on barren, silty, silty clay, or gravelly clay soils of the Mancos Shale Formation at elevations between 1,695 and 2,440 m.
Townsendia microcephala	Cedar Mountain Easter-daisy	BLM	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Rocky slopes and cobble ridges of the Bishop Conglomerate of the Uinta Mountains.
Townsendia strigosa	Strigose Easter-daisy	BLM	NL	UT-Duchesne, Uintah	Uinta; Argyle Canyon, Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	Desert scrub and sagebrush communities between 4,700 and 6,200 ft.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Invertebrates						
Oreohelix eurekensis	Eureka mountainsnail	NL	UT-SC	UT-Duchesne, Grand	Uinta	Terrestrial; forests of aspen, spruce, pine, and fir with open grassy areas with interspersed stands of sagebrush, juniper, and scrub oak.
Oreohelix yavapai	Yavapai mountainsnail	NL	UT-SC	UT-San Juan	None	Terrestrial; aspen and spruce groves with open areas of grass and sandstone outcrops.
Pyrgulopsis plicata	Black Canyon pyrg	NL	UT-SC	UT-Garfield	None	Known only from a complex of springs in Black Canyon, East Fork Sevier River, Garfield County, Utah, to which it is presumably strictly endemic.
Speyeria nokomis nokomis	Great Basin silverspot butterfly	BLM	NL	UT-Duchesne, Uintah	Uinta; Argyle Canyon, Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	Streamside meadows and open seepage areas with an abundance of violets, in generally desert landscapes.
Physa utahensis	Utah physa	NL	UT-SC	UT-Garfield	None	Vegetated springs.
Fish						
Catostomus discobolus	Bluehead sucker	BLM	WY-SC	WY-Lincoln, Sublette, Sweetwater, Uinta	Green River and Washakie	Wide range of stream habitats, including cold, clear mountain streams and warm, turbid streams; rarely occurs in lakes. Adults prefer moderate to fast-flowing water above rubble-rock substrate; young prefer quiet shallow areas near shoreline.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Fish (Cont.)						
Catostomus latipinnis	Flannelmouth sucker	BLM	WY-SC	UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah; Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Uinta, and Washakie; Asphalt Ridge, Hill Creek, Pariette, Raven Ridge, San Rafael, and Tar Sand Triangle STSAs	Moderate to large rivers. Typical of pools and deeper runs and often entering mouths of small tributaries; also in riffles and backwaters.
Gila copei	Leatherside chub	BLM	UT-SC, WY-SC	UT-Duchesne, Emery, Garfield, Wayne; WY-Lincoln, Uinta	Green River and Uinta	Adults occur in rocky flowing pools and riffles of cold creeks and small to medium rivers. Young occupy brushy areas or quiet pockets near shore.
Gila elegans	Bonytail	ESA-E	CO-E	UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Uinta; Asphalt Ridge, Hill Creek, Pariette, Raven Ridge, Sunnyside, Tar Sand Triangle, and White Canyon STSAs	Main stream of mid-sized to large rivers. Wild bonytail believed to have been extirpated in the Green River and the Colorado River. A number of experimental reintroductions have been made.
Gila cypha	Humpback chub	ESA-E	CO-T	UT-Carbon, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Uinta; Asphalt Ridge, Hill Creek, Sunnyside, Tar Sand Triangle, and White Canyon STSAs	Large rivers. Adults use various habitats, including deep turbulent currents, shaded canyon pools, and areas under shaded ledges in moderate current, riffles, and eddies. Young have been taken in backwaters over nonrocky substrate. Presumed to have been extirpated in Wyoming.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Fish (Cont.)						
Gila robusta	Roundtail chub	BLM	CO-SC, WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, San Rafael, Sunnyside, Tar Sand Triangle, and White Canyon STSAs	Rocky runs, rapids, and pools of creeks and small to large rivers.
Oncorhynchus clarkii pleuriticus	Colorado River cutthroat trout	BLM	CO-SC, WY-SC	CO-Delta, Garfield, Mesa, Rio Blanco; UT-Duchesne, Garfield, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; Argyle Canyon STSA	Requires cool, clear water and well-vegetated stream banks for cover and bank stability; in-stream cover, in the form of deep pools and boulders and logs, is also important; adapted to relatively cold water; thrives at high elevations.
Oncorhynchus clarkii utah	Bonneville cutthroat trout	BLM	WY-SC	WY-Lincoln, Uinta	Green River	Habitats ranging from high-elevation streams with coniferous and deciduous riparian trees to low-elevation streams in sage-steppe grasslands containing herbaceous riparian zones. Beaver ponds may be important as both summer and winter habitat for adults.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Fish (Cont.)						
Ptychocheilus lucius	Colorado pikeminnow	ESA-E	CO-T	CO-Rio Blanco (XN)[g]; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Piceance and Uinta; Asphalt Ridge, Hill Creek, Pariette, Raven Ridge, Sunnyside, Tar Sand Triangle, and White Canyon STSAs	Medium to large rivers. Young prefer small, quiet backwaters. Adults use various habitats, including deep, turbid, strongly flowing water and eddies, runs, flooded bottoms, or backwaters (especially during high flow). Found throughout the Green River and Colorado River. Presumed to have been extirpated in Wyoming.
Xyrauchen texanus	Razorback sucker	ESA-E	CO-E	CO-Garfield, Rio Blanco; UT-Carbon, Emery Garfield, Grand, San Juan, Uintah, Wayne	Piceance and Uinta; Asphalt Ridge, Hill Creek, Pariette, Raven Ridge, Sunnyside, Tar Sand Triangle, and White Canyon STSAs	Habitats include slow areas, backwaters, and eddies of medium to large rivers. Believed to have been extirpated in Wyoming.
Amphibians						
Bufo boreas	Boreal toad	BLM	CO-E; UT-SC; WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Uintah, Wayne; WY-Lincoln, Sublette, Uinta	Green River, Piceance, and Uinta	Marshes, wet meadows, streams, beaver ponds, glacial kettle ponds, and lakes interspersed in subalpine forest (lodgepole pine, Englemann spruce, subalpine fir, and aspen).
Bufo microscaphus	Arizona toad	NL	UT-SC	UT-Garfield, San Juan	None	Irrigation ditches and flooded fields, as well as streams bordered by willows and cottonwoods.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Amphibians (Cont.)						
Hyla arenicolor	Canyon treefrog	BLM	NL	UT-Garfield, Grand, Wayne, San Juan	Tar Sand Triangle and White Canyon STSAs	Temporary or permanent pools in rocky arid scrub and mountains in a wide range of elevations between 300 and 3,000 m.
Rana luteiventris	Columbia spotted frog	BLM	WY-SC	WY-Lincoln, Sublette	Green River	Rarely found far from permanent quiet water; usually at the grass-sedge margins of streams, lakes, ponds, springs, and marshes.
Rana pipiens	Northern leopard frog	BLM	CO-SC, WY-SC	CO-Garfield; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; all STSAs	Wet meadows, marshes, ponds, glacial kettle ponds, beaver ponds, lakes, reservoirs, streams, and irrigation ditches.
Spea intermontana	Great basin spadefoot	BLM	WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; all STSAs	Pinyon-juniper woodlands, sagebrush, and semidesert shrublands in rocky canyons, broad dry basins, and stream floodplains.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Reptiles						
Elaphe guttata	Corn snake	NL	UT-SC	UT-Grand, San Juan	White Canyon STSA	Rocky hillsides, meadows, along streams and river bottoms, in canyons and arroyos, in barnyards, near springs, and in wooded areas.
Crotalus oreganus concolor	Midget faded rattlesnake	BLM	CO-SC	CO-Garfield, Rio Blanco; WY-Sweetwater	Green River, Piceance, and Washakie	High, cold desert dominated by sagebrush, with an abundance of rock outcrops and exposed canyon walls.
Gambelia wislizenii	Longnose leopard lizard	BLM	CO-SC	CO-Garfield, Rio Blanco	Piceance	Flat or gently sloping shrublands with a large percentage of open ground; stands of greasewood and sagebrush on deep, sandy soils and broad outwash plains in or near the mouths of canyons.
Liochlorophis vernalis	Smooth greensnake	NL	UT-SC	UT-Carbon, Duchesne, Grand, San Juan, Uintah	Uinta; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, Sunnyside, and White Canyon STSAs	Meadows, grassy marshes, mountain shrublands, stream borders, bogs, and open, moist woodland.
Sauromalus ater	Common chuckwalla	NL	UT-SC	UT-Garfield, San Juan	None	Rocky desert; lava flows, hillsides, and outcrops.
Xantusia vigilis	Desert night lizard	NL	UT-SC	UT-Garfield, San Juan	Tar Sand Triangle and White Canyon STSAs	Arid and semiarid habitats among fallen leaves and trunks of yuccas, agaves, cacti, and other large plants; ranges locally into pinyon-juniper, sagebrush-blackbrush, and chaparral-oak.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds						
Accipiter gentilis	Northern goshawk	BLM	WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; all STSAs	Variety of forest habitats. Occasionally seen during migration in shrublands.
Aechmophorus clarkii	Clark’s grebe	NL	WY-SC	WY-Lincoln	Green River	Marshes, lakes, and bays. Nests among tall plants growing in water on the edge of large areas of open water.
Aegolius funereus	Boreal owl	NL	WY-SC	CO- Garfield, Rio Blanco; WY-Lincoln, Uinta	Green River, Piceance, and Washakie	Mature spruce-fir or spruce-fir/lodgepole pine forests interspersed with meadows.
Amphispiza belli	Sage sparrow	BLM	NL	WY-Lincoln, Sublette, Sweetwater, Uinta	Green River and Washakie	Breeds in sagebrush shrublands. During migration, occurs in grasslands and other types of shrublands.
Aphelocoma californica	Western scrub-jay	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Oak, pinyon, and juniper scrub, brush, and riparian woodland.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Asio flammeus	Short-eared owl	NL	UT-SC	UT-Carbon, Duchesne, Emery, Grand, Garfield, San Juan, Uintah, Wayne	Uinta; Asphalt Ridge, Pariette, San Rafael, Tar Sand Triangle, and White Canyon STSAs	Large open areas with low vegetation, including marshes, prairies, grassy plains, old fields, river valleys, meadows, savanna, and open woodland. Generally nests on high ground or upland sites.
Athene cunicularia	Burrowing owl	BLM	CO-T, UT-SC, WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; all STSAs	Open grasslands; nests and roosts in burrows dug by mammals.
Baeolophus ridgwayi	Juniper titmouse	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Pinyon-juniper woodland.
Bucephala islandica	Barrow's goldeneye	BLM	NL	CO-Garfield, Rio Blanco	Piceance	In winter, on reservoirs and rivers; in summer, on mountain reservoirs and ponds in forested areas.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Buteo regalis	Ferruginous hawk	BLM	CO-SC, UT-SC, WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; all STSAs	Grasslands and semidesert shrublands; is rare in pinyon-juniper woodlands. In winter, near prairie dog towns. Migrants and winter residents may also occur in shrublands and agricultural areas.
Botaurus lentiginosus	American bittern	NL	WY-SC	WY-Lincoln, Sweetwater, Uinta	Green River	Breeds primarily in large freshwater marshes, including lake and pond edges where cattails, sedges, or bulrushes are plentiful, and marshes where there are patches of open water and aquatic-bed vegetation.
Calcarius mccownii	McCown's longspur	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Sparse short-grass plains, plowed and stubble fields, and areas of bare or nearly bare ground. Nests on the ground, often on high, barren hillsides with southern exposures.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Centrocercus urophasianus	Sage grouse	BLM	CO-SC, UT-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; Argyle Canyon, Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, and Sunnyside STSAs	Sagebrush shrublands. In summer, also found in native or cultivated meadows, grasslands, aspen, and willow thickets adjacent to or interspersed with sagebrush.
Charadrius montanus	Mountain plover	BLM	CO-SC, WY-SC	CO-Rio Blanco; WY-Lincoln, Sublette, Sweetwater	Green River, Piceance, and Washakie	Casual migrant in valley areas of Colorado. In Wyoming, breeds in flat open areas such as alkali flats, prairie dog towns, tablelands, agricultural fields, and heavily grazed sites.
Coccyzus americanus occidentalis	Western yellow-billed cuckoo	ESA-C, BLM	WY-SC	UT-Duchesne, Garfield, Grand, San Juan, Uintah, Wayne	Uinta; Asphalt Ridge STSA	Lowland riparian forest.
Cygnus buccinator	Trumpeter swan	NL	WY-SC	WY-Lincoln, Sublette, Sweetwater	Green River and Washakie	Ponds, lakes, and marshes and breeds in areas of reeds, sedges, or similar emergent vegetation.
Cypseloides niger	Black swift	NL	CO-SC, UT-SC	CO-Garfield, Rio Blanco; UT-Duchesne, Uintah	Piceance and Uinta; Argyle Canyon, Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	Nests on cliffs near or behind waterfalls. Foraging birds occur at high elevations over montane and adjacent lowland habitats.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Dolichonyx oryzivorus	Bobolink	NL	UT-SC	UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Uinta; all STSAs	Breeds in tall grass areas, flooded meadows, prairies, deep cultivated grain fields, and hayfields with dense vegetation. During migration, found in rice fields, marshes, and open woody areas.
Empidonax traillii extimus	Southwestern willow flycatcher	ESA-E	CO-E	CO-Garfield, Rio Blanco; UT-Carbon, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Piceance and Uinta; P.R. Spring, San Rafael, Tar Sand Triangle, and White Canyon STSAs	Nests in riparian corridors, islands, and sandbars vegetated with willow, tamarisk, or other shrubs.
Falco peregrinus anatum	American peregrine falcon	BLM	CO-SC	CO-Garfield, Rio Blanco; WY-Sublette, Sweetwater	Green River, Piceance, and Washakie	Nests on cliffs and forages over adjacent coniferous and riparian forests. Migrants and winter residents occur mostly around reservoirs, rivers, and marshes but also may be seen in grasslands, agricultural areas, and other habitats.
Gavia immer	Common loon	NL	WY-SC	WY-Lincoln, Sublette, Sweetwater, Uinta	Green River and Washakie	Breeds in clear-water lakes containing both shallow and deepwater areas and shoreline or island nest sites. Occurs on inland lakes and rivers during migration.
Grus americana	Whooping crane	ESA-XN	CO-E	CO-Garfield, Rio Blanco	Piceance	Rare migrant in valleys, where it occurs on mudflats around reservoirs and in agricultural areas.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Grus canadensis tabida	Greater sandhill crane	NL	CO-SC	CO-Garfield, Rio Blanco	Piceance	Migrants occur on mudflats around reservoirs, moist meadows, and agricultural areas. Breeds in open areas with grassy hummocks and watercourses, beaver ponds, and natural ponds lined with willows or aspens.
Gymnogyps californianus	California condor	ESA-E	NL	UT-Grand	Tar Sand Triangle and White Canyon STSAs	Mountainous areas at low and moderate elevations, especially rocky and brushy areas with cliffs available for nest sites; forages in grasslands, oak savanna, mountain plateaus, ridges, and canyons. Roosts in snags or tall open-branched trees near important foraging grounds.
Haliaeetus leucocephalus	Bald eagle	NL	CO-T, WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; all STSAs	Near reservoirs and large rivers. In winter, they may also occur locally in semideserts and grasslands, especially near prairie dog towns.
Icterus parisorum	Scott's oriole	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Pinyon-juniper and arid oak scrub on foothills, desert slopes of mountains, and more elevated semiarid plains.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Lanius ludovicianus	Loggerhead shrike	NL	WY-SC	WY-Lincoln, Sublette, Sweetwater, Uinta	Green River and Washakie	Breeds in open country with scattered trees and shrubs, savanna, desert scrub, and, occasionally, open woodland.
Melanerpes lewis	Lewis's woodpecker	NL	UT-SC; WY-SC	UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Uinta	Green River and Uinta; all STSAs	Lowland and foothill riparian forests, agricultural areas, and urban areas with tall deciduous trees.
Numenius americanus	Long-billed curlew	BLM	CO-SC, UT-SC, WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; all STSAs	Short-grass prairie, wheat fields, and fallow fields. Nests are usually close to standing water. Migrants occur on shorelines and in meadows and fields.
Pelecanus erythrorhynchos	American white pelican	BLM	UT-SC	CO-Garfield, UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Piceance and Uinta; all STSAs	Large reservoirs with breeding sites on islands. Is a migrant in the study area.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Picoides arcticus	Black-backed woodpecker	NL	WY-SC	WY-Lincoln	Green River	Boreal and montane coniferous forests, especially in areas with standing dead trees such as burns, bogs, and windfalls; less frequently in mixed forest; rarely, in winter, in deciduous woodland.
Picoides tridactylus	Three-toed woodpecker	NL	UT-SC	UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Uinta; Argyle Canyon, Hill Creek, P.R. Spring, Sunnyside, Tar Sand Triangle, and White Canyon STSAs	Dense coniferous forests; associated with fir and spruce at higher elevations; mainly in lodgepole pine forests or in mixed-conifer forests at lower elevations.
Plegadis chihi	White-faced ibis	BLM	WY-SC	CO-Garfield, Rio Blanco; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, and Washakie	Migrant and summer visitor to wet meadows, marsh edges, and reservoir shorelines.
Psaltriparus minimus	Bushtit	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Woodlands and scrub habitat with scattered trees and shrubs, brushy streamsides, pinyon-juniper, and pine-oak associations.
Sitta pygmaea	Pygmy nuthatch	NL	WY-SC	WY-Lincoln, Sublette	Green River	Pine forest and woodland, especially ponderosa pine; less frequently in pinyon-juniper woodland.
Sterna caspia	Caspian tern	NL	WY-SC	WY-Lincoln	Green River	Breeds on sandy or gravelly beaches and shell banks of large inland lakes.
Sterna forsteri	Forster's tern	NL	WY-SC	WY-Lincoln	Green River	Nests on inland lakes and marshes.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Strix occidentalis lucida	Mexican spotted owl	ESA-T	NL	UT-Emery, Garfield, Grand, San Juan, Uintah, Wayne	Uinta; Raven Ridge, Tar Sand Triangle, and White Canyon STSAs	Most common where unlogged closed-canopy forests occur in steep canyons; uneven-aged stands with a high basal area and many snags and downed logs are most favorable.
Tympanuchus phasianellus columbianus	Columbian sharp-tailed grouse	BLM	CO-SC	CO-Garfield	Piceance	Gambel oak and serviceberry shrublands, often interspersed with sagebrush shrublands, aspen forests, wheat fields, and irrigated meadows and alfalfa fields. Display grounds are on knolls or ridges.
Mammals						
Antrozous pallidus	Pallid bat	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Arid deserts and grasslands, often near rocky outcrops and water.
Brachylagus idahoensis	Pygmy rabbit	BLM	UT-SC, WY-SC	UT-Garfield, Wayne; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River and Washakie; Tar Sand Triangle STSA	Dense stands of big sagebrush growing in deep loose soils.
Cynomys leucurus	White-tailed prairie dog	BLM	UT-SC, WY-SC	UT-Carbon, Duchesne, Emery, Grand, Uintah; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Uinta, and Washakie; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, and San Rafael STSAs	Open shrublands, semidesert grasslands, and mountain valleys. Occasionally invades pastures and agricultural lands at lower elevations.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Mammals (Cont.)						
Corynorhinus townsendii pallescens	Townsend's big-eared bat	BLM	CO-SC, UT-SC, WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne; WY-Sweetwater	Green River, Piceance, Uinta, and Washakie; all STSAs	Semidesert shrublands, pinyon-juniper woodlands, and open montane forests.
Cynomys gunnisoni	Gunnison prairie dog	NL	UT-SC	UT-Grand, San Juan	None	High mountain valleys and plateaus (elevations between 1,830 and 3,660 m) that are open or are sparsely vegetated with shrubs, junipers, or pines.
Cynomys parvidens	Utah prairie dog	ESA-T	NL	UT-Garfield, Wayne	None	Grasslands in level mountain valleys in areas with deep, well-drained soil and vegetation that prairie dogs can see over or through.
Euderma maculatum	Spotted bat	BLM	UT-SC, WY-SC	CO-Garfield, Rio Blanco; UT-Duchesne, Garfield, Grand, San Juan, Uintah, Wayne; WY-Sweetwater	Green River, Piceance, Uinta, and Washakie; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, San Rafael, Tar Sand Triangle, and White Canyon STSAs	Ponderosa pine of montane forests, pinyon-juniper woodlands, and open semidesert shrublands. Roosts occur in rocky cliffs with access to water.
Gulo gulo	Wolverine	NL	CO-E, WY-SC	CO-Garfield, Rio Blanco; WY-Lincoln, Sublette	Green River and Piceance	Boreal forests and tundra.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Mammals (Cont.)						
Idionycteris phyllotis	Allen's big-eared bat	NL	UT-SC	UT-Garfield, Grand, San Juan, Wayne	P.R. Spring, Tar Sand Triangle, and White Canyon STSAs	Mountainous areas near cliffs and boulders and in pine-oak, coniferous forests, or riparian woods. Forages over streams and ponds.
Lasiuris blossevillii	Western red bat	NL	UT-SC	UT-Carbon, Emery, Grand, Garfield, San Juan, Wayne	P.R. Spring, San Rafael, Tar Sand Triangle, and White Canyon STSAs	Riparian habitats dominated by cottonwoods, oaks, sycamores, and walnuts; rarely found in desert habitats.
Lynx canadensis	Canada lynx	ESA-T	CO-E, WY-SC	CO-Garfield, Rio Blanco; UT-Emery, Uintah; WY-Lincoln, Sublette, Uinta	Green River, Piceance, and Uinta; Asphalt Ridge STSA	Northern coniferous forests. Uneven-aged stands with relatively open canopies and well-developed understories are ideal.
Microtis mogollonensis	Mogollon vole	NL	UT-SC	UT-San Juan	None	Mountain meadows, grassy openings in woodland.
Microtus richardsoni	Water vole	NL	WY-SC	WY-Lincoln, Sublette, Uinta	Green River	Subalpine and alpine meadows close to water, especially swift, clear, spring-fed or glacial streams with gravel bottoms.
Mustela nigripes	Black-footed ferret	ESA-XN	CO-E	CO-Rio Blanco; UT-Carbon, Duchesne, Emery, Grand, San Juan, Uintah	Piceance, Green River, Uinta, and Washakie; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, San Rafael, and Sunnyside STSAs	Historically occupied areas ranging from the shortgrass and midgrass prairie to semidesert shrublands.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Mammals (Cont.)						
Myotis evotis	Long-eared myotis	BLM	NL	WY-Lincoln, Sublette, Sweetwater, Uinta	Green River and Washakie	Conifer and deciduous forests, caves and mines.
Myotis thysanodes	Fringed myotis	BLM	UT-SC, WY-SC	CO-Garfield, Rio Blanco; UT-Duchesne, Garfield, Grand, San Juan, Uintah, Wayne; WY-Sublette	Green River, Piceance, and Uinta; Argyle Canyon, Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, Tar Sand Triangle, and White Canyon STSAs	Ponderosa pine woodlands, greasewood, oakbrush, and saltbush shrublands.
Nyctinomops macrotis	Big free-tailed bat	BLM	UT-SC	CO-Garfield; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Piceance and Uinta; Asphalt Ridge, Hill Creek, Pariette, P.R. Spring, Raven Ridge, San Rafael, Tar Sand Triangle, and White Canyon STSAs	Roosts in crevices on cliff faces or in buildings.
Perognathus flavus	Silky pocket mouse	NL	UT-SC	UT-San Juan	None	Sandy soils in arid grasslands, shrublands, and pinyon-juniper woodland, in valley bottoms, hillsides, and mesas.
Peromyscus crinitus	Canyon mouse	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Rocky habitats: gravelly desert pavement, talus, boulders, cliffs, and slickrock.
Peromyscus truei	Pinon mouse	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Among rocks or on rocky slopes in a variety of habitats, including pinyon-juniper woodlands, desert scrub, limestone cliffs, and riparian woodlands.
Sorex preblei	Preble’s shrew	NL	WY-SC	WY-Lincoln, Uinta	Green River	Arid and semiarid shrub-grass communities.

TABLE E-1 (Cont.)

Scientific Name	Common Name	Federal Status[a]	State Status[b]	States and Counties in Which Species Could Occur	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Mammals (Cont.)						
Tamias dorsalis utahensis	Cliff chipmunk	NL	WY-SC	WY-Sweetwater	Green River	Rocky outcrops, steep hillsides; only recorded presence in Wyoming is in the vicinity of Flaming Gorge.
Thomomys clusius	Wyoming pocket gopher	BLM	NL	WY-Sweetwater	Green River and Washakie	Well-drained, often gravelly soils of ridge tops and edges of deeply eroded stream-cut washes, and shrubland habitats.
Thomomys idahoensis	Idaho pocket gopher	BLM	WY-SC	WY-Lincoln, Sublette, Uinta	Green River	Open sagebrush, grasslands, and subalpine mountain meadows with relatively shallow stony soils.
Vulpes macrotis	Kit fox	NL	CO-E, UT-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, Wayne	Piceance and Uinta; all STSAs	Semidesert shrubland and margins of pinyon-juniper woodlands.
Vulpes velox	Swift fox	BLM	WY-SC	WY-Sweetwater	Green River and Washakie	Open flat prairies and plains with flat to rolling terrain and sparse vegetation.

Footnotes on following page.

TABLE E-1 (Cont.)

[a] Federal listings: BLM = listed by the BLM as sensitive; C = candidate for listing; E = listed as endangered; ESA = Endangered Species Act; PT = proposed for listing as threatened; T = listed as threatened.

[b] State listings: CO = Colorado; E = listed as endangered; SC = listed as species of special concern; T = listed as threatened; UT = Utah; WY = Wyoming.

[c] States and counties within species range in which oil shale or tar sands projects could occur.

[d] Oil shale basins or tar sands areas in which species could occur based on published distributions.

[e] To convert meters to feet, multiply by 3.281.

[f] NL = not listed.

[g] XN = experimental population, nonessential.

Source: Goodrich and Neese (1986); UDWR (1998, 2006, 2007); Colorado Rare Plant Technical Committee (1999); Keinath et al. (2003); CDOW (2006); NatureServe (2006); University of Wyoming (2006); Flora of North America (2007); Natural Resources Conservation Service (2007); Utah State University (2007a,b).

APPENDIX E REFERENCES

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APPENDIX F:

PROPOSED CONSERVATION MEASURES FOR THE PREFERRED ALTERNATIVE

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APPENDIX F:

PROPOSED CONSERVATION MEASURES FOR THE PREFERRED ALTERNATIVE

CONSERVATION MEASURES

The following conservation measures are recommended by the U.S. Fish and Wildlife Service (USFWS) to support the conservation of species listed under the Endangered Species Act (ESA). For purposes of the programmatic environmental impact statement (PEIS), these conservation measures are assumed to be generally consistent with existing conservation agreements, recovery plans, and completed consultations. It is the intent of the Bureau Land Management (BLM) and the USFWS to ensure that the conservation measures presented here are consistent with those currently applied to other land management actions where associated impacts are similar. However, it is presumed that potential impacts from development alternatives described in the PEIS are likely to vary in scale and intensity when compared with land management actions previously considered (e.g., oil and gas exploration and production, surface mining, and underground mining). Hence, final conservation measures will be developed commensurate with the anticipated level of impact on the selected alternatives and will be consistent with agency policies. Current BLM guidance on similar actions (e.g., fluid mineral resources) requires that the least restrictive stipulation that effectively accomplishes the resource objectives or resource uses for a given alternative should be used while remaining in compliance with the ESA.

Conservation Measures Generally Applicable to All Listed Species

1. Surveys will be required prior to operations unless species occupancy and distribution information for the area is complete and available. All surveys must be conducted by qualified individual(s) approved by BLM. For bald eagles and Mexican spotted owls (and other raptors), surveys should be conducted up to 1 mi from the proposed disturbance to determine nest and roost status and will be conducted in accordance with existing guidelines.

2. Lease activities, upon initiation of implementation, will require monitoring throughout the duration of the project. To ensure that the desired results are being achieved, minimization measures will be evaluated and, if necessary, Section 7 consultation reinitiated.

3. Water production will be managed to ensure maintenance or enhancement of riparian habitat and surface water quality.

4. Avoid loss of riparian and wetland habitats where possible with mining and in situ processing. Minimize loss of riparian and wetland habitat with roads, pipelines, and other ancillary facilities. Restore wetland and riparian habitat when avoidance with facilities is not possible. Any incidental take statement (if warranted) will need to be based on an estimate of avoidance and if unavoidable, quantify extent of potential take.

5. Transportation management plans should be developed and used as a means for minimizing habitat fragmentation and destruction.

Species Specific Conservation Measures

Colorado River Endangered Fishes—Bonytail, Colorado Pikeminnow, Humpback Chub, Razorback Sucker

1. Within 0.5 mi of critical habitat; a) avoid all mining and drilling activities and, b) minimize surface disturbance and vegetation removal for roads, pipelines, water diversion and acquisition facilities, and other ancillary facilities. When surface disturbance for any of the features in item b above is necessitated within 0.5 mi of critical habitat, the BLM should confer with USFWS to minimize potential impacts to critical habitat and/or endangered fish.

2. For tributaries to the major rivers that contain listed fish species or their designated critical habitat, drilling or mining will not occur within the 100-year floodplains or riparian corridors that are within the zone of influence of the major rivers.

3. To avoid excessive stream sedimentation during the spawning period, avoid construction activities (e.g., for roads, pipelines, utilities) within critical habitat from April 1 through September 30 of any year.

4. Avoid the installation of water diversion structures that may pose a risk to the Colorado River fishes or their critical habitat (e.g., minimize entrainment or impingement by using screens, baffles).

5. Avoid the release of selenium into surface waters, and where possible, implement measures to reduce selenium concentrations in the Upper Colorado River Basin. For example, decrease erosion in areas with selenium-rich soils (e.g., shale-derived soils), maintain adequate vegetation cover on work areas where possible, control ephemeral streamflow with water spreading structures, do not irrigate in areas with selenium-rich soils, and avoid impacting selenium-rich soils on steep slopes (>50%). If selenium-rich slag/waste piles are created, they should be isolated and located so that this material does not reach critical habitat.

6. All new pipelines and other controlled surface uses crossing any critical or occupied habitat of the Colorado River fishes will adhere to the following stipulations:
   a. Pipelines shall not be constructed in known spawning sites or backwaters.
   b. No work in the active river channel will take place between July 1 and September 30. This will avoid adverse affects from sedimentation during spawning, and when larval fishes are drifting in the river channel.
   c. After construction, the streambed will be returned to preconstruction contours.
   d. Pipelines transporting substances other than water will have automatic shut-off valves.
   e. Pipelines transporting substances other than water will be double-walled where they cross the 100-year floodplain and river.
   f. A spill/leak contingency plan will be developed prior to pipeline use.

7. Implement the Utah Oil and Gas Pipeline Crossing Guidance (from BLM National Science and Technology Center).

8. If water is obtained for project-related activities from any surface water source (stream, pond, etc.), or from any groundwater source that has a connection to surface water, the BLM will require that all water withdrawals undergo appropriate Section 7 consultation in accordance with procedures existing at the time of the proposed action. Any applicant for a water withdrawal less than the Colorado River Recovery Program sufficient progress threshold (in 2007, 4,500 ac-ft/yr) shall pay the appropriate depletion fee, depending on whether the depletion is a historical or new depletion. Only new depletions over 100 ac-ft/yr are subject to the fee requirement. Projects withdrawing more than the sufficient progress threshold shall complete an additional item from the Colorado River Recovery Implementation Plan Recovery Action Plan as agreed to by the USFWS (new depletions would also be subject to the depletion fee).

Colorado River Cutthroat Trout

1. Maintain a minimum 0.25-mi buffer (both sides) of occupied Colorado River cutthroat trout streams and upstream tributaries. The buffer would be extended beyond the 0.25-mi minimum in areas where slopes exceed 50%; the buffer would extend out to where the land is relatively level. The idea is to keep any sediment from reaching the occupied Colorado River cutthroat trout reaches by making sure that mining and drilling take place on flat ground in areas where Colorado River cutthroat trout occur. Linear features such as roads and pipelines may be allowed within the buffer zones. Keep in mind that there are only a handful of known Colorado River cutthroat trout populations in the oil shale and tar sands planning area, and these conservation measures would affect only a very small portion of the area proposed for leasing (5% or less).

2. No water withdrawals will occur from waters occupied by Colorado River cutthroat trout, based on current information.

3. Oil shale and tar sands activities will be consistent with the "Conservation Agreement for Colorado River Cutthroat Trout (*Oncorhynchus clarkia pleuriticus*)" for the states of Colorado, Utah, and Wyoming (June 2006).

Bald Eagle[1]

1. A year-round avoidance of 0.5-mi of known bald eagle nests if topographic and/or vegetative buffers exist or of areas within 1 mi if nest is in line of sight of activity will be established. This avoidance requirement may be adjusted based on a demonstration of nonoccupancy during the last 7 years. Any modification will be in coordination with USFWS.

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[1] Nesting and wintering dates can vary by location. Contact local USFWS office for dates specific to a given area.

2. A year-round avoidance of 0.25-mi if topographic and/or vegetation buffers exist to 1-mi if roost is in line of sight of activity will be established for all known bald eagle winter roost sites. This avoidance requirement may be adjusted based on a demonstration of nonoccupancy during the last 7 years. Any modification will be in coordination with the USFWS.

3. Avoid loss or disturbance to riparian habitats containing cottonwoods, conifers, or other tree species that, when mature, may provide roost or nest trees for bald eagles. Minimize loss of any other riparian plant species (including box elders, willows, and river birch).

4. The USFWS recommends that the BLM and contractors be informed of the risk or potential for wildlife vehicle collision (particularly bald eagles) in the project area and requested to limit vehicle speed to reduce such potential. In addition, contractors should move any big game carcasses found along project area roads away from the roadway by 30 ft (generally 60-ft-wide ROWs) to minimize the potential for bald eagle and vehicle collisions while eagles feed on roadside carrion. Furthermore, the BLM and contractors, in an additional effort to protect bald eagles, will coordinate with appropriate officials for necessary removal of any big game carcasses along county or state roads.

5. To preclude bald eagles or other raptors from nesting on human-made structures such as cell phone towers and condensate tanks and to avoid impeding operation or maintenance activities, install antiperching devices on structures to discourage use by eagles and other raptors.

6. Bury electric lines, where practicable, especially in areas of high bald eagle use. If lines cannot be buried, power lines will be built at a minimum, to standards identified by the Avian Power Line Interaction Committee (2006) to minimize electrocution potential (see *Suggested Practices for Raptor Protection on Power Lines: The State of the Art in 2006*; available at http://www.eei.org/products_and_services/descriptions_and_access/suggested_pract.htm). Moreover, power lines will be built according to the additional specifications listed below. The project proponent should ensure that these additional standards to minimize bald eagle mortality associated with electric utility distribution lines will be incorporated into the stipulations for all project actions. It should be noted that these measures vary in their effectiveness to minimize mortality, and may be modified as they are tested in the field and laboratory. Local habitat conditions should be considered in their use. The USFWS does not endorse any specific product that can be used to prevent and/or minimize mortality. The following recommendations should be incorporated into the design plan of new distribution lines or when modifying existing facilities.

   For new distribution lines and facilities:
   a. Raptor-safe structures (e.g., with increased conductor-conductor spacing) that address adequate spacing for bald eagles (i.e., minimum of 60 in. for bald eagles) are to be used.
   b. Equipment installations (e.g., overhead service transformers, capacitors, reclosers) should be made bald-eagle safe (e.g., by insulating the bushing conductor terminations and by using covered jumper conductors).

c. Jumper conductor installations (e.g., corner and tap structures) should be made bald-eagle safe by using covered jumpers or providing adequate separation.
d. Arrestor and cutout covers should be employed when necessary.
e. Lines should avoid high avian-use areas such as wetlands, prairie dog towns, and grouse leks.

For modification of existing facilities:
a. Problem structures that include dead ends, tap or junction poles, transformers, reclosers and capacitor banks, or other structures with less than 60 in. between conductors or a conductor and ground should be identified and rectified.
b. Exposed jumpers should be covered.
c. Any pole-top ground wires should be capped.
d. Grounded guy wires should be isolated by installing an insulating link.
e. On transformers, install insulated bushing covers, covered jumpers, and cutout covers and arrestor covers, if necessary.
f. When bald eagle mortalities occur on existing lines and structures, bald eagle protection measures should be applied (e.g., modify for raptor-safe construction, install safe perches or perching deterrents, nesting platforms or nest-deterrent devices).
g. In areas where midspan collisions are a problem, install line-marking devices that have been proven effective. All transmission lines that span streams and rivers should maintain proper spacing and have markers installed.
h. Poles will be moved if topographic issues or impacts to vegetative or wildlife resources were identified at the construction site.

7. When constructing communication towers, refer to the USFWS *Guidance on the Siting, Construction, Operation, and Decommissioning of Communication Towers,* which can be found at http://www.fws.gov/migratory birds/issues/towers/comtow.html.

Mexican Spotted Owl[2]

1. Within the range of the Mexican spotted owl, avoid surface disturbance where suitable nesting habitat for the species occurs (steep-walled, rocky canyons, typically with a closed-canopy of mature, mixed coniferous forest) (see the recovery plan [USFWS 1995] for the spotted owl, particularly Table III.B.1). (The range of the Mexican spotted owl published in the recovery plan should be extended to include the individuals observed within Dinosaur National Monument.)

2. Within areas of oil shale and tar sands potential in Utah and Colorado, prior to leasing of mineral rights, the Bureau will develop a map of BLM lands with Mexican spotted owl habitat that is comprised of areas with steep slopes (>40% slope), canyons and rocky outcrops overlapping dense, mixed-conifer vegetation (canopy cover greater than 40% if data are available). This mapping effort would be considered a broad-based approach from which more specific and intensified habitat analyses could be initiated.

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[2] Contact local USFWS office for breeding season dates specific to a given area.

3. Where possible, conduct field surveys for the Mexican spotted owl in areas of suitable habitat in order to gain a better understanding of Mexican spotted owl distribution and status throughout areas of oil shale and tar sands potential in Utah and Colorado. Field surveys should emphasize areas that have not been previously or recently surveyed. Areas of particular interest include the Book Cliffs and areas surrounding Dinosaur National Monument.

4. Unless species occupancy and distribution information is complete and available, field surveys shall occur in areas where proposed human activities may remove or modify Mexican spotted owl habitat or otherwise adversely affect the species. Current USFWS survey protocol will be followed. Existing protocols require that four surveys be conducted each season for two consecutive seasons. All surveys must be conducted by a qualified individual(s) approved by BLM.

5. Assess habitat suitability for both nesting and foraging using accepted habitat models in conjunction with field reviews. Apply the conservation measures below if project activities occur within 0.5 mi of suitable owl habitat. Determine potential effects of actions to owls and their habitat. Document type of activity, acreage and location of direct habitat impacts, and type and extent of indirect impacts relative to location of suitable owl habitat. Document if action is temporary or permanent. A temporary action is completed prior to the following breeding season leaving no permanent structures and resulting in no permanent habitat loss. A permanent action continues for more than one breeding season and/or causes a loss of owl habitat or displaces owls through disturbances (i.e., creation of a permanent structure).

6. For all temporary actions that may impact owls or suitable habitat:
   a. If the action occurs entirely outside of the owl breeding season (e.g., March 1 to August 31 in Utah), and leaves no permanent structure or permanent habitat disturbance, action can proceed without an occupancy survey.
   b. If action will occur during a breeding season, a survey for owls should be performed prior to commencing activity. If owls are found, activity must be delayed until outside of the breeding season.
   c. Rehabilitate access routes created by the project through such means as raking out scars, revegetation, gating access points, etc.

7. For all permanent actions that may impact owls or suitable habitat:
   a. Survey two consecutive years for owls according to accepted protocol prior to commencing activities.
   b. If owls are found, no actions will occur within 0.5 mi of identified nest site. If the nest site is unknown, no activity will occur within the designated protected activity center.
   c. Avoid drilling and permanent structures within 0.5 mi of suitable habitat unless surveyed and not occupied.
   d. Reduce noise emissions (e.g., use hospital-grade mufflers) to 45 dBA at 0.5-mi from suitable habitat, including canyon rims. Placement of permanent noise-generating facilities should be determined by a noise analysis to ensure that noise does not encroach upon a 0.5-mi buffer for suitable habitat, including canyon rims.

e. Limit disturbances to and within suitable habitat by staying on approved routes.
f. Limit new access routes created by the project.

8. Avoid surface disturbance (e.g., facilities, roads, pipelines) and vegetation removal within designated critical habitat where any of the primary constituent elements are present at the project scale.

Southwestern Willow Flycatcher

1. In project areas potentially occupied by the southwestern willow flycatcher, surveys for the southwestern willow flycatcher should be conducted.

2. Project activities will maintain a 300-ft buffer from suitable riparian habitat year long.

3. Project activities within 0.25 mi of occupied breeding habitat will not occur during the breeding season of May 1 to August 15.

4. The USFWS recommends postactivity surveys for southwestern willow flycatchers for any project or mitigation areas authorized by the BLM. Surveys must be conducted by individuals who have been properly trained in approved survey protocol. Surveyors must be familiar with and adhere to the general survey techniques and guidelines in Sogge et al. (1997). Flycatcher survey training must be completed prior to being permitted to conduct surveys. All reporting requirements must be followed.

5. For projects that may alter or destroy habitat that are in or near occupied, suitable, potentially suitable, or potential habitat, the USFWS recommends using fencing instead of flagging to delineate the project area. Fencing is more visible to construction workers and more clearly demarcates the construction zone.

6. If nest parasitism is monitored, when flycatcher nest parasitism exceeds 10% of surveyed nests, consult with USFWS to implement measures to reduce parasitism rates.

Black-footed Ferret

1. Prairie dog towns potentially occupied by black-footed ferrets or within 1.5 km of prairie dog towns occupied by black-footed ferrets should be surveyed and mapped by qualified individuals approved by BLM before surface-disturbing activities are conducted. Surveys should be in accordance with the 1989 *Black Footed Ferret Survey Protocol* or other methods upon USFWS review and approval. Mapping should be conducted in accordance with Biggins et al. (1993). Should black-footed ferrets or signs of them be observed within a prairie dog town or complex where project-related activities are proposed, the federal agency shall coordinate Section 7 consultation or conferencing with the USFWS on the proposed action. This measure applies to: (1) all habitats occupied by ferrets and (2) all suitable habitats within the oil shale and tar sands area. The BLM will confer with the appropriate USFWS Field Office for definitions of suitable habitat within each state.

In Wyoming (non-10(j) populations), in the event that no ferrets or signs of them are observed during the survey, ground-disturbing activities may occur within 1 year of the date of survey completion within the town surveyed. However, surveys should be completed as close to the date of project initiation as possible to avoid the possibility of a ferret moving into the area after surveys have cleared the area. Alternatively, all suitable habitat within the entire complex in which the town is located may be surveyed and, if no ferrets or sign are found, the complex will be designated “ferret-free” and no further Section 7 review for the black-footed ferret will be required for activities occurring within any prairie dog town within the complex. Future observations of ferrets or their sign shall, however, require reinitiation of Section 7 consultation. The BLM and the project proponent are encouraged to work with the USFWS to block clear all prairie dog towns within or contiguous with the analysis area. Future actions, including maintenance, work over, and reclamation within towns previously cleared of ferrets may require additional survey work unless the entire complex containing the town has been block cleared.

Results of all surveys shall be reported to the appropriate USFWS Field Office, including maps of areas surveyed, surveyor qualifications, method of survey, and length of survey, date, weather, snow cover, survey results, and copies of field data sheets.

2. Where possible, avoid placement of structures that provide suitable nest or perch sites for avian predators within ferret habitat. Ensure that garbage is contained to prevent attraction by coyotes, skunks, and other predators. This measure applies to: (1) all habitats occupied by ferrets and (2) all suitable habitat within the oil shale and tar sands area. The BLM will confer with the appropriate USFWS Field Office definitions of suitable habitat within each state.

3. Where possible, post and encourage reduced vehicle speeds at night on roads in or near occupied habitat to reduce chances of vehicular mortalities.

4. Ensure that reclamation is conducted so that impacts to active prairie dog colonies are minimized. This measure applies to all suitable habitats within the oil shale and tar sands area. The BLM will confer with the appropriate USFWS Field Office for definitions of suitable habitat within each state.

5. In areas where black-footed ferrets could be encountered, employees, operators, and contractors shall be educated on the natural history of the black-footed ferret, identification of ferrets and their sign, potential impacts for disease transmission from dogs to ferrets, activities that may affect ferret behavior, and ways to minimize these effects. This measure applies to all suitable habitats within the oil shale and tar sands area. The BLM will confer with the appropriate USFWS Field Office for definitions of suitable habitat within each state.

6. Observations of black-footed ferrets, their sign, or carcasses shall be reported to the nearest BLM and USFWS office within 24 hours. This measure applies throughout the oil shale and tar sands area.

7. Encourage the use of *White-tailed Prairie Dog Conservation Measures* (as revised), in white-tailed prairie dog habitat.

8. Whenever possible, project activities will be designed to avoid adverse influence on prairie dog habitat occupied by black-footed ferrets. If adverse impacts to occupied prairie dog habitat are unavoidable, activities will be designed in coordination with the USFWS to (1) impact the smallest area practicable, (2) impact those areas with the lowest prairie dog densities, and (3) minimize habitat fragmentation in prairie dog towns occupied by black-footed ferrets or those towns suitable for reintroduction. Offsite mitigation may also be recommended. Impacts to black-footed ferret habitat will be monitored to evaluate cumulative effects.

9. Whenever possible, project activities will be designed to not adversely impact black-footed ferret populations. A monitoring program will be developed, when necessary, to evaluate impacts. This measure applies to all habitats occupied by ferrets within the oil shale and tar sands area.

10. Project activities in Uintah and Duchesne Counties, Utah, will be conducted consistent with the Division of Wildlife Resources' 2007 *Northeastern Region Black-Footed Ferret Management Plan* and the BLM's 1999 *Book Cliffs Resource Area Management Plan Amendment for Black-footed Ferret Reintroduction, Coyote Basin Area, Utah*.

11. This measure applies specifically to the black-footed ferret management area and subcomplexes described by the Utah Division of Wildlife Resources' 2007 *Northeastern Region Black-Footed Ferret Management Plan*. Within the boundaries of the three subcomplexes (Coyote Basin, Snake John Reef, Bohemian Bottom), activities involving the development or construction of permanent surface disturbances will be prohibited within one-eighth mi of the home range of any black-footed ferret. Within the boundaries of the management area, if a ferret observation is recorded, or has been recorded within the last 5 years, no surface disturbance will be allowed within 0.44 mi (about 700 m) of the observation location if the following two criteria are met: (1) the ferret is/was observed in suitable habitat (the BLM will confer with the appropriate USFWS Field Office for definitions of suitable habitat within the management area) and (2) the ferret has established residency in the immediate locale (i.e., a documented home range has been established). The appropriate size of the protected area surrounding a ferret's home range may be adjusted in coordination with the USFWS according to future research and new information, and pursuant to the relevant local, site-specific species management plan, if available.

Canada Lynx[3]

1. Within a Lynx Analysis Unit (LAU), ensure that mapping of lynx habitat, nonhabitat, and denning habitat occurs. Also map foraging habitat, and topographic features important for lynx movement. Identify whether all lynx habitat within an LAU is in suitable or unsuitable

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[3] Landscape linkages may be the only issues.

condition. May involve interagency coordination where LAUs cross administrative boundaries.

2. Limit disturbance within each LAU to 30% of the suitable habitat within the LAU. If 30% of the habitat within an LAU is currently in unsuitable condition, no further reduction of suitable conditions shall occur as a result of management activities. Map oil and gas production and transmission facilities, mining activities and facilities, dams, timber harvest, and agricultural lands on public lands and evaluate projects on adjacent private lands, in order to assess cumulative effects. This will involve interagency coordination where LAUs cross administrative boundaries, primarily with the U.S. Forest Service.

3. Management actions shall not change more than 15% of lynx habitat within an LAU to an unsuitable condition within a 10-year period. This will involve interagency coordination where LAUs cross administrative boundaries.

4. Maintain denning habitat in patches generally larger than 5 acres, composing at least 10% of lynx habitat. Where less than 10% is currently present within an LAU, defer any management actions that would delay development of denning habitat structure. This will involve interagency coordination where LAUs cross administrative boundaries.

5. Ensure that key linkage areas that may be important in providing landscape connectivity within and between geographic areas across all ownerships are identified, using best available science.

6. Ensure that habitat connectivity within and between LAUs is maintained.

7. Document lynx observations (tracks, sightings, along with date, location, and habitat) and provide these to the state natural heritage database, and request an annual update from them on all sightings for review.

8. In the event of a large wildfire, ensure that a postdisturbance assessment prior to salvage harvest is conducted, particularly in stands that were formerly in late successional stages, to evaluate potential for lynx denning and foraging habitat.

9. On projects where over-snow access is required, ensure that use is restricted to designated routes.

10. Within lynx habitat, the BLM shall ensure that key linkage areas and potential highway crossing areas are identified, using best available science.

11. The BLM shall ensure that proposed land exchanges, land sales, and special use permits are evaluated for effects on key linkage areas.

12. If activities are proposed in lynx habitat, the BLM shall ensure that stipulations and conditions of approval for limitations on the timing of activities and surface use and occupancy are developed for leasing, and that more site-specific conditions of approval are

developed at the permitting stage. Examples include requiring that activities not be conducted at night, when lynx are active; and avoiding activity near denning habitat during the breeding season (April or May to July) to protect vulnerable kittens.

13. Provide for the continuation of foraging habitat in proximity to denning habitat.

14. Provide habitat conditions through time that support dense horizontal understory cover and high densities of snowshoe hares. This includes, for example, mature multistoried conifer vegetation. Focus vegetation management, including timber harvest and the use of prescribed fire, in areas that have potential to improve snowshoe hare habitat (dense horizontal cover) but that presently have poorly developed understories that have little value to snowshoe hares.

15. Determine where high total road densities (>2 mi per mi^2) coincide with lynx habitat, and prioritize roads for seasonal restrictions or reclamation in those areas.

16. Limit public use on temporary roads constructed for project activities. Design new roads, especially the entrance, for effective closure upon completion of project activities. Upon project completion, reclaim or obliterate these roads.

17. Minimize building of roads directly on ridgetops or areas identified as important for lynx habitat connectivity.

18. Where needed, develop measures such as wildlife fencing and associated underpasses or overpasses to reduce mortality risk.

19. Protect existing snowshoe hare and red squirrel habitat.

20. Use remote sensing equipment and bunch maintenance activities to reduce activity in the area as well as reduce the compaction of snow.

Threatened, Endangered, and Proposed Plants[4]

1. Surveys for listed plants will be conducted prior to ground disturbance wherever there is the potential for their occurrence in projects areas. Surveys in suitable habitat should be conducted when the plant can be detected, and during appropriate flowering periods. Documentation should include, but not be limited to, individual plant locations and suitable habitat distributions, and all surveys must be conducted by qualified individuals approved by the BLM. Surveys should extent at least 200 m beyond the perimeter of work areas. Surveys are generally valid for one year.

2. Consistent with existing or current recovery plans, the proposed action will be designed to support recovery objectives. For example:

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4 Refer to the PEIS for a list of all threatened, endangered, and proposed plants.

a. Designs will prevent surface runoff from work areas from entering plant occupied habitat.
b. Construction will occur below and away from the slope of occupied habitat, where feasible, to avoid slope failure or accelerated erosion;
c. No surface disturbance will occur within 100 m of a listed plant. If an area that is closer than 200 m from a listed plant must be disturbed (e.g., for mining, drilling, roads, pipelines), the edge of any area to be disturbed that is between 100 to 200 m of any listed plant should be temporarily fenced to keep disturbance from further approaching the listed plant's habitat. To avoid working in listed plant habitat and drawing attention to listed plants, the edge of disturbance should be fenced, not the nearby plant population. This measure could be modified with the approval of BLM and USFWS.
d. If a surface disturbance must be located less than 200 m from a listed plant, appropriate dust-abatement actions, commensurate with the level of use, must be taken in consultation with the USFWS and BLM.

3. If ground-disturbing activities occur within 200 m of listed plants, the plants should be monitored in accordance with the *Measuring and Monitoring of Plant Populations*, BLM Technical Reference 1730-1, 1998, during the blooming period for plant health, vigor, and the occurrence of transported dust from project activities. Data should also include a site description with GPS coordinates, size of the area occupied, estimated number and age range of plants, and evidence of habitat disturbance, plant damage, or mortality. Post-construction monitoring for invasive species must also be conducted. Annual reports should be provided to the BLM and the USFWS.

4. "Translocation" (transplanting) shall not be used as a rationale to defend a "not likely to adversely affect" or a "no effect" determination for endangered or threatened species.

5. Vehicle travel will avoid suitable and occupied habitat.

6. In consultation with USFWS, evaluate projects that remove topsoil in areas of suitable habitat for listed species shall set aside and replace the topsoil when ground work is completed to preserve the seed bank and associated mycorrhizal species, and to discourage invasive species.

7. When possible, revegetation should be limited to native species that will not compete with the rare species at that site. Revegetation projects should require a site-specific plan for areas with listed plant species, to be developed in consultation with the BLM and the USFWS.

8. Protective stipulations for endangered or threatened species should include appropriate measures to protect pollinator species that have been identified.

9. When listed plant species are near project areas, dust control measures should be employed to minimize fugitive dust deposition on plant surfaces.

10. When listed plants are near project areas, appropriate dust control measures will be determined in consultation with the BLM and the USFWS to minimize fugitive dust deposition on plant surfaces.

11. For riparian and wetland-associated species (e.g., Ute ladies'-tresses), ensure that water extraction or disposal practices do not result in a change of hydrologic regime outside of the range of natural variability.

12. Place produced oil, water, or condensate tanks in centralized locations, away from occupied habitat. Overspray from evaporation ponds should be located such that it falls at least 200 m from listed plant locations, if these are necessary.

Species Determined Not To Be within the Action Area

Gray Wolf (Per discussion with USFWS, wolves are not within the action area, so they will not be addressed in the PEIS or biological assessment [BA].)

Candidate Animal Species Determined To Be within the Action Area

Yellow-Billed Cuckoo (This species is within the action area only in Utah, and because it is a candidate species, it will not be addressed in the BA, but these conservation measures will be in the PEIS.)

1. Construction of roads, pipelines, and power lines in riparian habitat should not occur from June 1 through August 1.

2. Prohibit permanent surface-disturbing activities within 0.25 mi of any suitable yellow-billed cuckoo habitat. Exceptions should be evaluated on a case-by-case basis to avoid adverse impacts.

3. To avoid direct impacts or changes in riparian habitat, do not adversely modify stream channel morphology or annual streamflow regimes in suitable habitat.

4. Prohibit non-surface-disturbing activities within yellow-billed cuckoo habitat that will have adverse effects to the yellow-billed cuckoo or its habitat (e.g., boat and raft landings, outfitting camps, firewood collection) within 0.25 mi of occupied habitat.

5. Chemical insecticides shall not be applied within 0.25 mi of yellow-billed cuckoo occupied habitat.

6. Prohibit herbicide application for grasshopper control in yellow-billed cuckoo habitat within 0.25 mi of any active nests.

7. If technically feasible, biological control should be used in place of chemical pest control.

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APPENDIX G:

SOCIOECONOMIC AND ENVIRONMENTAL JUSTICE ANALYSIS METHODOLOGIES

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APPENDIX G:

SOCIOECONOMIC AND ENVIRONMENTAL JUSTICE ANALYSIS METHODOLOGIES

The analysis of the socioeconomic impacts of oil shale and tar sands development in Colorado, Utah, and Wyoming consists of two interdependent parts. The analysis of *economic impacts* estimates the impacts of construction and operation of oil shale and tar sands facilities and associated power plants, coal mines, and temporary housing on local employment and income. Because of the relative economic importance of oil shale and tar sands development in small rural economies and the consequent incapacity of local labor markets to provide sufficient workers in the appropriate occupations required for development construction and operation in sufficient numbers, oil shale and tar sands development is likely to result in a large influx of temporary population. Given these considerations, the analysis of *social impacts* assesses the potential impacts of oil shale and tar sands development on population, housing, local public service employment and expenditures, crime, alcoholism, illicit drug use, divorce rates, and mental illness. Also covered is social disruption; since it may occur with rapid population growth and the “boom and bust” economic development associated with oil shale and tar sands facilities, a review of the literature on social disruption is included. Finally, under social impacts, the analysis covers environmental justice impacts on minority and low-income populations.

The analysis assesses the impacts of oil shale and tar sands development and the associated power plants, coal mines, and temporary housing in a region of influence (ROI) in each state. The ROIs consists of the counties and communities most likely to be impacted by oil shale and tar sands development (see Section 3.10.1 of this programmatic environmental impact statement [PEIS]). Selection of these counties was based on counties used in the *Final Environmental Statement for the Prototype Oil Shale Leasing Program* (DOI 1973).

G.1 ECONOMIC IMPACTS ON LOCAL EMPLOYMENT AND INCOME

The analysis of socioeconomic impacts of oil shale and tar sands development, power plants, coal mines, and temporary housing on regional employment and income were assessed for the PEIS by using direct employment data in association with regional economic multipliers.

G.1.1 Direct Employment Data

To provide appropriate direct employment estimates for the analysis, a review of a number of relevant documents was undertaken, including *Final Environmental Statement for the Prototype Oil Shale Leasing Program* (DOI 1973); *Final Environmental Impact Statement, Proposed Development of Oil Shale Resources by The Colony Development Operation in Colorado* (BLM 1977); *Final Programmatic Environmental Impact Statement, Development Policy Options for the Naval Oil Shale Reserves in Colorado* (DOE 1982); *Final Supplemental Environmental Impact Statement for the Prototype Oil Shale Leasing Program* (BLM 1983a);

Final Environmental Impact Statement, Uintah Basin Synfuels Development (BLM 1983b); and *Utah Combined Hydrocarbon Leasing Regional Final Environmental Impact Statement* (BLM 1984). Following this review, direct employment data were taken from a number of different sources.

G.1.1.1 Oil Shale Facilities

Direct employment data for the construction and operation of surface and underground mine facilities with surface retorting for the development of oil shale resources were based on data taken from the *Final Environmental Statement for the Prototype Oil Shale Leasing Program* (DOI 1973). Data on oil shale developments using in situ processing under Alternatives B and C were available from Thompson (2006a). For Alternative A (No Action Alternative), data were based upon numbers presented in the four environmental assessments prepared by the companies conducting oil shale research, development, and demonstration projects (BLM 2006a–c; 2007). Employment numbers for oil shale facilities are presented in Section 4.11.3.

G.1.1.2 Tar Sands Facilities

Construction and operations direct employment data for tar sands facilities were available in the *Utah Combined Hydrocarbon Leasing Regional Final Environmental Impact Statement* (BLM 1984), but only for two technologies (surface mining and in situ processing) and only for two production levels (190,000 bbl/day and 175,000 bbl/day, respectively). These values were converted to direct employment values per 1,000 bbl/day, as shown in Table G-1.

For the socioeconomic assessment, direct employment was estimated as an average of all the assessed tar sands development technologies on the basis of a 20,000-bbl/day production level. To estimate per facility direct employment values, a general assumption of 40,000 bbl/day per facility was used as representative of a typical commercial tar sands project. The per facility values were then estimated as direct or total values times the ratio of the per facility production to the total production.

TABLE G-1 Input Data for Tar Sands Direct Employment Estimates

Action	Direct Employment (FTE/1,000 bbl/day)[a]
Surface mining, construction	50.5
Surface mining, operations	34.6
In situ, construction	68.9
In situ, operations	12.8

[a] FTE = full-time equivalent.

Source: BLM (1984).

G.1.1.3 Power Plants and Coal Mines

Power plant construction and operations direct employment data were taken from Thompson (2006b,c), which described a 1,500-MW plant proposed for Ely, Nevada. Employment data for coal mines were from U.S. Department of Energy (DOE) (2007a,b,c) and industry sources (Hill and Associates 2007).

G.1.2 Temporary Housing Construction Data

The impacts of the construction of temporary housing were assessed by using estimates of the number of in-migrating direct and indirect workers and accompanying family members, with updated construction labor cost factors taken from the *Final Environmental Statement for the Prototype Oil Shale Leasing Program* (DOI 1973).

G.1.3 Economic Multipliers

Economic multipliers captured the indirect (off-site) effects of construction and operation of oil shale and tar sands facilities and associated power plants and housing developments. Multipliers for each ROI were derived from IMPLAN® input-output economic accounts for each ROI (Minnesota IMPLAN Group, Inc. 2007). These accounts show the flow of commodities to industries from producers and institutional consumers, consumption activities carried out by workers and owners of capital, and imports from outside the region. Each IMPLAN model contains 528 sectors representing industries in agriculture, mining, construction, manufacturing, wholesale and retail trade, utilities, finance, insurance and real estate, and consumer and business services. Each model also includes information for each sector on employee compensation; proprietary and property income; personal consumption expenditures; federal, state, and local expenditures; inventory and capital formation; imports; and exports.

Assumptions that were made in the analysis about the expected pattern of procurement within the ROI for the various materials and equipment and the extent of local wage and salary spending by oil shale and tar sands facility and power plant workers and temporary housing construction workers are described in Section 4.11 of this PEIS.

Impacts on ROI employment are described in terms of the total number of jobs (direct plus indirect) created in the region in the peak year of construction and in the first year of operation of oil shale and tar sands facilities and the associated power plants and temporary housing construction. Impacts on ROI income are described in terms of total income generated by direct and indirect construction and operations activities. The relative impact of the increase in employment in the ROI was calculated by comparing total oil shale and tar sands development construction employment over the period in which construction is expected to occur with baseline ROI employment forecasts over the same period. Forecasts were based on data provided by the U.S. Department of Commerce (2007).

G.2 SOCIAL IMPACTS

G.2.1 Population

An important consideration in the assessment of impacts of oil shale and tar sands development is the number of workers, families, and children that would migrate into the ROI, either temporarily or permanently, with the construction and operation of oil shale and tar sands facilities, power plants, and temporary housing. The capacity of regional labor markets to provide workers in the appropriate occupations required for oil shale and tar sands development construction and operation in sufficient numbers is closely related to the occupational profile of the ROI and occupational unemployment rates. Assumptions made about the number of in-migrating oil shale and tar sands facility, power plant, temporary housing construction, and indirect workers required to produce goods and services resulting from increased local demand associated with oil shale and tar sands facility, power plant, and temporary housing worker wage and salary spending are described in Section 4.11, together with the number of workers bringing family members into each ROI. The residential location of in-migrating workers was estimated by using a gravity model to assign workers to communities based on population size and distance from potential oil shale and tar sands projects (see Section 4.11). The national average household size was used to calculate the number of additional family members accompanying direct and indirect in-migrating workers.

Impacts on population are described in terms of the total number of in-migrants arriving in the region in the peak year of construction. The relative impact of the increase in population in the ROI was calculated by comparing total oil shale and tar sands development construction in-migration over the period in which construction is projected with baseline ROI population forecasts over the same period. Forecasts were based on data provided by the three states (Colorado State Demography Office 2007; Utah Governor's Office of Planning and Budget 2007; Wyoming Department of Administration and Information 2006).

G.2.2 Housing

The in-migration of workers occurring during construction and operation associated with oil shale and tar sands facility and power plant development would substantially affect the housing market in the ROI in the absence of temporary housing developments. The analysis considered these impacts by estimating the increase in demand for vacant housing units in the peak year of construction resulting from the in-migration of direct oil shale and tar sands facility, power plant, and indirect workers into each ROI. The relative impact on existing housing in the ROI was estimated by calculating the impact of oil shale and tar sands–related housing demand on the forecasted number of vacant housing units in the peak year of construction. Forecasts were based on data provided by the three states (Colorado State Demography Office 2007; Utah State Governor's Office of Planning and Budget 2006; Wyoming Department of Administration and Information 2006).

G.2.3 Public Services

Population in-migration associated with construction and operation of oil shale and tar sands facilities and the associated power plants and temporary housing construction workers would translate into increased demand for educational services and for public services (police, fire protection, health services, etc.) in each ROI. The impacts of in-migration associated with oil shale and tar sands and power generation facilities on county, city, and school district revenues and expenditures were based on per capita expenditure data provided in the jurisdictions' annual comprehensive financial reports (see Section 3.11). Impacts on public service employment were calculated by using the existing levels of service (the number of employees per 1,000 people required to provide each community service) to estimate the number of new police officers, firefighters, and general government employees required in the peak year of construction and first year of operations. Similarly, the number of teachers in each school district required to maintain existing teacher-student ratios across all student age groups was estimated. Impacts on health care employment were estimated by calculating the number of physicians in each county required to maintain the existing level of service, based on the existing number of physicians per 1,000 population, and the number of required additional staffed hospital beds to maintain the existing level of service, based on the existing number of staffed beds per 1,000 population. Information on existing employment and levels of service was collected from the individual jurisdictions providing each service (see Section 3.11).

G.2.4 Social Disruption

The relative economic importance of oil shale and tar sands facilities and associated power plant and temporary housing developments is likely to create a large influx of temporary population both during construction and at the start of the operation phases of each project. Because population increases are likely to be rapid, and in the absence of adequate planning measures, local communities may be unable to quickly cope with the large number of new residents; social disruption and changes in social organization are likely to occur. Community disruption can also lead to increases in social distress; in particular, increases in drug use, alcoholism, divorce, juvenile delinquency, and deterioration in mental health and perceived quality of life. Changes in cultural values may also occur as the resident population is exposed to, and may be required to at least partially adapt to, the cultural values of the in-migrant population.

The assessment of the impacts of oil shale and tar sands development on social disruption was based on a literature review drawing on past experience of social change associated with resource development projects in rural areas, particularly developments that have led to “boom and bust” economic development in communities in the western United States, where rapid in- and out-migration and the associated community upheaval occurred both during and after resource extraction. Extensive literature in sociology (in the journals *Rural Sociology*, *Pacific Sociological Review*, and *Sociological Perspectives*, among others) is available on the problems of community adjustment. The review included the social impacts of a wide range of energy developments, including coal mining, oil and gas development, and power generation in the western states, in addition to the social impacts that have occurred with past oil shale and tar sands development. The review also included studies of the social impacts of oil shale and tar sands development in Colorado, Utah, and Wyoming identified in the *Final Environmental Statement for the Prototype Oil Shale Leasing Program* (DOI 1973) and in five EISs—Colony Oil Shale Final EIS (BLM 1977), Naval Oil Shale Reserves Final Programmatic EIS (DOE 1982), Prototype Oil Shale Leasing Program Final Supplemental EIS (BLM 1983a), Uintah Basin Synfuels Development Final EIS (BLM 1983b), and Utah Combined Hydrocarbon Leasing Regional Final EIS (BLM 1984).

Social disruption and the resulting community adjustment that may occur in small, relatively self-contained communities arising from "boom and bust" surges in population size may have a number of components (Figure G-1). A "boom" stimulus provides new jobs that bring growth in population size and change the demographic composition of the community. Social change resulting from the need to accommodate new residents changes the perceived quality of life and leads to changes in social relations. Social problems, such as divorce, substance abuse, and crime, can occur. Social problems may be mitigated by community planning and management of growth, allowing the community to more easily adjust to new residents. After some period of time, employment associated with the boom may decrease, whereby the community may replace the jobs afforded by the initial economic stimulus or, as is more likely, employment is reduced in size by a "bust," whereby the cycle of adjustment is repeated, mitigated to a greater or lesser degree by community planning efforts.

G.2.5 Environmental Justice

Executive Order 12898 (U.S. President 1994) formally requires federal agencies to incorporate environmental justice as part of their missions. Specifically, it directs agencies to address, as appropriate, any disproportionately high and adverse human health or environmental effects of their actions, programs, or policies on minority and low-income populations. The analysis of the impacts of oil shale and tar sands development on environmental justice issues follows guidelines described in the Council on Environmental Quality's *Environmental Justice Guidance under the National Environmental Policy Act* (CEQ 1997).

The analysis method has three parts: (1) a description of the geographic distribution of low-income and minority populations in the affected area; (2) an assessment of whether the

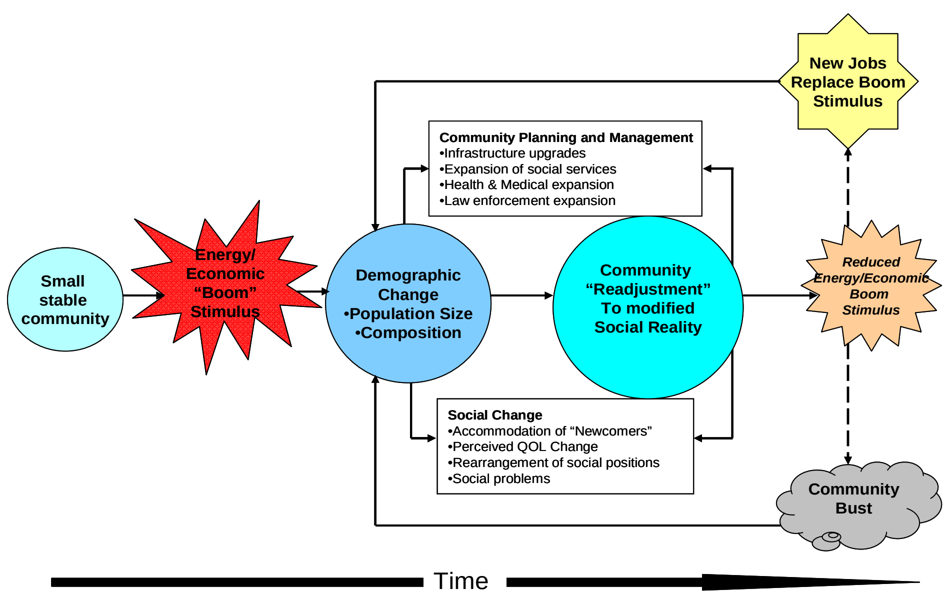

FIGURE G-1 The Cycle of Social Adjustment to "Boom" and "Bust"

impacts of construction and operation would produce impacts that are high and adverse; and (3) a determination about whether these impacts disproportionately impact minority and low-income populations. The description of the geographic distribution of minority and low-income groups is based on demographic data from the 2000 Census. To fully evaluate the potential environmental justice impacts of the oil shale and tar sands development, the distribution of minority and low-income populations is described at the census block level. On the basis of data at the individual block level, the minority and low-income population within a 50-mi buffer zone around each oil shale and tar sands resource location was analyzed.

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APPENDIX H:

APPROACH USED FOR INTERVIEWS OF SELECTED RESIDENTS IN THE OIL SHALE AND TAR SANDS STUDY AREA

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APPENDIX H:

APPROACH USED FOR INTERVIEWS OF SELECTED RESIDENTS IN THE OIL SHALE AND TAR SANDS STUDY AREA

H.1 PURPOSE

Land use plan amendments to allow for application for leasing and future development of oil shale and tar sands resources are being proposed in parts of Colorado, Utah, and Wyoming, where there has been considerable experience with large-scale energy development, including oil and gas, coal mining, electric power generation, and attempts to develop oil shale resources.

Development of oil shale and tar sands resources is not only likely to produce significant impacts on the economies and communities in the regions of influence (ROIs) in each state, but would produce impacts occurring alongside rapid development of oil and gas resources. Among energy developments, oil shale and tar sands projects, in particular, are often associated with "boom-and-bust" type development, requiring local communities to make considerable adjustment to rapid economic and social change. In order for this programmatic environmental impact statement (PEIS) to provide a comprehensive and understandable presentation of the potential scale of the economic and social impacts of oil shale and tar sands development, a series of interviews was conducted with residents in the ROIs in each state. These interviews provided information that adds anecdotal flavor to the social and economic baseline and impact data presented in the PEIS, adding text and verbatim quotations that summarize viewpoints, perceptions, and attitudes toward large-scale energy development.

H.2 SAMPLING STRATEGIES

A number of sampling strategies were used to identify a small list of possible respondents that could adequately capture some sense of the level of variation in views of the project. Specifically, a list of potential interviewees included:

- Individuals who provided comments as part of the oil shale and tar sands project scoping process, documented in the Scoping Summary Report;

- Individuals who have witnessed various stages of development associated with energy projects, such as impacts on ranching and the associated traditional quality of life, including local and county planning officials, community leaders, community service providers, environmental groups, newspaper reporters, realtors, local citizens groups, and motivated local individuals with specific concerns; and

- Individuals located in proximity to locations at which energy project developments are likely to occur (e.g., Piceance Basin) and who are likely to be impacted by specific aspects of project development, such as water restrictions, air quality, road congestion, property values, quality of life, etc.

During the interview process, some respondents provided contact information for additional individuals that were subsequently interviewed, if it was apparent that these individuals would allow the process to provide more complete and balanced coverage of a particular topic or topics.

H.3 INTERVIEW FORMAT AND STRUCTURE

Informal interviews were conducted with individuals by telephone, without questionnaires. After a brief introduction to the project, each interview was structured around a series of preselected issues that addressed the perceived concerns and historical experience of each interviewee, in order to focus the interview and limit responses to information relevant to the presentation in the PEIS. Interviews elicited viewpoints on three general aspects of large-scale energy development:

- Past developments, particularly those that have produced “boom-and-bust” economic and social conditions deemed relevant;

- The current situation, including the ongoing impact of oil and gas development and increased recreational land use; and

- The likely impact of new developments, particularly oil shale and tar sands, alongside the projected impact of oil and gas development and recreational land use.

Each interview included open-ended questions on the progress of key variables throughout the past, present, and future experience with energy development, including housing cost and availability, congestion, community service quality and availability, employment, quality of life, environmental quality, and other variables identified by respondents, where applicable. Respondents were asked to identify and describe their perception of mitigation strategies that have been, are being, and might be used in the future.

As it was the intention of each interview to fully capture the viewpoints, perceptions, and attitudes toward large-scale energy development in a semistructured format, each interview session allowed for some improvisation toward the goal of providing useful anecdotal information, including different ways to frame questions and elicit responses, recognizing different levels of respondents’ perceived viewpoint, personal and professional participation, and residential location.