BLM

FES 08-32

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

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

Volume 4: Comments and Responses (CD)

September 2008

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FES 08-32

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Vols. 3 & 4

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

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

September 2008

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
ATSDR	Agency for Toxic Substances and Disease Registry
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
CDC	Centers for Disease Control and Prevention
CDOT	Colorado Department of Transportation
CDOW	Colorado Division of Wildlife
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
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 field
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
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
IUCNNR	International Union for Conservation of Nature and Natural Resources
JMH CAP	Jack Morrow Hills Coordinated Activity Plan
KOP	key observation point
KSLA	Known Sodium Leasing Area
LAU	Lynx Analysis Unit
LETC	Laramie Energy Technology Center
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
MPCA	Minnesota Pollution Control Agency
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
OSEW/SPP	Oil Sands Expert Workgroup/Security and Prosperity Partnership
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
PRLA	preference right lease area
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
RFDS	reasonably foreseeable development scenario
RMP	Resource Management Plan
ROD	Record of Decision
ROI	region of influence
ROS	Recreation Opportunity Spectrum
ROW	right-of-way
SAGD	steam-assisted gravity drainage
SAMHSA	Substance Abuse and Mental Health Services Administration
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
SWWRC	Sates West Water Resources Corporation
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
UIC	underground injection control
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
WCA	areas recognized as having wilderness characteristics
WDEQ	Wyoming Department of Environmental Quality
WGFD	Wyoming Game and Fish Department
WRAP	Western Regional Air Partnership
WRCC	Western Regional Climate Center
WRSOC	White River Shale Oil Corporation
WSA	Wilderness Study Area
WSR	Wild and Scenic River
WTGS	wind turbine generator system
WYCRO	Wyoming Cultural Records Office

CHEMICALS

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

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)
dBA	A-weighted decibel(s)
°F	degree(s) Fahrenheit
ft	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)
kPa	kilopascal(s)
kV	kilovolt(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)
mm	millimeter(s)
MMBtu	thousand Btu
mph	mile(s) per hour
MW	megawatt(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)
yd^2	square yard(s)
yd^3	cubic yard(s)
yr	year(s)
μm	micrometer(s)

ENGLISH/METRIC AND METRIC/ENGLISH EQUIVALENTS[a]

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)

[a] In general in this PEIS, only English units are presented. However, where reference sources provided both English and metric units, both values are presented in the order in which they are given in the source.

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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 was subsequently 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, 2006); Price, Utah (January 11, 2006); Vernal, Utah (January 12, 2006); Rock Springs, Wyoming (January 13, 2006); Rifle, Colorado (January 18, 2006); Denver, Colorado (January 19, 2006); and Cheyenne, Wyoming (January 20, 2006);

- 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 PUBLIC COMMENT ON THE DRAFT PEIS

The EPA published the Notice of Availability (NOA) of the Draft PEIS in the *Federal Register* on December 21, 2007 (72 FR 72751–72753). Publication of the NOA began a 90-day public comment period on the Draft PEIS, which was subsequently extended 30 days, ending on April 21, 2008.

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The Draft PEIS was posted in its entirety on the Oil Shale and Tar Sands PEIS Web site. Printed copies of the document and CDs containing the electronic files for the document were mailed upon request. Comments on the document were received by two methods:

- An electronic comment form on the project Web site, and
- Traditional postal mail.

More than 102,000 people and organizations participated in the public comment process. Nearly 170 recognized organizations (public and private) provided comments on the Draft PEIS. Ninety-eight percent of the comment letters were campaigns. For the unique letters, 90% were submitted via the project Web site and 10% were sent by postal mail.

All comments, regardless of how they were submitted, received equal consideration. On the basis of the documents received during the public comment period, comment categorization resulted in approximately 4,500 individual comments. The BLM reviewed all comments and made changes to the Final PEIS, as appropriate. Responses to comments are provided in Volume 4 of the Final PEIS. Volume 4 has not been printed for distribution but is provided on a CD in a pocket attached to the back cover of Volume 3. Reponses to comments from the cooperating agencies (as identified in Section 7.5) are printed at the end of this chapter.

7.3 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 7.3-1 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 expressed an interest in consultation with the BLM for this project, as summarized in Table 7.3-1.

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.

7.4 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.

TABLE 7.3-1 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 expressed concern with certain specific areas that are located in the vicinity of the PEIS study areas. Follow-up consultation will be conducted.
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 7.3-1 (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.

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 continued 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.

7.5 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, and the Department of Public Health and the Environment;
- 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. Comments from 12 of the 14 cooperating agencies and the BLM's responses to those comments can be found at the end of this chapter. No comments on the PEIS were received from Duchesne County or the Town of Rangely.

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 7.3 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 prior to granting leases for oil shale or tar sands development and prior to approving development plans for lease areas. 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).

7.6 REFERENCES

BLM (Bureau of Land Management), 2002, *Handbook H-1601-1—Land Use Planning Handbook*, Release 1-1675, U.S. Department of the Interior.

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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ATTACHMENT 7.5A

COOPERATING AGENCY COMMENTS AND RESPONSES

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OSTS_00038

USDA United States Department of Agriculture | Forest Service | Intermountain Region | 324 25th Street Ogden, UT 84401 801-625-5605

File Code: 2820
Date: MAR 0 4 2008

BLM Oil Shale and Tar sands PEIS
Argonne National Laboratory EVS/900
9700 S. Cass Avenue
Argonne, IL 60439

Dear Ms. Thompson:

We have completed our review of the 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. Due to the programmatic nature of the analysis and decision we only have a few comments or suggestions.

The description of Alternative C (section 2.4.3.2) states that lands are excluded from leasing where surface disturbance and seasonal limitations are in place to protect known sensitive resources. Excluding those lands at the programmatic level would limit or preclude the ability to address the effects of those exclusions during the leasing analysis. Table 2.4.3-3 identifies things such as slopes, raptor nests or habitat, wildlife habitat, and other as resource areas that would not be available for lease application. If literally applied, there probably are extremely few public lands available for lease application. We therefore continue to support Alternative B as the preferred or more appropriate alternative to select. 38-001

Section 3.1 refers to "Areas Recognized as Having Wilderness Characteristics", i.e., Table 3.1.1-4, Table 3.1.1-9 but it is unclear what such a status implies or means. It states these areas might be addressed in Resource Management Plan revisions, but isn't any resource issue a potential item to be addressed in such a revision? Also, note that WCA is used in Table 3.1.1-11 and WCA is not included in the list of acronyms. 38-002

On page 3-43 is a table listing Federal and State Recreation Areas. Range Creek is another one to consider which is administered by the Utah Division of Wildlife. It is an area of very rich cultural resources, similar to the Nine Mile area and open to the public via a permit process. Following is a web site for more information. It should be fairly close to the Sunnyside Special Tar Sand Area. http://wildlife.utah.gov/range_creek/index.php 38-003

In the first paragraph under 3.10.3 on page 3-231 the second sentence states, "Federal land in these areas includes land administered by the BLM, USFWS, NPS, DOI, and BOR…" Since all of those agencies are within the 'DOI', the use of DOI is redundant. Also should the FS be included in that listing? 38-004

In conclusion, based on the programmatic nature of this analysis we believe the documents are thorough and provide sufficient information for the decision being made. It will also provide an

Ms. Thompson OSTS_00038 2

excellent document to tier to or reference during subsequent analyses should lease applications be received.

If you have questions, please contact Barry Burkhardt, Assistant Director for Minerals of our Bio-Physical Resources Staff, at 801-625-5157.

Sincerely,

for HARV FORSGREN
Regional Forester

cc: Barry Burkhardt

Responses for Document 00038

00038-001: The BLM acknowledges the commentor's preference for Alternative B.

00038-002: The text in Section 3.1 of the PEIS has been revised to define the meaning of wilderness characteristics. Also, the term Wilderness Characteristic Areas has been added to the notation list and glossary.

"Areas Recognized as Having Wilderness Characteristics" (WCAs) are areas that are not officially identified as "wilderness" under the Wilderness Act of 1964, nor are they "wilderness study areas" (WSAs) that were identified by BLM inventories in the 1970s and 1980s under the authority of FLPMA. Generally, they are areas that were identified by various groups, and then inventoried by the BLM to determine if they possessed the characteristics of wilderness as described in the Wilderness Act. The BLM may manage the lands to protect and/or preserve some or all of those characteristics through the land use planning process. In addition, under the land use planning process, the BLM must consider a range of alternatives for the lands identified with wilderness characteristics. This gives the public the ability to fully compare the consequences of protecting or not protecting the wilderness characteristics on these non-WSA lands.

00038-003: Thank you for the comment. Range Creek is an appropriate addition and has been added to Table 3.1.1-11 in Chapter 3.

00038-004: The text in Section 3.10.3 of the PEIS has been changed to address information provided in the comment.

OSTS_00094

UINTAH COUNTY

STATE OF UTAH

Our past is the nation's future

COMMISSIONERS:
Michael J. McKee
David J. Haslem
Darlene R. Burns
ASSESSOR - Rolene Rasmussen
ATTORNEY - JoAnn B. Stringham
CLERK-AUDITOR - Michael W. Wilkins
RECORDER - Randy J. Simmons
TREASURER - Wendy Long
SHERIFF - Jeff Merrell
SURVEYOR - John Slaugh

March 17, 2008

Bureau of Land Management
Oil Shale and Tar Sands Resources PEIS
Argonne National Laboratory EVS/900
9700 South Cass Avenue
Argonne, IL 60439

RE: Programmatic EIS Oil Shale and Tar Sands

Dear Sir/Madam:

Thank you for the opportunity to comment on the Oil Shale and Tar Sands Programmatic EIS. Uintah County has always been interested in the further development of Oil Shale and Tar Sands within the County. Enclosed are the comments we feel should be addressed in the PEIS at this time.

Sincerely,

UINTAH COUNTY COMMISSION

Michael J. McKee

Michael J. McKee

David J. Haslem

Darlene R. Burns

Darlene R. Burns

COUNTY BUILDING • 152 EAST 100 NORTH • VERNAL, UTAH 84078

OSTS_00094

General Comments

Of primary concern to Uintah County is how the decisions in this Programmatic Environmental Impact Statement (PEIS) will be incorporated into existing and draft resource management plans of the Bureau of Land Management (BLM).

Appendix C-9 provides all lands within the most geologically prospective oil shale areas that are not excluded from commercial leasing by existing law and regulation, Executive Orders, administrative land use designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing.

The existing and draft RMPs do not analyze oil shale occurrence to the extent that the PEIS does. Thus, decisions that were made may exclude leasing of oil shale and tar sands without full analysis of the decisions. In some cases, the RMP recognized that the decisions in the PEIS would be incorporated at some later date, others did not. As a result, decisions were made that created mineral withdrawals, no surface occupancy rights-of-way exclusion areas, areas with wilderness characteristics and such, which exclude these areas from mineral development and thus commercial leasing of oil shale and tar sands. Some of these areas overlap some of the most accessible and high quality oil shale and tar sand resources. 94-001

As a result, some areas identified in the PEIS as available for commercial leasing will be closed by management decisions contained in the RMP without adequate analysis or disclosure of impacts.

It is Uintah County's position that the BLM must remain focused on developing a PEIS for an Oil Shale and Tar Sands Resource Management Plan. Failure to development this will greatly delay attainment of identified national concerns. Two of the most critical are:

United States oil shale, tar sands, and other *unconventional fuels are strategically important domestic resources that should be developed* to reduce the growing dependence of the United States on politically and economically unstable sources of foreign oil imports.

The Task Force concurs that the domestic and global fuels supply situation and outlook is urgent. Increasing global oil demand, declining reserve additions, and our increasing reliance on oil and product imports from unstable foreign sources require the Nation to take *immediate action* to catalyze a domestic unconventional fuels industry. 94-002

BLM should revert to its original plan to apply the PEIS throughout the entire leasing program, and should use all available methods to expedite development of the program as Congress intended.

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The PEIS focuses too narrowly on oil sand operations intended to produce Crude Oil Refinery feedstock (a.k.a. Crude Oil), and comes to the conclusion that since the economics of producing crude oil aren't very good, it doesn't make sense to despoil BLM lands for the slim economic margins of such productions. The quality of the bitcmuch of the sands in the Uintah Basin would be of greater value when refined into higher value asphalt products. 94-003

Specific Comments

Page 1-8, 2-39&5

Individual projects should be considered based on site specific analysis and technology specific to the proposed action. Lands should not be eliminated for development based solely on failure to be included in this PEIS. Wording should be added to clearly define how additional lands could be made available should additional lands be feasible and should new data prove development to be feasible. 94-004

Page 5-109

The impacts of temporary construction workforce are inconsistent with facility size anticipated in the project area, which is likely to consist of modules constructed off site. 94-005

Page 5-110

Workforce estimates should be recalculated, as they are based on operations much larger than those anticipated in the project area. After this analysis has been accomplished, other dependent analysis should be adjusted accordingly. 94-006

Page 6-202

Discussion of impacts on recreation. See previous comment. 94-007

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Section A.4. Spent Shale Management, Page A-48

2nd Paragraph

Underground disposal of spent shale back into underground mines should not be discounted on its face just because leaching of constituents from spent shale may occur. It predisposes that mitigating measures can be taken to overcome the problem and meet regulatory requirements. The disposal of spent shale, either underground or as in the case of Uintah County, in abandoned gilsonite trenches, would resolve open trench issues. Underground disposal reduces reclamation and visual issues. These opportunities must be fully considered and analyzed. 94-008

3rd Paragraph

Eliminate the term "Popcorn Effect" here and later in the text. Any solid material that is reduced in size as a result of crushing or grinding will create void space between particles and the density will decrease, and the volume of a given mass will increase. Even when compacted, the density cannot reach the original density that the rock had in its original solid condition. This is not an issue specific to spent shale and is a myth that should not be formally perpetuated. 94-009

Section A.5. Ongoing and Expected Future Oil Shale Development Technologies, Page A-50

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

2nd Paragraph

The Energy Security Act of 2005 authorizes expansion of the R,D&D leases to up to 5,760 acres, or 640 acres more than cited. 94-010

5-3

It appears that impact analysis was based on production methods having the greatest environmental impacts resulting in impacts that are highly unlikely to occur at the predicted methods of development in the project area. Project analysis would address development impacts should they exceed impacts considered in the PEIS. Impacts should be based on the type of development and technology likely to be used in the project area. 94-011

This section should be reanalyzed to insure that a lease allotment of 5760 acres is adequate to support 20,000 bbl/day of production. If not changed, analysis should be developed to support this assumption.

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Preferred Alternative

Selection of Alternative B as the preferred alternative is clearly the decision most consistent with the underlying provisions of the Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005.

The Act "declares that it is the policy of the United States that-- (1) United States oil shale, tar sands, and other unconventional fuels are strategically important domestic resources that should be developed to reduce the growing dependence of the United States on politically and economically unstable sources of foreign oil imports; (2) the development of oil shale, tar sands, and other strategic unconventional fuels, for research and commercial development, should be conducted in an environmentally sound manner, using practices that minimize impacts; and (3) development of those strategic unconventional fuels should occur, with an emphasis on sustainability, to benefit the United States while taking into account affected states and communities." Alternative B is the most responsive to this direction. Alternative B also is the most responsive to the recommendations of The Task Force on Strategic Unconventional Fuels that was created by the 2005 Act. 94-012

Responses for Document 00094

00094-001: All decisions related to land use planning for oil shale and tar sands resources in the ongoing RMPs will be made in the ROD for this PEIS. The ROD will amend the existing plans (MFP or RMP or ongoing RMP if the PEIS is completed first) by making land use planning decisions on whether or not lands will be available for application for future leasing and development of oil shale or tar sands on public lands for those areas where the resource is present. Additional site-specific NEPA analysis will be completed on any future lease application before any leases would be issued. If, as part of this preleasing NEPA analysis, the BLM determines that leasing and subsequent development of the oil shale or tar sands resources would cause significant impacts, the BLM can require the applicant to: 1) mitigate the impact so that it is no longer significant, 2) move the proposed lease location, or if neither of these options resolves the anticipated conflicts, 3) the BLM can decide that development of the oil shale or tar sands resources outweighs protection of the on-site resources and approve the application. This preleasing NEPA analysis would include opportunities for public involvement and comment that are part of the PEIS process and every other planning and NEPA process the BLM undertakes.

00094-002: The BLM is taking a staged approach to comply with the mandates set forth by Congress. Because of the identified uncertainties in analyzing impacts associated with leasing decisions, it is not possible to meet the requirements of NEPA to support leasing at this time. The BLM believes that the identification of lands open to oil shale and tar sands leasing is the first step in securing the role of oil shale and tar sands as a viable domestic energy source. Each subsequent step (leasing decisions and plan of development decisions) will bring oil shale and tar sands closer to reducing U.S. dependence on foreign oil.

00094-003: Thank you for your comments. The BLM has made no conclusions regarding the economics of oil shale development. The PEIS examines alternatives for making lands available for future commercial leasing of both oil shale and tar sands resources.

00094-004: Although excluded from consideration under decisions in this PEIS, should industry come forward with an economically and environmentally sound proposal outside of the most geologically prospective area identified in the PEIS, the Secretary of the Interior and the BLM have the authority to consider commercial development proposals in a new NEPA analysis that could further amend local land use plans to allow for such a development.

00094-005: Given the programmatic nature of the PEIS, the purpose of the analysis of socioeconomic impacts is to provide an overview of the type and magnitude of impacts that would likely occur with the construction and operation of representative oil shale and tar sands facilities. As the technologies, scale of development, and project locations associated with oil shale and tar sands resources and ancillary development are not known, the analysis described in the PEIS was based on a series of assumptions regarding project production levels, direct project employment, direct and indirect population (workers and their families) in-migration rates, and the provision and location of direct and indirect worker housing during both construction and operations phases. These assumptions, described in Section 4.11 of the PEIS, were based on publicly available NEPA reviews, past BLM experience with oil shale and tar sands and other energy-related projects, and industry data on power generation and coal mining. These assumptions are reasonable for a programmatic review of potential socioeconomic impacts.

Assumptions regarding the retention of wages associated with housing construction and OSTS and ancillary facility construction and operation are presented in Section 4.11 of the PEIS.

00094-006: See response to Comment 00094-005.

00094-007: The meaning of this comment is not clear, however, the potential impacts to recreation and travel activities are generally discussed in Sections 3.10.3, 4.2.1.4, and 5.2.1.3 of the PEIS. General impacts on recreation and travel management and on areas that might be used by recreationists by alternative are included in the Land Use sections in Sections 6.1 and 6.2. The economics of recreation activities are discussed in Sections 4.11.1.5 and 5.11.1.3.

The discussions that relate to both recreation and travel activities conclude that areas that are undergoing development for oil shale or tar sands would not be available for recreational uses. It is also pointed out that areas that may currently be available for OHV use may be closed if an area is leased for commercial development. The PEIS contains scenarios that describe the economic effect of hypothetical decreases in recreation employment. The overall assessment is that the potential impacts on recreation and travel visitation and the recreation-based economy are not identifiable based on current information and the potential impacts of each of the alternatives are not clear at this time. Impacts to recreation and travel will be highly specific and would be included in any site-specific analysis on a proposed commercial lease. The PEIS is not making any travel-related decisions.

00094-008: Thank you for your comment. The discussion does not discount in-mine disposal of spent shale. Rather, it is intended to point out both the advantages and potential disadvantages of such a disposal strategy. Future lease applications must include a detailed plan of development that would involve characterizing all wastes and identifying proper management strategies that conform to all applicable regulations.

00094-009: The BLM agrees that the bulk density of oil shale will decrease upon crushing and sizing in preparation for retorting. There is conflicting data in the open literature as to whether additional volume and density changes occur during retorting. The text in Section A.4 has been modified to remove the term “popcorn effect.” From an environmental perspective, the volumetric increase, together with the accompanying reduction in bulk density, may increase the potential both for erosion and for leaching of hazardous constituents and thus is an important consideration in the design of disposal strategies for spent shale from technologies employing AGR.

00094-010: The RD&D leases were issued pursuant to a *Federal Register* Notice that predated the enactment of the Energy Policy Act of 2005. The 5,120 acres is the maximum lease acreage designated in the Mineral Leasing Act of 1920, prior to its amendment by the Energy Policy Act of 2005, which changed the maximum lease size to 5,760 acres. The conversion lease size for those RD&D leases is correct.

00094-011: In the PEIS the BLM analyzes the environmental consequences of an allocation decision, and assumptions in the PEIS are for programmatic analysis purposes only. If commercial applications to lease are received in the future, there will be a subsequent level of NEPA analysis of specific parcels that may be offered for lease, as well as additional land use planning, if necessary, and issues such as the amount of surface disturbance will be considered at that time. The lease size mentioned is statutorily set, but whether that acreage would support a 20,000 bbl/day operation would have to be considered at the site-specific level.

00094-012: The BLM acknowledges the commentor’s preference for Alternative B.

OSTS_00126

DAVE FREUDENTHAL
GOVERNOR

THE STATE OF WYOMING

STATE CAPITOL
CHEYENNE, WY 82002

Office of the Governor

March 19, 2008

BLM Oil Shale and Tar Sands
Attn: Draft Programmatic EIS Comments
9700 South Cass Avenue
Argonne, IL 60439

To Whom It May Concern:

Thank you for the opportunity to comment on the Oil Shale and Tar Sands Programmatic Environmental Impact Statement (PEIS). Because I believe a careful, research-driven approach is the key to unlocking the energy potential of western oil shale, I support the "No Action" Alternative A at this time. 126-001

The technologies that may one day be used for large-scale, economical production of synfuels from oil shale are unproven and still unknown. Based on this lack of technological information, it is not feasible to make long-term policy decisions to manage this industry. Potential technologies and their impacts must be understood before oil shale leasing, lease-land allocations and Resource Management Plan modifications move forward. 126-002

The Energy Policy Act and current RD&D projects

Following the enactment of section 369 of the 2005 Energy Policy Act, the U.S. Congress charged the BLM with publishing final regulations for commercial oil shale leasing. Since then, noticeably less emphasis has been placed on oil shale commercialization, and a restriction has been put on Interior Department appropriations preventing the preparation or issuance of final oil shale commercial leasing regulations in fiscal year 2008. The state of Wyoming interprets these signals from Congress as an invitation to take a more deliberate, circumspect approach to oil shale – one which will allow private industry to continue research and development, and provide adequate time for public understanding of what future developments might entail. 126-003

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BLM Oil Shale and Tar Sands
March 19, 2008
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The five Research, Development and Demonstration (RD&D) projects currently underway will serve as the foundation from which to identify technological hurdles, gauge economic viability, and assess socioeconomic and environmental impacts. Only if one or more of these 160-acre projects are proven economically and environmentally viable should the ramping up to commercial-scale operations be considered. Finally, the promulgation of regulations should await completion of the RD&D phase, in order to give states the necessary data and time to completely understand the risks. 126-003 (cont.)

Advantages of Alternative A over Alternatives B and C

Oil shale development has had a checkered past, and, if not undertaken cautiously and correctly this time, efforts at commercial development could be impeded for years to come. The state of Wyoming remembers well the results of the "Colony Project" and "Black Sunday" in the Colorado's western slope communities. Between 1969 and 1979, the U.S. Department of Energy funded an in-situ fracturing and retort operation near Rock Springs. Efforts to remediate that operation are still ongoing.

Alternative A defers action, but it also does something very important for future oil shale development. It provides adequate time to identify a reserve, the synfuel that theoretically could be contained within the oil shale resource. Alternative A does this without attempting to describe the synfuel reserve. The PEIS has identified a tremendous oil shale resource in Wyoming and estimated billions of barrels of synfuel, but the reserve is governed by unknown technological, environmental, geological, socioeconomic, and economic constraints. Before a reserve is identified and quantified, potential impacts must be assessed. It would seem a peculiar use of time and money to allocate lands available for commercial leasing for an unknown synfuel reserve, especially when there is no known technology to recover the energy reserves. 126-004

Alternatives B and C both intersect with Adobe Town, an area in south central Wyoming that was recently designated by the Wyoming Environmental Quality Council (EQC) as "Very Rare or Uncommon." Once this designation is finalized under Wyoming Statute 35-11-112 (a) (v) and Chapter 7 of the Rules of Practice and Procedure rules by the Environmental Quality Council, development in the Adobe Town area for oil shale and gravel development will be subject to state regulation. Specifically, non-coal mining will be limited by the Director of the Department of Environmental Quality under Wyoming Statute 35-11-406 (m) (iv) if the proposed mining operation would irreparably harm, destroy, or materially impair Adobe Town. 126-005

Conclusion

I appreciate your consideration of these comments and urge the selection of Alternative A in the PEIS. I firmly believe that it is the best option for both the state and the future of oil shale development. It is worth underscoring once again that Alternative A would still allow the five RD&D leases to operate, which if any of the projects prove 126-001 (cont.)

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BLM Oil Shale and Tar Sands
March 19, 2008
Page 3

viable, could result in both commercial-scale development and data sets that would clarify the still-uncertain impacts. 126-001 (cont.)

Best regards,

Dave Freudenthal

Dave Freudenthal
Governor

DF:pjb

c: Senator Mike Enzi
Senator John Barrasso
Representative Barbara Cubin
Governor Bill Ritter, Colorado
Governor Jon Huntsman, Utah

Responses for Document 00126

00126-001: The BLM acknowledges the commentor's preference for Alternative A.

00126-002: Congress declared its intent in the Energy Policy Act of 2005 for the Nation to pursue the development of oil shale and tar sand resources, among other unconventional fuels, in an environmentally sound manner. As required by that Act, the BLM initiated this PEIS intending to provide the environmental analysis for issuance of commercial leases that would convey development rights to lease holders. As discussed in the Draft PEIS, because of various uncertainties regarding location of developments, technologies to be employed, and the lack of knowledge of specific impacts on various resources, the BLM decided not to analyze the environmental impacts of issuing particular leases at this time and instead decided to analyze amendments of land use plans. Amending those plans is necessary, but not sufficient, to proceed to commercial development of federal oil shale resources.

The decisions analyzed in the PEIS include no commitment by the BLM to offer for lease public lands without additional site-specific NEPA analysis. This additional analysis will consider any new or site-specific information regarding proposed oil shale technology and any anticipated environmental consequences. New information on technologies may be a consequence of research on the RD&D leases or result from research or studies from other sources. Specific mitigation measures, management prescriptions, and the best available practices to minimize impacts will be applied as a result of site-specific NEPA evaluations. In addition, the BLM will involve the state, local communities, and the public throughout the NEPA processes.

00126-003: In the Energy Policy Act of 2005, Congress set a deadline for the BLM to complete this PEIS, and that direction has not been rescinded. While the original Congressional deadline has been exceeded, that does not allow the BLM to postpone this PEIS.

The Energy Policy Act of 2005 directed the Secretary of the Interior to (1) complete a PEIS for a commercial leasing program for oil shale and tar sands resources on public lands, and (2) publish a final regulation reestablishing such a program. The BLM, through its rulemaking process, is drafting a proposed set of regulations to outline the policies and procedures to implement a commercial leasing program. The BLM published a proposed rule for the management of a commercial oil shale leasing program in the *Federal Register* on July 23, 2008. As mentioned in the comment, Congress has provided direction to not finalize the regulations in FY08, but they have not removed the original requirement.

00126-004: The BLM is complying with the intent of Congress. In the Energy Policy Act of 2005, Congress mandates the Secretary to complete the PEIS for oil shale and tar sands resources with emphasis on the most geologically prospective lands within

Wyoming. The purpose of the delineation of these areas is to provide a starting place for the amendment of land use plans and for consideration of commercial development. New sources of energy take a great amount of time and private capital to develop and bring on line. Therefore, it is important to provide a framework for the development of a viable oil shale industry to meet the Nation's future energy needs. This would include a systematic process for the exploration, development, and production of the oil shale resources. The PEIS stipulates that site-specific NEPA analysis will be required prior to any leasing or development decision.

00126-005: The BLM worked closely with 14 cooperating agencies, including the State of Wyoming, to determine the scope of the PEIS. Each agency brought an important local perspective and expertise to the process, resulting in the modification of the PEIS's scope from a leasing decision to an allocation decision. This new allocation decision does nothing more than remove an administrative barrier preventing the BLM from accepting applications to lease oil shale or tar sands resources. The amendment of land use plans does not authorize any ground-disturbing activities and is not an irreversible or irretrievable commitment of resources under NEPA. Moreover, the amendment does not constitute the granting of any property right. In this respect, the allocation decision does not conflict with any State plan or designation. However, the BLM looks forward to the State of Wyoming providing information about the State important designations during subsequent NEPA analysis when specific technical and environmental information is available for analysis. At that time, conflicts with the Wyoming Environmental Quality Council's decisions and/or Adobe Town designation can be addressed.

OSTS_00154

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Washington, D.C. 20240

In Reply Refer To:
FWS/DHRC/BCPA/DCN035616

MAR 2 1 2008

Memorandum

To: Director, Bureau of Land Management

From: Acting Deputy Director, Fish and Wildlife Service Rowan W. Gould

Subject: Comments on the *Draft Oil Shale and Tar Sands Resource Management Plan Amendments to address Land Use Allocation in Colorado, Utah, and Wyoming Programmatic Environmental Impact Statement*

The U.S. Fish and Wildlife Service has reviewed the Bureau of Land Management's (BLM) *Draft Oil Shale and Tar Sands Resource Management Plan (RMP) Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement* (draft PEIS) and has prepared the enclosed detailed comments pursuant to the: (1) Fish and Wildlife Coordination Act; (2) Endangered Species Act; (3) Migratory Bird Treaty Act; (4) Bald and Golden Eagle Protection Act; (5) the Clean Water Act; (6) National Wildlife Refuge System Administration Act of 1966; (7) Section 369 of the Energy Policy Act of 2005 (EPAct), and other applicable Executive Orders, regulations and policies.

The Service appreciates the considerable task before BLM in meeting the requirements of Section 369 of the EPAct while also meeting the requirements of the National Environmental Policy Act (NEPA) and we acknowledge Section 369 requires the Department of the Interior to undertake a series of steps leading to the commercial leasing of BLM-administered lands. The draft PEIS analyzes the effects of amending 12 land use plans in Colorado, Utah, and Wyoming to include areas of oil shale and tar sands resources for commercial leasing, exploration, and development. The draft PEIS presents Alternative A, the No Action Plan, that would not amend current land use plans but would continue six Research, Development and Demonstration (RDD) projects; BLM's Preferred Alternative, Alternative B, which would amend land use plans to make approximately 2 million acres of land containing oil shale and about 430,000 acres of tar sands available for leasing; and Alternative C, which would amend land use plans to make approximately 830,000 acres of oil shale resources and 230,000 acres of tar sands available for commercial leasing.

A programmatic environmental impact statement addresses a group of similar or related actions as a whole, and thus is a powerful tool in assessing broad, cumulative issues and impacts (Service NEPA Procedures, 550 FW 2). The Service's primary concern with the draft PEIS is the lack of 154-001

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information about the potential mining technologies to be employed, to the extent that identifying and mitigating cumulative impacts is extremely difficult. BLM identified this problem in the draft PEIS: "Because commercial oil shale development technologies are still largely in a research and development phase, many details regarding the specific technologies that would be used in the future to produce oil from oil shale are unknown" (page 2-12, draft PEIS). 154-001 (cont.)

To remedy this concern, it is our understanding that once viable technologies are identified through the RDD program, the BLM will conduct additional NEPA analysis to evaluate the large-scale, cumulative effects of a leasing program, including specific areas to be leased and the conditions and stipulations under which leases will be sold. The Service supports this approach.

The Service recommends Alternative C be selected as the agency preferred alternative. 154-002

We have provided General Comments in Attachment 1 and Specific Technical Comments in Attachment 2 to assist the BLM in preparation of a final PEIS. We appreciate the opportunity to provide comments and recognize the BLM for their efforts to coordinate with the Service. Please contact Mr. Gary Frazer, Assistant Director - Fisheries and Habitat Conservation at (202) 208-6394, or Nancy Lee, Chief, Branch of Conservation Planning Assistance at (703) 358-2440, if you have any questions or need further information.

Attachments

Attachment 1

Fish and Wildlife Service (Service) Comments on the Bureau of Land Management's *Draft Oil Shale and Tar Sands Resource Management Plan (RMP) Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement* (draft PEIS)

GENERAL COMMENTS

The Bureau of Land Management (BLM) proposes to amend 12 land use plans to designate lands available for commercial leasing of oil shale and tar sands and has determined it would have no impact on the environment (p.ES-5, draft PEIS). This conclusion is based on a project description proposing only the *designation* of lands that would be available for leasing. Actual decisions on specific leasing proposals would occur in the future and require additional National Environmental Policy Act (NEPA) compliance. However, the draft PEIS clearly states that BLM intends to establish a commercial leasing program to facilitate future development. Accordingly, the draft PEIS addresses the potential large-scale impacts of mining by evaluating "impact-producing factors" (water used, land disturbed, etc.) and information currently available on mining technologies.

The Service appreciates BLM's considerable task of meeting the requirements of both Section 369 of the Energy Policy Act of 2005 (EPAct) and NEPA. We acknowledge Section 369 requires the Department of the Interior to take steps leading to commercial leasing of BLM-administered lands in Colorado, Utah and Wyoming. The Service also appreciates the stepwise fashion in which BLM has approached the development of a commercial leasing program. It is our understanding that once viable technologies are identified through the Research, Development and Demonstration (RDD) program, BLM will conduct additional NEPA analysis evaluating the large-scale impacts of a leasing program, including specific areas offered for lease and the conditions and stipulations under which leases will be sold. Depending on the scope of actual development actions, and to address the cumulative effects of a commercial leasing program, a separate PEIS may be necessary.

The draft PEIS strives to assess the broad implications of designating lands that could be made available for commercial leasing, but the task is particularly difficult without identifying viable mining technologies to be employed. The draft PEIS notes that additional NEPA analysis will be required prior to commercial leasing, but it is not clear at what level the analysis will take place. The Service believes further NEPA analysis will be needed at the programmatic level to address the cumulative effects of a defined leasing program. Without this level of analysis once technologies are identified and better understood, the Service is concerned that large-scale leasing may have significant impacts to listed and non-listed species. 154-003

The Service recommends Alternative C be selected as the agency preferred alternative (with the modifications provided below), assuming a separate programmatic evaluation is 154-004

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conducted once mining technologies and the details of the leasing program are defined. The Service believes Alternative B suggests a commitment to oil shale and tar sands development that is too large to be sustainable and may threaten the existence of a number of species.

General Modifications to Alternative C

The Service recommends that all designated and proposed critical habitat for threatened, endangered and candidate species be excluded from designated lease sale areas. In addition, we recommend that the BLM:

1) Exclude watersheds occupied by the Colorado River cutthroat trout (*Oncorhynchus clarki pleuriticus*) from designated lease sale areas.

2) Include larger no-lease buffers around designated critical habitat for endangered Colorado River fish. The Service recommends a buffer of at least 500 feet from the stream or river banks (Castelle et al 1992, and USFWS 2001). These larger buffers would also more effectively conserve non-listed species (waterfowl, migratory birds, native fish, etc.) that depend on these river corridors. 154-004 (cont.)

3) Include no-lease buffers surrounding Mexican spotted owl critical habitat that is at least one-half mile from canyon rims.

4) Exclude all sage-grouse leks, brood areas, and winter range from lease sale areas. Many of these use-sites have been mapped, but for those not yet identified, an exclusion radius from leks like those described in Christiansen and Bohne (2008) (e.g., 3 to 4 miles, with 0.6 m no surface-occupancy (NSO)) would be appropriate. Additionally, a number of small lease sale parcels (<1 square mile each) may be located within important sage-grouse habitats. We recommend the BLM coordinate the determination of these exclusion areas with our Ecological Services Field Offices in Utah, Wyoming, and Colorado.

5) Exclude from leasing the three Areas of Critical Environmental Concern (ACEC) in the Piceance Basin of Colorado (Duck Creek, Ryan Gulch, and Dudley Bluffs) which have been established to protect known populations of Dudley Bluffs twinpod and Dudley Bluffs bladderpod. We recommend that the ACECs not be available for oil shale leasing to avoid the destruction of plant resources for which these ACECs were designated.

Threatened and Endangered Species Consultation

The Service commends BLM for including a discussion of known listed species and critical habitat locations that are likely to be encountered by future oil shale and tar sands development projects within the draft PEIS. We also recognize the efforts of the BLM to coordinate with the Service in the development of measures to support the conservation of federally listed threatened and endangered species presented in Appendix F. However, 154-005

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the Service remains concerned about the lack of information available on mining technologies and the potential for cumulative impacts to listed species. With particular regard to the potential need for Colorado River water, the unknown effects of area-wide oil shale and tar sands development could threaten listed species within the Colorado River basin. We encourage BLM to further develop and incorporate conservation measures for listed species in the final PEIS and into future NEPA documents associated with specific leasing and development actions. NEPA analyses should include specific conservation guidelines for special-status species that will be applied to site-specific NEPA, consultation, and implementation documents of all future proposed projects. We recommend you contact our Field Offices for assistance in the development of these guidelines. The inclusion of guidelines at this level of NEPA review would set standards to direct the future planning and implementation of oil shale projects and ensure that special-status species are considered for future site-specific projects within the PEIS study area. 154-005 (cont.)

The BLM is proposing to conduct Section 7 consultations during supplemental Environmental Assessments associated with future lease sales and projects. We have concerns regarding a fragmented consultation process and the ability to conduct a cumulative effects analysis using this approach, not only for oil shale and tar sands development but also for other land development in the project area. The Service recommends using a landscape level evaluation approach for several select species in the area once viable technologies and program details are identified. Species that should have landscape level plans based on land use and future oil shale tar sand development include the four endangered fish of the Colorado River and tributaries, the black-footed ferret, white-tailed prairie dog, and the greater sage-grouse. Consultation provides better outcomes for listed species when it occurs early in the process and effects to the species are considered on the larger, landscape scale necessary for recovery. 154-006

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Attachment 2

Fish and Wildlife Service (Service) Comments on the Bureau of Land Management's *Draft Oil Shale and Tar Sands Resource Management Plan (RMP) Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement* (draft PEIS)

SPECIFIC TECHNICAL COMMENTS

Table ES-2, p. ES-6 and Table 2.3.2-1, p. 2-17 and 2-18: The Service recommends elaborating on how the Bureau of Land Management (BLM) would monitor and evaluate both indirect and cumulative impacts of extensive leasing, of oil shale and tar sands development and production activities. The draft PEIS is unclear how determinations for new leases and expanded development would be made, and if necessary curtailed, at levels that would effectively protect wildlife, plant, and habitat resources of project areas from indirect and cumulative impacts. 154-007

Section 2.3.3, p. 2-22, lines 1-4: Please clarify the relationship of the draft PEIS to other simultaneous or future administrative action taken by BLM field offices. For example, the Price, Utah, BLM Field Office, has distributed a draft RMP in which the Preferred Alternative removes Areas of Critical Environmental Concern (ACEC) designations. Withdrawal of ACEC designation would seem to conflict with the draft PEIS Alternative B (avoid leasing in existing ACECs closed to mineral development). Please clarify whether ACECs withdrawn by the field office draft RMP implies that those areas would now be open for lease applications, or whether they would lose ACEC designation but remain excluded from oil shale and tar sands development by virtue of the draft PEIS protective measures. 154-008

Table 2.3.3.-3, p. 2-33: This table lists "Resources Covered by Stipulations and Restrictions in Place for Oil and Gas Leasing" for the individual states of Utah, Colorado, and Wyoming not available for application for leasing for commercial oil shale and tar sands development. We believe it would be helpful to maintain a single consistent list of resources not state by state lists. 154-009

Table 2.6-1, p. 2-63, and Table 2.6-2, p. 2-78:
(1) These two tables summarize the potential impacts of the alternatives. The tables include "wildlife" and "threatened and endangered species" resources but do not specifically address BLM-designated sensitive species. Sensitive species are discussed under Alternative C at page 2-33 and page 2-49. The Service recommends including BLM-designated sensitive species impacts in the summaries presented in these tables. 154-010

(2) These two tables identify raptor habitat of only 147,000 and 13,000 acres, respectively. We recommend reevaluating raptor habitat acres identified. Raptor habitat should include nesting territories, concentration and wintering areas, foraging habitats, and migration corridors. The acres of raptor habitat in Table 6.1.2-5, p. 6-48 and Table 6.2.2-5, p. 6-189 also appear to be low. 154-011

Figure 3.1.1-15, p. 3-37: The Service manages three facilities located within or near BLM-administered lands. Areas with the most geological prospective oil shale resources overlay the boundaries of Seedskadee National Wildlife Refuge, located north of Green River, Wyoming. Ouray National Fish Hatchery and Ouray National Wildlife Refuge are located along the Green River south of Vernal, Utah and are in close proximity to areas designated as the most geologically prospective oil shale resource and Special Tar Sand Area (STSA).

We recommend that the three Service facilities be delineated on the final PEIS maps of the potential impacts of oil shale and tar sands development. The Service can provide geospatial data for these areas and other Service resources to the BLM for their inclusion on the official maps. We also recommend that the potential effects of oil shale and tar sands development on Service facilities be discussed in the final PEIS. The Service is concerned that the potential impacts from future oil shale and tar sands development in these areas could affect the facilities, and in turn our ability to successfully fulfill responsibilities for endangered species recovery (i.e., support for the private-public partnership Colorado River Endangered Fishes Recovery Program) and fish and wildlife conservation. Among the factors that could potentially impact the facilities are diminished water supply, water quality, blasting and other noise, establishment and spread of invasive species, increased vehicular traffic, and fragmentation of habitat buffers. We encourage the BLM to coordinate with the Service to ensure that appropriate measures are included in the BLM land use plans to comply with the compatible use of the National Wildlife Refuges and the integrity of the National Fish Hatchery. 154-012

Table 3.1.2-1, p. 3-43: We recommend that you recheck state recreation areas identified for Utah within the 50-mile radius, as some areas appear to be missing (e.g., Mallard Springs and Stewart Lake Wildlife Management Areas). 154-013

Section 3.4.1.2, p. 3-60; Section 3.4.1.3 p. 3-62; and Section 3.4.3.2, p. 3-84, line 9: In addition to salinity (TDS), selenium is a significant water quality issue in western Colorado and eastern Utah. The potential for increased selenium concentrations in surface waters and the effect on aquatic resources should be considered as a potential project impact. The Service recommends selenium be addressed in the document. Also, at Table 2.6-2, p. 2-78, changes in water quality (increased concentrations of selenium and total dissolved solids) resulting from surface disturbance or water storage/application on top of Mancos shale formations are extremely likely. 154-014

Section 3.4.1.4, p. 3-65: Recovery of ESA-listed fishes in the Upper Colorado River Basin depends in part upon adequate instream flows in the Colorado River and the tributaries used by these fishes. Much work has been done by the Colorado River Endangered Fishes Recovery Program and the Service to evaluate the flow requirements for these fish. We suggest that Tables 3.4.1-2 to 3.4.1-4 include these instream uses and flow requirements for the listed fish. We also recommend that estimates of the water depletions from oil shale and tar sand development be determined, and that these be used to identify the impacts to river flows and to the listed fish. Please contact the Service's 154-015

Utah and Colorado Ecological Services Field Offices for further information on instream flows. 154-015 (cont.)

Table 3.4.1-3, p. 3-68: The projected "water surplus" is based on water "legally available," which is, in turn, based on an assumption of 6 million acre-feet for the upper basin per year. Water allocations are divided among upper and lower basin and are different than identified here. Please indicate how the amount was calculated. Also, because "legally available" water may exceed what is actually available, another metric (such as actual water available over the last 10 years) could be useful in characterizing water availability. 154-016

The text in Section 3.4.1.4, p. 3-72, lines 43-46, states that the demand for water was greater than the available supply of water. This seems to contradict numbers in table 3.4.1-3 which we interpret as showing a water surplus. Please clarify short-term and long-term water usage and consequent impacts to aquatic resources.

Section 3.4.3.1, p. 3-79, entire section: We recommend that this section also identify the possible impacts of groundwater and surface water development on springs and seeps. 154-017

Section 3.7.1, p. 3-108, line 21-33, and Table 3.7.1-1, p. 3-109 to 3-111: This text discussion and the table information should include the roundtail chub, and the flannelmouth and bluehead suckers. These three species have all experienced population declines in recent years due to habitat loss through water development and the introduction of nonnative species, and are listed by the State of Utah as "sensitive species." We recommend that the table identify the species as "rare to common" rather than "common to abundant."

In the draft PEIS evaluation of these species, it may be useful to indicate that these three species are managed under interagency "Conservation Agreements" (CA), and identify the conservation measures specified in the Agreements. References for the conservation agreements are: 154-018

Utah Department of Natural Resources, Division of Wildlife Resources. 2006. Conservation and Management Plan for Three Fish Species in Utah: Addressing needs for Roundtail Chub (*Gila robusta*), Bluehead Sucker (*Catostomus discobolus*), and Flannelmouth Sucker (*Catostomus latipinnis*).

Utah Department of Natural Resources, Division of Wildlife Resources. 2006. Range-Wide Conservation Agreement and Strategy for Roundtail Chub (*Gila robusta*), Bluehead Sucker (*Catostomus discobolus*), and Flannelmouth Sucker (*Catostomus latipinnis*). Prepared for Colorado River Fish and Wildlife Council. Publication Number 06-18.

The Colorado River cutthroat trout is also managed under interagency Conservation Agreements. We recommend that: (a) this species be listed as such in Table 3.7.1-1; (b) 154-019

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the text indicate that the species is managed under an interagency Conservation Agreement; and (c) the CA conservation measures be specified. References are:

CRCT Conservation Team. 2006. Conservation agreement for Colorado River cutthroat trout (*Oncorhynchus clarkii pleuriticus*) in the States of Colorado, Utah, and Wyoming.
Colorado Division of Wildlife, Fort Collins. 10 p.

Lentch, L.D., and Y. Converse. 1997. Conservation Agreement and Strategy for Colorado River cutthroat trout in the State of Utah. State of Utah Publication Number 97-20. Utah Division of Wildlife Resources, Salt Lake City Utah.

154-019 (cont.)

Section 3.7.2, Plant Communities and Habitats: The draft PEIS only briefly mentions that the Green River shale barrens support a plant community comprised of several species endemic to the Green River formation (p. 3-123). This entire plant community is vulnerable to oil shale and tar sand resource development. Within the Uinta Basin in Utah, this community is most prominent along the southern margin of the oil shale lease area. Figure 2.3-1, at page 2-112, illustrates that this area lies within an area delineated in the draft PEIS as potentially surface mineable (i.e., Area Where Overburden is <500 ft).

The endemic species of this community include the following:

Dragon milkvetch (*Astragalus lutosus*)
oil shale columbine (*Aquiliegia barnebyi*)
Barney's thistle (*Cirsium barnebyi*)
oil shale catseye (*Cryptantha barnebyi*)
Graham's catseye (*Cryptantha grahamii*)
Ephedra wild-buckwheat (*Eriogonum ephedroides*)
Shrubby reed-mustard (*Glaucocarpum suffrutescens*)
Graham's beardtongue (*Penstemon grahamii*)
White River penstemon (*Penstemon scariosus albifluvis*)

Additional endemic species of this community occur in Colorado and Wyoming. Because these species are not protected as federally listed endangered or threatened species, and given the potential impacts associated with oil shale development, the Service recommends that they be designated as BLM special status species. Care should be taken to preserve the best representations of this community, because that community structure would be a desirable end-state for a significant portion of the rehabilitated and re-vegetated sites of oil shale and tar sand development projects.

154-020

Section 3.7.4.1.10, p. 3-160: The habitat for Dudley Bluffs bladderpod (*Lesquerella congesta*) should be corrected to state that it is restricted to the Thirteenmile Creek Tongue of the Green River Formation. 154-021

Section 3.7.4.1.16, p. 3-163, line 43 and Section 4.8.1.4, p. 4-101, line 6: : For clarification, closed canopy forests are not a requirement for Mexican spotted owls in 154-022

Utah's canyons. The owl has been found to nest in and use sparsely vegetated canyon habitats. Please update this section accordingly. 154-022 (cont.)

Section 3.7.4.1.21, p. 3-167, line 40 and Section 4.8.1.4, page 4-101, line 13: For clarification, southwestern willow flycatchers have been documented along the White River of the Uinta
Basin. However, at this time, the subspecies has not been determined for this locality. 154-023

Section 3.7.4.1.22, pp. 3-167 and 3-168, Uinta Basin Hookless Cactus: For clarification, the Service recently published a Federal Register notice (72 FR 53211, September 18, 2007) proposing to recognize three separate species of *Sclerocactus* for the taxonomic entity *Sclerocactus glaucus* originally listed in 1979 (44 FR 58868, October 11, 1979). These three species are: *Sclerocactus glaucus*, now restricted to western Colorado in lowlands in the Colorado and Gunnison River valleys; *Sclerocactus brevispinus* (Pariette cactus), restricted to the Pariette Dray drainage in the Uinta Basin in northeastern Utah; and *Sclerocactus wetlandicus* (Uinta Basin hookless cactus), restricted to lowlands above the current flood plains of the Green River from Ouray National Wildlife Refuge to Nine-mile creek in extreme northeastern Carbon County Utah and along the lower reaches of the Duchesne and White Rivers. The range of *Sclerocactus brevispinus* includes portions of the Uinta Basin oil shale area and the Pariette STSA. The range of *Sclerocactus wetlandicus* includes portions of the Uinta Basin oil shale area and the Pariette, Argyle Canyon, and Hill Creek STSAs. 154-024

Section 3.7.4.1.23, p. 3-168, lines 34-36: For clarification, the Utah prairie dog is not confined to level mountain valleys. The Utah prairie dog is the only prairie dog species to occur in southwestern Utah and has the most limited range of all the prairie dog species. However, it is one of three species that occur in the State of Utah along with the white-tailed prairie dog and the Gunnison's prairie dog. 154-025

At page 3-169, line 13, please note that the Utah prairie dog is listed as threatened rather than endangered. The Service recently completed a 90-day finding and concluded that a petition to uplist the species from threatened to endangered was not substantially supported. The Service's 5-year status review describes the status of the species.

Section 3.7.4.4, p. 3-175, Other species of concern: As stated in the draft PEIS, Graham's beardtongue (*Penstemon grahamii*) was proposed for threatened status and designated critical habitat under the ESA in January 2006 (71 FR 3158). A principal reason for that proposal was the threat of potential extensive habitat destruction of its limited habitat as a consequence of oil shale development, especially surface mining. Graham's beardtongue is strictly endemic to oil shale barrens of the Green River formation and most are closely associated with the kerogen rich shales of the Mahogany Ledge. 154-026

The Service later withdrew that proposal (71 FR 76303, December 19, 2006), in part because the Service was assured by the BLM that surface mining was an unlikely development scenario for oil shale development:

> "*P. grahamii* occurs within a very limited portion (0.035 percent of the land area) of broad geological basins in Colorado and Utah underlain by oil shale, and in fact, the plant depends on oil shale rock outcrops for its habitat. However, our information clearly demonstrates that the location of potential future oil shale research projects and subsequent, foreseeable commercial development operations do not overlap with proposed critical habitat for *P. grahamii*. The facts do not support a conclusion that because this plant only grows directly on the surface of rich oil shale bearing strata it will be extirpated or even impacted by future development. Presently, there is no industry interest in surface mining the Mahogany outcrops. Further, there is no evidence that potential, foreseeable oil shale development would occur in the vicinity of the Mahogany ledge outcrops. Industry's demonstrated future interests in oil shale development are not in surface mining the Mahogany ledge. In fact, the greatest industry interest is clearly centered nearly 30 miles east of the nearest *P. grahamii* proposed critical habitat[1]."

In addition, the BLM committed to retaining Graham's beardtongue as a sensitive species e.g.:

> "…If the FWS finds the protections of the ESA are not warranted, this species will remain a BLM special status species and will be afforded continued protection under our existing regulatory authorities, policies and land use planning decisions[2]." 154-026 (cont.)

The Service relied on these assurances in our decision to withdraw the proposed listing of Graham's beardtongue. However, the draft PEIS delineation of the "Area Where Overburden is < 500 ft" (Fig. 2.3-1, p. 2-11) includes over 90 percent of the area that the Service had formerly proposed as critical habitat units for Graham's beardtongue, and includes nearly the entire occupied habitat of the species. Also, at pages 2-14, 2-15, 2-25 and Table 2.3.2-1 (p. 2-17) the draft PEIS sets forth in the preferred alternative (Alternative B) leasing for an oil shale surface mine and an associated retort within that area cited above and thus within the occupied range of Graham's beardtongue. The same leasing proposals are also included within Alternative C, however, Alternative C would provide for the avoidance of a portion of the habitat of Graham's beardtongue (p. 2-27 and maps at figure 2.3.3-2 (p. 2-24) and figure 2.3.3-5 (p. 2-30).

The draft PEIS does not recognize Graham's beardtongue as a BLM sensitive species (3-174 and 4-86 to 4-92, Appendix E). It does, however, provide a discussion of the species as "Other Species of Concern" (p. 3-175). The species does occur in the Uinta Basin Oil

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[1] Page 6 The Bureau of Land Management; Formal Response to the U.S. Fish and Wildlife Service, Proposed Threatened Status for *Penstemon grahamii* (Graham's beardtongue) With Critical Habitat, May 11, 2006

[2] Kathleen Clarke, Director, Bureau of Land Management, cover letter to: The Bureau of Land Management; Formal Response to the U.S. Fish and Wildlife Service, Proposed Threatened Status for *Penstemon grahamii* (Graham's beardtongue) With Critical Habitat, May 11, 2006

Shale area in Utah and in the Hill Creek and P.R. Spring STSAs. The Service recommends at Section 3.7.4.4, p. 3-176, lines 1-10, or other sections of the draft PEIS identify the interagency Graham's beardtongue Conservation Agreement (CA).

We recommend that Graham's beardtongue (*Penstemon grahamii*) be designated by BLM as a special status species in both Colorado and Utah. The Service also recommends that the BLM avoid oil shale or tar sands lands and any land exchanges within the "Area Where Overburden is < 500ft." (Fig. 2.3-1, p.2-11) until the conservation measures envisioned in the draft conservation plan for the species are implemented. 154-026 (cont.)

Section 3.7.4.4, p. 3-175, line 18: As a clarification, please note that the bald eagle is still protected by the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act. 154-027

Section 3.7.4.4, p. 3-175, entire section: As clarification, we recommend that this section also include a discussion of the white-tailed prairie dog and the Gunnison prairie dog. 154-028

Section 4.1.1, p. 4-3, line 42: In describing the assumptions of oil shale surface mining, the text states, "Topsoil and subsoil removed as overburden would be separately stockpiled and vegetated to mitigate or eliminate erosion." We recommend adding that stockpiles should be vegetated with native species only, especially in or near areas of rare endemics plants. 154-029

Section 4.8.1.2, p. 4-64, line 6: Because reclaiming an area with native vegetation (especially mature shrubs) will take up to 20 years, we recommend that the restoration and monitoring plan be established for a similar time period to ensure vegetation and habitat restoration is completed and meets established goals, rather than a short commitment of 3-5 years as identified in the text. 154-030

Section 4.8.1.3.1, p. 4-68, line 19: Depending on type of disturbance activity and avian species (e.g., some raptors), disturbance to bird nesting could occur at distances significantly greater than 0.25 mile. The Service recommends expanding the discussion of habitat disturbance to bird nesting to include more specific information.

Studies have indicated that wildlife are disturbed over surprisingly long distances from rural roads and highway corridors. Disturbance to wildlife has generally been inferred from relative densities of a species or group of animals at varying distances from a road. For instance, Van der Zande et al. (1980) confirmed earlier conclusions of Veen (1973) and showed that lapwings and godwits were disturbed to distances up to 1.24 miles from a highway located in the Netherlands. Similarly, plant, bird, and herptile species richness was observed to diminish with increasing density of paved roads, out to a distance of again at least 1.24 miles from the road (Findlay and Houlahan 1996). Based on their statistical models, a 2m/ha increase in total paved road density was assumed to have the same impact on herptile and mammal species richness as the loss of 50% of the wetland proper. In forested habitats, road noise reduced bird population density and breeding 154-031 success within 0.3 to 0.6 miles of roadways. Breeding dispersal patterns were indicative that roadside areas provided lower quality habitats (Reijnen and Foppen 1994, Foppen and Reijnen 1994, Reijnen et al. 1995). 154-031 (cont.)

Table 4.8.1-2, p. 4-84: Please include water depletions as an Impact Category in this Table. 154-032

Table 4.8.1-2, p. 4-84: The Service recommends the following changes to characterizations of the impacts:

1) Habitat Fragmentation/Terrestrial Amphibians and Reptiles -- change to "Large" – because these species have smaller home ranges, habitat fragmentation could affect more than 50 percent of a local population, resulting in a large measurable change in carrying capacity; 154-033

2) Habitat Fragmentation/Terrestrial Birds -- change to "Large" -- there is substantial research/literature regarding the effects of habitat fragmentation (particularly roads) on bird populations; 154-034

3) Habitat Fragmentation/Terrestrial Mammals -- change to "Large" -- it is likely that mammal populations will be measurably affected or eliminated in project areas due to the high degree of habitat loss, habitat fragmentation, and human disturbance; 154-035

4) Alteration of Topography/Terrestrial Invertebrates -- change to "Large" -- small population sizes or small home ranges of many invertebrates could result in measurable effects from topography changes; 154-036

5) Alteration of Topography/Terrestrial Amphibians and Reptiles -- change to "Large" -- small population sizes or small home ranges of many amphibians and vertebrates could result in measurable population level effects from topography changes; 154-037

6) Changes in Drainage Patterns/Terrestrial Amphibians and Reptiles -- change to "Large" -- small population sizes or small home ranges of many amphibian and reptile species could result in measurable population level effects from drainage alterations; 154-038

7) Changes in Drainage Patterns/Terrestrial Mammals -- change to "Large" -- significant changes in drainage pattern can impact burrowing animals such as prairie dogs which are a primary food source for black-footed ferret; 154-039

8) Human Collection/Upland Plants -- change to "Large" -- the Service is aware of numerous instances of collectors poaching endangered plant species, particularly in areas that are more open to access due to roads; 154-040

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9) Human Collection/Wetland and Riparian Plants -- change to "Large" -- the Service is aware of numerous instances of collectors poaching endangered plant species, particularly in areas that are more open to access due to roads; 154-041

10) Human Disturbance/Harassment/Terrestrial Amphibians and Reptiles -- change to "Moderate" -- at a minimum, there is evidence of individual reptile and amphibian displacement from human presence, and it is likely that continuous human presence would result in a population level effect; 154-042

11) Increased Human Access/Upland Plants -- change to "Large" -- the Service is aware of numerous instances of collectors poaching endangered plant species, particularly in areas that are more open to access due to roads; 154-043

12) Increased Human Access/Wetland and Riparian Plants – change to "Large" the Service is aware of numerous instances of collectors poaching endangered plant species, particularly in areas that are more open to access due to roads; 154-044

13) Increase in Predation Rates/Aquatic and Wetland Animals -- change to "Moderate" – it is unclear why the determination is "None;" 154-045

14) Increase in Predation Rates/Terrestrial Invertebrates -- change to "Moderate" -- it is unclear why the determination is "None;" 154-046

15) Spread of Invasive Species/Terrestrial Amphibians and Reptiles/Terrestrial Birds/Terrestrial Mammals -- change to "Moderate" or "Large" -- invasive species occur at large, landscape-level scales with effects to entire ecosystems; 154-047

16) Temperature Increase in Water Bodies/Wetland and Riparian Plants -- change to "Moderate." 154-048

<u>Pages 4-85, 6-38, 6-39:</u> Chapter 4 and Chapter 6 appear to present contradictory information. Page 4-85 referring to all alternatives states, "Three ACECs in the Piceance Basin of Colorado (Duck Creek, Ryan Gulch, and Dudley Bluffs) were established to protect known populations of the Dudley Bluffs twinpod and Dudley Bluffs bladderpod. These areas would not be available for leasing, and, therefore, would be protected from the direct effects of oil shale development." However, pages 6-38 and 6-39 indicate that ACECs that are <u>not</u> closed to mineral leasing include Duck Creek, Ryan Gulch, and Dudley Bluffs ACECs. Please clarify this apparent discrepancy. 154-049

<u>Table 4.8.1-3, p. 4-86:</u> The Service recommends listing the type of effect (e.g., collection, habitat fragmentation, water depletion, etc.) in the Potential Effect column. 154-050

<u>Section 4.8.1.4, p. 4-101, lines 13-14:</u> The text reads, "Direct impacts on these habitats are not anticipated because they occur within designated ACECs…" It is the 154-051

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understanding of the Service that areas located within an ACEC are not necessarily precluded from energy development. Please clarify. 154-051 (cont.)

Section 4.8.2.1, p. 4-102 and Section 5.8.2.1, p. 5-90, line 16: Previous BLM Resource Management Plans have committed to conserving and recovering all special status species and the ecosystems on which they depend. The Service agrees with this management direction and commends the BLM for placing high importance on special status species, including listed fish species.

With these conservation goals in mind, the Service is concerned by the threats presented by oil shale and tar sands development within the 100-year floodplain. We recommend that avoidance of oil shale and tar sands development in the 100-year floodplain be listed as a commitment of the Aquatic Resources Mitigation Measures. Avoidance of oil shale and tar sands extraction activities in the floodplain of the Colorado River and its tributaries would lessen the threats posed by toxicant or contaminant spills or leaks in areas with sensitive fish species. 154-052

We also recommend that water quality monitoring be conducted to establish a baseline prior to site-specific project activity, during the life of the project, and be continued for a sufficient period beyond the termination of active operations to ensure the project site does not pose a threat to the river aquatic system.

Table 5.1.1-1, p. 5-4:
(1) The draft PEIS indicates that during surface mining, a typical retort or solvent extraction facility would use between 40,000 and 90,000 barrels of water per day and that most of the water ends up in tailing ponds even with recycling. The draft PEIS does not indicate whether there is a sufficient water supply to support this type of mining. We recommend a thorough assessment of water needs, sources, and impacts to aquatic resources. 154-053

(2) The text indicates for the production area 73-88 dBA at 500 ft is considered unacceptable for human residential use. Some further description of affects of noise on wildlife may be appropriate. 154-054

Section 5.8.2.3, p. 5-92, line 12: Pertaining to the discussion of waste-water lagoons, the Service recommends that creation of open surface water bodies be avoided because open wastewater pits have the potential to contaminate groundwater, leach selenium, provide vectors for West Nile Virus, and serve as an attraction to migratory birds. Waste pits, especially those with oil or surfactants on the surface of the water, have proven to be a significant source of mortality to migratory birds. 154-055

Section 6.1.1.7.3, p. 6-13, line 18: In this section, discussion of the impacts of Alternative A on wildlife appears to be limited to the changes in acres of vegetation or habitat removed due to the 'footprint' occupied by well pads, roads, and associated facilities. The footprint acreage is only one aspect of the wildlife impact. Disturbance of wildlife use areas for brooding, foraging, migration, and over-wintering can also occur 154-056

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due to increased vehicular traffic, noise, physical structures, increased human presence, alteration of water flow, and fragmentation of habitat. The Service recommends augmenting the text with discussion of these additional types of impacts. 154-056 (cont.)

Section 6.1.2.7, p. 6-46, and Section 6.2.2.7.3, p. 6-188 (entire sections): The wildlife sections do not discuss migratory birds other than raptors (and discusses raptors only briefly). The discussion of the effects of this Alternative on wildlife should include impacts on migratory birds in general. The corresponding sections of the other Alternatives also should include discussions of the impacts on migratory birds. 154-057

Table 6.1.4-5, p. 6-98: The table presents the acres of wildlife habitats identified for protection in the BLM land use plan that could be impacted by commercial oil shale development under each action alternative. The way that the information is presented can be interpreted to suggest that no sage-grouse, raptor, or big game habitats would be lost under Alternative C. This representation is inaccurate or at least presented in a way that may be misinterpreted. Please revise or clarify to reflect that the important habitats for these species are located within the areas open for lease applications under Alternative C. 154-058

Table 6.1.4-7, p. 6-100: This table indicates that no black-footed ferret habitat is included in land available for leasing under Alternative C. We believe this is incorrect. Alternative C appears to overlap a substantial portion of the range for reintroduced ferrets in Coyote Basin. Please contact our Utah, Ecological Services Field Office for clarification of the range of ferret reintroduction. 154-059

Table 6.1.4-7 can also be misinterpreted to imply that no threatened or endangered plant species are found on lands that would be available for leasing under Alternative C. This too would be incorrect. Service maps indicate that Dudley Bluffs bladderpod lie within the Alternative C boundaries, as does other potential habitat for the bladderpod and the Dudley Bluffs twinpod. Please clarify this in the final PEIS. 154-060

Table 6.2.4-3, p. 6-236: A 55-percent reduction in sage-grouse habitat is significant, and if accurate would represent substantial impacts to the species. The Service recommends evaluating the impacts in the draft PEIS on both a local population and range-wide scale. 154-061

Appendix C, Table C-1, Page C-5, para 3, Amendments Common to All Land Use Plans, Alternatives B and C: The text indicates that land use plan amendments would, "Specify that utilization will occur utilizing a lease by application process described in Section 2.2.3." Correct the reference; Section 2.2.3 does not include this description.

Appendix C, Table C-1, Page C-7, para 2 of Alternative B, and elsewhere in Table C-1: The text states, "As discussed in Section 2.2.3.1, all lands…[not excluded]… will be available for application of commercial leasing." Correct the reference; Section 2.2.3.1 does not exist. 154-062

Appendix C, Table C-1, Page C-7, para 2 of Alternative B, and elsewhere in Table C-1: The text states, "As discussed in Section 2.2.3.2, all lands…excluded from commercial

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leasing under Alternative B will also be excluded under Alternative C." The reference to Section 2.2.3.2 is in error (the section does not exist). 154-062 (cont.)

Appendix E, Table E-1, Pages E-21 to E-38: The Service recommends considering the status of Ute ladies'-tresses in Sweetwater and Sublette counties, Wyoming in the analysis. 154-063

Please clarify table E-1 (p. E-23) such that the endangered Colorado River fishes (bonytail, humpback chub, Colorado pikeminnow, and razorback sucker) are not known to occur in Wyoming, but they are affected by water depletions from the Colorado River basin in Wyoming. 154-064

Table E-1 on page E-38 indicates that black-footed ferrets do not occur in Wyoming. Please update this table to include black-footed ferrets as potentially occurring in white-tailed prairie dog towns in Sweetwater and/or Sublette counties Wyoming. 154-065

Appendix F: The title of Appendix F may be somewhat misstated. It is our understanding that that BLM intends the conservation measures to apply to subsequent leasing actions, rather than PEIS action (amendments of land use plans). Also, we understand that the conservation measures are intended to apply to subsequent leasing under any action alternative, rather than just the Preferred Alternative. Please clarify the title. 154-066

The appendix contains measures to avoid and minimize impacts to federally listed species and proposed plant species. The Service recommends that similar conservation measures also be provided for candidate plant species. 154-067

The Service recommends that conservation measures for migratory birds and raptor protection guidelines be included in conservation measures, as these birds are protected under the Migratory Bird Treaty Act. Bald and golden eagles are also protected under the Bald and Golden Eagle Protection Act. Additionally, for protection of migratory birds, the Service recommends avoiding initiation of land-disturbing activities during the breeding season. 154-068

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Response for Document 00154

00154-001: The BLM recognizes that additional NEPA analysis will be required and is committed to preparing the appropriate level of analysis prior to the issuance of any oil shale lease. (See page 2-19 of the Draft PEIS for the description of additional NEPA requirements.) Since leasing will be an entirely different decision, a new NEPA analysis will be required. It is inappropriate to speculate at this stage whether such NEPA analysis will be programmatic in nature.

This new NEPA analysis will analyze the leasing of parcels of land for commercial oil shale exploration and development and under what conditions or stipulations. The analysis will also contain any new information or circumstances relevant to the technology, the affected environment, and any associated environmental consequences. This information may be a consequence of research on the RD&D leases or a result of industry performing research or studies on nonfederal lands.

As required by NEPA, all subsequent NEPA documents will analyze the cumulative effects from other reasonably foreseeable future actions. The scope and nature of the specific proposed action will drive the type of NEPA analysis the BLM performs. As required by NEPA, the cumulative effects analysis would consider the present effects of past actions, to the extent that they are relevant, and present and reasonably foreseeable (not highly speculative) federal and nonfederal actions, taking into account the relationship between the proposed action and these reasonably foreseeable actions.

The affected environment of the action could vary greatly from a large regional area to a small discrete area. The scope of the analysis in the NEPA document would be dependent upon the number of applications received and the type and size of operations proposed by the applicant(s). This could result in a statewide, regional, basin-wide, or a site-specific impact analysis. Overall, the geographic extent of the analysis would be limited to those areas that could experience a change in the pattern of land use, as a consequence of a direct impact or other induced effects on the natural resources. The nature of the action can also vary greatly based on the type of technology or mining method. Another critical factor would be the type of infrastructure needed to support the operation, in particular, the source of electrical power.

Hypothetically, the proposal in subsequent NEPA documents could offer for commercial lease 1) only a limited number of parcels, 2) parcels located in a geologic basin, or 3) parcels located throughout a state. Estimated oil shale exploration and development activities assumed to occur as a result of issuing the leases would be based on actual applications, therefore analyses of proposed operations, hypothetical development scenarios, and an RFDS could be developed. Depending on the information included in the applications, technologies whose impacts would be analyzed could include any or all of underground and surface mining with surface retort operations and/or in situ operations.

Based on the nature of the proposed action, existing sources of electrical power may be sufficient to power the operation, or electrical power may need to be generated on lease using either conventional energy sources like natural gas or renewable energy sources like wind or solar. A third hypothetical analysis may include the expansion of existing power plants or the construction of additional power plants (coal, gas, nuclear). In each case, the scope of the NEPA analysis would be limited to the extent of the direct and indirect effects from activities described in a reasonably foreseeable development scenario.

For example, if the proposed action were to lease three tracts in Utah, using underground mining technology only, the scope and scale of the analysis would differ from the scope and scale of the analysis that would be done if the proposed action were to lease several parcels in all three states, using a variety of technologies. The geographic extent of analysis for a leasing decision is based on the extent of the potentially affected resource(s). In the first instance, the NEPA analysis would most likely not be a programmatic EIS, but would define the area subject to analysis as the area bounded by the three leases. The analysis may not necessarily include an analysis of building additional power plants (dependent on whether the additional mines could pull power off the existing grid or not). In the second instance, it may be appropriate for BLM to perform a regional NEPA analysis that would look at leasing in all three states and include an analysis of the power plants (coal, gas, nuclear) as well as refinery capacity that might be necessary for any development to occur.

In both instances, the NEPA analysis would be limited to the extent of effects from activities described in an RFDS. While the proposed leasing area may be the three Utah tracts, effects on some resources can be extensive, going beyond the boundaries of the proposed leasing area and determined by the distance over which effects remain significant (e.g., effects on air quality or effects on an entire watershed), while the effects on other resources remain within the leasing area boundary and are geographically limited by the resource itself (e.g., a specific species of threatened and endangered plant or a specific culturally significant feature). The impact zones of particular resources may be superimposed or may overlap only in part. All relevant effects, including those that extend outside the project, or, even, in some cases, the planning area where the project is located, must be evaluated and considered in the leasing decision that is made for the planning area.

Thus, while the BLM is committed to performing NEPA analyses prior to leasing, we cannot commit to a certain type of NEPA analysis (regional, planning area, or local). The proposed action will drive what analysis must be done to comply with the requirements of NEPA.

00154-002: The BLM acknowledges the commentor's preference for Alternative C.

00154-003: The BLM is committed to preparing the appropriate level of analysis prior to the issuance of any oil shale or tar sand lease, including the appropriate level of cumulative effects analysis.

It is inappropriate to speculate at this stage whether such future NEPA analysis will be programmatic in nature. A more appropriate level of analysis for a defined leasing program would be based upon the number of applications received, the location(s) referenced in the application(s), and the type and size of operations proposed by the applicant(s). This could result in a statewide, regional, basin-wide or a site-specific impact analysis. With a more focused scope at the leasing decision stage, the consequences and implications—direct, indirect and cumulative—to listed and nonlisted species, as well as other resources, can be better defined. This will result in a more informed leasing decision, as well as aid in the development of potential mitigation measures to minimize or eliminate any adverse impacts.

When commercially viable technologies are identified and better understood, the BLM will be better able to analyze impacts of leasing decisions. The scale of the leasing will be subject to the Secretary's discretion to offer leases for sale and the industry's interest in bidding for tracts. The exercise of this discretion, and the level of interest expressed by industry, will be informed by the increased amount of information regarding technologies and effects.

00154-004: The BLM notes USFWS's preference for Alternative C.

Alternatives B and C are limited to an allocation decision that provides an opportunity for subsequent levels of NEPA analysis prior to any decision on leasing or development of these resources. The only decision in this respect proposed to be made on the basis of the PEIS is to open or close lands to further consideration of leasing of these resources. With respect to the recommended specific exclusion of watersheds and the creation of no-lease buffers around critical habitat areas, consideration of the need for such exclusions would be more appropriate when areas are designated at the lease sale stage. Please note that all ACECs are excluded from application for commercial leasing under both Alternative B and C for tar sands and for Alternative C for oil shale. ACECs not specifically closed to mineral entry are open for application for commercial leasing in oil shale Alternative B. The fact that ACECs may be open for application does not indicate that they will be disturbed by development. The subsequent NEPA process considering a lease application will make specific decisions regarding the protection and management of any ACECs open for application. See descriptions of the alternatives in Sections 2.3.3, 2.3.3.2, 2.4.3, and 2.4.3.2. All subsequent NEPA analysis and decisions associated with potential leasing of parcels or potential plans of operations will be performed in full compliance with existing environmental laws and associated regulations.

In deciding whether to lease or to approve plans of development, the BLM will comply with the ESA, including all necessary consultations with the USFWS. In addition to compliance with the ESA, the BLM will offer leases only in conformance with its policies and procedures for BLM-designated sensitive species. For example, the BLM's policies for "exclusion radius" around greater sage-grouse leks might be amended between the date of this PEIS and the issuance of a lease or approval of a plan of development.

Furthermore, Alternative B does not imply a commitment to leasing that is too large to be sustainable or that would threaten the existence of species; as noted above, each of the action alternatives only contemplates opening certain lands to further consideration of leasing. Within the areas open for leasing under either Alternative B or Alternative C, the Secretary will retain the discretion to decide which particular tracts to offer for lease and the stipulations on such leases.

00154-005: The specific impacts associated with development and technology deployment cannot be assessed at this time given the state of the science in oil shale and tar sands extraction and processing. Technologies are evolving and specific information on impacts such as water depletions is not fully understood. Information is being gathered as part of the RD&D program. The conservation measures presented in Appendix F of the PEIS were developed in consultation with the USFWS. These measures are presented as examples of the types of measures that will be appropriate to mitigate impacts to special status species. Final conservation measures will be developed at the leasing and project development phase in consultation with the USFWS.

00154-006: The BLM is evaluating the amendment of land use plans in parts of Colorado, Utah, and Wyoming to identify public lands that would be available for future application for leasing for oil shale or tar sands development. The proposed action is a land use allocation and does not commit any mineral resources or authorize any BLM action that would have a direct, indirect, or cumulative impact under either NEPA or Section 7 of the Endangered Species Act (ESA) on threatened or endangered species.

The impact analysis provided in the PEIS qualitatively indicates the types of impacts that could occur as a result of the development of these resources, based on BLM experience with other types of mineral development. The reasons for presenting this information include to address additional information needed and to provide sufficient information for the decision maker to make a reasoned choice among the alternatives. Cumulative impacts, as defined pursuant to NEPA, to threatened and endangered species are discussed in Sections 6.1.5.3.7 and 6.2.5.3.7 of the PEIS. At this time, it is not possible to provide a quantitative evaluation of cumulative effects as requested in the comment. There are many uncertainties regarding the amount of development that is reasonably foreseeable, the types of technologies that might be deployed, and the locations of potential projects. Cumulative impacts will be evaluated in project-specific NEPA assessments and consultations conducted prior to leasing and development.

00154-007: In consultation with our cooperating agencies, the scope of the PEIS was changed from a leasing decision to an allocation decision. The only decision in this respect proposed to be made on the basis of the PEIS is to open or close lands to further consideration of leasing of these resources. Consequently, the decision to offer specific parcels for lease was dropped from consideration in the PEIS. Specific monitoring requirements to evaluate environmental consequences are more suited at future leasing and/or plan of development stages. Although specific monitoring plans are not included, examples of potential types of mitigation measures to protect wildlife, plants, and habitat resources are provided for consideration at subsequent stages of NEPA analysis (see Sections 4.8.2 and 5.8.2).

The PEIS outlines the process for making subsequent decisions regarding both leasing and development. For example, see Chapter 1 and Chapter 2 (Sections 2.3.3 and 2.4.3).

00154-008: All decisions related to land use planning for oil shale and tar sands resources in the PEIS study area will be made in the ROD for the PEIS. The ROD will amend the existing plans (MFP or RMP or ongoing RMP if the PEIS is completed first) by making land use planning decisions on whether or not lands will be available for application for future leasing and development of oil shale or tar sands on public lands for those areas where the resource is present. Additional site-specific NEPA analysis will be completed on any future lease application before any leases would be issued. If, as part of this NEPA analysis, the BLM determines that leasing and subsequent development of the oil shale or tar sands resources would cause significant impacts, the BLM can require the applicant to: 1) mitigate the impact so that it is no longer significant, 2) move the proposed lease location, or if neither of these options resolves the anticipated conflicts, 3) the BLM can decide that development of the oil shale or tar sands resources outweighs protection of the on-site resources and approve the application. This NEPA analysis would include opportunities for public involvement and comment that are part of the NEPA process.

Under the provisions of FLPMA, the BLM has designated ACECs where special management attention is required to protect and prevent irreparable damage to important cultural, historic, and scenic values, fish and wildlife resources, other natural systems or processes, or to protect life and safety from natural hazards. In ACECs not closed to mineral entry, the BLM has specific management prescriptions outlined in the local land-use planning document to protect the relevant and important values. However, the ACEC Manual (BLM Manual 1613) states: “Normally, the relevance and importance of resource or hazards associated with an existing ACEC are reevaluated only when new information or changed circumstances or the results of monitoring establish a need.” Therefore, if there is new information or changed circumstances associated with the leasing of lands within ACECs open to mineral development, the ACEC will be reevaluated to consider whether to retain the ACEC designation or develop additional management prescriptions in the NEPA analysis associated with the proposed leasing decision. ACECs closed to mineral entry are not available for application for commercial leasing. If an ACEC is closed by the BLM field office, it will have to undergo further NEPA analysis, as it will still have been excluded from the analysis covered in this PEIS.

00154-009: The referenced stipulations are developed for each BLM planning unit. Although BLM plans are generally developed with full knowledge of how other planning areas have handled similar situations, the final decisions are generally tailored to meet local conditions.

00154-010: Tables 2.6-1 and 2.6-2 have been revised to include a summary of impacts on BLM-designated sensitive species.

00154-011: The raptor habitat acreages presented in Tables 2.6-1 and 2.6-2 represent raptor habitats identified in BLM RMPs that have been identified for protection that could be developed under Alternative B for oil shale and tar sands, respectively. The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of the lands for commercial development. Therefore, providing more detailed discussion of raptor habitat is beyond the scope of the PEIS. Detailed discussion of raptor habitats, and quantitative analyses of potential impacts to raptors, would be conducted for any proposed project. Also, policies and BMPs that would be implemented at the project-specific level are expected to avoid impacts to raptor habitat and, where not possible, minimize and mitigate impacts to the extent practicable.

00154-012: USFWS lands, although subject to the Mineral Leasing Act (16 USC 668dd(c)), are not under consideration to be opened for leasing under this PEIS, and, accordingly, are not subject to direct impacts of potential commercial development on BLM-administered lands. Indirect impacts, however, depending on where commercial development might occur, are possible. Although the specific USFWS facilities are not identified by name, potential indirect effects of commercial development are discussed throughout the Ecological Resources sections of the PEIS in Chapters 4, 5, and 6. Once site-specific proposals are known, potential indirect impacts on USFWS and other federal, state, and private lands will be included in the NEPA analysis reviewing the proposed lease. The requested facilities, plus the Brown’s Park NWR, have been added to maps in the document for reference.

00154-013: Thank you for the comment. Mallard Springs Wildlife Management Area has been added to Table 3.1.1-11 in Chapter 3.

00154-014: The Mancos shale formation is recognized as a major source of selenium in the Gunnison Basin, creating an issue in Colorado. The formation is not exposed on the surface in Piceance Basin and is stratigraphically under the productive zones of oil shale. Disturbance of the formation is unlikely. Selenium occurs in other streams in Utah, as shown in the 303(d) list (Table 3.4.1-1). The issue has been added to the text in the PEIS.

00154-015: Tables 3.4.1-2 to 3.4.1-4 focus on the water demand and consumptive uses of water. As instream flows are not considered consumptive uses, they are not included in the tables. CWCB has the exclusive authority to protect instream flows. A list of stream segments with current instream flows requirements in Water Divisions 5 and 6 has been added to the PEIS and is presented in Appendix I. Protection of Endangered Species Fishes is described in Section 3.7.4.

Water depletion due to oil shale development depends on many factors, including project sites, technologies to be used, and various activities involved in the development. The depletion issue would be handled at the project-level when these factors are better defined. Impacts of water depletion would be addressed in subsequent project-specific NEPA documents.

00154-016: The assumed 6 million acre-ft for the Upper Basin is based on the results of the “Hydrologic Determination” study of 1988 that calculated the water availability of the Upper Basin. The study used long-term historical data from 1906 to 1986 and assumed that the Lower Basin states could have 7.5 million acre-ft of water and the Upper Basin’s contribution of 0.75 million acre-ft of water delivered to Mexico.

Historically, the natural flow of the Colorado River fluctuated annually. However, the Hydrologic Determination concluded that the assumed 6 million acre-ft for the Upper Basin per year rarely triggered water calls from the Lower Basin states.

Water demand differs from water consumption. The latter is the basis in various Colorado River compacts. Water demand does not take into account existing water delivery infrastructure (such as reservoirs to trap the water and canals to deliver the water to end users) and represents a desired quantity. The water consumption value that is used in Table 3.4.1-3 represents water actually used and is equal to the amount of water delivered minus the amount of water returned to streams or returned flows. Water demand in the western states generally is much larger than the water consumed.

The stream flow impacts on aquatic resources are described in Section 4.8.1.4.

00154-017: This section describes the water resource, while corresponding sections in Chapters 4 and 5 discuss the possible impacts on the water resource. Impacts to springs and seeps are included in Sections 4.5 and 5.5.

00154-018: Additional information pertaining to the occurrence and distribution of fish species (especially sensitive native fish species) within the Piceance Oil Shale Basin has been added to Sections 3.7.1 and 3.7.1.1.4 of the PEIS, including information about roundtail chub, bluehead sucker, flannelmouth sucker, and mountain sucker. Information about mussel species within the basin has also been added. References to the conservation agreement documents identified in the comment have been added.

00154-019: Text has been added to Section 3.7.1 to identify that the Colorado River cutthroat trout is managed under an interagency conservation agreement, and references to the conservation agreement have been added. Appendix F of the PEIS identifies conservation measures that would be applied to listed and sensitive species, including Colorado River cutthroat trout.

00154-020: Text regarding oil shale endemic species has been added to Sections 3.7.2, 4.8.1.2, 5.8.1.2, 6.1.1.7.2, 6.1.2.7.2, 6.1.3.7.2, 6.1.4.7.2, 6.2.2.7.2, 6.2.3.7.2, and 6.2.4.7.2. The BLM special status species designation is determined by each BLM State Director. The USFWS request to identify all oil shale endemic plant species as special status species should be directed to the BLM State Directors for Colorado, Utah, and Wyoming.

00154-021: The text in Section 3.7.4.1 has been revised as suggested.

00154-022: The text in Section 3.7.4.1 has been revised as suggested.

00154-023: The text in Section 3.7.4.1 has been revised to indicate the currently understood range of the southwestern willow flycatcher.

00154-024: Section 3.7.4.1 of the PEIS has been revised to include recent USFWS findings for the Uinta Basin hookless cactus complex.

00154-025: Section 3.7.4.1 of the PEIS has been revised to indicate that the Utah prairie dog is one of three prairie dog species found in the state of Utah. This section discusses the USFWS 90-day review and the decision to keep the Utah prairie dog listed as threatened.

00154-026: The PEIS identifies lands available for potential future leasing decisions. Leasing decisions will be based on future NEPA analysis where site-specific information will be available for the area under consideration. Appropriate stipulations can and will be developed for those areas that are eventually identified for leasing. Although the overburden is less than 500 ft thick and surface mining would be more economically feasible, underground mining where surface disturbance could create unacceptable risks can be required. Graham's beardtongue is a sensitive species on both the Colorado and Utah BLM sensitive species lists and, as such, is protected by the policies established under BLM Manual 6840. In addition, the BLM is signatory to the interagency Graham's beardtongue Conservation

Agreement and is committed to accomplishing the tasks identified in it to ensure attainment of its goals and objectives, and ultimately the long-term conservation of the species. The Conservation Agreement has not yet been signed by all involved parties.

00154-027: The text in Section 3.7.4.1 has been revised as suggested.

00154-028: This section describes species for which the USFWS and the BLM developed conservation measures specifically for the oil shale program. Because the USFWS and the BLM did not develop conservation measures for the white-tailed prairie dog or Gunnison prairie dog, the text in Section 3.7.4.1 has not been revised.

00154-029: The BLM agrees that only native species should be used to revegetate overburden stockpiles. The text has been modified accordingly.

00154-030: As discussed on pages 4-1 and 5-1 of the Draft PEIS, the PEIS provides examples of mitigation measures that the BLM may consider adopting, if site-specific analysis warrants. The measures are not proposed as a final or a comprehensive list of required stipulations or management prescriptions. Project-specific requirements to ensure the successful reclamation of disturbed land would be established by BLM prior to leasing.

00154-031: The information presented in the PEIS that addresses disturbance impacts to wildlife is of sufficient detail for the purposes of the PEIS. The PEIS is a programmatic-level document that analyzes allocation decisions. Programmatic environmental impact statements are used to evaluate broad policies, plans, and programs and they provide an effective analytical foundation for subsequent project-specific NEPA documents. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development. Subsequent project- or site-specific NEPA documents will be prepared to evaluate specific occurrences of wildlife, analyze the environmental consequences of leasing (including consideration of direct, indirect, and cumulative effects of disturbance to wildlife), reasonable alternatives, and possible mitigation measures to protect resources and resource values, as well as what level of development may be anticipated. Site-specific NEPA analysis would include mitigation such as best management practices (BMPs), specific protections, or avoidance to mitigate impacts to wildlife from disturbance.

00154-032: Water depletion has been added as an impact category to Table 4.8.1-4.

00154-033: The text in Table 4.8.1-4 has been modified to indicate that the impacts of habitat fragmentation on terrestrial amphibians and reptiles could be large.

00154-034: Table 4.8.1-4 has been modified to indicate that the impacts of habitat fragmentation on terrestrial birds could be large.

00154-035: Table 4.8.1-4 has been modified to indicate that the impacts of habitat fragmentation on terrestrial mammals could be large.

00154-036: Table 4.8.1-4 has been modified to remove the column on impacts to terrestrial invertebrates because no special status terrestrial vertebrates are found in the study area.

00154-037: We disagree that changes in topography would have a large adverse effect on terrestrial amphibians and reptiles. Terrestrial species are less likely to be affected by changes in topography because they are less dependent on water or wetland features that would be affected by the changes in drainage patterns brought about by changes in topography. The text was not changed in response to this comment. Note that vegetation clearing and habitat fragmentation effects on these species are considered large.

00154-038: Table 4.8.1-4 has been changed to combine "alteration of topography" and "changes in drainage patterns" into one impact category. As noted above, we believe that changes in drainage patterns would not have a large adverse effect on terrestrial amphibians and reptiles. Terrestrial species are less likely to be affected by changes in drainage patterns because they are less dependent on water or wetland features. The text was not changed in response to this comment. Note that vegetation clearing and habitat fragmentation effects on these species are considered large.

00154-039: The BLM disagrees that changes in drainage patterns would have a large adverse effect on terrestrial mammals. Terrestrial species are less likely to be affected by changes in drainage patterns because they are less dependent on water or wetland features. Note that the effects on these species of vegetation clearing, habitat fragmentation, and injury or mortality of individuals are considered large. The text was not changed in response to this comment.

00154-040: The text in Table 4.8.1-4 has been revised as suggested.

00154-041: The text in Table 4.8.1-4 has been revised as suggested.

00154-042: Table 4.8.1-4 has been modified to indicate that the impacts of human disturbance and harassment on terrestrial amphibians and reptiles could be moderate.

00154-043: The text in Table 4.8.1-4 has not been revised as suggested. The human access impacts presented in the table relate to trampling or erosion impacts associated with improved access. The human collection category relates to the impacts mentioned in the comment. That impact magnitude has been revised to "large."

00154-044: The text in Table 4.8.1-4 has not been revised as suggested. The human access impacts presented in the table relate to trampling or erosion impacts associated with improved access. The human collection category relates to the impacts mentioned in the comment. That impact magnitude has been revised to "large."

00154-045: Table 4.8.1-4 has been modified to indicate that the impacts of increased predation rates on aquatic and wetland animals could be moderate.

00154-046: Table 4.8.1-4 has been modified to remove the column on impacts to terrestrial invertebrates because no special status terrestrial vertebrates are found in the study area.

00154-047: Table 4.8.1-4 has been modified to indicate that the impacts of invasive plant species on terrestrial amphibians and reptiles, terrestrial birds, and terrestrial mammals could be moderate.

00154-048: The text in Table 4.8.1-4 has been revised as suggested.

00154-049: The text in Chapters 4 and 6 of the PEIS has been modified to remove the inconsistency and indicate that these ACECs would be available for application for leasing.

00154-050: Without project-specific details including development plans, locations of facilities, water needs, mitigation measures, and the locations of special status species, it is not possible to identify the impacts that could occur on specific special status species with any specificity. General habitat information has been added to Table 4.8.1-5 and 4.8.1-6. The reader can use this information to determine the types of impacts possible for each species on the basis of information presented in Table 4.8.1-1.

00154-051: The commentor is correct in stating that some ACECs are available for mineral development. The text in the PEIS has been corrected.

00154-052: There are existing federal laws, regulations, and Executive Orders placing requirements on federal agencies that will require extensive review of potential impacts within 100 year floodplains that would be addressed in subsequent NEPA analysis. Some of these are listed in Appendix D of the PEIS. Additionally, potential mitigation measures that could be applied depending on the specific situation are included in Sections 4.5.3, 5.5.3, 4.8.2, and 5.8.2. The BLM has identified that prior to future leasing and approval of plans of development, site-specific NEPA analysis will be required that, depending on the environment of the site, will address the kinds of issues raised by the USFWS.

00154-053: Section 5.5.2 includes subsections discussing estimated water availability at each of the STSAs. These estimates are related generally to the requirements of operations. Water availability to support a given operation relying on a given technology would be determined in a site-specific NEPA analysis. Determinations about water would be based in part on state regulations regarding water rights and any reservoir construction.

00154-054: The potential effects of noise from tar sands development on wildlife are presented in Section 5.8.1.3.

00154-055: Any specific evaluation of wastewater lagoon development will be deferred to subsequent project-level planning prior to lease development. However, depending on the process method used and other mitigating circumstances, it may be necessary to establish open-surface water bodies. The mitigation measure pertaining to water bodies in Section 5.8.2.3 has been modified to state that such water bodies could have benefit to wildlife, but that they should be fenced or covered if they have poor water quality.

Site-specific NEPA analysis would include mitigation such as BMPs, specific protections, or avoidance to mitigate on eliminate impacts to wildlife from commercial oil shale or tar sands development. Mitigation measures, including those pertaining to wastewater lagoons or other surface water bodies, would be determined in conjunction with input from federal, state, and local agencies, and interested stakeholders.

00154-056: Section 4.1.8.3 provides an overview of impacts to wildlife that could occur from the types of impacts mentioned in the comment.

The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development. Therefore, the specific number and locations of projects cannot be identified within the PEIS. Subsequent project- or site-specific NEPA documents will be prepared to determine whether or not a lease will be offered in a specific area. This will include an evaluation of the specific occurrences of key wildlife habitats, analyses of the environmental consequences of leasing and future exploration and development, including consideration of direct, indirect, and cumulative effects (including those of other existing or reasonably foreseeable future oil shale and tar sands leases), reasonable alternatives, and mitigation measures to protect wildlife habitats, as well as what level of development may be anticipated. Project-specific NEPA analyses would also include mitigation such as BMPs, specific protections, or avoidance to mitigate or eliminate impacts to important wildlife habitats. Mitigation measures would be determined in conjunction with input from federal, state, and local agencies, and interested stakeholders.

00154-057: Impacts on migratory birds that would be common to all alternatives are addressed in Sections 4.8.1.3 and 5.8.1.3 for oil shale and tar sands, respectively. (Impacts on special status [e.g., threatened and endangered] migratory bird species are addressed in Sections 4.8.1.4 and 5.8.1.4.) The discussion in Chapter 6 of the PEIS mainly presents a comparison of the amount and location of lands that could be developed by commercial leasing under the various alternatives. The wildlife information presented in Chapter 6 was meant to provide a few comparative examples of habitat currently identified for protection or state-identified habitat that overlap with lands available for leasing under the various alternatives.

00154-058: Table 6.1.4-5, which has been updated to include information for Alternative A, pertains to areas of select wildlife habitat that are currently protected under existing land use plans that could either be opened to leasing or remain unavailable to leasing under the various alternatives considered in the PEIS. It is acknowledged that wildlife habitat would be impacted under any alternative, including Alternative C.

See also response to Comment 00154-056.

00154-059: The text in Section 6.1.4.7 has been revised to clarify the entries in the table. The acres presented are those that have been identified in BLM land use plans as having lease stipulations to protect black-footed ferret habitat.

00154-060: The text in Section 6.1.4.7 has been revised to clarify the entries in the table. The acres presented are those that have been identified in BLM land use plans as having lease stipulations to protect threatened and endangered plant species.

00154-061: Table 6.2.4-3 presents the acreage of state-identified wildlife habitat within areas identified that could be available for commercial tar sands development. It is not the intent of the table to imply that all of these areas would be impacted by commercial tar sands leasing.

The sage grouse is a special status species and subsequent leasing decisions will be informed by the need to prevent the species from becoming an ESA-listed species. Site-specific NEPA analysis would include mitigation such as BMPs, specific protections, or avoidance to mitigate or eliminate impacts on sage grouse from commercial oil shale or tar sands development. Mitigation measures would be determined in conjunction with input from federal, state, and local agencies, and interested stakeholders. Mitigation of impacts to sage grouse would include recommendations included in BLM's national sage grouse habitat conservation strategy, as well as those contained in state-wide and regional sage grouse conservation strategies that have been prepared by state agencies.

00154-062: Section references have been corrected in Appendix C.

00154-063: We were unable to find information to suggest the Ute ladies'-tresses is found in either Sweetwater or Sublette counties. In Wyoming, the species is known from Converse, Goshen, Laramie, and Niobrara counties in the Antelope Creek, Horse Creek, and Niobrara River watersheds of the southeastern portion of the state.

00154-064: Table E-1 presents the counties and habitats in which the species are found. Tables 4.8.1-6 and 5.8.1-4 indicate that all depletions from the Colorado River Basin are considered to have an adverse effect on these species.

00154-065: The text in Table E-1, Section 3.7.4.1, and Tables 4.8.1-6 and 5.8.1-4 has been revised on the basis of the comment.

00154-066: The title of Appendix F has been revised as suggested.

00154-067: Conservation measures were mutually developed to address ESA-listed species conservation needs. Conservation measures were not developed universally for all candidate species, due in part to limited information. The PEIS does not preclude the development and application of conservation measures for any species at the next level of NEPA analysis.

00154-068: The list of mitigation measures presented in Chapters 4 and 5, as well as the conservation measures presented in Appendix F, is not meant to be a final list of measures to be employed for an oil shale or tar sands lease. Mitigation and conservation measures would be subject to modification on the basis of consultation with federal, state, and local agencies, and interested stakeholders at the project-specific lease and development stage. Any actions undertaken for oil shale or tar sands leases developed on BLM-administered lands would have to comply with both the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act. Spatial and temporal mitigation measures to protect these species would be developed on a lease-specific basis.

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United States Department of the Interior

BUREAU OF RECLAMATION
Upper Colorado Regional Office
125 South State Street, Room 6107
Salt Lake City, Utah 84138-1147

IN REPLY
REFER TO:
UC-700
ENV-6.00

March 14, 2008

MEMORANDUM

To: PEIS Manager, Bureau of Land Management
Attention: Sherri Thompson

From: Nancy Coulam
Chief Environmental Officer

Subject: Draft Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocation in Colorado, Utah, and Wyoming and Programmatic Environmental Impact Statement (PEIS)

Reclamation appreciates the opportunity to work with you on this NEPA analysis. Staff from the Upper Colorado Region reviewed the published document and they have some general and specific comments.

General Comments

We appreciate the attention that the BLM has paid to our prior comments on administrative drafts of the PEIS. Our biggest concern remains that technologies are not presently available to prevent salt loading and the introduction of other contaminants into the Green and Colorado rivers under the action alternatives. The PEIS does document the potential for adverse effects to the water quality in the Colorado River and we appreciate that. We believe the final should acknowledge that increased erosion and sedimentation could lead to increased salt loading and water quality concerns. We believe best management practices that are currently being investigated under the research and development projects could partially take care of this, and that the development of best management practices could be included as mitigation measures. 156-001

Specific Comments

Page 3-61, last paragraph It says, "reservoir salt leaching" and it should be "reservoir evaporation." 156-002

Response for Document 00156

00156-001: The general impacts of oil shale and tar sands development on water resources are described in Sections 4.5.1 and 5.5.1, respectively. However, the specific impacts and the magnitude of the impacts caused by soil erosion, dissolved salts, and sedimentation would be addressed in subsequent project-specific NEPA documents and are not provided in the PEIS.

00156-002: "Reservoir salt leaching" refers to the leaching of soil surrounding a reservoir and the leached dissolved salts that empty into the reservoir.

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John Martin
Glenwood Springs, CO

Larry McCown
Rifle, CO

Trési Houpt
Glenwood Springs, CO

Garfield County

BOARD OF COUNTY COMMISSIONERS

March 17, 2008

Mike Nedd, BLM Assistant Director
Minerals, Realty and Resource Protection
1849 C Street N.W.
Washington, DC 20240

Dear Mr. Nedd:

We are submitting these comments on the Oil Shale PEIS under the public period. We respectfully appreciate Garfield County being included as a cooperating agency during this entire PEIS process.

Sincerely,

John Martin, Chair
Garfield County Board of County Commissioners

cc: Sherri Thompson, Project Manager
BLM Colorado State Office

108 Eighth Street, Suite 213 • Glenwood Springs, CO 81601
(970) 945-5004 • Fax: (970) 945-7785

GARFIELD COUNTY COMMENTS

ON

BLM OIL SHALE PEIS PUBLIC DRAFT

INTRODUCTION

Garfield County wishes to thank the BLM for including the County as a Cooperating Agency throughout this PEIS process. The County has attended a majority of the Cooperating Agency meetings and public meetings that have been conducted over the past two years.

When this process began, the purpose of the PEIS project was to provide for commercial leases for the extraction and processing of oil shale. About a year into the project, the purpose was changed from awarding commercial leases, to identifying what lands might be made available for commercial leasing at a future date. This change in purpose was, in part, driven by a lack of information and knowledge of the exact process(es) that might be utilized in the extraction and processing of oil shale. Without a clear understanding of the process(es) that might be utilized, it was extremely difficult to determine the impacts that might be experienced in the three state area where oil shale operations might take place.

As a basis of Garfield County's analysis of the PEIS documents, and the drafting of these comments, the following assumptions were made:

- That no Tar Sand activities would take place within Colorado;
- That no surface mining activities would take place within Colorado;
- That the purpose of the PEIS study was to identify lands that might be made available for commercial leasing at some time in the future;
- While the bulk of Volumes 2 & 3 address the various existing technologies for extraction of the petroleum product from the shale material, and the refining of the product, it seems premature to provide in depth comments until the specific process is known, which could be totally different than those discussed in the draft document.
- That prior to any future commercial leasing, additional site specific NEPA analysis would be conducted and analyzed; and,
- That this PEIS would be used, as the basis, to amend 12 land use plans in Colorado, Utah, and Wyoming, to provide the opportunity for leasing. **"The land use plans currently in use do not address development of oil shale resources."**

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OVERALL COMMENTS

- Garfield County submitted comments on an earlier draft document (June 6,2007), provided to Cooperating Agencies. Many of the comments submitted at that time still apply to this Public Oil Shale and Tar Sands PEIS publication, and have been included in these comments, as appropriate.
- The earlier draft document contained four "Alternatives" none of which were acceptable to Garfield County. Garfield County offered an "Alternative E" which proposed delaying any decisions regarding commercial leasing until such time that the current RD&D projects could be completed and the proposed technologies and their impacts better understood.
- Under this revised draft, the alternatives have been reduced to three alternatives: Alternative A (no action, would include only the development approved in the existing RD&D leases); Programmatic Alternative B, (the BLM's Preferred Alternative); and, Programmatic Alternative C. Under Alternative B, a total of 1,991,222 acres would be made available for application for commercial leasing, including the 6 RD&D projects. (359,798 acres in Colorado) Under Alternative C, a total of 830,296 acres would be made available for application for commercial leasing, including the 6 RD&D projects. (40,325 acres in Colorado)
- It appears that the reason the BLM rejected Alternative A (the no action alternative) is found on page 6-103, of the Public PEIS document, which states " Under the no action alternative, the BLM's approach to commercial oil shale development would be fragmented and would require costly and time-consuming individual land use plan amendments. This is likely to translate into greater costs and, possibly, protracted time lines for establishing commercial oil shale development on public lands". 157-001
- The above statement is somewhat confusing since the existing nine BLM Management Plans will have to be amended prior to any commercial leasing of oil shale lands. It would seem that a delay in the amendments of the Management Plans, until after the RD&D projects are completed, would not result in any additional costs over that required to do them now. The benefit would be that the preferred process would be known and the impacts capable of being accurately determined, so the plans could reflect actual operations.
- If the concern is the loss of time in getting the Management Plans amended, due to waiting for the RD&D projects to be completed, then Alternative C would still drive the amendments, with far less impacts on all concerned.
- Alternative B would make 87% of public lands available for application for leasing, as compared to 36% under Alternative C.
- On page 6-104, of the PEIS document, there is a summary statement that says " alternative A, the no action alternative, would do the least to facilitate future commercial oil shale development. Alternatives B and C 157-002

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would be equally effective in facilitating commercial oil shale development over the next 20 years, by virtue of the land use plan amendments."

- On page ES-3, it is stated, that "once the PEIS has been completed and additional information becomes available, the BLM will conduct NEPA analyses, including consideration of direct, indirect, and cumulative effects, reasonable alternatives, and possible mitigation measures, as well as what level of development may be anticipated. On the basis of this NEPA analysis to be conducted at the lease stage, the BLM will consider further amendment of one or more plans, including, but not limited to, the establishment of general lease stipulations and best management practices." Given this statement it again would appear that Alternative C should be the "Preferred Alternative". This alternative places far less acreage at risk, especially since the actual process(es) are unknown, and the actual impacts are unknown. 157-002 (cont.)
- If Alternative C were the preferred alternative, it would seem reasonable that at some future point in time, if oil shale development is proven economically feasible, and is in commercial production, plans could then be amended to provide for more public land to be made available, if necessary, to recover a larger percentage of the resource. An added benefit of such an approach would be possible advancements in technology that would positively benefit oil shale production, and all stakeholders.
- It was noted that the maximum recoverable resource, included in the PEIS, was only approximately 50% of the 1.2 trillion barrels that has been discussed in both public meetings and the public media. This discrepancy places a cloud over all of the estimated data and impacts included in the PEIS. 157-003
- The PEIS was very unclear if possible commercial leasing would / could occur south of the Roan Plateau. 157-004
- The PEIS referred to Federal, State and private property owner reviews and approvals, but omitted reference to local government review and approval. 157-005
- There was no single chart or table provided that showed all of the assumptions included in the PEIS, thus no ability to compare or evaluate conflicts therein.
- There was not a clear understanding or definition of the "threshold effects" statements contained in the PEIS documents. For example: how is "moderate effect" and "large effect" defined? A table showing these definitions, thresholds and effects would be very helpful. 157-006
- The PEIS document acknowledges that additional development will most likely occur on private lands, above and beyond the development on Federal lands, but does not include any discussion of possible effects, on a cumulative basis, of such private development. 157-007
- The PEIS document does not address how, or if, local land use codes and regulations will be considered in the commercial leasing process, or how such consideration would take place. 157-008

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- Population growth, in the different communities within Garfield County, appears to be higher than those shown in the PEIS document, which refers to the growth as "moderate". At the present time, Garfield projections for just the Rifle area are an increase from approximately 8,200 people to approximately 50,000 people by 2030, which is not deemed as moderate. 157-009
- Local community housing would include "temporary housing built in local communities" per the PEIS document. This appears to run counter to current local land use codes, and local government will. 157-010
- The PEIS document does not adequately deal with the adverse impacts of reductions in traditional recreational use of the Federal lands involved; or the lack of local facilities to support traditional recreational uses of lands in, or near, the ROI. 157-011
- In general, there is a need for the PEIS to address cumulative time lines, population growth, and labor needs in the same section, charts, and analysis for socioeconomic impacts. 157-012

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SPECIFIC COMMENTS

Land Use

- On page 6-68 there is a statement that " although Alternative C makes approximately 1.2 million fewer acres available for application for commercial leasing, it does not provide for less potential development of commercial oil shale than does Alternative B."
- If this is an accurate statement, then it makes a compelling argument for Alternative C being the preferred alternative rather than Alternative B. 157-013
- Alternative C has an added benefit over Alternative B in that it removes from application for leasing approximately 23,000 acres of land identified as Areas of Critical Environmental Concern (ACECs).
- Under both Alternative B & C, the preference right lease areas established for the five Colorado RD&D projects would not be available for application for leasing, other than to the existing RD&D leaseholders. Does this mean that the leaseholders would use their process, or would they have to use the preferred process, selected from the RD&D projects by the BLM? If a leaseholder, following the RD&D projects, were to decide not to move forward on oil shale production, would the preference acres be frozen, or would they be an asset of the leaseholder and open for sale, pending an additional NEPA process, and approval of the BLM? 157-014
- Under Alternative B, there are approximately 2 million acres of proposed lease area. These lands include 10 ACECs totaling 23,000 acres, approximately 185,000 acres of potential ACECs, and 170,000 acres of lands with wilderness characteristics. Under Alternative C, there are only approximately 830,000 acres of proposed lease area. These lands include 157-013 (cont.)

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110,000 acres of lands with wilderness characteristics and 137,000 acres of lands with potential for designation as ACECs. 157-013 (cont.)

- At the present time, the Piceance Basin is in a major natural gas boom. The basin is one of the largest untapped natural gas reserves in the country, at a time when the demand for natural gas is increasing. The region has already experienced a tremendous amount of impacts as a result of this natural gas boom. Technology, and best management practices have worked to increase the extraction of the gas, while reducing the surface impacts on the land. Alternative C would likely have less of an impact on the natural gas play, thus reducing the risk of a substantial reduction in exploration and production of natural gas. Until such time that the process(es) are known for oil shale production, and the cumulative impacts determined, the recovery of natural gas should not be impeded. 157-015
- The White River BLM Office is in the process of amending their 20 year Management Plan to accommodate an increased level of activity in the exploration and production of natural gas. This plan, at the present time, does not have a provision for oil shale development built into it. The designation of lands, that will be available for future commercial oil shale development, could require the White River Management Plan to be completely revised before it is even completed; again, without any knowledge of how oil shale development will be done in the future, or what the impacts might be. 157-016
- The BLM anticipated the potential development of 1,100 oil and gas wells in their current plan, and are now projecting more than 21,000 wells could be drilled in the planning area over the next 20 years. How would these projections be impacted by Alternative B, or C? It is stated in the PEIS document, that natural gas recovery is not compatible with the recovery of oil shale. Again, without knowing what process(es) will be used, and the magnitude of the operations, it would appear that a known resource with improving technologies and best practices, would be placed at risk for a totally unknown, at this time. 157-015 (cont.)
- The PEIS document also states that recreational use of the lands would not be compatible with oil shale recovery operations. Recreational use of the lands, under consideration, is a major economic factor for the counties and municipalities encompassed within the identified acreage. Again to place a known economic driver at risk, for a driver that is so questionable at this time, does not make sense. 157-017
- There is considerable private acreage within the geographic area under consideration, that will not necessarily be bound by the same rules and regulations that might apply to public lands. This is another unknown that further argues for minimizing the amount of acreage that would be available for future leasing at this time. 157-018

Environmental/Ecological

- Without knowledge of the process(es) that might be used in commercial lease operations, it is not possible to predict or analyze the impacts to the environment or ecological resources.
- Even without specific knowledge, impacts will be proportional to the amount of land impacted.
- Based on the analysis included in the draft PEIS document, there are considerable differences in the potential environmental and ecological impacts between the various technologies under consideration. The potential demand for water is a prime example of these differences. Power demands are another example of how impacts can, and will vary, based on the technology(ies) that will ultimately be used if commercial leasing occurs.
- Wildlife will be greatly impacted as the amount of acreage increases. The geographic area under consideration is prime winter range for many species, as well as major breeding grounds for the Greater Sage Grouse.

157-019

Socioeconomics

- On page 6-61, and several places within the draft PEIS document, it is stated that, "the designation of lands as available for leasing and the amendment of land use plans would not have socioeconomic impacts." Garfield County must question this statement on the basis that, the fact lands would be specified for possible oil shale development could alter the potential value of the land on a speculative perspective. Potential impacts on visual resources, noise, air quality, etc. could alter how the public would perceive the value and desirability of properties surrounding lands designated for future commercial leasing. 157-020
- Alternative B, could potentially alter the exploration and development of natural gas and oil, thus impacting the economy of the entire region. It could be possible that the identification of lands available for future commercial oil shale leases, could accelerate the exploration and development of gas and oil, thus increasing impacts and the costs of mitigation of impacts on local governments. The reverse could also be possible. How would the White River BLM office react to requests for permits to drill oil and gas wells on lands designated as available for future commercial oil shale leases. 157-021
- It is critical that local governments and communities attempt to get ahead of the curve on the development of infrastructure and social programs to manage future growth resulting from energy development. Without accurate knowledge of the direction of commercial oil shale development, it is extremely difficult to plan, much less implement the development of public works and social programs. 157-022
- The PEIS document does not take into account the cumulative impacts of existing and future traditional oil and gas development. It is critical that a 157-023

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total cumulative, regional, socioeconomic impact scenario be developed and planning be done on a regional basis. 157-023 (cont.)

- The PEIS document, does not address housing issues, except to say that additional housing will be developed by the energy companies on leased land, or by private entrepreneurs on private land. How this will be done and at what costs is not discussed adequately. 157-024
- Discussion of possible changes to public policy, required to address future commercial oil shale development, is also omitted from the PEIS document.
- Regardless of the future of oil shale development, the fact that lands will be identified for possible future leases, could alter the character of existing communities and the quality of life. 157-025
- The PEIS document clearly identifies two separate areas of the Piceance Basin, the north, and the south. The south Piceance Basin is located within Garfield County and is largely associated with the Parachute Creek drainage. This area is also a major area of natural gas exploration and development. The PEIS document does not address what affect the current natural gas development will have on future commercial oil shale leases and development. 157-026
- The socioeconomic impacts section generally relates to overall impacts and does not provide specific breakdowns of impacts on each county and/or municipality. This makes it very difficult for specific entities to digest and evaluate and estimate mitigation of potential impacts. 157-027
- The PEIS discusses a number of individual steps and/or operations, and indicates potential population and/or worker numbers, but there is no place where these are summarized in one table so the cumulative, timing, impact(s) can be evaluated.
- Estimated steps in the respective processes, alternatives, need to be shown in a chart where cumulative impacts and timelines are set forth in a clear and precise fashion so total employment, population, and associated socioeconomic impacts can be identified and evaluated. 157-028
- Assumptions necessary to estimate impacts at a more specific level of geographic detail, than the five county "Region of Influence (ROI), needs to be clearly and precisely spelled out.
- Local governments should not have to develop their own set of assumptions to determine potential impacts, but should be using a common set so consistency, and comparable impacts and costs of mitigation are assured. 157-029
- The PEIS contains much uncertainty, which compounds the ability of counties and local governments to determine socioeconomic impacts to their respective jurisdictions, much less the ability to evaluate the potential impacts and costs of mitigation. 157-030
- The PEIS proposes large, employer-housing compounds located on Federal lands, but does not provide sufficient discussion regarding the socioeconomic impacts, and needs, that will be caused by such 157-031

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developments; i.e. schools, recreation, shopping, supply and demand impacts on prices, governmental services, etc.

- No expectations of local governments and/or communities related to employer provided, remote housing was discussed. 157-031 (cont.)
- A discussion of the short term verses long term effects / impacts, of remote, employer provided housing needs to be included and evaluated as part of the PEIS document.

Resources / Facilities Required

- The PEIS assumes that any additional power requirements would come from coal fired generation facilities.
- Given the time frames included in the PEIS document for commercial operations to ramp up, there would not appear to be adequate time to permit, build, and test new coal fired generation plants.
- Given the abundance of natural gas in the region, and to be produced as a by product of the oil shale recovery operations, gas fired generation facilities should have been included in the PEIS document and evaluated. 157-032
- Local impacts would be greatly altered based on the type of additional power generation facilities required. (Coal verses Natural Gas generation facilities)
- Environmental impacts would also change based on the type of power generation facilities built.
- If there are compelling reasons for limiting additional power generating facilities to coal, the direct and indirect socioeconomic effects of such generation should be totally considered and evaluated in the PEIS document. 157-033
- The discussion of what, and how much, raw materials, will be utilized for the construction of the oil shale facilities and infrastructure, and where it will be acquired, is very suspect. Gravel for instance is becoming a very scarce commodity in Garfield County and the price has escalated on a geometrically progressing scale. 157-034
- Construction labor in the entire region is in short supply and is currently being recruited from as far away as the east coast. To assume that local labor markets can absorb any of the increased construction demands would be suspect. 157-035
- The PEIS assumes a fairly linear progression of impacts as oil shale ramps up. This assumption does not take into account the local carrying capacity of the county and local municipality infrastructure. In place of a linear projection, it will most likely be a stair step impact, with major infrastructure changes required, to build increased carrying capacity prior to demand, followed by a linear decline in carrying capacity as growth occurs. 157-036
- The ability of local communities to absorb, or ramp up to meet the direct and indirect population growth in housing and / or infrastructure requirements, varies greatly by community. For example, Glenwood Springs is relatively land bound, and its community waste water treatment capacity is near

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maximum, thus, they would be impacted much differently than Rifle, which has very different land issues, and is in the process of, or has recently expanded their waste water and residential water systems. 157-036 (cont.)

- The PEIS document assumes that all petroleum based products recovered from oil shale will be shipped out of the region and refined at facilities in other areas. The PEIS document does not adequately assess the manner in which these petroleum resources will be transported, or if there is adequate capacity in other locations to receive and refine the resource. Costs of increased transportation systems and refining facilities, to process recovered product, was not adequately addressed. To assume that no other refining facilities will be required is suspect. If additional facilities will be required, where will they be located, how will the resource get to them, and what is the impacts and cost? 157-037
- There was not adequate discussion within the PEIS document on where and how the water needed in the respective oil shale alternatives would be acquired, or come from. The future / secondary impacts of diverting water from public use, to oil shale, needs to be evaluated. 157-038

SUMMARY

- On page 2-51 "The BLM has determined that Section 369 of the Energy Policy Act of 2005 requires the agency to evaluate establishment of commercial leasing programs for oil shale and tar sands development. "The "no action alternative" for oil shale and tar sands (Alternative A) effectively is a no leasing alternative." "Any alternative in the PEIS that did not evaluate opening public lands for commercial leasing would not be consistent with the Energy Policy Act."
- Based on this interpretation, the BLM has rejected Alternative A, and feels compelled to select between Alternative B and Alternative C. 157-002 (cont.)
- Again, we make reference to page 6-68 of the PEIS document, that states " Although, Alternative C makes approximately 1.2 million fewer acres available for application for commercial leasing, it does not provide for less potential development of commercial oil shale than does Alternative B."
- In the Piceance Basin, Alternative C would likely have less of an impact on oil and gas operations since considerably fewer acres of potentially valuable oil and gas deposits, in a rapidly developing area, would be available for application for commercial oil shale development.
- The PEIS document needs to provide a section that includes time lines and cumulative data concerning all impacts on population, labor requirements, facility requirements, and resources required. 157-039
- The PEIS document makes the statement that no surface mining will be done in Colorado, and that only the In-Situ process will be allowed. There is one below surface mining operation currently allowed under the RD&D 157-040

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grants. Is this below ground process already ruled out for commercial leasing within Colorado? 157-040 (cont.)

- Ongoing cumulative effects on groundwater should be monitored and mitigated if, and when, necessary. The final PEIS document should contain language describing this commitment. 157-041
- The PEIS process, commercial leasing regulations, and pricing alternatives for commercial leasing are all occurring simultaneously, with overlapping impacts. This process is taking place prior to the results of the current RD&D projects being concluded and a preferred technology determined. Until the appropriate technology is known and evaluated, the impacts and cost of mitigation cannot be determined, thus the lease pricing, and potential bonus payments, is at best a guess. This does not appear to be prudent public policy nor ensure appropriate and adequate protection of public resources, or return on public equity. 157-042
- The PEIS document acknowledges, in several places, that there will be both primary and secondary impacts, but secondary impacts are not adequately addressed, nor are general growth that will be required to support, and / or address secondary impacts. 157-043

CONCLUSIONS

The Energy Policy Act of 2005 directed the Secretary of the Interior to undertake a series of steps. In Summary, Congress directed that the Secretary shall:

- Complete a PEIS for a commercial leasing program for oil shale and tar sands on public lands;
- "Not later than 6 months after completion of the PEIS, the Secretary shall publish a final regulation establishing a commercial leasing program;"
- Consult with the Governors of States with significant oil shale resources on public lands … and other interested persons;
- "If the Secretary finds sufficient support and interest exists in a State, the Secretary may conduct a lease sale in that State under the commercial leasing program."

Given the above charges from Congress, it would appear that commercial leasing could move forward rapidly following final publication of this PEIS document.

And given that the BLM has determined that a "No Action Alternative" (Alternative A) is not consistent under the Energy Policy Act of 2005,

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GARFIELD COUNTY WOULD OFFER THE FOLLOWING RECOMMENDATIONS:

- Garfield County's preferred alternative would still be "The Alternative E" that was included as the final position in our comments previously submitted on June 6, 2007. Under this alternative, it would allow appropriate testing to occur, but would delay the evaluation and decision regarding commercial leasing until such time that the proposed technologies, and their impacts, are better understood, and the current RD&D processes and findings are available concerning economic and commercial viability of oil shale operations. 157-044
- Before the final analysis of a preferred alternative is completed, results of the current RD&D leases should be obtained and evaluated, along with cumulative impacts of each alternative.
- The final PEIS document and Leasing Regulations needs to include a policy statement that requires lessees to work with local and county governments, and accept financial responsibility for developing and funding energy related public services that will be required. 157-045
- The final PEIS document and Leasing Regulations should contain a commitment to continuously provide for air quality monitoring and mitigation if needed for oil shale development, and any additional requirements for power and water generation. 157-046
- The final PEIS document needs to include a commitment to monitor, evaluate, and mitigate impacts on local entities regardless of which alternative is selected. This commitment should carry forward to project specific NEPA analysis, once commercial oil shale leasing programs are underway. 157-045 (cont.)
- Given the BLM's assertion that Alternative A is not an option, there are only, realistically, two alternatives from which to choose, Alternative B or Alternative C. Since Alternative C does not result in less potential development of oil shale than does Alternative B, and includes far less acreage being made available for commercial leasing, and far less impacts on the environment, wildlife, and local governments and population, Garfield County would recommend that Alternative C be the preferred alternative rather than Alternative B. 157-002 (cont.)

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00157-001: The BLM has rejected no alternative. The ROD associated with the Final PEIS will provide a concise public record of its decision, which will include the rationale for that decision. The referenced text in Section 6.1.4 of the Draft PEIS on page 6-103 provides comparisons of alternatives. The paragraph and statement compare and contrast the alternatives.

00157-002: The BLM acknowledges the commentor's preference for Alternative C.

00157-003: The BLM has based its analysis on those extraction technologies that are believed to be most likely applied to future oil shale developments; however, allocation decisions are not being based on the resource numbers identified. The resource numbers quoted were for purely comparative purposes. The actual recovery numbers are yet to be determined and are contingent on the type of recovery method. This is also true for any recovery numbers that are being proposed by in situ methods. The purpose of the PEIS is to identify lands to be opened or closed to oil shale development, not to compare technologies. Additionally, the BLM's assumptions are in no way preemptive of alternative extraction technologies, and applicants for future leases are free to propose alternative technologies for extraction and processing of oil shale, together with a detailed plan of operation describing how they will identify, manage, and mitigate anticipated environmental impacts.

00157-004: The southernmost portion of the most geologically prospective area for oil shale is encompassed by the Roan Plateau planning area (see Figure 3.1.1-2). Within the Roan Plateau planning area, some land would be made available for application for commercial leasing under Alternative B and none would be made available under Alternative C (see Figures 2.3.3-1 and 2.3.3-4).

00157-005: Where previously omitted, local government review and approval has been added to the text of the PEIS.

00157-006: Assumptions regarding analysis of oil shale and tar sands technologies are located in Sections 4.1 and 5.1, and assumptions regarding cumulative impact analysis are in Section 6.1.5.1.

The potential magnitude of impacts in different impact categories (e.g., habitat fragmentation and water depletions) is defined for ecological resources in Sections 4.8.1 and 5.8.1 of the PEIS. Impact magnitude is described in these sections as small, moderate, or large using the following definitions. A small impact is one that is limited to the immediate project area, affects a relatively small proportion of the local population (less than 10%), and does not result in a measurable change in carrying capacity or population size in the affected area. A moderate impact could extend beyond the immediate project area, affect an intermediate proportion of the local population (10 to 30%), and result in a measurable but moderate (not destabilizing) change in carrying capacity or population size in the affected area. A large impact would extend beyond the immediate project area, could affect more than 30% of a local population, and result in a large, measurable, and destabilizing change in carrying capacity or population size in the affected area.

Generally, for other resources, the meaning of comparative statements can be understood from the context of impact descriptions in the text that are specific to each resource area.

00157-007: Sections 6.1.5.2 and 6.1.5.3 have been revised to more clearly acknowledge the potential for oil shale development on nonfederal (e.g., private, state, Tribal) lands. However, the extent and impacts of such development are unknown at this time. It is assumed that development of oil shale or tar sands facilities on nonfederal lands would have impacts similar to such facilities located on federal lands, as described in Chapters 4 and 5 of the PEIS.

00157-008: The FLPMA and the Energy Policy Act of 2005 have specific requirements for coordination of activities with various levels of government (see Section 202(c)(9) of FLPMA and Section 369(e) of the Energy Policy Act). The BLM's Land Use Planning Handbook (H-1601-1) provides extensive guidance in Section I, paragraphs C, D, E, and F, regarding the role and the opportunities for participation in BLM planning and environmental processes.

There are also numerous places in the PEIS (among them, Sections 1.2, 2.3.3, and 2.4.3) that identify requirements for future coordination with various levels of government and for compliance with existing law and regulation. Appendix D contains a nonexclusive list of regulatory requirements potentially applicable to commercial oil shale and tar sands development.

Although rare, it is possible that a local or state regulation could interfere with the implementation of the statutes under which the BLM would lease or approve operations and that such an ordinance would be pre-empted.

00157-009: ROI Population projections presented in Section 6.1.1.10 were taken from county population forecasts prepared by each state and reflect growth rates projected in those forecasts.

Rather than present data at the county level, given the programmatic nature of the PEIS, the purpose of the data presented in Section 3.10 is to provide an overview of socioeconomic conditions in a region of influence around each oil shale and tar sands resource area, based on the likely residential location of project workers, and consequently the region in which the majority of socioeconomic impacts of the prospective facilities would most likely occur.

00157-010: The BLM has stated in the PEIS that housing developments will not be placed on public lands. Local land use regulations will determine how, where, and if both permanent and/or temporary housing will occur within their jurisdictions

00157-011: The economic impact of oil shale and tar sands development on recreation assesses the impact of a 10% and a 20% reduction in ROI recreation employment in each state ROI. Impacts include the direct loss of recreation employment in the recreation sectors in each ROI, and the indirect effects, which represent the impact on the remainder of the economy in each ROI as a result of a declining recreation employee wage and salary spending, and expenditures by the recreation sector on materials, equipment, and services.

In the Colorado ROI, the total (direct plus indirect) impacts of oil shale development on recreation would be the loss of 1,415 jobs with a 10% reduction in recreation employment, and 2,830 jobs if recreation employment were to decline 20% (Table 4.11.1-7). Income lost as a result of the 10% decrease in recreational employment would be $18.3 million, with $36.5 lost for the 20% loss in employment. In the Utah ROI, 388 jobs and $3.2 million in income would be lost in the ROI as a whole as a result of a 10% reduction in recreation employment, and 776 jobs and $6.3 million in income would be lost with the 20% reduction. In the Wyoming ROI, 1,360 jobs and $7.2 million in income would be lost under the 10% scenario, with 2,719 jobs and $14.4 in income lost if 20% of recreation-related employment were lost in the ROI.

Public lands in each ROI are used primarily hunting and other forms of dispersed outdoor activities. Table 3.1.2-1 in the PEIS provides a listing of the many recreational areas and other areas that may provide recreation opportunities located within about a 50-mi radius of the oil shale and tar sands resources. Whether or not there are adequate facilities to support traditional recreational activities in each ROI is beyond the scope of the PEIS.

00157-012: The cumulative impacts analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decisions proposed in the PEIS (i.e., amending land use plans to allow certain lands to be considered for future leasing). A more specific cumulative analysis of socioeconomic impacts would be more appropriate prior to a leasing or development decision if and when specific technical and environmental information becomes available.

The cumulative impacts analysis in the PEIS summarizes the past, present, and reasonably foreseeable other activities (for example, oil and gas development, coal mining, minerals development) for the study area, and presents a preliminary qualitative assessment of the incremental impacts of those activities considered in conjunction with oil shale and tar sands development. At this preliminary stage, when the specifics of the extent of future oil shale and tar sands development are unknown, the discussion of the potential impacts of oil shale development are based on the BLM's experience with comparable surface-disturbing activities from other types of mineral development. In order that the decision maker might have sufficient information to make a reasoned choice among the alternatives, the BLM has developed a general analysis of the potential incremental impacts from all past, present, and reasonably foreseeable actions, in conjunction with a single hypothetical oil shale or tar sands facility, with the understanding that there might be more than one, or even many, oil shale/tar sands facilities developed in the future. For the purpose of this analysis, parameters for consideration (such as jobs created) were developed where possible (see Section 6.1.5.3.10). For some parameters (such as air emissions), no estimates with respect to possible development could be made because the data would depend entirely on technology-specific inputs.

Prior to leasing (when site-specific and technology-specific data will be available) or approval of a plan of development (when accurate information on employment, etc., will be available), additional environmental analysis will be performed including a cumulative analysis, as appropriate.

00157-013: Assumptions as to the level of activity are too speculative to support a meaningful RFDS for this PEIS. Therefore, it was decided not to develop an RFDS. However, as part of subsequent NEPA analysis, an RFDS will be developed to project a likely anticipated oil shale and tar sands activity supported by a clear set of supportable assumptions. An RFDS was not developed for this PEIS because most of the information necessary for producing an RFDS is unknown and not reasonably available at the present experimental stage of the oil shale and tar sands industry.

00157-014: The existing terms and conditions of the individual RD&D projects will control the future availability and development of both the RD&D and PRLA acreages. Since these are valid existing rights, decisions regarding the operation of these leases are beyond the scope of this PEIS. The PEIS does, however, consider two separate options for future leasing of lands currently included in these leases should the current lessees relinquish their leases.

00157-015: It is BLM’s policy to optimize the recovery of both resources in an endeavor to secure the maximum return to the public in revenue and energy production; prevent avoidable waste of the public’s resources utilizing authority under existing statutes, regulations, and lease terms; honor the rights of each lessee, subject to the terms of the lease and sound principles of resource conservation; and protect public health and safety, and mitigate environmental impacts. The projections of oil and gas wells within the current plan are taken into consideration during the cumulative effects analysis (see Section 6.1.5.2.1).

00157-016: All decisions related to land use planning for oil shale resources in the White River RMP area (and in the whole PEIS study area) will be made by the PEIS and should not require a complete revision. The Record of Decision on the final PEIS will amend the existing White River RMP as described in Appendix C. The BLM recognized that there were several ongoing land use planning efforts, as well as planned planning efforts that would begin while the BLM was preparing the PEIS. The BLM determined that it would be more administratively efficient to prepare the PEIS and provide a more focused analysis of the environmental consequences of a commercial oil shale and tar sands program than to disrupt the ongoing planning efforts.

00157-017: The statement in the current Draft PEIS has been clarified to discuss the potential nature of the conflict between oil shale and tar sands development and other uses of public lands.

The intent of the description in the Draft PEIS was to convey that, although the potential impact (i.e., surface disturbance) and duration of commercial development are unknown (see assumptions in Sections 4.1 and 5.1), impacts are likely to be similar to known uses such as coal mining, or oil and gas development. Surface disturbance during development and production may well displace other uses until reclamation is completed. The expected impact on other public land uses, including recreation, will be reviewed as part of subsequent NEPA analysis.

Recreational use, although important, does not necessarily have absolute priority over other authorized uses of federal land, including mineral development. The FLPMA mandate is one of multiple use and sustained yield of a variety of resources and land uses (Section 102(a)(7)). The BLM appreciates the commentor’s concern for the economic importance of recreation, and acknowledges that the economic contributions of commercial oil shale operations will be somewhat uncertain, at least in the beginning. Nonetheless, the Energy Policy Act of 2005 requires the BLM to establish a leasing program for oil shale. There are risks and opportunities in every decision the BLM makes regarding competing land uses. At this stage, as explained in Chapters 1 and 2 of the PEIS, the decision to be made is quite limited. At subsequent stages, when applications for commercial lease of these resources are actually received and accepted, analysis of precisely these issues will take place and decisions made in accordance with BLM’s statutory obligations.

00157-018: There is a substantial amount of nonfederal land in the study area (see discussion in Section 3.1); however, the scale and timing of potential future oil shale and tar sands development on these lands, as well as the technologies that would be used for development, are highly speculative at this time. Text has been added in Sections 6.1.5 and 6.2.5 to clarify that future levels of commercial oil shale and tar sands development (both on public and private lands) are unknown.

00157-019: The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development. Impacts would depend on many factors, including project sites, technologies to be used, and various activities involved in the development. The impacts to wildlife (including greater sage-grouse) and surface and groundwater as well as the sources of required electric power would be addressed in subsequent project-specific NEPA documents. Depending on the type and level of development, regional water impacts may limit oil shale and tar sands development (Section 6.1.5.3.4). These site-specific NEPA analyses will evaluate specific occurrences of species of concern, analyze the environmental consequences of leasing and future exploration and development, including consideration of direct, indirect, and cumulative effects, reasonable alternatives, and mitigation measures to protect resources and resource values, as well as what level of development may be anticipated.

00157-020: The text in Sections 6.1.2.10, 6.1.3.10, and 6.1.4.10 of the PEIS has been changed to indicate that there may be impacts on property values resulting from the designation of BLM land for oil shale in tar sands development.

00157-021: Conflicts associated with potential oil shale leasing and existing oil and gas leases will be analyzed, and stipulations could be developed to mitigate the conflict consistent with BLM policy. It is the BLM's policy to optimize the recovery of both resources in an endeavor to secure the maximum return to the public in revenue and energy production; prevent avoidable waste of the public's resources utilizing authority under existing statutes, regulations, and lease terms; honor the rights of each lessee, subject to the terms of the lease and sound principles of resource conservation; and protect public health and safety, and mitigate environmental impacts.

For example, a very high percentage of WRFO is currently leased for oil and gas development and will honor the valid existing rights according to the terms and conditions of the lease. Some leases in the White River Planning Area have specific stipulations, which allow the BLM to locate well pads to not interfere with oil shale leasing (leasing or operations). Oil and gas operators submit applications for Permit to Drill in order to receive approval from the BLM to explore and develop the petroleum resources on their leases. As stated previously, the PEIS does not grant a property right and, therefore, there is no immediate conflict. However, if the area is opened to potential future oil shale leasing, specific conditions of approval could be developed to address potential conflicts, as a result of the NEPA documentation associated with the APD approval process.

Various factors can affect the level of exploration and development associated with oil and natural gas. Economics and market conditions will continue to drive exploration and production activities. The production of oil and gas is also dependent on the ability to transport product to refineries, especially whether there is excess capacity to carry new production. Energy demand, tightening of air quality standards, and protection of sensitive/threatened and endangered species may also impact the location and pace of oil and gas development. It is not anticipated that the designation of lands available for future commercial oil shale leases would be a major contributing factor to the level of exploration and development.

00157-022: The BLM believes that taking a measured approach to oil shale development, where each step builds upon a prior step, ensures that state and local communities have the opportunity to be involved and are fully informed of the activities associated with the program. The FLPMA and the Energy Policy Act of 2005 have specific requirements for coordination of activities with various levels of government (see Section 202(c)(9) of FLPMA and Section 369(e) of the Energy Policy Act). In addition, the BLM is committed to providing opportunities for state, local and Tribal governments to play a key role, as cooperating agencies, in the land use planning process. The BLM's Land Use Planning Handbook (H-1601-1) provides extensive guidance in Section I, paragraphs C, D, E, and F, regarding the role and the opportunities for participation in BLM planning and environmental processes.

00157-023: The cumulative impacts analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decisions being proposed in the PEIS (i.e., amending land use plans to allow certain lands to be considered for future leasing). A more specific cumulative analysis of socioeconomic impacts would be more appropriate prior to a leasing or development decision if and when specific technical and environmental information becomes available. However, projected levels of oil and gas development over 20 years (see Tables 6.1.5-4 through 6.1.5-6) were included in the socioeconomic cumulative impact assessment presented in Section 6.1.5.3.10. See also response to Comment 00157-012.

00157-024: As the scale and timing of oil shale, tar sands, and ancillary facility development are not known, the analysis described in the PEIS was based on a series of assumptions regarding direct project employment, direct and indirect population (workers and their families) in-migration rates, and the provision and location of direct and indirect worker housing during both construction and operations phases that may be built to accommodate increases in project populations. The location of project housing is unknown but is not expected to be on public land and is likely to be largely temporary in nature. Additional services may be provided for housing developments, the locations of which are also unknown. Housing developed in local communities may be similar in nature to housing built for the local residential market. Text has been added to Section 4.11 of the PEIS indicating assumptions made with regard to the nature of temporary housing. Sections 4.11 and 5.11 describe the impacts of constructing housing that would be occupied by workers and their families on ROI employment and income. The timing and location of housing developments would be assessed as part of future NEPA reviews associated with individual oil shale and tar sands and ancillary facility development.

00157-025: The BLM is undertaking the PEIS under direction from Congress in the Energy Policy Act of 2005, which was an outgrowth of public energy policy discussions. While the BLM is providing an analysis to assess the impacts of the current direction, public policy discussions are outside the scope of the PEIS. In Chapters 4 and 5, the PEIS has identified a range of issues regarding oil shale and tar sands technologies that could be part of future discussions.

The socioeconomic analysis in the PEIS concluded that there would not be effects associated with the land allocation decisions other than a possible effect on property valuation.

00157-026: Overall, it is BLM's policy to optimize the recovery of both resources in an endeavor to secure the maximum return to the public in revenue and energy production; prevent avoidable waste of the public's resources utilizing authority under existing statutes, regulations, and lease terms; honor the rights of each lessee, subject to the terms of the lease and sound principles of resource conservation; and protect public health and safety, and mitigate environmental impacts. The feasibility of concurrent oil shale and natural gas development on the same properties is discussed in Section 4.2.1.1, which states that existing oil and gas or other mineral leases would likely preclude oil shale development, and also that areas leased for oil shale development in the future would be unlikely to be used for natural gas production. See response to Comment 52763-003.

00157-027: As the scale of development and project locations associated with oil shale, tar sands, and ancillary development, and consequently the size and residential location on in-migrating workers and their families, are not known, assessing the impact on individual local governments was not possible in the PEIS. The analysis in the PEIS was limited to estimating impacts for a region of influence in each state, which includes the counties in which project workers are likely to reside. As described in Section 4.11.1.1 of the PEIS, for the purposes of the analysis, in-migrating population assumed with each facility was assigned to local communities in each ROI based on facility direct workforce, community population, and intervening distances. Expenditure levels to support the in-migrating population at existing levels of service in each community were then projected for each county and aggregated to the ROI level.

When commercial-scale oil shale or tar sands resource development occurs, additional NEPA analyses would be undertaken, where project locations, employment levels, and the residential location and number of in-migrating workers in each phase of development would be known for each individual community in the ROI. This would enable individual local government-specific analyses of oil shale and tar sands development and ancillary facility impacts on local tax revenues, facility and infrastructure capacity and expansion costs, and on the local government expenditures required to maintain different levels of service.

00157-028: Please see response to Comment 00157-012. The cumulative impacts analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decisions being proposed in the PEIS (i.e., amending land use plans to allow certain lands to be considered for future leasing).

00157-029: See response to Comment 00157-027.

00157-030: The BLM is conducting a phased decision-making process—proceeding from land use planning to leasing to operational permitting. The land use planning or allocation decision does nothing more than remove an administrative barrier preventing the BLM from accepting applications. Therefore, subsequent NEPA analysis will be required prior to the leasing and development phases. Specific impacts on county and local governments will be analyzed in the future NEPA analysis, which can help counties focus on potential impacts associated with a potential leasing or plan of development proposal. The BLM also initiated the RD&D leasing process to provide important information that can be used as the BLM works with communities, states, and other federal agencies to develop strategies for managing any environmental effects, including those of impacts on local communities.

00157-031: The BLM did not propose any employer housing on federal lands in the Draft PEIS. Specifically, the PEIS states that the location of employer-provided housing is unknown but not expected to be on public land. See also response to Comment 00157-027. Additional NEPA analysis would enable individual local government-specific analyses of oil shale and tar sands and ancillary facility impacts on local tax revenues, facility and infrastructure capacity and expansion costs, and on the local government expenditures required to maintain different levels of service provision in local government and educational and recreational services. These analyses could also include impacts on the provision of privately provided services, such as shopping, and on local wholesale and retail price inflation.

00157-032: Based on the nature of the proposed action, existing sources of electrical power may be sufficient to power the operation, or electrical power may need to be generated on lease using either conventional energy sources like natural gas or renewable energy sources like wind or solar. A third hypothetical analysis may include the expansion of existing power plants or the construction of additional power plants (coal, gas, nuclear). In each case, the scope of the NEPA analysis would include the direct, indirect, and cumulative effects from activities described in a reasonably foreseeable development scenario.

00157-033: Please see the response to Comment 00157-032.

00157-034: As discussed in the Draft PEIS, there were various uncertainties regarding location of developments, technologies to be employed, and the lack of knowledge of specific aspects associated with the required infrastructure. These uncertainties also make it difficult to estimate the types and amount of raw materials required for oil shale and tar sands development. Therefore, the decision to offer specific parcels for leasing was dropped from consideration in the PEIS. Subsequent project- or site-specific NEPA documents will be prepared to analyze the environmental consequences of leasing and future exploration and development taking into consideration the types of resources necessary for full-scale development.

00157-035: As the technologies, scale of development, and project locations associated with oil shale and tar sands resource and ancillary facility development are not known, the analysis described in the PEIS was based on a series of assumptions regarding the source of direct project employees and direct and indirect population (workers and their families) in-migration rates during both construction and operations phases. As the commentor suggests, some positions in each ROI are currently being filled from distant states, with anecdotal evidence of this occurring in the oil and gas industry presented in Section 3.10.2 of the PEIS. Accordingly, the PEIS assumes only a certain portion of labor for OSTS and ancillary development will come from labor markets within each ROI. Assumptions relating to the extent to which local labor would be provided from within each ROI are different for ROI and for the construction and operations phase of each facility. These assumptions, described in Section 4.11 of the PEIS, were based on publicly available NEPA reviews, past BLM experience with oil shale and tar sands and other energy-related projects, and industry data on power generation and coal mining. These assumptions are reasonable for a programmatic review of potential socioeconomic impacts.

00157-036: Given the programmatic nature of the PEIS, the purpose of the analysis of socioeconomic impacts is to provide an overview of the type and magnitude of impacts that would likely occur with the construction and operation of oil shale and tar sands facilities. As the scale of development and project locations associated with oil shale and tar sands resource development are not known, the analysis described in the PEIS was limited to estimating impacts for an ROI in each state, based on the likely residential location of project workers. As described in Section 4.11.1.1 of the PEIS, in-migrating population assumed with each facility was assigned to local communities in each ROI based on facility direct workforce, community population, and intervening distances. Expenditure levels to support the in-migrating population at existing levels of service are then estimated for each community and aggregated for each ROI.

If commercial-scale resource development occurs, additional NEPA analyses would be undertaken, where project locations, employment levels, and the number of in-migrating workers in each phase of development would be known, enabling a detailed analysis of oil shale and tar sands, and ancillary facility impacts on local tax revenues, facility and infrastructure capacity and expansion costs, and on the local government expenditures required to maintain different levels of service. Additional sources of revenue from local, state, and federal sources (including mineral lease revenues) to support increased state and local government expenditures (including the cost of temporary housing and retail food establishment inspections) would be assessed, including impacts on TABOR local government revenue growth restrictions in Colorado, with some assessment made of the various channels available for local jurisdictions to receive funding from federal and state government.

00157-037: Attachment A1 in Appendix A and Attachment B1 in Appendix B contain descriptions of the expected reaction of the refinery industry to the availability of supplies of oil shale-derived feedstocks. In terms of additional refining capacity, the descriptions in A1 and B1 indicate that recent history has shown that the industry tends to expand existing facilities rather than develop wholly new ones.

Chapters 4 and 5 include summary information from Appendices A and B of the potential impacts associated with electrical transmission and pipelines corridors, additional workforce and housing needs, electrical generation capacity, refinery capacity, and timeline and other considerations (Sections 4.1.4, 4.1.5, 4.1.6, 4.1.7, 4.1.8, 5.1.3, 5.1.4, 5.1.5, 5.1.6, and 5.1.7, respectively). The analysis presented includes information on the impacts for one project to provide an example of the magnitude of potential effects. Section 6.1.5.3 contains the cumulative impact assessment for the alternatives, and Table 6.1.5-9 provides a summary of long-term activities including surface disturbance that would be related to transmission facilities and other activities associated with potential commercial development. The BLM believes that this level of information is adequate to support the proposed allocation decisions in the PEIS.

00157-038: The source of water needed for any oil shale and/or tar sands development projects would be specified in the project-specific NEPA documents and not in this PEIS. The water is unlikely to be diverted from public use water. Agricultural water might be a candidate for sources of water rights. Impacts on water resources caused by transfers of water from agricultural uses to oil shale development have been added to Section 4.5 of the PEIS. It would be a lessee's responsibility to obtain and maintain water rights necessary for its operations in accordance with state law. Thus, it would be mere conjecture to attempt an analysis of impacts from water demands for operations that might not obtain water rights.

00157-039: Please see response to Comment 00157-012. The cumulative impacts analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decisions being proposed in the PEIS (i.e., amending land use plans to allow certain lands to be considered for future leasing).

00157-040: The only technology excluded from Colorado in Alternatives B and C in the PEIS is surface mining. Underground and in situ processes are allowed in both alternatives. Alternative A, the no action alternative, allows all technologies, including surface mining.

00157-041: At this preliminary stage, when the specifics of the extent of future oil shale and tar sands development are unknown, the discussion of the potential cumulative impacts to groundwater is general (see Section 6.1.5.3.5). Groundwater impacts can be better assessed when the results of RD&D activities are available and when specific proposed locations for oil shale and tar sands development are known.

Prior to leasing (when site-specific and technology-specific data will be available) or approval of a plan of development (when accurate information on water use, air emissions, employment, etc., will be available), additional environmental analysis will be performed including a cumulative analysis of groundwater impacts, as appropriate.

00157-042: Thank you for your comment, but the promulgation of regulations on environmental protection standards, setting royalty rates and addressing bonding, establishing standards for diligent development, and determining the allowable size of leases are outside the scope of the PEIS.

00157-043: As a programmatic evaluation conducted in support of land use plan amendments, this PEIS does not address site-specific issues associated with individual oil shale or tar sands development projects. A variety of location-specific factors (e.g., soil type, watershed, habitat, vegetation, viewshed, public sentiment, the presence of threatened or endangered species, and the presence of cultural resources) will vary considerably from site to site. In addition, the variations in extraction and processing technologies and project size will greatly determine the magnitude of the impacts from given projects. The combined effects of these location-specific and project-specific factors cannot be fully anticipated or addressed in a programmatic analysis. As a result, additional, site-specific NEPA analyses will be conducted prior to the issuance of commercial leases and the approval of specific plans of development. Secondary impacts can be more adequately addressed at this later stage as additional project-specific and site-specific details are available.

00157-044: The BLM believes that the RD&D program will be a source of additional useful information regarding commercially viable oil shale technologies and their impacts. In the Energy Policy Act of 2005, however, Congress did not authorize the BLM to wait for additional information from the RD&D program before completing this PEIS. The BLM will analyze all available, relevant information in an appropriate NEPA document before issuing leases for oil shale or tar sands. That analysis will include any new information from research or lessons learned on the RD&D leases or from studies or operations on nonfederal lands.

The deadline Congress set for the BLM to complete this PEIS has been exceeded, but that does not allow the BLM to postpone this PEIS until new information becomes available or until the industry is ready to invest in commercial operations. Currently, there is sufficient information on a programmatic level to make a reasoned choice among the alternatives when considering whether lands should be opened or closed for application for commercial oil shale or tar sands leasing. The PEIS analyzes the environmental consequences of this allocation decision. The PEIS also describes the requirement for additional site-specific NEPA analysis prior to both issuance of commercial leases and approval of proposed exploration or development project.

00157-045: The BLM does not have the authority to require industry to fund specific public services, but it has been made clear that any federal lessees will be required to comply with all applicable federal, state, and local laws and regulations.

As noted in response to Comment 00154-007, specific monitoring requirements to evaluate environmental consequences are more appropriate at the leasing and/or plan of development stage. Although specific monitoring plans are not included, examples of potential types of mitigation measures to protect wildlife, plants, and habitat resources are provided for consideration at subsequent stages of NEPA analysis.

00157-046: Any commercial operations will be required by terms of their lease to comply with applicable laws and regulations regarding air quality protection and monitoring. Establishment of monitoring requirements and how they are funded are primarily a state function, and the BLM would have a limited role. As in many aspects of development on public lands, the BLM would expect to have a close working relationship with state and local regulators during the NEPA process.

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United States Department of the Interior

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Memorandum

To: Colorado State Director, Bureau of Land Management (BLM)
Attn: Sherri Thompson, Programmatic EIS Manager

From: Regional Director, Intermountain Region

Subject: Comments, Draft Programmatic Environmental Impact Statement to Amend Land Use Plans to Allow Oil Shale and Tar Sands Leasing (PEIS)

In our capacity as a Cooperating Agency in the BLM's PEIS, we offer the following comments for your consideration. National Park Service Director Bomar appreciated having the opportunity to meet with the BLM Director and his staff on March 14, 2008 to discuss the PEIS. From that meeting we understand that you envision a three-step process for ultimately leasing oil shale and tar sands resources. The process, as was communicated to the NPS, is to first amend land use plans to allow for oil shale and tar sands leasing, the second step would be to offer the leases, and the third step would be to review and take action on operational permits. As we understand it, BLM envisions amending land use plans based on a broad, generalized look at the potential for leasing with little detail. At the leasing phase where compensatory property rights would be created, the Bureau would prepare a detailed environmental analysis. At the site-specific permitting stage, the Bureau would carry out a final analysis of specific development proposals.

We appreciate that BLM is required to carry out § 369 of the Energy Policy Act of 2005, which directs that "[n]ot later than 18 months after the date of enactment of this Act…the Secretary shall complete a programmatic environmental impact statement for a commercial leasing program for oil shale and tar sands resources on public lands, with an emphasis on the most geologically prospective lands within each of the States of Colorado, Utah, and Wyoming." This Congressional direction calls for an analysis over a very large area under a very pressing timeframe, further complicating the Bureau's task. In addition, we realize that the Bureau has had to contend with a host of uncertainties and has had to make an array of assumptions in preparing this analysis.

As you know the mission of the National Park Service is to protect parks and to provide for their enjoyment in a manner that will leave them unimpaired for future generations. Because oil shale or tar sands development could adversely impact units of the National Park System, the Bureau must take into consideration such impacts in light of the Secretary's duties under the NPS Organic Act (16 USC 1, et. seq.) before opening public lands to such development. Among other things this act directs that "[t]he authorization of activities shall be construed and the protection, management and administration of these areas shall be conducted in light of the high public value and integrity of the National Park System and shall not be exercised in derogation of the values and purposes for which

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these various areas have been established, except as may have been or shall be directly and specifically provided by Congress."

The following eight units of the National Park System have a very high potential for being adversely affected by cross-boundary or direct impacts from exploration and development activities in what the PEIS calls the Region of Influence: Arches, Black Canyon of the Gunnison, Canyonlands and Capitol Reef National Parks; Colorado, Dinosaur and Fossil Butte National Monuments; and Glen Canyon National Recreation Area. Numerous additional national park units in the western United States could be adversely impacted by the regional air and water impacts likely to be generated from large scale, industrial activities associated with oil shale and tar sand development.

The PEIS contains a great deal more factual and background information useful to the analysis. But, from our perspective, the draft should still comprehensively analyze a mineral leasing and development process in the context of the three-state region that is also home to numerous National Park System units. New technologies may emerge but, fundamentally, what is being considered is an industrial process that requires logistics and infrastructure, uses electrical power and water, needs employees and oversight for operations, produces product that requires transport and has resultant impacts. Thus, we believe many of our comments from the scoping process (January 26, 2006) and our review of the preliminary draft (June 11, 2007) are still relevant. 267-001 (cont.)

We remain concerned with the potential impacts to NPS managed lands in light of the special protection they are afforded on behalf of the American public. As a result, we expect that any analysis of possible impacts associated with leasing of oil shale and tar sands will include an evaluation of the large scale, industrial development that may result from amending the twelve BLM Resource Management Plans. We are committed to working closely with BLM as the proposed plan amendment, possible leasing, and development scenarios move forward. We have prepared the attached detailed comments, which are geared toward improving the analysis contained in the environmental document and in assisting the BLM in meeting the requirements set forth in both the Energy Policy Act of 2005 and the National Environmental Policy Act (NEPA).

Thank you for the opportunity to comment on the PEIS. Questions or comments regarding this memorandum may be directed to Cordell Roy, State Coordinator—Utah, at (801) 741-1012, ext. 101 or his eMail address at cordell_roy@nps.gov.

Michael D. Snyder For

cc: Superintendents, GLCA, DINO, FOBU, CARE, CANY, ARCH, COLM, BLCA
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ATTACHMENT

NPS Comments on Draft BLM Programmatic EIS to Amend Land Use Plans to Allow Oil Shale and Tar Sands Leasing in Colorado, Utah and Wyoming (DES 07-06)

General Comments

The National Park Service has three primary concerns with the PEIS. First, the document limits its focus to amending 12 land use plans to open BLM managed lands for commercial leasing. As a result, the document does not fully address the requirements of the Act, which calls for a programmatic environmental impact statement for a commercial leasing program for oil shale and tar sands resources on public lands. It leaves the specifics of a commercial leasing program to a later time, and states that the Bureau intends to handle the NEPA compliance on such a program on a lease by lease basis.

Second, the document presents options for opening lands to commercial scale oil shale and tar sands development through a federal leasing program yet does not adequately analyze the impacts of doing so. Couched in terms that new technologies will emerge that may avoid many of the impacts associated with existing technology, the analysis presents an optimistic picture that impacts associated with the development of oil shale and tar sands can be avoided in the future. While such technologies may be developed in the future, NEPA compels a rigorous analysis based on available technology and information on environmental and socio-economic impacts. The current document does not reflect this requirement. 267-002

Third, in the past, BLM has always advised the NPS that it is most helpful to the Bureau if the NPS would raise adjacent park protection concerns during the Bureau's land use planning process when the Bureau is developing and/or amending existing land use plans. However, as relayed in the PEIS and conveyed to Director Bomar, the Bureau is now assuring us that the best time to raise park protection concerns is at the leasing stage. As a result, we will remain fully engaged in this process and will provide input at the leasing and site-specific permitting phase.

Depending upon the proximity of NPS units to potential oil shale or tar sands exploration or development, cross-boundary direct or indirect adverse effects may occur in the form of air or water quality impacts, sound, night sky, or visual impacts, and impacts on biologic or cultural resources. We also believe that large scale, industrial development associated with oil shale and tar sand development carries with it the potential for regional air and water impacts that may affect numerous parks in the western United States.

We realize that the BLM changed the focus of the draft preliminary EIS as a result of the Cooperating Agencies initial comments that the lack of information about specific, emerging technologies and their impacts rendered the analysis too speculative to support a decision to issue any leases. This same issue is evident in the current document, in which BLM's preferred alternative, Alternative B, makes nearly two million acres of public land available for oil shale and tar sands leasing without fully analyzing the magnitude of potential impacts to the environment. Under regulations implementing NEPA at 40 CFR § 1500.2(b), "[e]nvironmental impact statements shall be concise, clear, and to the point, and shall be supported by evidence that agencies have made the necessary environmental analysis." 267-003

After a careful review of Appendix A of the draft EIS, we believe that sufficient knowledge does exist to determine probable locations for future oil shale or tar sands development, and to project the type and extent of environmental impacts that may occur using current technology. The extensive history associated with past efforts to develop the oil shale resource along with the known impacts related to that development as presented in Appendix A would allow the BLM to undertake a more detailed and informative analysis than that presented in the existing document.

Deferring a detailed analysis of environmental impacts associated with the development of the oil shale and tar sands resource to the leasing stage of the process may not provide decision makers with enough information to fully comprehend the cumulative environmental consequences of making nearly two million acres of public land across a three-state region available for oil shale and tar sands leasing and subsequent commercial scale development. 267-003 (cont.)

Considering the above issues, we offer two separate options for the BLM that we believe would lead to a more appropriate analysis of potential development of the known oil shale and tar sands resource.

1. Postpone the programmatic environmental impact analysis for oil shale and tar sands development until the recently approved Research, Development and Demonstration projects bring to light results that can be applied to large scale development. We realize that given the direction contained in § 369 of the Energy Policy Act of 2005, this option may not comport with that statute. 267-004

2. Rewrite applicable sections of the exiting EIS to reflect documented impacts associated with currently available technology for development of the oil shale and tar sands resource. We recommend using the significant amount of information presented in Appendix A of the current document as a starting point.

Detailed Comments

Chapter 2, Page 2-2, Section 2.2.1, Existing Relevant Statutory Requirements – We recommend that the final EIS indicate that a large portion of the Tar Sands Triangle Special Tar Sand Area is located within Glen Canyon National Recreation Area. Glen Canyon, which is one of three NPS units open to federal mineral leasing, is not analyzed in the draft EIS because NPS lands are not considered "public lands" as defined under the Federal Land Policy and Management Act of 1976. However, lands in Glen Canyon may be subject to leasing of the tar sands resource in conjunction with other lands in the Tar Sand Triangle area thereby contributing to possible local and regional environmental impacts. With this in mind, we suggest the following language be added to Section 2.2.1: 267-005

43 C.F.R. §3141.4-2 (b) states that "[t]he issuance of combined hydrocarbon leases within units of the National Park System shall be allowed only where mineral leasing is permitted by law and where the lands are open to mineral resource disposition in accordance with any applicable Minerals Management Plan. In order to consent to any issuance of a combined hydrocarbon lease or subsequent development of combined hydrocarbon resources within a unit of National Park System, the Regional Director of the National Park Service shall find that there will be no resulting significant adverse impacts to the resources and administration of the unit or other contiguous units of the National Park System in accordance with §3109.2 (b) of this title. (Emphasis added).'" We also request that this paragraph contain the statement that "the finding of no resulting significant adverse impacts to the resources and administration of NPS units is a statutory and regulatory responsibility of the Regional Director, National Park Service, and is not a function of this EIS." 267-006

We recommend that sections of the final EIS addressing tar sands resources leasing contain a statement to the effect that the BLM recently adjudicated the status of 13 expired Combined Hydrocarbon Leases (CHL) in the State of Utah. Due to what the BLM has characterized as an administrative error which caused the leases to expire, BLM proposes to reinstate the leases upon payment of back rentals by lessees. The pending CHL leases cover over 148,000 acres and include lands in the Grand Staircase Escalante National Monument, several Wilderness Study Areas, and Glen Canyon National Recreation Area. The potential development of these leases needs to be factored into the cumulative analysis of the impacts associated with tar sands development in the areas that the Bureau is considering amending lands use plans to allow for new tar sands leasing. 267-007

Chapter 3, Page 3-95, Section 3.5.1.2, Global Climate Change – This section of the draft EIS addressing climate change contains language from various literature searches (Intergovernmental Panel on Climate Change and the National Academy of Sciences) acknowledging the potential effects of "greenhouse gas" emissions on global climate. However, the document does not present an analysis that would estimate the potential contribution to this phenomenon from oil shale or tar sands development. On February 28, 2008, the International Center for Technology Assessment, Natural Resources Defense Council, and Sierra Club filed a formal legal petition with the Council on Environmental Quality (CEQ) seeking to assure that climate change analyses are included in all federal environmental review documents. While CEQ is not yet requiring that NEPA documents contain an analysis of a project's potential contribution to global climate change, it is important to note that the Pew Center on Global Climate Change has stated that the refining of Canadian petroleum derived from Alberta oil sands produces 15 to 40 percent more carbon dioxide emissions than conventional oil. Section 526 of the Energy Independence and Security Act of 2007 states that "[n]o Federal agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related use, other than for research or testing, unless the contract specifies that the lifecycle greenhouse gas emissions associated with the production and combustion of the fuel supplied under the contract must, on an ongoing basis, be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources." 267-008

When considering the global climate change implications associated with the production, refining, and eventual combustion associated with the potential 61 billion barrels of petroleum derived from oil shale and tar sands resources contemplated under BLM's preferred alternative, we recommend that the BLM include a detailed climate change analysis in the final EIS.

Chapter 3, Page 3-232, Section 3.10.3.1 Visitation Statistics – Visitation to units of the National Park System is carefully tracked and reported in a timely manner. These data with accompanying economic and employment information is available at our website (**<u>www.nps.gov</u>**). For the eight parks in the Region of Influence the cumulative annual visitation (2006) is 4,460,683. The economic valuation of visitor spending for these parks in 2006 was $285,501,000. Tourism is a huge industry in the intermountain west. Given the 83 Federal and State Recreation Areas listed in Table 3.1.2-1 a more comprehensive discussion of tourism and visitation could be presented in this section than the one sentence mention of 1999 visitation from three Utah State Parks. The Institute for Outdoor Recreation and Tourism at Utah State University has great expertise in these matters and could provide great assistance to BLM in preparing the final EIS. 267-009

Chapter 3, Page 3-233, Section 3.10.4 Transportation – This brief section seems to focus on county roads. Based on information we have received from State of Utah Department of Transportation logistics planners, state highways in the Region of Influence are already stressed and exhibiting much shorter pavement life-cycling just from today's intense oil and gas activities. Add to that the level of development anticipated in BLM's earlier Reasonably Forseeable Development Scenario for oil shale and tar sands and we are concerned that transportation infrastructure impacts would be compounded. We mention this because such impacts, in addition to creating unsafe conditions, can adversely affect park visitation. For a more complete discussion of this issue, we refer BLM to our June 11, 2007 memorandum. 267-010

Chapter 4, Page 4-29, Section 4.5, Water Resources (and all other water resources sections) – We recommend that BLM undertake a more in-depth analysis of region-wide water consumption needs and possible contamination issues. As a downstream recipient of regional waters and manager of land resources dependent on regional aquifers, the NPS is concerned with the amount of water that may be consumed by large scale oil shale and tar sand development within the BLM's two million acre preferred alternative. As written, the draft EIS does not model or predict possible water quality and quantity impacts to region-wide resources including those managed or depended upon by other federal land management agencies. 267-011

Air Resources (all sections) – The draft EIS air quality sections do not analyze potential impacts to air quality in NPS units as well as regional air quality due to oil shale and tar sands development in the three state areas. The draft document states that it is not analyzing impacts to air quality "[s]ince all activities conducted or approved through use authorizations by the BLM must comply with all applicable local, state, tribal and federal air quality laws, statutes, regulations, standards, and implementation plans, it is unlikely that future oil shale/tar sands leasing and development would cause significant adverse air quality impacts." (See Mitigation Measures sections 4.6.2 and 5.6.2.) Another paragraph states that "[i]mpacts on air quality would be limited by applicable local, state, Tribal, and federal regulations, standards, and implementation plans established under the Clean Air Act and administered by the applicable air quality regulatory agency, with EPA oversight." There are many potential air quality related ecological effects that can occur at levels well below the values set in the aforementioned air quality laws, statutes, regulations, standards, and implementation plans. The final EIS should evaluate air quality impacts and can not dismiss them by pointing to other regulatory authorities. 267-012

We recommend that the final EIS address air quality impacts to the national ambient air quality standards (sulfur dioxide, nitrogen dioxide, ozone, carbon monoxide, particulate matter, and lead), maximum allowable increases of regulated pollutants (increments), mercury, carbon dioxide, visibility, and atmospheric deposition. We also recommend that it address air quality regionally, globally (carbon dioxide and mercury), and the special protection afforded Class I wilderness areas and national parks designated under the Clean Air Act.

Under some of the alternatives 12,000 to 15,000 megawatts of electrical generation are identified. If this is accomplished with typical coal-fired power plants it would mean the construction of six to eight new generating stations. The NPS experience to date has been that a single power plant has the potential to cause significant, and at times adverse, effects in those areas. The scale of the power generation raises concerns. We recommend that the air quality impacts from power generation in combination with the hydrocarbon processing be analyzed.

Lands Acquired under the Land and Water Conservation Fund (L&WCF) and the Urban Park and Recreation Recovery Programs (UPRR) – We recommend that BLM analyze in the final EIS whether any lands acquired using funds under the L&WCF and the UPRR programs would be affected by proposed oil shale and tar sands leasing and development. The NPS was unable to determine which if any such areas may be impacted. There are 3 sites in Colorado, 4 sites in Utah, and 31 sites in Wyoming acquired with L&WCF assistance.

We recommend that the Bureau consult directly with the officials who administer the L&WCF program in the State of Wyoming, Colorado and Utah to determine any potential conflicts with section 6(f)(3) of the L&WCF Act (Public Law 88-578, as amended). This section states: 267-013

> "No property acquired or developed with assistance under this section shall, without the approval of the Secretary [of the Interior], be converted to other than public outdoor recreation uses. The Secretary shall approve such conversion only if he finds it to be in accord with the ten existing comprehensive statewide outdoor recreation plan and only upon such conditions as he deems necessary to assure the substitution of other recreation properties of at least equal fair market value and of reasonably equivalent usefulness and location."

Responses for Document 00267

00267-001: Thank you for your comments. As a cooperating agency on the PEIS, you provided special expertise and agency knowledge that was valuable in helping to draft the PEIS. As preparation of the PEIS proceeded, and in consultation with all the cooperating agencies, it was determined that the analysis to support leasing decisions would require making many speculative assumptions regarding potential, unproven technologies, and consequently, the decision to offer specific parcels for lease was dropped from consideration in the PEIS. Since the PEIS's allocation decision does nothing more than remove an administrative barrier preventing the BLM from accepting applications, subsequent NEPA analysis will be required prior to the leasing and any development activities.

As required by NEPA, the BLM will prepare the appropriate level of NEPA analysis based on the nature and scope of subsequent leasing and development actions. This additional analysis will consider any new or site-specific information regarding proposed oil shale technology and any anticipated environmental consequences. The BLM is committed to providing the National Park Service the opportunity to become a cooperating agency on any subsequent NEPA analyses.

00267-002: The BLM is aware of the requirements of the Energy Policy Act of 2005, but the BLM is also aware of the requirements of other laws when preparing a programmatic environmental impact statement. The Energy Policy Act of 2005 did not exempt the Secretary from complying with the NEPA and other environmental laws and associated regulations. Consistent with the congressional mandates and in full compliance with NEPA, the BLM is moving forward with this broad-scale PEIS that analyzes the environmental consequences of a land use planning allocation decision. As pointed out by the cooperating agencies, the BLM cannot acquire information at this time to project the number, locations, or technologies of future commercial oil shale operations. Congress has not authorized the BLM to delay this PEIS until technologies have been proven commercially viable. Thus, this PEIS supports the programmatic decisions to amend land use plans to open certain lands to further consideration of oil shale or tar sands leasing and to close other lands to such leasing.

The PEIS, while not exhaustive in its identification of potential impacts of commercial development, discloses potential impacts of oil shale and tar sands development based primarily on BLM experiences with surface-disturbing activities from other types of mineral development (e.g., coal mining and oil and gas). The BLM cannot say for certain that those would be the impacts from commercial oil shale or tar sands development, but we can say, based on our experience with other types of mineral development, that those type of impacts may occur.

This PEIS fulfills three purposes: (1) it provides sufficient information for the decision maker to make a reasoned choice among the alternatives as to which lands should be open or closed to oil shale or tar sands leasing; (2) it addresses additional information needed by industry, government, and the public to facilitate future environmental analysis of leasing and development actions; and (3) it allows operators to compare environmental impacts of their proposed operations with those identified in the PEIS, and to include proposed mitigation measures (although not necessarily those potential mitigation measures discussed in the PEIS) as part of their proposed actions. It puts operators on notice that development of oil shale and tar sands can occur only if it is done in an environmentally acceptable manner. It also reiterates the obvious requirements that any development must comply with existing laws and regulations regarding the protection of the natural, social, and cultural environment.

00267-003: It is correct that it is most helpful to the BLM if the National Park Service raises adjacent park protection concerns during the BLM's land use planning process. However, for oil shale development, the BLM anticipates that it would proceed in a three-step decision-making process instead of, although similar to, that used for federal onshore oil and gas (two-step process). The BLM determined that it was necessary to segregate the normal process into (1) the allocation decision, (2) the leasing decision, and (3) the permit or plan of development decision because of the experimental stage of the oil shale and tar sands technologies. Normally, the BLM is able to include sufficient site-specific information in its NEPA documentation for RMP amendment so that an additional NEPA document is not required for issuing an oil and gas lease. The BLM welcomes the National Park Service's continued participation in subsequent NEPA analysis.

For the BLM to undertake a more detailed analysis, as suggested, too many unsupportable and highly speculative assumptions would need to be made, which would call into question the ability to make an informed decision. However, the BLM, using comparable information based on BLM's experience with surface-disturbing activities from other types of mineral development and the best available information, such as that contained in Appendix A, discloses potential impacts (direct, indirect, and cumulative) and provides the decision maker with available, essential information for making the allocation decision. At the leasing decision stage, a more specific analysis would be able to be completed based on more specific technical and environmental information.

00267-004: The National Park Service correctly states that Option 1 does not comport with the requirements of Section 369 of the Energy Policy Act of 2005. As discussed in response to Comment 00267-003, for the BLM to perform the analysis as suggested in Option 2 would require too many unsupportable and highly speculative assumptions and would call into question the ability to make an informed decision.

00267-005: Thank you for your suggestion to enhance the description of the process that would take place if oil shale or tar sands development would be considered on NPS lands. However, this PEIS addresses only BLM-administered lands, and the process for NPS lands is outside the scope of the decision to be made.

00267-006: This comment is a continuation of the previous comment; please see response to Comment 00267-005.

00267-007: Although these CHL leases do exist, for the purposes of analysis in the PEIS, the BLM assumed no development on these leases, because during the last 20 years no activities or development proposals were submitted to the BLM (see Section 2.4.2). The industry has not demonstrated any technology for tar sands that would be commercially viable. However, the cumulative impacts analysis for tar sands development (Section 6.2.5) does acknowledge the potential for tar sands development on nonfederal lands, and text has been added to state that there may also be future development on CHLs.

00267-008: Section 3.5.1.2 of the PEIS describes the existing state of knowledge regarding climate change. However, no climate change-related pollutant emissions would result from the alternatives examined for making BLM-administered lands available for potential future commercial leasing of either oil shale or tar sands resources. This section also indicates that the assessment of GHG emissions and climate change is in its formative phase, and it is not yet possible to know with confidence the net impact on climate. In addition, the Final PEIS has been modified to include the following text: “The lack of scientific tools designed to predict climate change on regional or local scales limits the ability to quantify potential future impacts. However, potential impacts on air quality due to climate change are likely to be varied. For example, if global climate change results in a warmer and drier climate, increased particulate matter impacts could occur because of increased windblown dust from drier and less stable soils. Cool season plant species’ spatial ranges are predicted to move north and to higher elevations, and extinction of endemic threatened and endangered plants may be accelerated. Because of the loss of habitat, or competition from other species whose ranges may shift northward, the population of some animal species may be reduced. Less snow at lower elevations would be likely to impact the timing and quantity of snowmelt, which, in turn, could impact aquatic species.”

00267-009: As public land in the three state ROIs is primarily used for hunting and other forms of dispersed outdoor activities, the numbers of visitors using these lands for these recreational activities are not available from all administering agencies. Although, as the commentor suggests, data on visitation may be available from some agencies, total visitation to each ROI is incomplete. Assessment of the impacts of oil shale or tar sands development on the recreational economy analyzes the impact of losses in employment and income in the sectors providing recreation goods and services in each ROI, and does not depend on visitation statistics. Resources in each ROI used for recreation are listed in Table 3.1.2-1 of the PEIS.

00267-010: The transportation sections in Chapters 4 and 5 of the Final PEIS have been supplemented to ensure that the discussion of impacts are consistent with the decisions in the PEIS. The Natural Park Service's comments are being addressed at a general level because of the lack of information regarding where development may occur.

00267-011: The PEIS uses long-term hydrologic data, states' water plans, and historical water consumption data to evaluate regional water availability in the oil shale basins. Potential contamination of water resources is also addressed at a programmatic level (see Section 4.5). The PEIS lays an analytical foundation for subsequent project-specific NEPA documents regarding oil shale leasing and development. The amount of water that may be consumed depends on many factors, including scale of development, technologies used in the development, economy, and the locations and hydrologic conditions of project sites. The development also is restricted by the ownership of water rights by developers at the time they apply for leasing. Finally, whether enough water is available for development depends on the results of intensive negotiations between various parties, including water rights owners, state and federal agencies, and municipal water providers as well as the developers.

The PEIS does not model possible water quality and quantity impacts to region-wide resources because there are so many factors that remain undefined. This PEIS is a programmatic-level document, analyzing allocation decisions. These allocations do not authorize the immediate leasing of the lands for commercial development, nor do they authorize commercial development. Modeling at this stage would rely on many speculative assumptions and would generate unreliable results for use in future project-specific NEPA analyses.

00267-012: As stated in Section 1.1 of the Draft PEIS, the BLM proposes to amend 12 land use plans in Colorado, Utah, and Wyoming to describe the most geologically prospective areas administered by the BLM in these states where oil shale and tar sands resources are present, and to decide which of those areas will be open to application for commercial leasing, exploration, and development. Additionally, the analysis conducted in preparation of this PEIS was based on available and credible scientific data. As a programmatic evaluation, conducted in support of land use plan amendments, this PEIS does not address site-specific issues associated with individual oil shale or tar sands development projects. A variety of location-specific factors (e.g., soil type, watershed, habitat, vegetation, viewshed, public sentiment, the presence of threatened or endangered species, and the presence of cultural resources) will vary considerably from site to site. In addition, the variations in extraction and processing technologies and project size will greatly determine the magnitude of the impacts from given projects. The combined effects of these location-specific and project-specific factors cannot be fully anticipated or addressed in a programmatic analysis. As a result, additional, site-specific NEPA analyses will be conducted prior to the issuance of commercial leases and the approval of specific plans of development. The BLM would invite other federal, state, local, and Tribal agencies to participate as cooperating agencies on these site-specific project-level NEPA documents.

The proposal (describing where oil shale and tar sands resources are present, and to decide which of those areas will be open to application for commercial leasing, exploration, and development) would not result in the emissions of any climate change-related (or other) air pollutants. Speculation about project locations and how development might occur would require many assumptions that are premature at this stage in the process. If a decision is made to make oil shale and/or tar sands available for future leasing, detailed potential air quality and climate impacts will be appropriately evaluated in detailed, site-specific NEPA analyses (including potential direct, indirect, and cumulative impacts) before issuing leases and approving plans of development.

00267-013: The decisions in the PEIS would only apply to BLM-administered lands that are open to mineral entry. In the case of any acquired lands, the BLM must publish an “opening order” that would make them available for mineral development. In the specific case of lands acquired by the BLM utilizing LWCF funds, the lands are not opened to mineral entry because of the clause contained in the comment. For that reason, no BLM-administered lands acquired utilizing LWCF funds would be available for application to lease under any alternative in the PEIS.

Thank you for your comment, Kenneth Parsons.

The comment tracking number that has been assigned to your comment is OSTSD52770.

Comment Date: March 19, 2008 16:33:43PM
Oil Shale and Tar Sands
Comment ID: OSTSD52770

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Attachment: RIO BLANCO COUNTY COMMENTS.doc

Comment Submitted:

See Attachment.

**RIO BLANCO COUNTY COMMENTS
ON
OIL SHALE PEIS DRAFT**

Introduction

Rio Blanco County thanks the BLM for including us as a Cooperating Agency during the PEIS process. When this process began, we understood the purpose of the PEIS project was to provide for commercial leases for the extraction and processing of oil shale. However, the purpose was changed roughly a year into the process from awarding commercial leases, to identifying what lands might be made available for commercial leasing at a future date. One reason for this change in purpose was, as we understood it, driven by a lack of definition of what processes had the potential to be commercially viable for the extraction and processing of shale oil. Without a clear understanding of these processes, it is extremely difficult to determine the impacts that might be experienced in the tri-state area where oil shale operations would take place. Further, there was a need for a contemporary, in-depth look at the current socioeconomic status in the region prior to projecting what the affect of oil shale leasing and development might be.

It is our understanding that no surface mining activities would take place within Colorado; that the purpose of the PEIS study was to identify lands that might be made available for commercial leasing at some time in the future; that the bulk of Volumes 2 and 3 address the various existing technologies for extraction of the petroleum product from the shale material, and the refining of the product, it seems premature to provide in depth comments until the specific process is known, which could be totally different than those discussed in the draft document, that prior to any future commercial leasing, additional site specific NEPA analysis would be conducted and analyzed; and, that this PEIS would be used, as the basis, to amend 12 land use plans in Colorado, Utah, and Wyoming, to provide the opportunity for leasing.

Rio Blanco County submitted comments on an earlier draft document, provided to Cooperating Agencies. Virtually all of the comments submitted at that time still apply to this Public Oil Shale and Tar Sands PEIS publication, and have been included in these comments, as appropriate. The earlier draft document contained four "Alternatives" none of which were viewed favorably by Rio Blanco County.

Research and Development

We reiterate our concern that none of the alternatives provide for a continuation of RDD leasing even though there is currently no proven commercial in-situ shale oil extraction process. This would seem to close the door to any research project which does not now currently have a RDD lease or own the mineral rights to oil shale outright. This does not seem conducive to developing a viable domestic commercial shale oil industry expediently. 52770-001

Local Government and Housing

The PEIS referred to Federal, State and private property owner reviews and approvals, but omitted reference to local government review and approval. Further, the PEIS document does not address how, or if, local land use codes and regulations will be considered in the commercial leasing process, or how such consideration would take place. Local community housing would include "temporary housing built in local communities" per the PEIS document. This appears to run counter to current local land use codes, and expressed views of local government. Given the current and projected levels of natural gas development in the Piceance and Uinta basins and the current utilization of mancamps due to housing limitations, this approach would mean building complete new towns from scratch. Significant limitations on domestic water sources will likely prevent the construction of new towns in Rio Blanco County. The PEIS proposes large, employer-housing compounds located on Federal lands, but does not provide sufficient discussion regarding the socioeconomic impacts that will be caused by such developments; i.e. schools, recreation, shopping, supply and demand impacts on prices, governmental services, etc. No expectations of local governments and/or communities related to employer provided, remote housing was discussed. 52770-002

SocioEconomics

In general, there is a need for the PEIS to address cumulative time lines, population growth, and labor needs in the same section, charts, and analysis for socioeconomic impacts. For example, population growth, in the different communities within Rio Blanco County, appears to be higher than those shown in the PEIS document, which refers to the growth as "moderate". At the present time, Rio Blanco projections for the county are an increase from approximately 6,200 people to approximately 18,000 people by 2030, which is not deemed as moderate.

A socioeconomic study is nearing completion which could potentially fill this need. This study, funded by the state of Colorado, has been overseen by a committee of local government officials from the study area and representatives of affected state agencies. The report documents the development and calibration of the Northwest Colorado Socioeconomic Projection (NWCSP) model and presents socioeconomic and fiscal forecasts for a multi-county region of northwest Colorado. The study area encompasses Mesa, Garfield, Rio Blanco and Moffat counties although economic projections recognize the resort influences in some adjoining counties and the interrelationship with similar resource development in nearby Wyoming and Utah. It is the hope of Rio Blanco County that this study, available April 11, 2008, at www.agnc.org, can be incorporated into the documentation for this PEIS. 52770-003

Air Quality

In reference to the conclusion stated on page ES-6 of "Some minor impacts on sensitive species, air quality, and visual resources may occur off-site. The environmental analyses completed previously by the BLM onthe projects resulted in Findings of No Significant 52770-004

Impact." does not seem warranted. The current and projected levels of natural gas development in the Piceance and Uinta basins, coupled with 3 class I wilderness areas just to the east (prevailing winds from the west), combusting natural gas at this level will likely violate air quality limits. The two recent air quality warnings for ozone issued in the upper Green River basin of Wyoming bear witness to how rapidly air quality can be affected by development in hitherto pristine regions. 52770-004 (cont.)

Power Generation

The PEIS assumes that any additional power requirements would come from conventional coal-fired generation facilities. Given current and projected levels of natural gas development in the Piceance and Uinta basins coupled with 3 class I wilderness areas just to the east (prevailing winds from the west), combusting coal conventionally in Moffat Co, CO, and Uintah Co, UT, is not a realistic assumption. Current projections for the Central Rockies indicate that current power production is already inadequate to deal with current growth rates. One new power plant is already under construction at Bonanza, UT, and more are needed. Also, given the time frames included in the PEIS document for commercial operations to ramp up, there would not appear to be adequate time to permit, build, and test new coal fired generation plants. The abundance of natural gas in the region, and to be produced as a by product of the oil shale recovery operations, gas fired generation facilities should have been included in the PEIS document and evaluated. Local impacts would be greatly altered based on the number and type of additional power generation facilities required. 52770-005

Miscellaneous

There was not a clear understanding or definition of the "threshold effects" statements contained in the PEIS documents. For example: how is "moderate effect" and "large effect" defined? A table showing these definitions, thresholds and effects would be very helpful. 52770-006

The PEIS document does not adequately deal with the adverse impacts of reductions in traditional recreational use of the Federal lands involved; or the lack of local facilities to support traditional recreational uses of lands in, or near, the ROI. 52770-007

Summary

Rio Blanco County thanks the BLM for this opportunity to critique the OSTS PEIS as it applies to our region. We see several areas such as air quality, power generation, and socioeconomic impacts which need further analysis and hope that these concerns may be addressed in order to provide a document which accurately and realistically depicts the implications of oil shale development.

Responses for Document 52770

52770-001: The description regarding the relationship of the RD&D projects to the PEIS, including the PRLA acreages, have been rewritten to clarify their situation. The scope of the analysis for the PEIS does not include review of the decisions by the Secretary to issue the existing RD&D leases described in Section 1.4.1. Those leases authorize activities on six 160-acre parcels located in Colorado and Utah and also identified conditions under which commercial development could occur on 4,970-acre preference right lease areas included in the leases. A total of 30,720 acres may be developed under terms of these leases. The RD&D leases are prior existing rights, and they are not subject to decisions in the PEIS with the exception that both Alternatives B and C address the subsequent availability of the lands contained in the leases should the initial lease holder relinquish the existing leases. Additional RD&D leases may occur on lands open for oil shale leasing.

52770-002: Programmatic environmental impact statements are used to evaluate broad policies, plans, and programs, and they provide an effective analytical foundation for subsequent project-specific NEPA documents. When applications to lease are reviewed, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and mitigation measures, as well as what level of development may be anticipated. This future analysis will be done in the context of ongoing and anticipated future development of other resources within the area of influence of any proposed oil shale lease and will take into account the types of local government impacts raised in this comment.

52770-003: Given the programmatic nature of the PEIS, the purpose of the analysis of socioeconomic impacts is to provide an overview of the type and magnitude of impacts that would likely occur with the construction and operation of representative oil shale, tar sands, and ancillary facilities.

The socioeconomic analysis described in the PEIS was limited to estimating impacts for an ROI in each state based on the likely residential location of project workers and, consequently, the region in which the majority of socioeconomic impacts of the prospective facilities would most likely occur. If commercial-scale resource development occurs, additional NEPA analyses would be undertaken, taking into account actual worker residential locations by county, and the consequent impacts on county population growth.

Population baseline data and projections were the most recent data available when the Draft PEIS was released. Population projections for each ROI, including data for 2004 presented in Section 6.1.1.10, were taken from county, population forecasts prepared by each state and reflect growth rates projected in those forecasts. The report cited in the comment was used to describe the potential growth of the oil and gas industry in northwest Colorado in the PEIS.

52770-004: Thank you for your comment.

52770-005: Evaluation of the complete impacts of power requirements for oil shale/tar sands development is considered to be too speculative for analysis at this time. The amount of power required varies with technology to be implemented, and the source of the power (and therefore the impacts) is unknown. Required power could come from coal-fired plants, nuclear plants, natural gas, or renewable energy sources.

52770-006: The potential magnitude of impacts in different impact categories (e.g., habitat fragmentation and water depletions) are defined for ecological resources in Sections 4.8.1 and 5.8.1 of the PEIS. Impact magnitude is described in these sections as small, moderate, or large using the following definitions. A small impact is one that is limited to the immediate project area, affects a relatively small portion of the local population (less than 10%), and does not result in a measurable change in carrying capacity or population size in the affected area. A moderate impact could extend beyond the immediate project area, affect an intermediate portion of the local population (10 to 30%), and result in a measurable but moderate (not destabilizing) change in carrying capacity or population size in the affected area. A large impact would extend beyond the immediate project area, could affect more than 30% of a local population, and result in a large, measurable, and destabilizing change in carrying capacity or population size in the affected area.

Generally, for other resources the meaning of comparative statements can be understood from the context of impact descriptions in the text that are specific to each resource area.

52770-007: Programmatic environmental impact statements are used to evaluate broad policies, plans, and programs and provide an effective analytical foundation for subsequent project-specific NEPA documents. The PEIS is considering the effects of the proposed decision to identify lands for application for commercial leasing, and no rights in federal lands are included in the proposed actions. The BLM did consider impacts on recreation use in the Land Use and Socioeconomic sections of Chapter 6 and found that, other than possible socioeconomic impacts on property values, there were no significant impacts associated with the proposed decision.

The issue of the adequacy of local recreation facilities is a highly specific issue and is beyond the scope of the PEIS considering land allocation decisions. This is an issue that may be addressed in subsequent NEPA analysis considering an application(s) for commercial leasing depending upon the situation in the particular area that would be affected.

Thank you for your comment, Governor Bill Ritter, Jr..

The comment tracking number that has been assigned to your comment is OSTSD52837.

Comment Date: March 20, 2008 12:47:36PM
Oil Shale and Tar Sands
Comment ID: OSTSD52837

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Comment Submitted:

Attached are the comments from Governor Bill Ritter, Jr., State of Colorado

These supercede the previous version. See Attachment.

STATE OF COLORADO

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Bill Ritter, Jr.
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March 20, 2008

BLM Oil Shale and Tar Sands Draft Programmatic EIS
Argonne National Laboratory
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Re: *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 (DES 07-60)*

To Whom It May Concern:

As the Governor of the State of Colorado, and in coordination with the Colorado Department of Natural Resources, Colorado Department of Public Health and Environment, and Colorado Department of Local Affairs (Departments), I respectfully submit the following comments regarding the Department of the Interior, Bureau of Land Management's (BLM) *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* (Draft PEIS). The Draft PEIS raises important issues for Coloradans, and all Americans, with respect to energy supplies, environmental protection, socioeconomic impacts, and national security. If BLM were to authorize a commercial oil shale industry in Colorado, such a development would likely constitute the largest industrial development in the State's history with enormous implications for all of Northwest Colorado and for the State itself.

For Colorado, there is much at stake in the outcome of this program. Colorado recognizes the importance of the oil shale resource to the country. In our uncertain world, a reliable, sustainable domestic oil-based resource is increasingly important. But equally important, from Colorado's perspective, is protection of the State's exceptional environment including our air quality, water quality, vegetation and soil resources. Northwest Colorado is blessed with a remarkably diversified economy in which agriculture, tourism, recreation, hunting & fishing, natural gas & mineral development, retirement communities, and their economic drivers co-exist in a relatively balanced and supportive way. Within the Piceance Basin, Colorado is beneficiary of some of the nation's most important wildlife resources, including robust elk populations and the largest migratory mule deer in North America. These wildlife treasures, the envy of other states, have gradually evolved and grown over the past century to the exceptional levels of today. The importance of the State's wildlife resources is not something Colorado takes for granted.

Similarly, Colorado is very mindful of the potential impacts of oil shale development on Colorado's water resources. The State is rapidly approaching full allocation of its Colorado River entitlements where Colorado will enter a new period of trading and sharing water between different users. If oil shale were to consume vast quantities of water, there would be corresponding impacts to the State's agricultural, recreational, and other energy sectors on the West Slope, the Front Range and even along the Eastern Plains. Hence, the State is very concerned that the water implications of this industry be understood prior to decisions regarding commercialization.

Therefore, the State places great importance on a thoughtful, comprehensive PEIS, whereby federal, state and local decision-makers will have the necessary tools in hand to evaluate what type of federal program makes the most sense at this point in time. Based on our evaluation of the Draft PEIS and the information in hand, it is premature for the BLM to make any decisions that allocate federal land to a commercial leasing program through its resource management plans or otherwise.

BLM must gain critical answers to many questions before any commitment to commercial leasing occurs. Equally important, BLM must similarly gain answers to such questions before any rules and regulations for commercial oil shale development can or should be finalized. Absent obtaining these answers, BLM and Colorado run the serious risk of development that will have tremendous adverse impacts on Colorado. 52837-001

The State continues to believe that the best course of action is to see the research and development program authorized by BLM developed, tested, and monitored so the answers can be forthcoming. Colorado is host to five of the six federal research and development sites and we are confident these programs will yield the necessary information upon which rules and regulations and commercial leasing can be based.

Importance of Northwest Colorado

Northwest Colorado is blessed with diverse, exceptional natural resources and a vibrant, diversified economy. For starters, it is the home to world-class hydrocarbon resources, holding trillions of cubic feet of clean-burning natural gas which are currently undergoing an unprecedented and historically unanticipated gas development boom. In 2006, natural gas and other energy-related development accounted for 15 percent of direct and secondary employment in the region. Similarly, the region has one of the most important oil shale deposits in the world, as described below.

The region also supports superlative wildlife resources. The Piceance Basin is home to the largest migratory mule deer herd in North America, a robust migratory elk population, one of only six greater sage-grouse populations in Colorado, populations of Colorado River cutthroat trout, and a host of other wildlife species. These wildlife resources have been built up over millennia and are of long-term statewide and national economic, ecological, and aesthetic importance. Colorado's future is reliant on these resources remaining strong and healthy.

In the last twenty years, the region has developed a growing recreational tourism industry as well as a vigorous hunting and fishing community. In 2006, approximately 17,000 jobs were found to be supported by the tourism industry for the region including Moffat, Rio Blanco, Garfield, and Mesa counties, representing about 15 percent of the jobs in the area. About 20 percent of the tourism jobs in Northwest Colorado are in the outdoor recreation segment -- or about 3,400 jobs.

The region also sustains a healthy agriculture industry, a vibrant and long-standing ranching tradition, and growing retirement communities. Employment in the agriculture and ranching industries contribute between 6 percent and 15 percent of all base jobs in the counties in this region. Retirees comprise 13 percent of the population in the region and their spending supports 11 percent of the basic jobs.

As a result of its abundance of natural resources, Northwest Colorado is experiencing extraordinary growth in population and associated challenges. Housing costs in the region, roughly 35 percent below comparable Denver metropolitan area costs just six years ago, now often match or exceed Denver-area prices. Housing affordability is a significant challenge to these local communities, and the capacity of local communities to absorb growth is already largely consumed. Many workers are housed in hotels and motels rather than conventional housing. Many of the conventional resources available to local governments to meet infrastructure needs, like aggregates and construction materials, are being diverted to the gas patch. Much of the transportation infrastructure in these communities is in disrepair and is being severely stressed by growth pressures. The costs to repair infrastructure will require up-front financing, before revenues become available from traditional sources such as severance taxes, property taxes, sales taxes, and federal royalties.

This region is thus vitally important to Colorado's future. It is in a precarious balance in the face of extraordinary pressures precipitated by possibly the largest industrial development in the history of the state. Everything state and federal policy makers do with regard to Northwest Colorado must protect the resources, values, and diverse economies and interests found there, and we cannot simply think of this region as an area to be sacrificed for any one purpose.

A Rational Approach to Oil Shale Development

Northwest Colorado is also home to extraordinary oil shale resources, among the richest in the world, yielding 25 gallons of oil or more per ton of rock and estimated to hold nearly 500 billion barrels of recoverable shale oil, which is more than double the proven reserves of Saudi Arabia. Successful development of this resource could provide a substantial new source of domestic oil for the United States, which would have positive implications for our national energy policy and national security. Demand for oil is rapidly increasing while additions to reserves are in decline, both domestically and globally. The United States currently imports considerable quantities of oil from unstable regions and regimes whose interests may conflict with ours.

Remarkable as Colorado's oil shale resource is, however, it has remained in the ground since its discovery over a hundred years ago. Past attempts at development have failed due to a number of challenges -- technical, economic, and environmental -- that have yet to be addressed, notwithstanding significant investment over the last 40 years by both government and industry. Given the significant oil shale resource and exigent national energy interests, Colorado is committed to seeing ongoing oil shale research and development move forward. Colorado officials have assisted BLM in reviewing applications for federal research and development leases, and the State currently hosts five of the six federal research and development leases issued in 2006. If successful, these research and development projects could set the foundation of a subsequent commercial oil shale industry.

Therefore, Colorado maintains that a prerequisite to federal oil shale leasing, regulation, and development is the development of information that will allow us to address historic challenges. Construction has not yet begun on the federal research and development leases, and these projects are critical in showing that new proposed technologies work, that they can be utilized economically, and that they will not have unacceptable impacts on Colorado's environment and communities.

Colorado is committed to working with the federal government and industry on oil shale efforts going forward. But this requires a thoughtful approach -- economically, environmentally, and socially -- rather than a rush to premature leasing and regulatory decisions. Yet another boom and bust cycle for energy development will be dire for Northwest Colorado, a region that retains considerable skepticism and frustration over the collapse of the oil shale boom of the 1970s. Another failed attempt at oil shale development could preclude development of this nationally significant resource for decades. Sound public policy requires allowing research projects to yield information that will answer crucial questions and allow the industry to proceed with public support, and Colorado will roll up our sleeves to work with other stakeholders to ensure that this happens.

As set forth more fully below and in the attached technical comments from the Departments, the approach set forth in the BLM's Preferred Alternative is misguided and unacceptable. The BLM proposes to open nearly 2 million acres of federal oil shale resources to potential oil shale development, yet it lacks information about the technologies that would be used or their impacts on the environment. Colorado recommends selection of Alternative A, which would allow activities on federal research and development leases to continue and potentially expand to commercial leases. Under this alternative, 223,860 acres in the White River Resource Area's Piceance Basin would continue to be available for future oil shale leasing under existing BLM plans. 52837-002

Because proven development technologies do not yet exist, the BLM cannot reliably analyze likely effects on water resources or air quality, impacts on local communities, energy requirements, or impacts on wildlife resources, and this information is critical to making sound land-allocation decisions in compliance with the law. 52837-001 (cont.) The BLM also failed to consider adequately the cumulative impacts of its proposed land allocation decisions, and this important analysis will be impossible when performing lease-by-lease reviews as the BLM proposes. There is simply no substitute for doing a thorough, comprehensive analysis at the programmatic stage that might set the framework for later individual leases. 52837-003 The BLM also proposes, without analysis, to do away with long-standing carrying capacity thresholds for the protection of 52837-004 communities, the environment, and wildlife resources. Given the information missing from the BLM's analysis, a decision to make 360,000 acres available for oil shale leasing is ill-advised. 52837-004 (cont.)

Similarly, the BLM lacks the information necessary to finalize any comprehensive set of rules and regulations for oil shale development. These regulations will establish environmental-protection standards, set royalty rates and address bonding, establish standards for diligent development, determine the allowable size of leases, and make myriad other important decisions that will directly and significantly affect how oil shale development proceeds. Until the basic answers are derived from the research and development program, establishing the rules for commercial leasing is premature. 52837-005

Again, Colorado supports the research and development approach and pledges its continued support of that effort. Once data is available from the research and development projects, it is possible that land allocation decisions can be made and regulatory requirements can be developed. But making land available or promulgating regulations in the absence of underlying data from the research and development projects is reckless and will lead to long-term and significant negative impacts on Colorado. 52837-006

DISCUSSION

The State of Colorado has consistently urged that federal oil shale leasing, regulation, and development be based on solid, reliable results that will emanate from the research and development leases. Such development could provide a substantial new source of domestic oil for the United States, but it must proceed in a reasoned and responsible manner. The process must take into account what has been learned from 100 years of efforts to develop this important resource, what we know and do not know about current proposed technologies, and the various changes in the environmental and social landscape of the region. Colorado is home to five of the federal research, development, and demonstration (RD&D) leases issued in 2006. The State supports an oil shale program in which research and development activities provide information that may inform commercial regulatory and leasing decisions. Because oil shale development will likely utilize untested technology with potential long-term impacts to Colorado's communities and the environment, the State has consistently opposed plans to commercialize leasing or production of federal oil shale resources prior to a meaningful evaluation of the results of the RD&D projects.

For these reasons, Colorado cannot support the BLM's selection of Alternative B – making 1,991,222 acres available for application for oil shale leases in the three-state region, including 359,798 acres in Colorado – as the Preferred Alternative in the Draft PEIS. As more fully set out below, Colorado recommends that the BLM adopt the **Alternative A** as the Preferred Alternative in the Final PEIS. Under this alternative, activities on federal research and development leases could continue and potentially be expanded to commercial leases, and 223,860 acres in the White River Resource Area would remain available for future oil shale leasing.[1] 52837-007

Colorado further recommends that the BLM explicitly commit to preparing a 52837-008

[1] BLM White River Resource Area, Record of Decision and Approved Resource Management Plan at 2-6 (July 1997).

supplemental PEIS at a later date, when adequate information, including information from the RD&D leases, is available, prior to proceeding with the establishment of commercial oil shale regulations and subsequent offering of commercial leases. 52837-008 (cont.)

Decisions about land allocations, regulatory requirements, financial assurances, taxation structures, and leasing should not be made until land managers and the public can reliably predict and understand the impacts that are likely to result from those decisions. Because the information necessary to develop that understanding does not yet exist, making any federal oil shale resources available for application for commercial oil shale leases is premature. It is highly probable that no production from the RD&D leases will occur within the next six years, and commercial oil shale production is not anticipated before 2020. 52837-009

Below are Colorado's summary comments about the BLM's management approach in the Draft PEIS. Supporting detailed technical comments from state officials with significant expertise regarding the potential for oil shale development's impact to Colorado's air and water quality, wildlife, communities, and quality of life are attached. From a regulatory standpoint, Colorado recognizes that there are several areas of complimentary jurisdiction and analysis. For instance, water quality issues arise in the technical comments of several Divisions, highlighting both the importance of this issue and the cross-cutting nature of the concerns raised by the possibility of oil shale development. As noted in the technical comments, the Draft PEIS identifies many significant concerns and contains several major deficiencies that must be remedied in the Final PEIS and before the BLM signs a Record of Decision (ROD). These include:

• The Piceance Basin contains unique or irreplaceable habitats for a host of wildlife species such as leks for greater sage-grouse, movement corridors for big game species, winter range for North America's largest migratory mule deer herd, and streams containing native cutthroat trout. The primary concern for wildlife due to oil shale development is the overall loss and fragmentation of this valuable wildlife habitat, the feasibility of reclamation of disturbed areas, and the damage that would accrue to wildlife populations. The detail provided in the Draft PEIS is insufficient to allow for an accurate or complete assessment of the cumulative impacts to wildlife habitats and populations that will occur from commercial-scale oil shale projects.

• The amount of water that may be available for oil shale development is a significant concern, as is the impact oil shale development poses to the State's entitlements under the Colorado River Compacts. We are also concerned about the impacts of oil shale development on existing instream flow segments in and adjacent to the leased land and any potential increases in flooding as a result. Finally, we are concerned about the interactions between oil shale development and the Colorado River Salinity Program and the Upper Colorado River Recovery Implementation Program. Oil shale development has the right to benefit from these programs, but adverse impacts must be minimal. 52837-010

• The BLM's socioeconomic analysis did not address statutory and regulatory oversight relative to the licensing, inspection, and enforcement of labor camps (man camps), retail food establishments, wholesale food firms, schools, childcare, mobile home parks, public accommodations (hotels/motels) and campgrounds.

• There is tremendous uncertainty of what the environmental impacts will be on both surface water and ground water quality due to commercial shale extraction operations. The PEIS does not address the impacts of additional growth on water and wastewater infrastructure in nearby communities. The PEIS also does not address potential impacts of water withdrawals on flows upstream of wastewater facilities, and the concomitant reduction in permit limits that might result for these facilities.

• The PEIS does not present sufficient data to assess potential degradation of the human environment and resulting health impacts to the affected public, potentially resulting from direct or indirect exposure to contaminated media. Scientifically defensible conclusions about potential risks and health impacts cannot be developed until detailed RD&D results are available to better characterize the potential for community exposure and the toxic potential associated with different development alternatives, based on technology-specific processes and fate and transport characteristics.

• The Draft PEIS fails to document or consider the large amount of information about baseline air monitoring being conducted in Colorado. The BLM must discuss this monitoring and commit to conducting the monitoring studies needed in the future to assess baseline air quality conditions. This would include, for example, monitoring in both the Piceance Basin and the Flat Tops Wilderness Area. Further, there is no emissions or operating data from any of the five RD&D leases. 52837-010 (cont.)

• All diversions and use of water must be done in compliance with Colorado Water Law. This will require all necessary approvals from the Colorado Water Courts, the Division of Water Resources and other governmental agencies, and gaining such approvals will require applicants to address all relevant technical concerns. The Draft PEIS fails entirely to acknowledge or discuss the need to comply with Colorado Water Law.

• There is no information about potential levels of Mercury, Ozone precursors, and Hazardous Air Pollutants occurring from oil shale development. This deficiency must be resolved prior to a Record of Decision.

• There is no discussion of the air quality impacts of the additional energy development for electricity generation that is an integral part of future commercial shale development on regional air quality levels (both for visibility and public health). If there is significant additional energy needed to develop this resource, then the impacts must be identified and disclosed in the BLM's PEIS.

• The Draft PEIS is woefully inadequate in assessing the needs and impacts of an industrial complex significantly greater than the infrastructure that exists today. While commercial oil shale development decisions will not be made until the 2012-2014 time frame (with commercial production around 2020), the same lead time will be required to develop water treatment and storage and power plants or networks to support such a commercial oil shale industry. 52837-010 (cont.)

Preferred Alternative

The State of Colorado recommends that the BLM abandon its intention to make large areas of Colorado available for application for commercial oil shale leasing, and instead adopt Alternative A as the Preferred Alternative in the Final PEIS. 52837-011

Colorado recognizes that oil shale development may offer potential to supplement the nation's energy supplies. Colorado's goal is that commercial oil shale development be done right – in a manner that avoids unacceptable and irreparable impacts on Colorado's land, air, water, wildlife resources, and communities and that minimizes those adverse environmental and socioeconomic impacts that would result from such development through front-end planning and financing and long-term monitoring and mitigation. According to the Draft PEIS, the lands the BLM proposes to make available for oil shale leasing in Colorado would result in production of 16 billion barrels of oil. Draft PEIS at 2-22. Elsewhere, however, the Draft PEIS concedes that "[f]uture production levels are unknown at this time," and that its discussion of impacts would necessarily be limited to "potential impact-producing factors." *Id.* at 4-2.

In view of the substantial adverse environmental impacts that could result from commercial oil shale development, and given the lack of reliable information and analysis to meaningfully assess likely impacts at this time, the only defensible alternative is Alternative A. BLM argues that "the amendment of land use plans to designate lands as available for application for commercial leasing would have no impact on the environment" since the actual decision whether to issue leases would be made at a later date. Draft PEIS at ES-5. This is an inconsistent argument that inherently undermines the value of this document. In summarizing a comparison of "Potential Environmental Impacts" of the three alternatives on various resources – water resources, air quality, land use, wildlife, socioeconomics, etc. – the BLM repeatedly states that each resource "would not be impacted by land use plan amendments." *See* Draft PEIS at 2-55 to 2-84. Yet, in other places BLM indicates that the result of this action will "facilitate" or "make possible" commercial oil shale development. Draft PEIS at E-5 and 6-36. BLM cannot have it both ways. The bottom line is that the great uncertainty that currently exists about the potential impacts of commercial oil shale development means that any change to the current applicable Resource Management Plans relative to oil shale development is premature and insupportable – and not without consequences on the land, resources, communities, and economy. 52837-011 (cont.)

Selection of the Alternative A would still allow activities on the five federal RD&D leases to proceed, and these leases could still potentially be converted to commercial production. Because concrete environmental and technological information is necessary to make long-term policy and land-management decisions, Colorado supports the RD&D efforts underway. 52837-002 (cont.) Making additional lands available for application to lease prior to the results of these projects will foreclose the necessary comprehensive analysis of the direct, indirect, and cumulative environmental impacts from commercial oil shale in conjunction with non-oil shale activities planned or currently underway. 52837-012 In addition, oil companies own substantial holdings of oil shale 52837-013 in the Colorado's Piceance Basin.[2] Though the BLM acknowledges that 14 companies owned private oil shale lands in 1979, *see* Draft PEIS at 3-207, the Draft PEIS fails entirely to acknowledge the development potential of private oil shale holdings. 52837-013 (cont.) Without substantially more information about the technologies to be used, their effects on the environment, the potential for oil shale development activities on private land, and the ability to effectively mitigate potentially significant environmental and socio-economic impacts, it is imprudent to allocate any additional federal lands as available for commercial oil shale leasing at this time. It is necessary to await the results from the RD&D projects before making additional federal oil shale resources available for application for commercial lease. Similarly, the results of these tests are necessary to inform the scope of rules and regulations for a commercial leasing program. 52837-001 (cont.)

If planning for and implementation of oil shale development efforts are not done responsibly and thoughtfully in the first instance, there is a greater risk that development will be delayed, and that any development that does occur will have unacceptable impacts. More specifically, BLM's preferred alternative would subject a substantial portion of Colorado to uncertain impacts that are likely to be significant, and this will erode public and political support for the fledgling industry. 52837-014

As noted by the RAND Corporation in Congressional testimony last year, the knowledge base about the economic, technical, and environmental feasibility of oil shale development is not yet adequate to support the formulation of a commercial oil shale leasing program.[3] This testimony noted that while a number of companies are making appreciable investments in oil shale research, "none of these firms has gathered technical information adequate to warrant a decision to invest hundreds of millions, if not billions, of dollars on first-of-a-kind commercial oil shale plants." RAND testimony at 3. The RAND Corporation found that "industry is years away from establishing commercial viability." *Id.*

Because industry is currently unable to commit its substantial resources to large-scale oil shale development, it is likewise premature for the BLM to select any alternative that would make federal oil shale lands available for application for commercial lease or to adopt leasing regulations at this time. 52837-011 (cont.)

Missing Information

The decision to make federal lands available for application for commercial lease is "intended to facilitate the establishment of a long-term program of commercial [oil shale] leasing." Draft PEIS at ES-5. This program, in turn, would lead to development activities utilizing untested technology to convert kerogen to shale oil, with unknown potential long-term negative impacts to Colorado's environment, public health and welfare, wildlife, and communities. The BLM concedes that "impacts on specific resources located within the 52837-015

[2] Federal lands overlie only about 80% of the estimated in-place oil shale resources, leaving 20% in private hands. *See* Bartis, *et al.*, "Oil Shale Development in the United States: Prospects and Policy Issues," RAND Corporation (2005) at 9.

[3] Senior Policy Researcher James T. Bartis, RAND Corporation, "Policy Issues for Oil Shale Development," testimony before House Committee on Natural Resources, Subcommittee on Energy and Mineral Resources, April 17, 2007, available at http://www.rand.org/pubs/testimonies/CT279.

1,991,222 acres [as provided in the Preferred Alternative] cannot be quantified at this time because key information about the location of commercial projects, the technologies that will be employed, the project size or production level, and development time lines are unknown." Draft PEIS at 6-36.

This finding triggers further information-disclosure requirements, according to regulations implementing NEPA. Because the information on oil shale impacts is essential to a choice as to whether to make land available for application for commercial oil shale leases yet cannot be obtained because it does not yet exist, the BLM is required to assess the relevance of the incomplete information and provide a summary of existing credible evidence relevant to the evaluation. 40 C.F.R. § 1502.22. The BLM, however, fails in the Draft PEIS to assess the relevance of the missing information on likely impacts of the oil shale development activities it is facilitating, and it provides only a general summary of the existing information. The BLM thus appears to dismiss the missing information as not necessary in assessing the propriety of making nearly 360,000 acres of federal oil shale resources available for application for commercial oil shale leases in Colorado. 52837-016

Given the paucity of information concerning the likely impacts of commercial-scale oil shale development, as well as the contradictory interpretations of NEPA requirements, Colorado continues to support the RD&D approach as a way to obtain an important part of the missing information that is required to make a reasoned choice among the various land management and policy alternatives. Colorado will continue to oppose any commercialization plan that calls for commercial leasing, or for the promulgation of leasing regulations, prior to a meaningful evaluation of the RD&D projects and proper NEPA analyses.[4] 52837-001 (cont.)

In order to be able to perform a meaningful environmental impact analysis and to reach a reasoned and informed decision regarding the feasible and appropriate scope of commercial oil shale development, BLM needs to proceed now to develop the information needed to fill the information gaps that limit the effectiveness of the current PEIS analysis. For example, needed information includes:

a. Baseline air quality monitoring;
b. Baseline ground and surface water quality monitoring; 52837-017
c. Baseline wildlife monitoring and specific conservation measures for deer, elk, sage grouse, and Colorado River cutthroat trout;
d. An analysis of the availability of water supplies;
e. An analysis of options for meeting power demands for oil shale development in a manner consistent with Colorado's renewable energy standard;
f. Paleoseismic studies of faults within the oil shale basin;
g. A thorough realistic housing analysis incorporating local constraints including buildable land and infrastructure; and

[4] *See* Colorado Statement on Unconventional Fuels, Task Force on Strategic Unconventional Fuels, America's Strategic Unconventional Fuels, Volume I at I-79 (Sept. 2007), *available at* http://www.unconventionalfuels.org/images/Volume_I_IntegratedPlan_Final_.pdf.

h. Baseline data for community infrastructure capacity that can be used to assess what additional infrastructure will be required to support oil shale development. 52837-017 (cont.)

Cumulative Impacts

The BLM proposes to make large areas of Northwest Colorado available for application for commercial oil shale leasing, without conducting the required analysis of the cumulative impacts of doing so. While the BLM claims in the Draft PEIS that it will study the cumulative impacts of proposed oil shale development projects when it receives an application for a commercial lease, the proper time to evaluate the regional cumulative impacts of a new oil shale leasing program is at the PEIS stage. In 2007, the Colorado General Assembly unanimously acknowledged that comprehensive planning of energy development on a basin-wide scale should be performed in order to adequately assess cumulative impacts. *See* HB07-1298, *codified at* C.R.S. § 34-60-128(3)(d)(II).

The BLM is proposing to make hundreds of thousands of acres open to application for oil shale leases, which could lead to multiple applications for large-scale oil shale projects. Logistically, the BLM simply cannot analyze the cumulative impacts of this decision when performing NEPA review on a project-specific, piecemeal basis in response to an individual application for a commercial lease. For example, an accurate assessment of cumulative impacts would be impossible where there are multiple applications under review simultaneously, at various times of review, and without knowing the number and size of projects that will be proposed in the future. The BLM has provided no assurance that it will be able to perform an adequate comprehensive review of cumulative impacts for each individual application prior to consideration and review of additional applications. 52837-018

It is important to understand the social and environmental circumstances present in Colorado today, as the analysis of cumulative impacts required by NEPA and requested herein is not merely an academic exercise. The State of Colorado is currently experiencing an unprecedented energy boom in many portions of our state. In particular, the areas that the BLM proposes to make available for application for commercial oil shale leases are experiencing rapid natural gas development. In Colorado's Piceance Basin, the BLM proposes to make 359,798 acres available for application for commercial oil shale leasing. Draft PEIS at 2-27. In this same area, the BLM is analyzing a change to management plans that could allow over 17,000 new natural gas wells to be drilled over the next twenty years.[5] In addition, the areas the BLM proposes to make available for application for oil shale leasing are seeing increased tourism and recreation opportunities. In 2006, approximately 17,000 jobs were found to be supported by the tourism industry for the region including Moffat, Rio Blanco, Garfield, and Mesa Counties, and tourism as a whole represents about 15% of the jobs in the area. Past research on segments of the tourism industry found that about 20% of the tourism jobs in Northwest Colorado came from the outdoor recreation segment -- or about 3,400 jobs. In the Piceance Basin's Game Management Unit 22, there were 4,582 deer and elk hunters in 2006.

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[5] *See* Reasonable Foreseeable Development Scenario for Oil and Gas Activities in the BLM White River Field Office: Rio Blanco, Moffat, and Garfield Counties, Colorado, Executive Summary at 3, *available at* http://www.blm.gov/rmp/co/whiteriver/documents/RFD_Executuve_Sumnmary.pdf.

Any oil shale leasing on top of this existing network of energy development and changing land uses will put significantly more pressure on an already fragile ecosystem and public temperament, and it will further stress the system that provides the goods and materials for infrastructure needs driven by the current demands.[6] Furthermore, the inherent limitation of the oil shale industry may be in the existing environmental standards for the area. The proposed gas development, under current leasing schedules, coupled with other current industry-based activities in the area, may leave only a small increment under existing environmental performance standards for oil shale. The limit may not be land, may not be economics, but rather the air and water quality standards themselves. This cannot be determined without a detailed cumulative analysis. 52837-018 (cont.)

Thus, it is vitally important to the Departments and to the State of Colorado that the BLM proceeds cautiously and moves forward thoughtfully with the development of a commercial oil shale leasing program that truly looks at the cumulative impacts in a programmatic way. As the epicenter of the developable oil shale resource in the United States, Colorado has much to gain if this resource is developed responsibly, and much to lose if the risks are not assessed and managed appropriately.

A Programmatic Environmental Impact Statement is intended to provide a meaningful analysis of the impacts of an overall program, prior to proceeding with project-by-project approvals. *See Kleppe v. Sierra Club*, 427 U.S. 390 (1976) ("[W]hen several proposals for coal-related actions that will have cumulative or synergistic environmental impact upon a region are pending concurrently before an agency, their environmental consequences must be considered together."). Because of the absence of information to allow a meaningful assessment of the potential impacts of commercial oil shale development at this time, the Draft PEIS does not satisfy its intended purpose. Therefore, BLM should explicitly commit to preparing a supplemental PEIS at a later date, when adequate technical information is available and the agency is committed to conducting the necessary cumulative impacts analysis, prior to proceeding with commercial oil shale regulatory and leasing actions. Only in such a document may the BLM perform the analysis of cumulative impacts required by NEPA and demanded by responsible public policy. 52837-019

Carrying Capacity Thresholds

Recognizing the importance of resources in the oil shale region and the threat posed by large-scale oil shale development, the BLM's 1987 RMP for the Piceance Basin set "Critical Carrying Capacity" thresholds for oil shale development for air quality, annual growth rate of communities, wildlife, and water quality.[7] The Piceance RMP provides for continual monitoring of oil shale development in relation to the carrying capacity thresholds, and mandates that "[a] project exceeding any one of the thresholds will not be leased or approved as proposed." These 52837-20

6 *See* DNR Executive Director Russell George on behalf of Governor Bill Owens, testimony before Senate Committee on Energy and Natural Resources, Oil Shale and Oil Sands Resources Hearing, April 12, 2005.

7 BLM, White River Resource Area, Piceance Basin Resource Management Plan Record of Decision at 2-3, 2-6 (May 1987).

carrying capacity management decisions were specifically incorporated when the BLM adopted a new RMP for the White River Resource Area in 1997: "The oil shale management decisions developed in the Piceance Basin Resource Management Plan (March 1985) are carried forward as decisions in this document (See Map 2-6)."[8]

Because the areas of the Green River Formation are relatively sparsely populated, boom and bust cycles associated with oil shale could have disastrous effects on the communities, stressing existing infrastructure with increased population and associated needs. Recognizing this, the 1987 Piceance Basin RMP set a carrying capacity threshold of 5-15% annual growth rate in communities. Because of the potential for significant effects on wildlife habitat from oil shale development, the Piceance RMP imposed a carrying capacity threshold for wintering mule deer. The RMP imposed on the BLM the obligation to preserve the habitat needed to maintain 24,900 mule deer (24,650 AUMs). This figure was found to be 83% of the actual wintering Piceance Basin herd of 30,000 on all lands, and to represent the minimum acceptable herd size agreed to by BLM and Colorado Division of Wildlife (CDOW) in 1987. The Piceance RMP also found that "[s]tringent wildlife habitat mitigation" could be imposed instead of prohibiting leasing, depending on actual site-specific and cumulative impacts to mule deer, although it neglects to set out any potential mitigation measures.

In the Draft PEIS, the BLM describes the carrying capacity of a system as being "the maximum level of activity that can be sustained within a specific area without significant, detrimental impact." Draft PEIS at 2-53. Nonetheless, and without analysis, the BLM appears to propose doing away with the carrying capacity thresholds for Colorado oil shale lands entirely. Though the BLM acknowledges that development of an oil shale lease "would represent a loss of habitat for these species and potentially a reduction in carrying capacity in the area," Draft PEIS at 4-72, it again relies on future, site-specific NEPA reviews to consider impacts. It states that "programmatic alternatives do not explicitly consider carrying-capacity thresholds nor propose that commercial leasing levels be constrained in the future by these thresholds." Draft PEIS at 2-53.

52837-020 (cont.)

While the Departments cannot say with certainty that the numeric standards in the Piceance Basin and White River RMPs for carrying capacities continue to be the proper thresholds, the concept of carrying capacity thresholds should not be disregarded lightly. These carrying capacity thresholds have been in place for over two decades, imposing objective standards to guard valuable and imperiled public resources from the cumulative impacts of unchecked oil shale management decisions. Given that the BLM is here effectively deferring an analysis of cumulative impacts to the site-specific leasing stage, the carrying capacity thresholds are even more important. The BLM's apparent proposal to jettison these standards without any analysis of the impacts of doing so ignores the work of BLM and the State of Colorado through the years on the issue.

In the Final PEIS, the BLM should analyze data on the current populations of wintering mule deer and elk and update, if necessary, the number that must be supported for the benefit of the species. Likewise, the BLM should assess the likely socioeconomic impact of a significant

[8] *See supra* note 1, *at* 2-6.

new industry in the oil shale region, in conjunction with the current localized natural gas industry. The agency should also reevaluate the carrying capacities for air and water quality in order to assess whether they are currently adequate to protect these vitally important public resources. 52837-020 (cont.)

The BLM's anticipated leasing regulations

The Draft PEIS attempts to address the BLM's proposal to amend resource management plans to allow for potential oil shale lease applications, as opposed to any regulations for such lease applications or a leasing program. However, the BLM has indicated that it expects to later promulgate such regulations pursuant to section 369(d)(2) of the Energy Policy Act of 2005. During recent stakeholder meetings, the BLM has also indicated that it intends to issue an Environmental Assessment (EA) in conjunction with such leasing regulations. Colorado is concerned that such an approach will not comply with NEPA.

It appears that the BLM's leasing regulations will address such critical issues as the leasing process, bonding, royalty rates, fair market value, and bonus bids. Such regulations would thus set in place factors that will directly and significantly affect how oil shale development proceeds. As such, promulgation of such regulations would constitute a "major federal action significantly affecting the quality of the human environment," and would require preparation of an EIS and signing of a Record of Decision prior to adoption. *See* NEPA § 102(C), 42 U.S.C. § 4332(2)(C).

According to the BLM, "Actions whose impacts are expected to be significant and which are not fully covered in an existing EIS must be analyzed in a new or supplemental EIS. An EIS should also be prepared if, after or during preparation of an EA, it is determined that the impacts of a proposed action are significant." *National Environmental Policy Act Handbook and Department of the Interior NEPA Guidance Manual 516, BLM Handbook H-1790-1*, at p. I-2. 52837-021

While an EA may be used to decide whether to prepare an EIS, such an interim step is not necessary here. An agency need not prepare an EA if it prepares an EIS. *See* 40 CFR § 1501.3(a). Congress and the BLM have already determined that an EIS is appropriate for the BLM's proposed leasing program. Moreover, the BLM's Draft PEIS amending resource management plans repeatedly makes clear that due to missing and incomplete information, the BLM cannot adequately assess the potential impacts of commercial oil shale leasing at this time. There are thus serious questions as to how a NEPA analysis for leasing regulations (particularly a mere EA) could adequately tier off of, or otherwise rely on, the current Draft PEIS amending resource management plans.

Preparing draft leasing regulations without the benefit of data from the RD&D projects that these regulations would address will make any conclusions and recommendations premature, incomplete, and possibly irrelevant. While the State of Colorado will have to await the BLM's publication of draft leasing regulations before providing further comment, Colorado wants BLM to know in advance the test to which the State will put such proposals.

Conclusion

Thank you for this opportunity to comment. The State of Colorado believes that the issues discussed above and in the attached technical comments must be addressed in the Final PEIS.

We look forward to continuing to work cooperatively with BLM to ensure that the significant challenges associated with oil shale development are addressed in a thorough and protective manner.

Sincerely,

Bill Ritter, Jr.
Governor

Technical Comments of
Colorado Department of Natural Resources,
Colorado Department of Public Health and Environment, and
Colorado Department of Local Affairs
on Bureau of Land Management's
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 (December 2007)

The following technical comments from divisions and staff of the Colorado Department of Natural Resources (CDNR), Colorado Department of Public Health and Environment (CDPHE), and Colorado Department of Local Affairs (DOLA) highlight major technical deficiencies in the Bureau of Land Management's (BLM) 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 (Draft PEIS).

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1) Division of Reclamation, Mining and Safety

There is very little real data with which to determine what the environmental effects of *in-situ* processing of oil shale will be since there has not yet been a commercial sized *in-situ* project to date. This information may be obtained in the next 5-10 years upon development and close monitoring through the various permitting processes of the RD&D projects. There is no stated mechanism to revisit the PEIS process in order to re-evaluate regional effects of commercial development if there is critical information gleaned from the RD&D operations. Instead, the PEIS states that such changes will be dealt with on a case by case basis via NEPA review of specific projects, a manner which is similar to the way that coal mining environmental impacts are evaluated. This approach will preclude consideration of regional impacts from the widespread use of new technologies for oil shale development. 52837-022

In Section 4.1.6, Table 4.1.6-1, the effects and needs of a 2,400 MW generating station are listed. Conspicuously missing are the effects of the coal mine that would be needed to feed the generating station. For example, the Craig Generating Station (1,284 MW) is fed primarily by the Trapper Mine which has a permitted acreage of 10,000 acres and a disturbed acreage of approximately 3,200 acres over its 25 year life. It is noted that the commercial options B, C and D would require the equivalent of almost 10 Craig-sized generating stations over the life of the commercial oil shale operations (12 GW of power required – although estimates of the electrical need for *in-situ* operations is not well documented since no commercial-scale operations have been started) for a total of not only the acreages listed in the table but also some 32,000 additional acres disturbed via coal mining with its own environmental and socio-economic effects and additional water requirements for coal processing, dust suppression, and other mine and workforce related activities. Additionally, if these mines are located near oil shale development areas, they will have their own effects on air quality which has also not been factored in. Moreover, there is no discussion on the effects of uranium fueled power plants and their environmental effects and operating needs if this type of power plant is used. 52837-023

Chapter 4, Table 4.5-1 lists the water resources available and expected to be available by 2040 (presumably when commercial oil shale operations would be fully functional). It is notable that the water requirements (on the lower estimate of the needs for commercial oil shale operations) will exceed those available in 2040 from surface sources. It is stated that the requirements can be made up from the ground water resources but the estimate of that resource varies by an order of magnitude (2.5 to 25 M ac-ft). The possible diminution of surface and ground water quantity and quality from the direct effects of oil shale development (e.g. mixing of aquifers, drainage of the upper aquifer into the lower aquifer, quality degradation from the release or organics, salts and metals via pyrolysis) is not accounted for in this table but should be estimated and included. 52837-024

Related to water balance for commercial operations, it is known that ground water in the Piceance Basin travels rather slowly and, therefore, is recharged rather slowly. It is also known and stated that both Piceance and Yellow Creeks (the main drainages out of the Piceance Basin) are both ground water fed creeks. It therefore seems reasonable to assume that withdrawal of the ground water for use in oil shale operations will most probably have a flow lessening effect on one or both of these creeks through the disruption of spring or seep flows that feed them. It is unclear whether this diminution in surface flow has been taken into account in the water balance estimates except for the statement that the freeze wall will mitigate these effects. The freeze wall will not be in existence after oil withdrawal and subsequent rinsing of the retorted area is complete and that area will have to recharge by some mechanism. This doesn't seem to be accounted for. 52837-025

The Draft PEIS omits discussion of several important issues. There is no mention or discussion of dissolved metals (boron, molybdenum, arsenic, and possibly others) and their effects on ground water from the *in-situ* pyrolysis of oil shale. There is no discussion of noise levels from resource development. There is no discussion on wilderness characteristic areas in Colorado. 52837-026

Legal Requirements

The Draft PEIS defers site specific NEPA analysis of potential impacts to 360,000 acres of public land in Colorado to future evaluations. There has to date never been commercially viable production of oil from Colorado oil shale resources, even though Colorado possesses the richest and most extensive global reserves. It is stated in the Executive Summary to the Draft PEIS that "As part of this PEIS, potential impacts of currently known technologies also have been described at the programmatic level to aid decision makers and readers in understanding the potential effects of future development." While this may be a currently legitimate course of action, it must be recognized that research and technology development for oil shale will require further analysis at the programmatic level, as opposed the project specific level, as the draft PEIS seems to presume. 52837-027

Chapter 2, Section 2.2.1 describes "Existing Relevant Statutory Requirements" and breaks out potentially applicable laws into general categories. Appendix D, Table D-3 places the Colorado Mined Land Reclamation Act (MLRA) into the "Energy Project Siting" category. The Energy Project Siting category is described in Chapter 2 as being relevant to "construction of facilities such as pipelines, gathering lines, transmission lines, or generation facilities." 52837-028

Essentially none of these activities are subject to regulation under the MLRA. The MLRA should be removed from the Energy Project Siting category in Appendix D, and should be included in the Appendix D tables under the following categories, over which the MLRA does exercise authority:

TABLE D-4 Floodplains and Wetlands
TABLE D-5 Groundwater, Drinking Water, and Water Rights
TABLE D-6 Hazardous Materials
TABLE D-7 Hazardous Waste and Polychlorinated Biphenyls
TABLE D-10 Pesticides and Noxious Weeds
TABLE D-13 Water Bodies and Wastewater
TABLE D-14 Wildlife and Plants

52837-028 (cont.)

It is stated in the Draft PEIS that Chapter 2, Section 2.2.1 "discusses, in very general terms, the major laws, Executive Orders (E.O.s), and policies that may provide environmental protection and compliance requirements for oil shale or tar sands development projects on public lands in Colorado, Utah, and Wyoming." However, there is little or no discussion, and no identified category of State mined land reclamation laws, even though each of the three potentially affected States have such laws. Mined land reclamation should be included in the listing of "major laws" for each of the three states, and the Colorado Mined Land Reclamation Act (34-32-101, *et. seq.*) should be specifically cited.

52837-029

Comments on Specific Passages of Draft PEIS

On page 1-3, the Draft PEIS states, "The BLM has identified the most geologically prospective areas for oil shale development on the basis of the grade and thickness of the deposits." Are the deposits sufficiently characterized that the agency can definitively state where the most geologically prospective areas are? Is the definition of a geologically prospective area based on detailed exploratory data, such as delineation drilling or geophysical surveys, or have extrapolations and generalizations been made from existing data? If there are deficiencies in the characterization of the geologically prospective areas, then important decisions regarding lease locations, or locations of facilities for exploration, extraction, infrastructure, and support are in danger of being made without adequate background information, leading subsequently to the risk of poorly conceived resource utilization.

52837-030

On Table 2.2.3-1 on page 2-8 of the Draft PEIS, the importance of the ACEC areas in this table are given considerable weight in the overall context of environmental impacts of oil shale development, yet very little specifics are provided for the ACEC areas.

52837-031

On page 3-73, the Draft PEIS states that "Oil shale basins and STSAs are situated in much smaller areas," yet it is unclear from the context of the passage to what the oil shale basins and STSAs are being compared.

52837-032

On page 3-77, the passage starting with "Topper et al. (2003) list common sources of..." is not particularly relevant to the subject of oil shale extraction. The passage refers to contaminants derived from hardrock and metal mines. The mining methods employed, and the geologic environment existing at oil shale deposits will be vastly different than those existing at

52837-033

hardrock or metal mining sites. The inclusion of this passage implies that the two types of mining situations could give rise to common environmental contaminants, which is an inaccurate and misleading implication. 52837-033 (cont.)

On page 4-3, the passage referring to the quantity of water used by oil shale operations, is one of many passages referring to the quantity of water that will be "used" by oil shale development, without sufficient explanation as to whether the water is actually consumed or simply diverted, used, and cycled back to the watershed as return flow. Proper emphasis on the amount of total water consumption versus simple usage will help provide a more realistic picture of the actual water demands of the oil shale industry. 52837-034

On page 4-6, the Draft PEIS states, "Regardless of the retort, spent shale volume would increase by 30%," yet it is unclear from the context of the passage over what the spent shale volume would increase by 30%. 52837-035

On page 4-12, the Draft PEIS states, "Project economics would likely select for sites closest to existing infrastructure." This passage is inconsistent with other passages in the document stating that companies will construct their own plants to provide power for operations. It seems a foregone conclusion that, due to the economic potential of oil shale development, project economics will drive the locations of power supply and infrastructure, not the other way around. 52837-036

On page 4-25, the Draft PEIS states, "In Colorado or Utah, 150 to 600 acres would be disturbed at any one time, while in Wyoming, the figure would be 1,000 to 2,000 acres." This is one of several passages in the document referencing the size of impacts or disturbances. However, it is unclear here and in other passages whether these numbers represent the total disturbance at any particular time, or per-site numbers within larger projects containing multiple sites, or something else. 52837-037

On page 4-33, in the paragraph that starts with "For in situ processes, the impact of in situ processing..." it is important to note that the permeabilities of the aquifers and aquitards may be affected not only by rock fracturing, but also by the removal of hydrocarbons. 52837-038

Finally on page 4-35, the Draft PEIS states, "In addition, the filled mine could become a vertical conduit for groundwater, resulting in a discharge area for the shallow aquifer and a recharge area for the deeper aquifer." An additional consideration is that of an upward hydraulic gradient. In the case of an upward hydraulic gradient, the opposite could be true, i.e., the filled mine could become a discharge area for the deeper aquifers and a recharge area for the shallow aquifer. 52837-039

2) Division of Wildlife

The Colorado Division of Wildlife (CDOW) appreciates the opportunity to comment on the December 2007 draft of the Bureau of Land Management's (BLM) Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming Programmatic Environmental Impact Statement (OSTS PEIS). Proposed oil shale 52837-040 development in Colorado would occur in the Piceance Basin, which includes portions of the BLM's White River, Glenwood Springs and Grand Junction Field Offices. As each of these field offices are currently undergoing or are about to begin Resource Management Plan (RMP) revisions, it will be important to incorporate new information from these revised RMPs in the OSTS PEIS, especially those areas protected by stipulations that would affect lands available for lease under Alternative C. It will be equally important for BLM to incorporate the impacts and other implications of oil shale development into these RMPs and to evaluate the cumulative impacts of oil shale leasing and development in each of the revised RMPs as well. It is as imperative now as ever that potential oil shale development impacts are evaluated and that an oil shale management strategy is developed to ensure that BLM's multiple use and sustained yield mandates are retained. CDOW expects the BLM to conduct meaningful analysis that is both specific and measurable to evaluate cumulative impacts resulting from mineral extractive industries. 52837-040 (cont.)

The Piceance Basin is home to the largest migratory mule deer herd in North America, a large migratory elk population, one of only six greater sage-grouse populations in Colorado, conservation and core conservation populations of Colorado River cutthroat trout, and a host of other wildlife species. These resources are of statewide economic, ecological, recreational, and aesthetic importance. Impacts to these wildlife resources from oil shale development will have local, regional, statewide, and even national implications to sportsmen and other wildlife enthusiasts. Areas that would be opened for commercial leasing under Alternative B include:

- 880 acres of important aquatic habitat
- 7 acres of bald eagle active nests (buffered at ½ mile--no surface occupancy)
- 190,478 acres of elk production area
- 6,506 acres of greater sage-grouse leks (buffered at 0.6 mile--no surface occupancy)
- 125,563 acres of greater sage-grouse production area (mapped as a 4 mile radius from leks to protect nesting and brood rearing habitat) 52837-041
- 78,093 acres of mule deer critical winter range
- 31,479 acres of mule deer migration corridor(s)

This list identifies the minimum set of specific species and habitats that CDOW believes require ***detailed and comprehensive*** analysis prior to any future commercial oil shale leasing in the Piceance Basin. The sum of these areas is shown on the attached map. When and if commercial leasing occurs, CDOW expects to consult with the BLM regarding the suitability of any lands proposed for leasing, the extraction mechanisms proposed, and mitigation techniques required to offset any impacts to wildlife and wildlife habitat that cannot be avoided. For CDOW to most effectively offset these impacts, it will be important for CDOW to be engaged in discussions with BLM early and often. This consultation should occur prior to the release of a NEPA scoping notice whenever possible.

Leasing Alternatives

Five Research, Development and Demonstration tracts have been recently permitted in the Piceance Basin, primarily for the purpose of evaluating oil shale extraction techniques and assessing the environmental impacts of oil shale development. Exploration of geologic conditions and development plans for these RD&D sites are only in preliminary stages. Therefore, the ability to successfully predict environmental impacts is yet to be determined. While we understand that some amount of RD&D must occur to determine if oil shale can be produced without impacting the environment, CDOW supports BLM's decision not to allow any additional RD&D projects and their associated preference lease right acreages to be permitted. The five existing RD&D tracts include preference rights for commercial leasing of more than 25,000 acres within the Piceance Basin.

CDOW supports a "go slow" approach to oil shale development while it remains in this "experimental" phase and prefers that BLM adopt Alternative A—the No Action Alternative—to allow these RD&D projects sufficient time to provide necessary information to support future commercial leasing. Alternative A includes preference rights allowing more than 25,000 acres of commercial oil shale leasing within the Piceance Basin. 52837-042

Alternatives B and C propose significant additional lease areas in Colorado. CDOW considers the lease availability proposed in these alternatives, especially the identification of the entire Piceance Basin in Alternative B, to be an irrevocable commitment of the mineral resource that, when developed, will have significant, adverse, and long term impacts on the wildlife resource and that will complicate BLM's statutory mandate to manage federal lands in compliance with the "multiple use" and "sustained yield" concepts required by the Federal Land Policy and Management Act of 1976. 52837-043

Section 4.8.1.3 of the OSTS PEIS describes a number of impact mechanisms, from direct mortality to habitat loss and fragmentation, through which wildlife could be impacted by oil shale development proceeding from decisions made in the OSTS PEIS. CDOW believes that each of these mechanisms will indeed occur as a direct or indirect result of oil shale development in the Piceance Basin and that the resulting impacts on wildlife will be severe and potentially long lasting. Table 4.8.1-1 states that the effect on wildlife from one or more of these impact mechanisms will be moderate to large for each class of wildlife evaluated. Moderate effects are defined as resulting in measurable loss of wildlife carrying capacity of up to 50% within the affected area. Large effects would result in more than 50% loss of affected wildlife. CDOW believes that the loss of 50% or more of the ability of the landscape to support wildlife from any single activity is neither moderate nor acceptable. In addition, the Piceance Basin does not currently and may not ever have the capacity to meet oil shale's requirements for infrastructure, power, or water. CDOW anticipates this could be a substantially limiting factor to development and should be reflected in the decision about the appropriate amount of the Piceance Basin to make available for leasing. 52837-044

Alternative B, BLM's Preferred Alternative, proposes to make the entire Piceance Basin available for leasing. Adoption of this alternative is unsupportable given the complete lack of understanding affirmed in the OSTS PEIS about the extraction processes that may be feasible and the impacts that development will create for wildlife and wildlife habitat. While the pre- and post-lease NEPA requirements established by the OSTS PEIS will provide substantial additional protection for wildlife, designating the entire Piceance Basin as open for leasing conveys some expectation to industry, governmental agencies and others that substantial commercial leasing will occur relatively quickly. This expectation cannot be met, given the current state of 52837-045 knowledge, and still meet the "environmentally sound" standard under which commercial oil shale leasing is to occur. 52837-045 (cont.)

Finally, CDOW believes that the three alternatives proposed in the draft OSTS PEIS, the no-action alternative and two commercial leasing alternatives, do not constitute a complete range of actions for analysis. Analysis of additional alternatives, including a phased approach to lease availability, would provide a more thorough understanding of the implications of lease availability and the development impacts that will follow. 52837-046

Additional Recommendations for Analysis Prior to Commercial Leasing

1. Neither the OSTS PEIS nor the White River RMP adequately addresses either the commercial development potential or the likely impacts that will result from oil shale development on the tens of thousands of acres of oil shale that were patented during the previous oil shale boom and that are now privately owned. Additionally, neither document combines an analysis of the landscape effects of additional BLM oil shale leasing and development, private oil shale development, existing oil and gas development levels, or the proposed increase in oil and gas activity within the White River Field Office. This separation of oil shale and oil and gas development impacts results in a piecemeal approach to NEPA that prevents a full presentation and analysis of the full effect of these federal actions. 52837-047

2. The OSTS PEIS needs to provide a more detailed analysis as to how the proposed alternatives will impact wildlife populations and habitat. For example, the Colorado Division of Wildlife believes that oil shale RD&D activities within the central portion of the Piceance Basin will increase oil and gas activity on the periphery. If oil shale is considered the priority mineral in the area of the RD&D's, and coincident oil and gas development occurs, ecosystem-level effects will significantly impact many different wildlife species. For instance, the Parachute/Piceance/Roan (PPR) greater sage-grouse population utilizes higher elevation areas in the southern portion of the Piceance Basin and in the Magnolia area. The PPR population of greater sage-grouse is geographically isolated. The unique characteristics of greater sage-grouse habitat in the PPR and the high range fidelity exhibited by the species will make adjustment to the increased activity challenging. Consequently, availability of expanded leases for commercial oil shale development, as proposed in the OSTS PEIS, in conjunction with expanded oil and gas development will likely lead to extirpation of the PPR sage-grouse population. The PPR population is one of only six greater sage-grouse populations in Colorado. Extirpation of this population will make the avoidance of future Endangered Species Act (ESA) listing actions substantially more difficult. Any ESA listing will directly affect industry as well as any other users of public lands within the oil shale development areas. 52837-048

3. The alternatives detailed within the OSTS PEIS need to more fully assess the off-site impacts that might result from oil shale development, including issues such as: 52837-049

-damage that private landowners will suffer from big game species as a result of added pressure of oil shale development on lands already impacted by natural gas development.

-effects of big game being forced to occupy alternate winter range habitat, resulting in reduced survival of big game herds and increased competition with livestock on private lands. 52837-049 (cont.)

-effects of oil shale development on water quality and quantity in federally designated critical habitat for threatened and endangered aquatic species in the White River below the confluence with Piceance Creek.

4. An assessment of the water quality impacts to all wildlife species that utilize the Piceance Basin should be provided for each alternative presented in the OSTS PEIS. The assessment should not only factor in the effects of oil shale development, but also consider existing and anticipated oil and gas development within the Piceance Basin, coal extraction areas and new power plants needed to supply power to the oil shale extraction operations, and pipelines and other infrastructure needed to support the oil shale and oil and gas operations. The assessment should include an evaluation of the direct or indirect effects to wildlife populations from:
   a. increased sedimentation; 52837-050
   b. increased stormwater runoff and salinity;
   c. rising water temperatures and lower stream water levels due to oil shale de-watering activities;
   d. increased contaminant spills to natural waterways; and
   e. increased concentrations of minerals, metals and other by-products liberated during the oil shale extraction and final reclamation processes and the level to which they cause detrimental water quality impacts to aquatic life and cold water fish species.

5. The assessment of changes to water quantity at a watershed level from oil shale development for each alternative should address the anticipated resulting impacts to wildlife populations due to: 52837-051
   a. elimination of springs, seeps, or other naturally occurring surface water expressions; and
   b. potential reduction and/or elimination of riparian habitat.

6. The discussion in the cumulative impacts section within the present draft OSTS PEIS lacks sufficient detail and analysis to make any determination of the cumulative impacts to wildlife resources resulting from oil shale development and the interplay between oil shale, natural gas, and other types of development occurring in the Piceance Basin. The section of the OSTS PEIS which analyzes cumulative impacts should be substantially expanded to include temporal and spatial boundaries outside the immediate defined project area in order to effectively address impacts to migratory wildlife. 52837-052

7. The analysis of cumulative impacts should include an assessment of the reasonable foreseeable development of commercial oil shale development in terms of the timing and distribution and size of oil shale production that will occur, including the maximum number of leases that could be in development at any one time and the maximum "footprint" of surface disturbance for any one operation. The assessment of cumulative impacts to wildlife should include an assessment of impacts to all wildlife species occurring within the most geologically prospective area of the Piceance Basin and also on lands within the Piceance Basin that will be subject to surface disturbance via other forms of mineral development and land uses. It should also be expanded to include impacts occurring on other lands outside the boundaries of the prospective area of oil shale development that contain populations of wildlife that utilize all or portions of the prospective area of oil shale development periodically throughout the year. The cumulative impacts analysis section of the OSTS PEIS should include: 52837-053
   a. an assessment of baseline wildlife data including an evaluation of the status or health of existing populations and how the various populations have been affected previously be other forms of disturbance (oil & gas development, roads, etc.);
   b. detail regarding the thresholds that will cause significant damage to various species;
   c. an inventory of all types of disturbance including oil shale development;
   d. an overlay of crucial habitats including existing migration corridors over the areas slated for commercial oil shale development;
   e. an assessment of the magnitude and extent of crucial habitat areas that will be eliminated as a result of oil shale development;
   f. an assessment of the magnitude and extent of crucial habitat areas that will be adversely affected; and
   g. the duration of time that wildlife populations will be affected.

Additional Issues That Should Be Addressed in the OSTS PEIS or in Subsequent NEPA Analyses

1. Range-wide and interstate conservation agreements and strategies exist for several species present within the Piceance Basin, including Colorado River cutthroat trout, flannelmouth sucker, bluehead sucker, roundtail chub, and greater sage-grouse. These agreements, and conservation actions recommended within them, should be incorporated and referenced in the OSTS PEIS and subsequent NEPA documents. 52837-054

2. Specific detail should be presented on how the landscape will be managed for multiple uses as well as diverse assemblages of wildlife species as required by NEPA. The OSTS PEIS should contain an evaluation of how industrialization and the accompanying urbanization through oil shale development will reduce the carrying capacity of the landscape. For example, where existing agricultural water rights are acquired to support oil shale development, existing irrigation-based agricultural uses of the land from which the water is acquired will be modified to support lower value dry land use of the lands and may result in a complete loss of agricultural benefits. The final OSTS PEIS and subsequent NEPA documents need to detail how these impacts to the carrying capacity of the landscape at a regional scale will directly and indirectly affect the wildlife 52837-055

populations of the region. The final OSTS PEIS needs to include detail how the "multiple uses" of the landscape will be maintained at a regional scale in light of oil shale lease availability and subsequent development. 52837-055 (cont.)

3. The OSTS PEIS contains very limited information and analysis of the feasibility of reclamation of commercial scale oil shale operations. Oil shale development coincident with oil and gas development will likely result in long-term surface disturbance and severely fragment wildlife habitat for extended periods. Additional information should be provided as to the types of habitat and vegetation that will likely not be re-established during final reclamation, those habitat types and vegetation that will be difficult to re-establish, and the length of time needed to successfully re-establish the habitats and vegetation that sustain resident and migratory populations of wildlife and the quality of these reclaimed areas for wildlife following final reclamation. The OSTS PEIS analyses should also include an assessment of the feasibility of reclaiming affected surface and groundwater resources that are used by wildlife within the Piceance Basin. 52837-056

4. The OSTS PEIS should include an assessment of the existence, location, and extent of noxious weed species and/or infestations within the Piceance Basin and the likelihood that they will become established more widely in the Basin as a result of widespread oil shale development. 52837-057

5. The OSTS PEIS should include a comprehensive and detailed analysis of the economic impact that changes in wildlife populations resulting from commercial oil shale development, along with oil and gas development, coal extraction and power plant generation, and supporting infrastructure, will have on local communities. Local communities in western Colorado rely heavily on hunting revenue. The short-term influx of energy development may offset the immediate economic impact that will result from loss of hunting revenues. However, as Colorado's history has shown, energy booms do not last forever, whereas the regional wildlife resource is renewable and provides a stable source of revenue to communities like Craig, Meeker, and Rifle. 52837-058

Research Cooperation Recommendation

Because the Piceance Basin holds such valuable energy reserves and also supports some of the richest wildlife habitat and most abundant wildlife resources in North America, CDOW has developed research proposals to evaluate methods to improve conservation of sage-grouse, mule deer, native plant communities, and the aquatic environments in the Piceance Basin as energy development proceeds. Determining how to extract energy reserves without negatively impacting wildlife populations is an essential test of the ability to promote responsible development. This information is a prerequisite to commercial oil shale development.

The key objectives of the research are to:

- Provide scientific, peer-reviewed, and experimentally-based research to test the effectiveness of mitigation strategies on mule deer and sage-grouse population performance and behavior in Colorado habitats.
- Avoid reliance on studies done in other states.

- Provide opportunities for evaluating creative mitigation solutions versus historically implemented timing regulations or fixed buffer zones.
- Provide a basis for developing consistent guidelines on a landscape level rather than an individual site basis.
- Reduce the need for individual energy companies to conduct independent studies on sage-grouse, mule deer, and appropriate habitat restoration.
- Evaluate potential solutions to allow for responsible energy development and still maintain Colorado's productive wildlife, natural resource values, and heritage.
- Obtain and evaluate baseline aquatic species and water quality information.

Many measures proposed to minimize and mitigate oil shale and natural gas development impacts on wildlife have not been tested. CDOW seeks to fill that knowledge gap. This project represents a comprehensive and coordinated effort to improve understanding of the effectiveness of energy development mitigation practices. CDOW is committing personnel and operational resources to the success of this project over the next decade. This project has been planned within BLM's White River Field Office. Support of this project by industry and land managers is very important. It may prove to be of critical importance in helping wildlife and land managers develop mechanisms to balance wildlife and their habitat requirements with energy development.

Summary

CDOW appreciates the opportunity to comment on this draft resource allocation OSTS PEIS pertaining to oil shale development in Colorado. The Piceance Basin and surrounding areas provide a significant wildlife resource and natural heritage to the people of Colorado and visitors to the state. CDOW understands the importance of the Piceance Basin's mineral resource. However, oil shale development is currently experimental, with poor understanding of the economic and technical aspects of development as well as the environmental impacts of development. For those reasons, CDOW advocates the "go slow" approach to oil shale development embodied in Alternative A.

CDOW is encouraged by the leasing approach taken in the OSTS PEIS, where detailed site-specific NEPA analysis will be required before parcels can be offered for commercial oil shale lease and before a site-specific plan of development is approved. The ability to evaluate impacts and to apply lease terms, stipulations, and mitigations once the development is fully understood provides substantially improved protection for wildlife and other resources on public lands eventually leased for commercial oil shale development. CDOW will participate in future BLM actions pertaining to oil shale leasing and development, including the Leasing NEPA stage and Plan of Operations stage, in order to ensure that adequate planning occurs and that measures for avoidance, minimization, and mitigation of impacts to wildlife are incorporated in future oil shale decisions. 52837-059

CDOW expects that oil shale leasing potential, commercial development, and cumulative impacts will be evaluated in great detail in the White River, Glenwood Springs and Grand Junction Resource Management Plan revisions that are currently in progress or that will begin soon as well as in this OSTS PEIS. Consideration of potential oil shale impacts along with those resulting from oil and gas development will be important for a complete analysis of impacts on 52837-060 wildlife and wildlife habitats and the possibility of maintaining desired future conditions. CDOW also strongly encourages BLM to engage in research, such as the Piceance Basin research project described earlier in this letter, to evaluate wildlife impacts and effective habitat mitigation. 52837-060 (cont.)

We encourage the BLM to strike a balance between the mineral and wildlife resources in the Piceance Basin by integrating these comments into a final Programmatic Environmental Impact Statement that contains adequate detail to assess the potential effects and impacts that the land allocation decisions being made will have on the other natural resources in the Piceance Basin and surrounding areas. Thank you for your consideration of these comments. We look forward to seeing them incorporated in the final OSTS PEIS.

3) Colorado Geological Survey

The Colorado Geological Survey (CGS) conducted a review of the BLM Draft Oil Shale and Tar Sands Resources Leasing Programmatic Environmental Impact Statement (PEIS) for content relevant to geologic resources including water. This review was conducted in order to determine whether the document is adequate to go forward with a decision to have a commercial leasing program for oil shale.

While the total content of the document is immense, it misses the mark in adequately addressing potential impacts to geologic resources by development of oil shale in Colorado and fails to clearly identify constraints under which leasing, exploration, and development would be allowed, particularly with respect to water and potentially damaging seismicity. 52837-061

The document purports that there will be no impact from simply changing management plans. However, dealing with oil shale leasing in individual management plans, rather than as a programmatic EIS that evaluates the cumulative effects of all resource development within the Piceance Basin, including oil shale; is a violation of the spirit and intent of Congress in directing that an EIS be performed for the programmatic leasing of commercial oil shale. Therefore, because a programmatic environmental impact statement was not performed for commercial oil shale leasing, the only acceptable alternative is Alternative A. 52837-062

Comments on Water Resources

Whereas the draft PEIS does use current estimates for water availability to Colorado from the Colorado River Basin under the Colorado River Compact, BLM really does not know how much water is available to apply to meet any new demands, regardless of the type of demand. A study, funded through SB07-122, is currently underway to evaluate water availability in the Colorado River Basin. The PEIS is inadequate without reliable data on Colorado River Basin water availability. 52837-063

The draft PEIS only addresses groundwater as it is tributary to the rivers. The document does not address "non-tributary" groundwater in the region, particularly as it relates to cumulative impacts from in situ processes within the groundwater aquifers. Non-tributary groundwater is important because its availability and use could affect the entire water demand 52837-064 equation in this region. The PEIS does not adequately address this aspect, and therefore, is inadequate in assessing cumulative impacts to water resources. 52837-064 (cont.)

There is too much uncertainty in what technologies might be used, and therefore, what the water demands associated with those technologies will be to make reasonable estimates of water demands for oil shale development under the three scenarios.

Both the Colorado River Basin and Yampa/White/Green Basin roundtables have embarked on needs assessments addressing M&I, agricultural, and non-consumptive needs within their watershed areas. Results from these needs assessments would also be of great value to evaluating potential cumulative impacts under different oil shale development scenarios. In addition, the Energy Development Water Needs Study, (funded through the statewide Water Supply Reserve Account) is underway and will address anticipated water needs associated with all energy development in the region. Without these assessments, the PEIS is inadequate to address cumulative impacts on water resources. 52837-065

Comment on Soil and Geologic Resources

The draft PEIS falls short in integrating cumulative impacts that might arise from oil shale development under the different scenarios. For example, additional power generation would be necessary to meet the demand at the thermo-electric in-situ facilities; however the draft PEIS does not appear to account for the increase in coal mining in the basin that would be required by the additional power plants to produce this energy. 52837-066

Comments on Hazardous Materials and Waste Management

Impacts of hazardous materials and waste management due to oil shale production cannot be differentiated between alternatives because significant data related to differing technologies, in particular in-situ oil shale processes, is yet to be generated. Without this type of data, the cumulative impacts for specific constituents of concern related to oil shale development in Colorado, such as mercury and arsenic among others, cannot be estimated. Therefore the PEIS is inadequate in allowing discrimination among the alternatives regarding hazardous materials and waste management. Alternative A is the only option in the absence of this data. 52837-067

Note: Constituent concentration units are not given in Table A-6. 52837-068

Discussion of 3.2.1.4- Piceance seismology

The draft PEIS is inadequate in terms of evaluating the earthquake risk that could have serious consequences for development in the Piceance Basin resulting from the issuance of rights to extract oil from the Green River Formation oil shale. The PEIS contains only one dismissive sentence on the seismic potential of the Piceance Basin. The seismicity section is inadequate to safely allow leasing from several standpoints: 52837-069

1. It does not address potential, induced seismicity from fluid injection near fault zones.

2. It does not address the seismogenic potential of Neogene faults in the area.

3. It does not address the probabilistic ground accelerations higher than 5% g in the USGS National Earthquake Hazard Maps, nor

4. It does not address deterministic ground accelerations of >50% g from a strong earthquake on the Dudley Graben fault.

a. Neogene faulting

Forty five years ago, there were no faults in Colorado that had been identified as being active during the Quaternary Period. Today, the catalog contains more than 90. And yet, many parts of Colorado have not been studied in detail for the extent and hazard of young faults, e.g. northwestern Colorado being one of the least studied areas of the state.

Ten, northwest-trending normal faults are shown on the Geologic Map of Colorado cutting Tertiary sediments of the Piceance Basin in the area of most prospective oil shale deposits. Several have prominent topographic expression that suggests a very young history with the potential of generating strong earthquakes. Their orientation and character show that they are Neogene in age and therefore should have been evaluated for potential earthquake hazards before any decisions to lease be made.

The Cimarron fault located at the southern end of the Piceance Basin, is a normal fault of identical attitude and has been shown to have Quaternary movement. The Cimarron fault has been assigned a Maximum Credible Earthquake of M 6.5. 52837-069 (cont.)

The Dudley Bluffs graben is in the heart of oil shale country. This fault is so youthful in appearance that a major geotechnical firm attributed it as the source of the Magnitude 6.6 earthquake that struck Colorado in 1882. Although that has been largely discredited, the recurrence interval for large earthquakes and the date of the most recent event on this fault has not been determined. If the fault is indeed active and if the mapped length of the fault ruptured in a single event, then the fault would generate a magnitude 6.7 event, with ground accelerations exceeding 50% g.

b. Induced Seismicity

Colorado is the world's premier location for induced earthquakes from liquid injection. The best known events were located at the Rocky Mountain Arsenal and were associated with fluid injection that triggered hundreds of earthquakes in the 1960s, twelve of which caused damage.

Two additional localities with extensive records of induced seismicity are in western Colorado in the Paradox Valley and on the north edge of the Piceance Basin at Rangely field. The potential for induced seismicity from injection of waste fluids including CO2 sequestration must be thoroughly investigated before any leasing decisions are made.

c. Probabilistic and Deterministic Ground Accelerations

The highest area of probabilistic ground accelerations in Colorado as shown on the 2002 USGS Earthquake Hazard Maps lies in the southern Piceance Basin. The PEIS correctly cites the 5% g accelerations from the 10% probability maps, but ignores the 20-30% g accelerations in the 2% probability map, and further ignores a >50% g from a deterministic event. 52837-069 (cont.)

The potential for damaging earthquakes in the Oil Shale province of Colorado needs much more study before any leasing decisions are made.

4) Division of Water Resources

The Draft PEIS does a good job of identifying potential physical impacts attributed to ground surface disturbance, water uses, wastewater disposal, alteration of hydrologic flow systems in surface water and groundwater, and the interactions between groundwater and surface water. However as detailed below, while the document includes what appears to be a comprehensive list of potential injury to water resources, it contains little discussion regarding the magnitude or mitigation of these impacts.

Because of the large openings created in underground mining operations, the hydrologic properties of the geologic material in the mine are permanently altered. Abandoned mine shafts, as well as partially refilled (by spent shale) mines, will enhance vertical and lateral groundwater movement in the mined area after dewatering ceases and groundwater levels are reestablished.

Groundwater may be extracted from aquifers for use as a resource or for dewatering to control groundwater inflow into a mine. Mine dewatering would be necessary where saturated conditions, including perched aquifers, are present. Dewatering would lower the potentiometric surfaces and/or water table of the aquifers that are intercepted by the surface mine. Because some deeper groundwater is the source for springs and seeps in the region, the lowering of the potentiometric surface would have the same effect as withdrawals from shallow, surficial aquifers, reducing or eliminating flow of the connected springs and seeps. Existing groundwater supply wells within the cones of depression also would have reduced yields or could be dewatered. 52837-070

Diversion or modification of some natural drainage, and the creation of new drainage near access roads and construction sites. In the case of natural drainage channels that are rerouted, modified, or diverted, the surface runoff would be altered accordingly, affecting downstream flow. Ground surface disturbance would degrade surface water quality and enhance streamflow in areas downstream of development sites, access roads, gravel pits, employer-provided housing, power plants, refinery plants, pump stations, substations, various support facilities, and along the ROWs of pipelines and electrical transmission lines.

In the case of the Shell's in situ conversion process (ICP) sites, fractures could also form in rocks across the entire freeze column. Increased porosity (and permeability) would also occur after kerogen, nahcolite, and other soluble minerals were removed from the rock. Such alteration of permeability would promote vertical as well as horizontal flow and transport of groundwater. The thermal fractures and fractures created by steam, water, or CO_2 in the source rock could potentially enhance the groundwater flow within aquifers and potentially increase the vertical hydraulic conductivities of aquitards after the retorted areas are refilled by groundwater. In other words, the flow system in the subsurface would be modified, as would be the groundwater discharge to the surface water bodies.

Dewatering operations prior to heating of the oil shale could lower the local groundwater potentiometric surface below overburden by as much as 1,600 ft (see Appendix A), and thus reduce groundwater discharge to local springs or streams that are hydraulically connected to the groundwater. Groundwater withdrawal to supply water for oil shale development would have a similar effect. The cone of groundwater depression could extend more than 2 miles from a dewatering well for one foot of drawdown. Existing groundwater supply wells within the cones of depression could have reduced groundwater yields or could be dewatered.

The retorted zone may become a groundwater discharge zone for the shallower aquifers and a groundwater recharge zone for the deeper aquifers.

The streamflow would be reduced in areas downstream of water intakes and could be increased downstream from discharge outfalls.

52837-070 (cont.)

Withdrawal of water from surface water bodies would reduce streamflows.

Groundwater withdrawals from a shallow, surficial aquifer would produce a cone of depression and reduce groundwater discharge to connected surface water bodies. The withdrawal could reduce streamflows.

If a reservoir is constructed to accommodate the water demand of a project, the construction and the operation of the reservoir can impact the environment. The flow pattern downgradient of the reservoirs could be altered, depending on the release schedule of the reservoirs.

In Colorado, the potential underground mining sites are located in the vicinity of Piceance Creek, Yellow Creek, and East Fork Parachute Creek. If the oil shale mine is situated above the water level of one of those creeks, dewatering the aquifers above the oil shale in support of mining operations could reduce groundwater discharge to the creek. On the other hand, if the oil shale mine is situated below the water level of the creek, the dewatering operations on the aquifers above the oil shale could dewater the creek.

The document provides an estimate of the amount of water necessary for oil shale development and water availability, although the authors are advised to revise the estimates based on the water availability estimates developed by Colorado's Statewide Water Supply Initiative (SWASI). There is very little analysis regarding the severity of the impacts. 52837-071

The report does not consider in detail the potential sources of water for oil shale development, fails to identify that existing water rights in the Colorado and White River drainages that are decreed for such use, and overlooks the potential administrative impacts on these drainages (i.e. alteration of call periods, curtailment of junior water rights, etc.). Note that these impacts may affect the Upper Colorado River Endangered Fish Recovery Program. 52837-072

The following are general comments that have appeared in prior reviews of the proposed oil shale demonstration projects:

The Applicant will need to document that the water used at the site was obtained from a legal source, or the water was diverted in priority under a water right decreed for such use or under an approved substitute water supply plan (see http://www.water.state.co.us/wateradmin/wateradmin.asp#swsp) or plan for augmentation.

The proposed operations may have potential impact on existing water rights near the project location. A plan for augmentation (or a State Engineer approved substitute water supply plan) will be required to replace all water depletions in time, place and amount such that no injury will occur to the vested water rights of others. The Applicant needs to demonstrate that the proposed project will not alter or impact the historic operation of existing vested water rights.

Water is commonly collected via surface water drainage collection and conveyance systems to manage drainage throughout mining sites. These systems typically consist of ditches, storm sewers, culverts, curbs, paving and storm water ponds. Stormwater runoff collected and stored out-of-priority, must be released to the stream system within 72 hours. This may require a discharge permit from CDPHE-WQCD. Otherwise, the operator will need to make replacements for evaporation through an approved substitute water supply plan (see http://www.water.state.co.us/wateradmin/wateradmin.asp#swsp) or plan for augmentation. 52837-073

Jurisdictional size dams must be approved by the State Engineer prior to construction. For non jurisdictional size dams, a Notice of Intent to Construct a Non-jurisdictional Water Impoundment Structure must be filed 10 days prior to construction. There structures are governed by CRS 37-87-101 through 125 and the Rules and Regulations for Dam Safety Construction 2CCR-402-1. (See http://www.water.state.co.us/damsafety/dams.asp)

All monitoring wells, injection wells, freeze wells and heater wells must be permitted as monitoring wells pursuant to CRS 37-92-602. All de-watering wells and/or water supply wells, or wells that will be converted to de-watering wells and/or water supply wells, must be permitted pursuant to CRS 37-90-137.[1] All water well construction must be in compliance with the Water Well Construction Rules 2CCR-402-2, which may require submittal and approval of a variance from the rules. All wells permitted by the State Engineer must be constructed by a water well construction contractor licensed by the State of Colorado.[2] All permanent pump installations and cistern installations shall be completed by only a pump installation contractor licensed by the State of Colorado or a private pump installer (CRS 37-91-102(12.5) and 37-91-109(2)). Pumping equipment may be installed in wells constructed and used solely for purposes of aquifer remediation (recovery well) or temporary dewatering of the aquifer (dewatering well) by authorized individuals or anyone directly employed by or under the supervision of an authorized individual. (See http://www.water.state.co.us/boe/)

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1 See http://www.water.state.co.us/groundwater/groundwater.asp.

2 See Board of Examiner Rules 2 CCR 402-14.

In conclusion, note that due to the complexities of the hydrogeologic systems and the lack of information regarding the impacts of such projects, which are currently in the research and development phase, the detail provided by the PEIS is insufficient to allow for a complete and accurate determination of the effects to water resources that will occur from a specific Oil Shale and/or Tar Sands project. As such, each project must be reviewed based upon its own merits. 52837-074

5) Colorado Water Conservation Board

The Colorado Water Conservation Board (CWCB) is the state agency charged with promoting, protecting, conserving and developing Colorado's water resources in order to secure the greatest utilization of those resources for the benefit of present and future generations, and to minimize the risk of flood damage and related economic losses. The CWCB, as the state water planning agency, has a long association with activities concerning the Colorado River Compact and the "Law of the River." The CWCB submits the following technical comments on the draft ***"Oil Shale and Tar Sand Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming Programmatic Environmental Impact Statement" (PEIS),*** which comments will be included as part of the State's overall comment package. The CWCB has had the opportunity to review previous comments concerning the use of water for oil shale development and reaffirms their support of those comments. However, we feel it necessary to expand on those comments in certain areas.

While the document provides an estimate of the amount of water necessary for oil shale development and a discussion of water availability, there remains a need for additional information and clarity. The authors are advised to review and revise the estimates of water availability and uses by the State of Colorado based on information contained in the recently released Phase I Report done pursuant to Colorado's Statewide Water Supply Initiative (SWSI) and to utilize that information to better analyze the severity of various impacts. Not only is the amount of land impacted important, but with respect to water related impacts the amount of water used to support various levels of production at any given point in time is important in order to determine the impact to Colorado's water allocations under the Colorado River and Upper Colorado River Compacts. It would be much more useful to move Table 3.4.1-5 and the discussion of it to Section "3.4.1.1 Water Allocation" and expand that discussion to show the impact to states allocations at various levels of oil shale production. Without this type of analysis, the impacts of oil shale development can not be gauged with any real understanding. 52837-075

The report while discussing water availability and some water features still does not adequately describe the water available to projects on the lands potentially leased. There needs to be a clear linkage between water available, the water remaining available to a state under the compacts, and some indication of the availability under various hydrologic conditions. It is not sufficient to simply say so much water is available at a given point without providing some broad estimate of the water available for appropriation under various levels of compact development. The maps would be more useful if there was better linkage to water supplies in addition to showing watersheds and features. The potential sources of water for oil shale development fail to identify and consider existing water rights in the Colorado and White River drainages that are decreed for such use. The PEIS also overlooks the potential administrative impacts on these 52837-076 drainages (i.e. alteration of call periods, curtailment of junior water rights, etc.) by not considering water rights. Furthermore, the PEIS utilizes a hydrologic determination of water available to the Upper Colorado River Basin of 6.0 million acre-feet. However, the PEIS needs to also acknowledge that the Upper Basin has a legal entitlement to 7.5 million acre-feet and footnotes to that affect need to be made to the appropriate tables in the PEIS as well. 52837-076 (cont.)

The CWCB is a participant in the Colorado River Salinity Control Program and while the discussion of the Program is very helpful it remains incomplete. The discussion does not identify any specific BLM salinity control projects in or near the potentially leased lands and whether or not those projects will be impacted or how they may be protected during development of an oil shale leasing program. While BMP's will be employed during a leasing program, there is no discussion or cross reference to those BMP's. There are also NPDES permitting requirements administered by the respective state health departments that must be complied with for salinity control and those policies should be referenced as part of this discussion. It is fine to state that these NPDES standards must be complied with, but additional discussion of those polices and BMP's jointly is necessary to understand the relationships and how help minimize impacts of oil shale development. 52837-077

Colorado is also a participant in the Upper Colorado River Endangered Fish Recovery Implementation Program (UCRIP). While the purpose of the UCRIP is to offset the impacts of water development while recovering the Colorado River endangered fish, the UCRIP nevertheless is concerned about the potential impacts of oil shale development on the UCRIP efforts to recover the fish and the progress the Program has made to date. In addition to the very extensive discussion of threatened and endangered species already included, the PEIS needs to include a brief discussion of the UCRIP and the BMP's that BLM may require to help insure the recovery efforts of the UCRIP are supported and not adversely impacted. 52837-078

The CWCB administers an Instream Flow Program and has some instream flow segments either on leased lands or on streams that may be impacted by oil shale development. Those stream segments have not been identified. Identifying and incorporating a list of impacted water rights along with consultations with the CWCB and BLM's instream flow coordinator will help identify the affected stream reaches and measures that can be taken to mitigate the impacts of oil shale development on those streams. 52837-079

The PEIS needs to discuss whether or not there are any increases in flood potential resulting from oil shale development and whether or not any water users, agricultural operations or other communities will be impacted. If impacts are identified, what measures will be taken to mitigate those impacts? 52837-080

STATE OF COLORADO

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Colorado Department of Public Health and Environment

1) Water Quality Control Division

The PEIS contains insufficient data defining potential environmental impacts to justify moving forward with a lease program for 360,000 acres of land in Colorado for oil shale production. The BLM should commit to gathering baseline surface water and ground water quality data at locations in and around the RD&D project sites for appropriate parameters and monitor at those sites during the construction and operation of the RD&D projects to gather data that could be used to establish expected environmental impacts for a commercial-scale project. 52837-081

We are concerned that the approach (Executive Summary – Page 5) of generally describing impacts in this PEIS and the proposal to identify detailed environmental impacts on a lease-by-lease basis will not address cumulative impacts to the environment on a geographic scale. The PEIS proposes that each EIS for a lease would have to describe off-site impacts but does not provide a process to address the cumulative impact of all leases on environmental conditions. For example, the impact on a watershed of discharges from sources on multiple leases would not be captured in an EIS for a single lease. As well, if power or water would need to be imported to support an in-situ project, this proposed approach would have each project proponent evaluating environmental impacts due to their proposal (e.g. power transmission lines, water pipe and reservoirs, etc.) without assessing the cumulative impact of these actions. Furthermore, this approach would not encourage consolidation of these types of infrastructure which could reduce the overall environmental impact. Of note, the cumulative impacts section (6.2.5) does not provide information of any value to allay the concern that the lease-by-lease approach will result in a reasonable assessment of cumulative impacts. 52837-082

The PEIS does not address the impacts of additional growth on water and wastewater infrastructure in nearby communities nor does it address potential impacts of water withdrawals on flows upstream of wastewater facilities and the concomitant reduction in permits limits that might result. Similarly, detailed water supply projections would need to be compared to available stream flows to determine if there is a sufficient water supply. In order to address this issue, specific population growth projections would need to be made for all the potentially impacted communities. Then, the capacities of the water and wastewater infrastructure would need to be assessed to identify gaps. At that point, projections could be made about the cost and impact of the efforts that would be needed to fill the gaps. 52837-083

A more meaningful environmental impact analysis should include regional numeric ground water modeling, including predictive simulations of both quantity and quality impacts. 52837-084

Our involvement with other EIS investigations has included such modeling efforts, and it is not uncommon to assess regional groundwater and surface water impacts using numeric models. A regional numeric model to assess oil shale development impacts on surface and groundwater would allow some quantitative assessment of the development on the scale envisioned by BLM under their current preferred alternative. There is currently no attempt to quantitatively assess cumulative impacts to surface and groundwater resources within the PEIS. Without additional information regarding these impacts the only feasible alternative would be the no-action alternative. 52837-084 (cont.)

General comment on socioeconomic analysis: State and local governments will need to invest significant resources to support these efforts, much of which (such as providing permits, etc.) would need to occur prior to actual commercial operations. The proposed socioeconomic studies do not appear to address funding for these efforts. This analysis is in Chapter 4. There is still no discussion of the impact on State and local governments. State approval is needed prior to constructing a new water or wastewater treatment system or expanding existing systems. Thus, if a city or town would need to expand its drinking water and/or wastewater treatment systems to meet the demands of the oil shale project workforce, either for direct service or water hauling, then that entity would need state approval prior to undertaking construction. The analysis suggested above could be evaluated to determine the number of systems needing to be constructed and/or expanded and the extent of the expansion, to estimate the levels of state and local government impacts. 52837-085

The PEIS does not address that surface waters may also be used as drinking water supplies. Specifically, the PEIS should state that commercial development projects will be designed to avoid (if possible) or mitigate impacts to surface waters that are used as public water supplies. 52837-086

Section 7.4 does not list CDPHE as a cooperating agency. 52837-087

Water quality issues

On page 2-5, first paragraph, the Draft PEIS should state that any discharge of spent shale leachate into waters of the United States or waters of a state would require a National Pollutant Discharge Elimination System (NPDES) permit or the state equivalent. The discussion that follows that sentence on page 2-5 is irrelevant as any discharge to state waters would require a state-issued permit under Colorado law. 52837-088

On page 2-5, second paragraph, this section should note that Colorado regulations prohibit the cumulative discharge of one ton per day or more of salinity from a commonly owned development unless amounts greater than one ton per day are mitigated elsewhere. 52837-089

In Section 3.4.1.2 (page 3-60), the Draft PEIS seems to focus on salinity as the key water quality issue. Although salinity was discussed, we found no discussion of the potential for any contribution of selenium or other pollutants expected to be found in the native soils/formations to area waters. Selenium is a significant water quality issue in the Colorado River Basin and around Colorado in general. The Department is aware that, according to the USGS, the targeted oil shale rich layers are expected to be at least 6000' to 7000' above the Mancos shale which is 52837-090 the significant source of selenium. That being said, in addition to identifying and addressing the issue of other potentially naturally occurring contaminants, the PEIS should address other sources of selenium as well. 52837-090 (cont.)

In Section 3.4.1.3, addressing 303(d) listed water bodies does not address listed segments along the lower Colorado River. The current 303(d) list for the lower Colorado River includes 8 segments, and it is anticipated that the number of listed segments could easily double during the next listing cycle. The PEIS lacks any substantive discussion of potential ramifications of the proposed preferred alternative on 303(d) list water bodies. Until such analysis is conducted the only appropriate alternative is the no-action alternative. 52837-091

Section 4.5 describes potential impacts from nonpoint source runoff, but does not attempt to quantify any potential impacts, nominally due to mining exemptions from NPDES requirements. However, Colorado does not exempt any construction activity from stormwater discharge permits impacting areas larger than one acre. Construction associated with oil shale development will represent a significant cumulative impact, especially in light of the increase emphasis on sedimentation impairments to surface water. The PEIS inadequately address the nonpoint source sedimentation impacts of the preferred alternative, and therefore until such impacts can be quantified the no-action alternative represents the only viable option. 52837-092

In Section 4.5.1, the Draft PEIS indicates that runoff from surface disturbances related to the oil shale operations would be non-point sources. In fact, and disturbance of one acre or more during construction would require a point source stormwater permit. This error is repeated in section 4.5.1.1. 52837-093

Section 4.5.1.2 states that the drawdown associated with ground water withdrawals from the shallow aquifers will impact springs, seeps, and surface water flows. The PEIS fails to address the magnitude of this impact, nor address the potential cumulative affect on both water availability and water quality. Significant dewatering associated with several of the currently envisioned oil shale production technologies will impact the timing and long term availability of water within the basin. These cumulative impacts are currently not addressed under the preferred alternative, and need to be considered. Therefore only the no-action alternative is appropriate. 52837-094

In Section 4.5.1.3, second paragraph, the Draft PEIS incorrectly states "Since discharge of surface runoff at a mining site is exempted from NPDES permits, surface runoff not intercepted at these sites could create a nonpoint source of contaminants and degrade the water quality of downgradient surface water bodies." As a mining activity, runoff from the mine site would require a Colorado stormwater permit. 52837-095

Section 4.5.1.3 describes implementation of potential UIC disposal of poor quality water and states that EPA R8 is responsible for permitting. While this is true for Colorado, it is not necessarily true for Utah or Wyoming which have delegated UIC programs. Current Colorado ground water regulations also address several potential oil shale related ground water contaminants that would not be addressed through the Region 8 UIC permitting process. The 52837-096

PEIS does not address Colorado's independent authority to regulate potential ground water contamination not addressed under the Region 8's UIC implementation of the SDWA. 52837-096 (cont.)

Section 4.5.1.4 describes the potential of aquifer degradation due to alterations in the permeability and hydraulic conductivity of both aquifers and aquitards. This could have ramifications for contamination of ground water from pollutants remaining in after extraction activities at an in-situ operation are suspended and could lead to increased loadings, including TDS, in surface water bodies as well. Information to confirm that impacts from pollutant leaching due to increased porosity and permeability due to in-situ mining can be appropriately managed should be addressed at one or more RD&D projects before commercial development to determine whether ground water contamination will occur during production or after production when the aquifer in the zone of withdrawal becomes saturated. 52837-097

Section 4.5.2 assumes that power requirements for a traditional mining scenario would not increase over current energy consumption levels. One of the largest consumptive uses of both power and water under a traditional mining scenario is associated with dewatering. This assumption cannot be validated until realistic estimates of the amount of traditional mining that would occur can be made. The preferred alternative inadequately estimates the amount and associated cumulative impacts associated with potential oil shale development utilizing traditional mining methods. 52837-098

Section 6.1.2.4 states "The inability to predict specific locations for potential future commercial development and the lack of information regarding the type of technology that might be employed make it impossible to predict the specific impacts on water resources that could occur with commercial development. Quantification of such impacts would depend on the specific location of the lease area being developed, as well as the design of the project and associated infrastructure." Again, this underscores a the lack of information that should preclude moving forward with a selected alternative that proposes developing 360,000 acres of land in Colorado for oil shale production. 52837-099

Drinking water and source water protection

Page 2-4 line 5 should indicate that compliance with Colorado Primary Drinking Water Regulations is required. 52837-100

Page 2-4 lines 32 to 38 should indicate that compliance with state and local regulations and ordinances with respect to Source Water Protection is required. 52837-101

Appendix A Pages A-27 (beginning on line 36) and A-29 (beginning on line 4) describe two recovery techniques, solvent flooding and chemically assisted recovery, which may be of concern if used near water supply aquifers. The PEIS should state that one of the criteria used to select recovery technique would be water supply protection. 52837-102

Appendix A Pages A-69; A-71; A-72; A-72; A-78; all refer to "potable water" and the trucking or hauling of that water. Trucked or hauled water must meet the requirements of the Colorado Primary Drinking Water Regulations. 52837-103

Appendix D should recognize that Colorado has primacy for implementing the Safe Drinking Water Act in Colorado. This has impacts throughout the document. All systems meeting the definition of public water system must comply with Colorado Primary Drinking Water Regulations which includes water hauling and the need for design approval prior to constructing a new system or expanding existing systems. Thus, if a city or town would need to expand its drinking water treatment system to meet the demands of the oil shale project workforce, either for direct service or water hauling, then that entity would need design approval prior to undertaking construction. 52837-104

Table D-5 on page D-9 should refer to any of the Colorado regulations relating to groundwater or drinking water. Similarly, Tables D-12 and D-13 should specifically reference Colorado's regulations. 52837-105

In Appendix D there should be sections under D.2 ADDITIONAL INFORMATION REGARDING THE REGULATORY AND POLICY ENVIRONMENT addressing each of the tables (this was done for Air Quality – it needs to be done for all). 52837-106

The document refers vaguely to environmentally sensitive areas, but there does not seem to be specific approach to defining these areas or a method of selecting best management practices for sensitive areas (e.g.: around drinking water intakes, wells). Other questions come to mind like… will waste pits be allowed in environmental sensitive areas? This leads to question of how the BLM might incorporate locally driven source water protection plans in the potentially impacted areas and downstream. Is there a plan to develop a watershed protection plan with specific best management practices that will be implemented, enforced, and evaluated over the time frame of the project? The BLM's process to addressing local concerns and selecting Best Management Practices (BMPs) in environmentally sensitive areas should be clearly defined. 52837-107

In the mass volume of information provided, source water protection is mentioned once in section 2-4, but there is no mention of a process for planned coordination. It also indicates that … "If hazardous chemicals or materials are used during the construction or operation of a project that is located within a wellhead protection area, reporting or control measures **may** apply". This language is very weak and does not significantly address potential drinking water impacts. 52837-108

Table 2.2.3-1 indicates existing ACEC's Intersecting Oil Shale or Tar Sand Areas. There seems to be a fair amount of ACEC's in the oil shale areas, but no specific environmental plans for the ACEC areas. The document indicates it will be handled by the local BLM offices. Will a guidance document be prepared to assist these local offices? Will there be an effort to establish standardized BMP's? 52837-109

2) Air Pollution Control Division

Overarching Comments

The scope of this one document is huge and the format, style of the writing and organization of the document seems to reflect a "business as usual approach" by the BLM. This 52837-110 is disappointing, given the history of oil shale development in the west and the significance it now is taking on when considering it alongside the expansion of oil and gas and coal development. In our mind, a much more creative and informative approach should have been pursued. As a result of the document's size and organization, the interested reviewer must be highly motivated to seek out critical information so as to form conclusions. There is probably no way to easily remedy this at this stage but assessing this development proposal's impact over three states is not going to be easily accomplished with the document in its current form. 52837-110 (cont.)

There are a number of significant issues that Colorado must have comprehensive and clearly written information about for the state to make any recommendation about the further development of this resource. For example, there are a number of air quality concerns that are not addressed in this draft PEIS to any substantive degree. These include:

1. **Regional air quality concerns** – There are several areas of concern not described to any sufficient degree in the document. These include: impacts from Mercury emissions; regional and local ozone impacts (both health and secondary impacts); impacts on regional haze; impacts on nitrogen deposition; and the impacts of hazardous air pollutants. 52837-111

2. **Urban and small community air quality levels** – Currently the Denver metro area is developing a SIP revision for the 8-hour ozone NAAQS. The draft document should describe whether and how the proposed development will affect the attainment and maintenance of the ozone standard. Additionally, the state has been required to develop and submit air quality plans for PM10 in many western Colorado towns. The state, in cooperation with the western slope communities of Aspen, Steamboat Springs, Telluride and Pagosa Springs, has successfully developed and implemented air quality plans (SIPs) to address violation of the PM10 NAAQS. The draft document has not aqequately identified how these areas are going to maintain compliance with the NAAQS. 52837-112

3. **Community exposure to Hazardous Air Pollutants** – Colorado has been implementing a state-wide air toxics program for several years and high on our list of source categories of concern are categories related to energy development. The Colorado Air Quality Control Commission adopted significant additional control requirements on oil and gas drilling and extraction operations and we are concerned about the levels of benzene and other HAPs compounds on the residents of Colorado. The impact of these pollutants deserves greater attention in the draft PEIS. 52837-113

4. **Oil shale related electrical power generation development** – The draft PEIS identified the need for significant additional power generation capacity to drive the shale (and tar sands) extraction/refining process across the west. Then the BLM backs off this major issue entirely. Nowhere in the document is the role of alternative energy applications raised or discussed as an option in meeting the additional power needs for this proposal. Further, the impacts of energy development itself should receive more attention in this document. This is an issue of tremendous significance because of the impact of coal fired utility plants and their impact on air quality. The 52837-114

PEIS should identify this issue a support a no action alternative until the overall energy needs and howi t will be provided can be more specifically detailed 52837-114 (cont.)

5. **Cumulative impacts to air quality** – The overarching direction of the narrative in the air quality impacts section, Section 6.1.4.5 Air Quality Impacts, last paragraph, page 6-94 can only lead to the conclusion of supporting the No Action Alternative. This paragraph states that "Because of the need for project- and site-specific information, it is not possible to identify the nature and magnitude of regional air quality impacts of commercial oil shale development under either Alternative B or Alternative C." Given this, the only logical selection is Alternative A (No Action). This is the only proposed alternative that presents any substantial evidence that no significant, adverse direct or cumulative air quality impacts are likely to occur (analyzed under previous NEPA analyses for the six RD&D projects, which would proceed under Alternative A). The potential adverse impacts which could occur under Alternatives B and C may be unacceptable to Colorado and therefore these Alternatives can not be supported without further analysis and quantification of impacts. This again points to a need for a comprehensive dispersion modeling analysis that will address the near-field and far-field impacts of both the oil shale leasing program and cumulative sources (all existing and reasonably foreseeable non-oil shale/tar sands development sources, including existing and proposed oil and gas leasing on federal and private lands, and the expansion of electric utilities in the region). The current proposal lacks the comprehensive analysis necessary for Colorado to support either Alternative B or Alternative C. 52837-115

6. **Baseline monitoring for Colorado's Class I areas** – This is a critical concern. The Draft PEIS misses a great deal of information about baseline ambient air quality monitoring currently being conducted in Colorado. As part of the PEIS, the BLM needs to discuss recent air quality monitoring in the prospective oil shale areas, and to commit to future ambient monitoring needed to assess the baseline environmental conditions. In Colorado, monitoring is needed both in the Piceance Basin itself, and in the Flat Tops Wilderness, a sensitive area that is likely to be impacted by industry emissions.

   For the Flat Tops area, we note the following history, and future needs.

   Recent AQRV Monitoring In and Near Flat Tops Wilderness Area 52837-116

   Shell began baseline monitoring in the Ripple Creek Pass (RCP) area, north of the Flat Tops Wilderness Area (FTWA) in January 03. Shell is to be commended for contacting federal land managers, the Air Division, and the US Geological Survey back in 2002 for input about what parameters needed to be monitored and characterized. Some monitoring is scheduled to cease in March 08, while other work will continue.

   Flat Tops: What Should Be Monitored and Why

   1. Every-Third-Day chemically speciated fine particles with an IMPROVE II sampler at RCP (this was run at RCP from Jan 03 thru March 08). Purpose: Very

good indicator of type of particles in the air; excellent measure of visibility/haze; and very useful for trends as well as event/episode characterization.

2. Hourly Nephelometer at RCP (at RCP in past). Purpose: Very good high time resolution air quality indicator; very useful for better understanding of short-term episodes that are averaged over by the IMPROVE sampler.

3. Hourly meteorological parameters (at RCP in past): full suite of parameters necessary for AERMOD model. Purpose: Very useful as inputs to air quality modeling; very useful in understanding air flow trajectory and source area/receptor area relations on average and in episode characterizations.

4. Digital camera system, at least 3 images/day (9am, noon, 3pm). Purpose: Provides images of visual air quality; helps establish relationships between other quantitative measures and how the air actually looked; can help communicate with public and officials about haze/visibility concerns; can be used for trends over time.

5. Wet deposition by NADP/NDN (at RCP in past). Purpose: chemistry of precipitation (rain, snow etc) in bulk help understand sources, possible concerns about aquatic and terrestrial impacts of acids or metals, and is very useful tool to track changes in chemistry of wetfall over time. Dry Deposition is needed also. 52837-116 (cont.)

6. In Situ Snow Pack Sampling (in and near FTWA and RCP, this has been and continues to be done by USGS). Purpose: chemical characterization of what chemicals, acids, metals are actually accumulated in the snowpack is essential to understanding what the ecosystem sees during snowmelt; also provides helpful trend information over time. Near or in FTWA and further downwind is essential.

7. Mercury sampling in bulk sampler (MDN) and in snowpack as well as other accumulators (some work has been done with this and may continue in RCP and FTWA by USGS). Purpose: mercury has the potential to be released in oil shale development. It is a potent neuro-toxin that needs to be tracked and better understood. USGS is very interested in sampling additional lakes in FTWA to learn whether they vary in mercury amount and sensitivity. USGS also looking at fish samples and potentially phytoplankton samples to test for mercury in lakes.

8. Lake sampling (Ned Wilson lake in FTWA was sampled in recent past). Purpose: chemical characterization of what ends-up in actual aquatic ecosystem after emissions are released, transported, deposited etc and ultimately end-up in a lake/pond. These areas are the locations where fish, salamanders etc are impacted. Several lakes should be sampled long-term after a lake reconnaissance has been conducted in and around FTWA.

For the Piceance Basin and Areas Affected by Oil Shale Development:

9. Additional long-term baseline monitoring sites are needed in both rural areas and within potentially affected communities. The monitoring network should be designed to support all applicable regulatory programs. Sites should monitor meteorology and the concentrations of criteria pollutants, particularly sulfur dioxide (SO2), ozone (O3), oxides of nitrogen (NOx), PM2.5, PM10, and carbon monoxide (CO). Meteorological data collection should include 10 meter towers, taller towers, and profilers. Meteorological instrumentation and collection should be designed to meet the needs of air quality modeling systems. In addition, meteorological data should be collected for purposes of evaluating the performance of the meteorological models. 52837-116 (cont.)

10. A TSP sampler, to analyze for lead and other metals, is also suggested. Mercury evels in air should be sampled, to establish pre-industry levels of this air toxic. Due to recent oil and gas development, concentrations of benzene, toluene, ethylbenzene and other petroleum-related air toxics need to be determined.

11. In addition, monitoring short-term field studies should be designed and conducted to support application of regional air quality modeling systems. Specifically, baseline data is needed to evaluate baseline model performance.

All monitoring protocols should be developed in consultation with CDPHE and subject matter experts. Data should be publically available."

The Air division staff members have prepared additional general and specific comments in several areas. Critical comments relate to BLM commitments to address monitoring, dispersion modeling, and the emission impact from leasing and project development. These comments are included below.

1. In several areas, the Draft PEIS lacks a meaningful analysis that is necessary to make an informed decision about the appropriate scale of commercial oil shale development.

Comment/What is still needed
Until some or all of the Research Design and Development projects are underway and are able to provide information to inform a potential commercial leasing program the BLM will not have enough detailed information about the various processes to analyze the potential direct The Final PEIS must provide a clear direction to ensure that information that is currently lacking will be collected and evaluated. The BLM should indicate in the Final PEIS how a broad stakeholder process will be initiated.

52837-117

Comment/What is still needed	
Several sections of the document refer to additional project-specific NEPA analyses that would be performed, subject to public agency review and comment, prior to approval of commercial leasing programs. However, to ensure that cumulative impacts from commercial scale development are adequately addressed, the PEIS should emphasize and provide more detail regarding BLM commitment to performing a cumulative local and regional scale modeling assessment prior to issuing leases for commercial-scale development. The PEIS document should emphasize the importance of the stakeholder process and indicate that any decision by BLM to grant commercial leases would be made only after completion and acceptance of a comprehensive local and regional scale cumulative air quality modeling analyses that has been developed with input and approval from all affected federal, state, and local agencies.	52837-118
Volume 2, Section 4.1.6 Expansion of Electricity-Generating Capacity, page 4-13 The Draft PEIS indicates, "Additional power generation capacity would need to be developed in the region to support commercial oil shale development; however, at this time, definitive information about the power requirements of commercial oil shale development is not available." even though the power requirements are not known at this time. The Final PEIS should set the standards for what is expected of the lease applicants as far as mitigation expectations for their power generation needs. Most of the Western States have established Renewable Portfolio Standard Programs, with the goal of increasing the percentage of renewable energy in the state's electricity mix to 20 percent over the next 20 years. This is the same time frame the BLM is considering in this Draft PEIS. The BLM should require that all leases obtain at least 20 percent of their energy needs from renewable energy. There are a number of rural residences in the area surrounding the proposed land use allocations that utilize renewable energy for nearly 100% of their energy needs.	52837-119
Volume 2, Section 4.6.2 Mitigation Measures (Air Quality), page 4-5-- The Draft PEIS is 1460 pages long and about one-half of a page has been devoted to providing 5 possible mitigation measures for air quality. The Final PEIS needs to include a better discussion of the mitigation measures indicated and provide more examples of possible mitigations that will be required of lease applicants. Offset programs should be included in the list of potential mitigation programs.	52837-120

Comment/What is still needed	
Volume 2, Section 6.1.4.5 Air Quality, page 6-94According to the Draft PEIS, "Thus, compared to Alternative B, the areas where local air quality could be affected by future commercial oil shale development under Alternative C would be reduced by 89% in Colorado, 22% in Utah, and 70% in Wyoming." Without more information about the potential direct, indirect and cumulative air quality impacts of the oil shale development in Colorado, we must support the alternative with less significant air quality impacts.	52837-121
Comments Regarding the Next Step (Amendment of Specific Resource Management Plans) This Oil Shale PEIS provides the basis to amend specific Bureau of Land Management Resource Management Plans (RMPs) in Colorado, Wyoming, and Utah. The Colorado Air Pollution Control Division believes that these resource management plans should determine which areas of each BLM region should, or should not, be available for an oil shale leasing program. Therefore, the RMPs should carefully address the issue of which land areas are least sensitive to oil shale activities, and make only those areas available to the program. This is particularly important, since the current Utah oil shale research, development, and demonstration lease can be potentially expanded to include an area that is eligible for Wild and Scenic River status. According to lines 32 – 38 on page 2-28, major portions of the five Colorado RD&D "preference" lease areas for expansion to commercial scale would not be allowed for leasing under the present Alternative C, because they involve some sensitive areas. Lease areas should be delineated in ways that avoid such impacts in the future.	52837-122
The Draft PEIS states "in situ processing does not involve mining, with limited waste material disposal , it does not permanently modify land surface topography and therefore produces fewer air pollutant emissions." This is not so. Though this phase produces fewer *PM* emissions, it produces other criteria and hazardous air pollutants. These pollutants are not even addressed in this paragraph.	52837-123
Volume 2, Sections 6.1.2.5, 6.1.3.5, 6.2.2.5, 6.2.3.5 Air Quality, pages 6-47, 6-71, 6-185, 6-211 These identical sections mention "[o]perational releases of certain hazardous air pollutants (such as benzene, toluene, formaldehyde, and diesel PM) could also affect onsite workers and nearby residences (if any are present), but these impacts would be localized to the immediate project location and subject to further analyses prior to implementation." No mention is made of mercury even though research indicates that mercury is a component released from oil shale with even more severe environmental and health impacts than the HAPs mentioned.	52837-124

Comment/What is still needed	
Volume 2, Section 6.1.1.5 Air Quality, pages 6-8 and 6-9 In this section, BLM states that "the EAs, prepared for the RD&D projects … predicted potential air quality impacts using atmospheric dispersion methods….The air quality analyses presented in the EAs indicate that no significant adverse direct, or cumulative air quality impacts are likely to occur." The air quality analyses presented in the EAs indicate that no significant adverse direct, or cumulative air quality impacts are likely to occur." These air quality analyses have already been deemed suspect and inadequate by the Division.	52837-125
Appendix A Volume 3, Table A-10 EGL RD&D Project Air Emissions Summary, page A-66 EGL's sulfur dioxide emissions are unreasonable high. There is no discussion of how these could be reduced. Can they mitigate this by scrubbing the boiler emissions or using a lower sulfur fuel? Further, there is no mention of VOC or hazardous air pollutants in their emission inventory yet these are inevitable.	52837-126
Volume 3, Table A-14 Phase 3 Estimated Emissions, page A-83 The estimate for hazardous air pollutants is 1.8% of VOC emissions This is an unreasonably low estimate and should be researched and verified in the Final EIS.	52837-127

2. The Draft PEIS has indicated that substantial adverse impacts to air quality are likely to occur.

Impact identified/Level of certainty in PEIS
The overarching direction of the narrative in the air quality impacts section, Section 6.1.4.5 Air Quality Impacts, last paragraph, page 6-94 can only lead to the conclusion of supporting the No Action Alternative. This paragraph states that "Because of the need for project- and site-specific information, it is not possible to identify the nature and magnitude of regional air quality impacts of commercial oil shale development under either Alternative B or Alternative C." Given this, the only logical selection is Alternative A (No Action). This is the only proposed alternative that presents any substantial evidence that no significant, adverse direct or cumulative air quality impacts are likely to occur (analyzed under previous NEPA analyses for the six RD&D projects, which would proceed under Alternative A). The potential adverse impacts which could occur under Alternatives B and C may be unacceptable to Colorado and therefore these Alternatives can not be supported without further analysis and quantification of impacts. This again points to a need for a comprehensive dispersion modeling analysis that will address the near-field and far-field impacts of both the oil shale leasing program and cumulative sources (all existing and reasonably foreseeable non-oil shale/tar sands development sources, including existing and proposed oil and gas leasing on federal and private lands, and the expansion of electric utilities in the region). The current proposal lacks the comprehensive analysis necessary for Colorado to support either Alternative B or Alternative C. 52837-128 The overarching direction of the narrative in the air quality impacts section, Section 6.1.4.5 Air Quality Impacts, last paragraph, page 6-94 can only lead to the conclusion of supporting the No action alternative. This paragraph states that "Because of the need for project- and site-specific information, it is not possible to identify the nature and magnitude of regional air quality impacts of commercial oil shale development under either Alternative B or Alternative C." Given this, the only logical selection is Alternative A (No Action). This is the only proposed alternative that presents any substantial evidence that no significant, adverse direct or cumulative air quality impacts are likely to occur (analyzed under previous NEPA analyses for the six RD&D projects, which would proceed under Alternative A). The potential adverse impacts which could occur under Alternatives B and C may be unacceptable to Colorado and therefore these Alternatives can not be supported without further analysis and quantification of impacts. This again points to a need for a comprehensive dispersion modeling analysis that will address the near-field and far-field impacts of both the oil shale leasing program and cumulative sources (all existing and reasonably foreseeable non-oil shale/tar sands development sources, including existing and proposed oil and gas leasing on federal and private lands, and the expansion of electric utilities in the region). The current proposal lacks the comprehensive analysis necessary for Colorado to support either Alternative B or Alternative C.

3. **Several information gaps must be filled to support an informed decision regarding the feasible and appropriate scope of commercial oil shale development at a later date, when more information is available.**

Area of concern/What is needed to make decision
Regional air quality concerns – There are several areas of concern not described to any sufficient degree in the document. These include: impacts from Mercury emissions; regional and local ozone impacts (both health and secondary impacts); impacts on regional haze; impacts on nitrogen deposition; and, the impacts of hazardous air pollutants. Until some or all of the Research Design and Development projects are underway and are able to provide information to inform a potential commercial leasing program, the BLM will not have enough detailed information about the various processes to analyze the potential direct, indirect, and cumulative environmental, cultural, and socioeconomic impacts of a commercial leasing program. The Final PEIS must provide a clear direction to ensure that information that is currently lacking will be collected and evaluated. The BLM should indicate in the Final PEIS how a broad stakeholder process will be initiated. This stakeholder group should be utilized to collect and evaluate the data that is needed to inform future site-specific EIS's and develop regulations for potential commercial leasing. The information provided in the Draft PEIS does not provide the State of Colorado and others enough information to determine whether commercial oil shale leasing program in Colorado could be developed without significant direct, indirect and cumulative environmental, cultural, and socioeconomic impacts. 52837-129
Oil shale related electrical power generation development – The EIS identified the need for significant additional power generation capacity to drive the shale (and tar sands) extraction/refining process across the west. Nowhere in the document is the role of alternative energy applications raised or discussed as an option in meeting the additional power needs for this proposal. Further, the impacts of energy development itself should receive more attention in this document. The draft PEIS identified the need for significant additional power generation capacity to drive the shale (and tar sands) extraction/refining process across the west. Then the BLM backs off this major issue entirely. Nowhere in the document is the role of alternative energy applications raised or discussed as an option in meeting the additional power needs for this proposal. Further, the impacts of energy development itself should receive more attention in this document. This is an issue of tremendous significance because of the impact of coal fired utility plants and their impact on air quality. The PEIS should identify this issue a support a no action alternative until the overall energy needs and how it will be provided can be more specifically detailed 52837-130

Area of concern/What is needed to make decision	
In the Draft PEIS Volume 1, Section 2.3.1, page 2-16, BLM commits to the following: "If and when applications to lease are received and additional information becomes available, the BLM will conduct NEPA analyses, including consideration of direct, indirect, and cumulative effects, reasonable alternatives, and possible mitigation measures, as well as what level of development may be anticipated." Only if these analyses contain approved analysis techniques, and if the cumulative effects include the appropriate sources, will the information be useful for stakeholders to make a determination of the potential impacts of the commercial leasing program.	52837-131
Several sections of the document refer to additional project-specific NEPA analyses that would be performed, subject to public agency review and comment, prior to approval of commercial leasing programs. However, to ensure that cumulative impacts from commercial scale development are adequately addressed, the PEIS should Emphasize and provide more detail regarding BLM commitment to performing a cumulative local and regional scale modeling assessment prior to issuing leases for commercial-scale development. The PEIS document should emphasize the importance of the stakeholder process and indicate that any decision by BLM to grant commercial leases would be made only after completion and acceptance of a comprehensive local and regional scale cumulative air quality modeling analyses that has been developed with input and approval from all affected federal, state, and local agencies.	52837-132
Volume 1, Section 3.5.3 Air Quality, page 3-101*:* The Draft PEIS states, "On the basis of limited monitoring data, air quality in the region is expected to be good (i.e., concentration levels for most criteria pollutants [except O3] are well below their applicable standards)." There is limited monitoring data in the region and background values will be crucial in making informed decisions on site-specific proposed commercial leasing projects in the future. It is time for the BLM to participate with other state, local and federal agencies in developing and funding a monitoring program in the region. A state must have better understanding of the contribution of oil and gas development to air quality emission levels, especially ozone, is needed. Since much of the oil and gas development is occurring on BLM lands and will be in the same areas as those proposed for oil shale development, BLM should take the lead in providing background monitoring for this region. Therefore to pile on the oil shale issue on top of this makes a decision to proceed with amending the documents to facilitate leasing premature.	52837-133

4. Other areas of concern/comment

Topic- Climate change - Section 4.6.1 Common Impacts, last paragraph, page 4-48: The last two paragraphs of this section discuss greenhouse gas emissions (GHG) and potential impacts of direct emissions of GHG from oil shale activities. The statement is made that "increasing concentrations of GHG, however, are likely to accelerate the rate of climate change" but that "direct emissions of climate change air pollutants from oil shale development facilities are likely to be a small fraction of global emissions". Since the technology and potential emissions from future commercial oil shale development are virtually unknown, the last statement cannot be supported. Furthermore, even if these emissions will be a small fraction of global emissions, it is plausible that they will be a significant fraction of local and regional GHG emissions and may in fact be a significant contributor to climate warming on a regional level. Given the large uncertainty regarding commercial oil shale emissions and the implications for climate change, the "No Action" alternative should be supported until further evidence and analysis can be provided.	52837-134
Volume 1, Table ES-1, page ES-5 The Colorado Air Pollution Control Division cannot support an alternative that will make areas identified as Areas of Critical Environmental Concern (ACEC) available for commercial oil shale leasing.	52837-135
Page 2-51, Section 2.5.2, Lines 24-40. The No-Action Alternative. This section indicates that several comments received during the public scoping process "suggested that BLM should not move forward to establish commercial leasing programs for oil shale". The PEIS addresses these concerns by stating: "The no action alternatives for oil shale and tar sands (Alternatives A) effectively are no leasing alternatives. Any other alternatives in the PEIS that did not evaluate opening public lands for commercial leasing would not be consistent with the Energy Policy Act." Colorado notes that Alternative A includes the six research and development leases that currently exist on public lands. Therefore, the BLM has made public land leases available to the oil shale industry. The limited-size, developmental nature of these projects in appropriate, given that technology for processing oil shale is not mature. Colorado also notes that NEPA requires that for any contemplated action, the no-action alternative must be given serious consideration. Therefore, choosing the no-action alternative is feasible.	52837-136

Page 4-17, Section 4.2.1.1. Lines 17 –26. This section states: "A significant portion of the land within the most geologically prospective oil shale areas is already undergoing mineral development, particularly for the development of oil and gas resources. Commercial oil shale development, using any technology under consideration in this PEIS, is largely incompatible with other mineral development activities and will likely preclude these other activities while oil shale development and production are ongoing." Page 6-3, Section 6.1.12, lines 32 – 39 indicates that, due to natural gas flammability, gas wells cannot be allowed near an in-situ oil shale site. If a goal of the Congress was to increase US energy independence, via the development of fuel from oil shale, then Colorado asserts that this goal is already being met by the large expansion of traditional oil and gas activity in the area. Indeed, oil shale, an unproven technology, can interfere with established operations for extracting oil and gas.	52837-137
Volume 1, Section2.3.3.2, Alternative C, pages 2-28 and 2-32. This section states, "Although the White River and Book Cliffs RMPs allow commercial leasing for oil shale development, as shown in Figures 2.3.3.4, 2.3.3-5, and 2.3.3.-6, under Alternative C, portions of three of the five preference right lease areas for the Colorado RD&D leases are not available for application for commercial leasing. These include portions of the areas associated with the Chevron, EGL, and Shell Site 2 RD&D projects. For the other two Colorado RD&D projects, Shell Sites 1 and 3, none of the preference right lease areas coincide with the areas available for application for commercial leasing. As with Alternative B, for the OSEC RD&D project in Utah, portions of the area are not available for application for commercial leasing under Alternative C because they are excluded due to the presence of a potentially eligible WSR, Evacuation Creek (see Section 2.3.3.). Under the terms of the RD&D program, the federal government has a commitment to grant the RD&D companies leases for commercial development within the preference right lease areas, provided that all conditions of the program are met (See Section 1.4.1). As a result, all lands within the preference right lease areas would be available for issuance of commercial leases to the RD&D companies under Alternative C if they meet all conditions of the program. For commercial oil shale development to occur on lands excluded by Alternative C, the specific land use plans would need to be amended to consider the excluded area for potential leasing. The federal government is not under an obligation to grant leases for commercial development within these areas to any other applicants." It is somewhat unclear as to what "under an obligation" means. In order for the RD&D areas to expand to their full preference areas, additional NEPA analyses are required, because the original Findings of No Significant Impacts addressed only the research scale of 160 acres, not the full-scale areas.	52837-138
Most of the Western States have established Renewable Portfolio Standard Programs, with the goal of increasing the percentage of renewable energy in the state's electricity mix to 20 percent over the next 20 years. This is the same time frame the BLM is considering in this Draft PEIS. The BLM should require that all leases obtain at least 20 percent of their energy needs from renewable energy. There are a number of rural residences in the area surrounding the proposed land use allocations that utilize renewable energy for nearly 100% of their energy needs.	52837-139

3) Hazardous Materials and Waste Management Division

Oil shale development offers tremendous potential to supplement the nation's energy supplies. Colorado's goal is that commercial oil shale development be done right – in a manner that avoids unacceptable impacts on Colorado's land, water and wildlife resources, and minimizes and mitigates those adverse environmental and socioeconomic impacts that would result from such development. If planning for and implementation of oil shale development efforts are not done responsibly and thoughtfully in the first instance, we all lose. There is a greater risk that development will be delayed and that any development that does occur will have unacceptable impacts.

In view of the potentially substantial adverse environmental impacts that the PEIS acknowledges could result from commercial oil shale development, and the lack of factual information and analysis to meaningfully assess likely impacts at this time, the only defensible alternative is the "no action" alternative. The information currently presented provides no support for amending the current Resource Management Plans to "facilitate" or "make possible" commercial oil shale development. Just as it was inappropriate for the BLM to select a leasing alternative in the Preliminary Draft PEIS that the State reviewed in June due to substantial uncertainties, it is inappropriate for the agency to select any alternative here that would make lands available for applications for commercial lease. 52837-140

A Programmatic Environmental Impact Statement is intended to provide a meaningful analysis of the impacts of an overall program, in this case commercial oil shale development, prior to proceeding with project by project irretrievable commitments of resources. Because of the absence of information to allow a meaningful assessment of the potential impacts of commercial oil shale development at this time, the current draft PEIS does not satisfy its intended purpose. Therefore, BLM should commit to preparation of a supplemental PEIS at a later date, when adequate information is available, prior to proceeding with commercial oil shale leasing. 52837-141

While the BLM claims that it will study the cumulative impacts of proposed oil shale development when it receives an application for a commercial lease, the proper time to evaluate the regional cumulative impacts of new oil shale development is at the PEIS stage. The BLM is proposing to make hundreds of thousands of acre open to oil shale leasing, which could lead to multiple applications for large-scale oil shale projects. The BLM cannot analyze the cumulative impacts of this decision when performing NEPA review on a project-specific, piecemeal basis. 52837-142

Although BLM's plans regarding the development of commercial oil shale leasing regulations are unclear at this time, we note that the current PEIS also provides no meaningful analysis of environmental impacts that could form the basis to support the issuance of such regulations. For example, setting an appropriate royalty rate should be based on the feasibility and cost of oil shale development technology, the anticipated environmental impacts of such technology, and the costs of mitigation of such impacts. None of that information is included in this PEIS. 52837-143

Oil shale development will use untested technology with potential long-term negative impacts to Colorado's environment and communities. Colorado therefore supports the RD&D approach. Colorado will not support any commercialization plan that calls for commercial leasing, or for the promulgation of leasing regulations, prior to a meaningful evaluation of the RD&D projects. 52837-144

Specific Technical Comments:

Capacity: There is insufficient information to determine exactly what type or types of solid and/or hazardous waste treatment, storage and disposal facilities will be required for the RD&D projects. The information, such as geology, hydrology and engineering requirements may require substantial effort, resources and time. It is not clear that the resources and time were allocated, even in the RD&D process to define the needs and develop the capacity to support the RD&D project. This is important because all waste types and all waste volumes must be accounted for and managed appropriately. Without an understanding of the types and volumes of the wastes to be generated, it is not possible to determine the additional capacity for the waste storage, treatment and disposal facilities needed to support even the RD&D approach identified in #6 above. 52837-145

Regulatory Compliance: While this comment pertains to the later aspect of commercial oil shale development, there appears toe be a flaw even in the RD&D phase identified in element #6 above. Page 2-18 Table 2.3.2-1 under the Regulatory and Operational Constraints for Alternative A (960 acres for 6 RD&D projects) where it states "[N]ot applicable; no commercial leasing would occur under this alternative." The federal, state and local solid and hazardous waste statutes and regulations must be adhered to for RD&D projects, even if no commercial leasing occurs. This would be applicable to the generation, storage, treatment, transportation and ultimate disposal of solid and/or hazardous waste. 52837-146

4) Disease Control and Environmental Epidemiology Division

1. Current knowledge about in-situ and other oil shale (OS) technology is inadequate to fully assess associated environmental impacts or determine necessary mitigation measures. More detailed analysis of enhanced potential for community exposure and potential toxic impacts associated with different in-situ OS technologies is needed before an appropriate action alternative can be selected. Data gaps/inadequacies that need to be addressed to fully and adequately compare PEIS alternatives include: 52837-147

    - Development of a chemical inventory associated with different OS technologies and select alternatives;

    - Assessment of the toxic potential of various chemically-assisted OS technologies, based on detailed R&D findings;

    - Identification of metrics to establish baseline conditions;

- Identification of metrics to assess baseline risks, analyze trends over time, and generally improve the scientific accuracy of the analysis of degradation to the human environment and potential risk to health associated with specific OS technologies;

- Determination of areas of greatest community impact anticipated during the active production phase of commercial OS development projects, through identification of significant exposure pathways associated with specific technologies;

- Quantitative estimate of exposure dose and potential health impacts to the affected public, due to direct impacts from air, water or surface contamination, or from indirect exposure to contaminated media, such as use of contaminated surface or ground water for drinking water, agricultural, or recreational use;

- Identification of methods to assess cumulative effects, where additive impacts are anticipated. Additional environmental studies are needed to be able to assess incremental impacts within the common geographic area. Establish risk-based systems to support decisions about avoidance or mitigation of adverse impacts to public health, and to allow meaningful comparison of alternatives in the future.

52837-147 (cont.)

2. Development of the PEIS and leasing for commercial OS development should include sufficient detail to ensure stipulations for protection of resources and prevention or mitigation of impacts to the public that are consistent with other allowed energy uses, such as conventional oil and gas development.

52837-148

Specific Comments

Page 2-50, section 2.5.1, 2nd paragraph - The PEIS states that published information is too dated to accurately describe commercial OS technologies of the future. This section of the report concludes that, under conservative assumptions, impacts could be significant, but uncertainties are currently too great to develop reliable assumptions. While this conclusion seems reasonable, it also appears to indicate there is very little basis to compare action alternatives at this time. For example, the lack of detailed process information makes it impossible to determine the degree of degradation, potential for exposure, or significance of toxic impacts associated with chemical-specific technologies prior to availability of RD&D results. No information is available to fully assess the long-term potential for health impacts to the affected public due to direct or indirect exposure to contaminated media (i.e., use of contaminated groundwater or surface water for drinking water or agricultural use; recreational contact with degraded surface water).

52837-149

Page 4-2, Section 4– The paragraph at the top of the page states that information presented in section 4 "does not necessarily define the range of possible technologies and issues that may develop". Alternative technologies are anticipated to have different potential to cause significant impacts, due to differences in associated process methods and chemicals, and unique fate and transport characteristics. It is not possible to assess the effects of activity or evaluate actual outcomes with the general information available. Therefore, conclusions about potential risks and impacts to public health associated with the various alternatives are highly uncertain.

52837-150

Table 4.14-2 - Estimated health risks for chemical exposure in workers fails to take into account systemic toxic effects, other than cancer, which may be associated with process chemicals, naturally-occurring pollutants, or other by-products of OS development. 52837-151

Section 6 – Impact assessments of the OS alternatives are generally lacking in discussions of the toxic potential of process chemicals and wastes, or potential routes for offsite exposure. Impacts would depend on factors such as location and quantity of leases and technology-specific differences in fate and transport of contaminants, but no detailed analysis is provided in the discussion of the alternatives. Benchmarks to compare toxic potential for different technologies, under different conditions, are not provided or discussed. These data gaps preclude a firm scientific basis for selection of the preferred alternative. 52837-152

5) Consumer Protection Division

Section 3.10, 4.10 and 4.11 Appendix I (Socioeconomic analysis methodology).

Statutory and regulatory oversight relative to the licensing, inspection, and enforcement specific to labor camps (man camps), retail food establishments, wholesale food firms, schools, childcare, mobile home parks, public accommodations (hotels/motels) and campgrounds are not addressed.

Inspections relative to mobile home parks, public accommodations and campgrounds are only done on a complaint basis. The increase in the number and use of these facilities will dictate the need for additional resources to respond to the associated complaints which are not addressed in the PEIS.

Labor camp housing is only inspected on a complaint basis, however the food service portion is addressed as indicated in the bullet below addressing retail food establishments. The labor camp regulations are the authority used to address man camps. The Labor Camp regulations were adopted in 1968 and a revision will be needed to address issues relative to man camps. 52837-153

Retail food establishments (restaurants, grocery stores, school cafeterias, food service to summer camps) whether associated with man camps or are community-based require minimally, plan review and approval, pre-opening inspections, licensing, routine inspections on a semi-annual basis, and any additional regulatory activity needed for non-compliance. If an establishment moves from one location to another, which may occur more frequently with man camps, the license is non-transferable and all the plan review, pre-opening, etc. must be repeated. All these activities are resource intensive and additional increases needed to perform these functions are not addressed in the PEIS.

Schools are inspected on an annual basis. Any new construction must go through the plan review submittal and approval process. There are no statutory or regulatory fees required to be paid for the plan review and inspection services. The increase in resources needed to perform these functions are not addressed in the PEIS.

Child care facilities are inspected on an annual basis. There are no regulatory or statutory fees assessed for these facilities. The increase in resources needed to perform these functions are not addressed in the PEIS.

6) CDPHE Climate Change

Commercial development of oil shale will result in carbon dioxide emissions from production, refining and transportation. Because production of oil from oil shale is expected to be energy intensive, commercial oil shale development will have significant greenhouse gas implications. Most of these emissions will come from processing plants as well as power plants that provide electricity to oil shale facilities. While some of these emissions could be reduced by capturing carbon dioxide for enhanced oil recovery in nearby oil production areas and geological sequestration of the carbon dioxide, section 2.5.3 indicates that such an evaluation should occur at the time of site-specific NEPA analysis of a specific plan of development. In addition, there will be indirect greenhouse gas emissions from population growth and the commensurate demand for infrastructure and services, none of which is addressed.

52837-166

While sections 3.5.1.2 and 4.6.1 offer brief tutorials on the science behind climate change and point out that increasing concentrations of greenhouse gas emissions are likely to accelerate the rate of climate change, section 4.6.1 goes on to merely conclude that "direct emissions of climate change air pollutants from oil shale development facilities are likely to be a small fraction of global emissions." It is irrelevant whether the emissions will be a small fraction of total global emissions. That is true for every major emitter. The PEIS offers no specificity or any analysis of the primary contributors of carbon dioxide emissions from oil shale development, such as the power plants needed to provide electricity to oil shale facilities. The PEIS is lacking a meaningful analysis of impacts from oil shale development to climate change and, accordingly, offers no substantive provisions on which to comment.

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General Comments:
The Colorado Department of Local Affairs evaluated the Colorado socioeconomic components of the "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". Due to the uncertainty of the oil shale development technology and resulting impacts the total socioeconomic effects of oil shale development cannot be properly evaluated. Making lands available through the resource management plans does not address the scope or magnitudes of oil shale development and its resulting socioeconomic impacts. 52837-154

Additionally, the assumptions of socioeconomic impacts provided in the PEIS are very narrow and do not provide the reader the broad spectrum of potential production realities. The assumptions are for **one operation** with three different types of technology at **one level of production**. Chapter 6 which compares the alternatives does not discuss how likely one operation versus 10 operations would be or how different levels of production would increase or decrease employment levels. 52837-155

Finally, after reviewing the Draft PEIS we strongly feel that the PEIS is missing important components. Below we have identified socioeconomic impacts that we feel have not been addressed or not addressed fully. These issues should be addressed prior to decisions being made.

Issue: A thorough, realistic, housing analysis must be included in the PEIS. The assumptions used concerning the use of "temporary" housing, especially the ability to locate buildable land and infrastructure for the housing and related structures seem very unrealistic. Additionally, a clearer discussion of the meaning of the concept "temporary", as it relates to workforce and housing, needs to be presented. One of the primary assumptions in Chapter 4.11 is that a high percentage of the workforce would be housed in temporary company housing. However, no data or research is presented that supports that assumption. The indirect and induced effect of the direct oil shale workers would create additional demand for housing that has not been adequately addressed in the PEIS. Affordable and attainable housing is a current concern in the ROI. Even a moderate spike in demand for housing will impact the entire community. 52837-156

Recommendation: Include a complete, realistic, housing impact analysis in the PEIS. Research and present information from other similar projects throughout the world. Identify the elements included in the concept of "temporary" as it relates to workforce and housing needs and present information and research regarding this "temporary" assumption when the timeline appears longer term. Present information or support documents regarding workers choosing to live in temporary work camps when the time frame may be longer term. Present information on the strengths and threats of this "temporary" or not so temporary workforce. Include in the "mitigation measures" the need for a housing program that would engage the industry, the community, and where necessary the state or federal government. 52837-156 (cont.)

Issue: The baseline information related to housing vacancy is not a true picture. Vacant housing units can either be truly vacant and for sale or for rent, they can be "seasonal" housing or they can be second homes and not a primary residence. In this case and especially in this ROI it would be very wrong to assume that all vacant homes are available for use. Additionally, the BLM PEIS suggests that up to 15 % of the workforce would be accommodated in rental housing and motels - this seems unrealistic in a market with 1 - 3% vacancy rates. 52837-157

Recommendation:
Review the Census Bureau vacancy data to identify what percentage of the housing units could be considered available for a local workforce and are not a part of the growing second home cohort. Review and revise assumptions that the local housing market could absorb 15% of the workforce.

Issue: There is no baseline data presented for community infrastructure capacity. (water, sewer, water treatment, energy, schools, hospitals, emergency management etc.) Without this baseline data it is impossible to evaluate what the community infrastructure demands will be with oil shale development. For example, will population increases due to oil shale development push local infrastructure capacity over their current planning horizon and create major unforeseen costs to local governments.

Recommendation: A standard state and local government fiscal analysis is needed which would include: 52837-158

1) Community facility capacity over the period of analysis.
2) Baseline facility utilization rate (is there available capacity or a deficit?)
3) Project facility capacity requirements over time
4) Capital costs of facility capacity required by project impacts
5) Public revenues generates by the project
6) Discussion of the net of cost and revenues with regard to timing or jurisdictional mismatch.

Issue: One of the primary socioeconomic impacts resulting from population change is the impacts to local governments. Chapter 3 mentions that maintenance of county roads is the largest dollar impact to Rio Blanco County yet, in Chapter 4.11. there are no transportation/infrastructure costs included in the impact assessment. Additionally, other impacts to local governments are noted in terms of social disruptions (4.11.) and again, no costs are included in the analysis. 52837-159

Recommendation: A more complete set of costs to local governments needs to be included in the analysis to enable an adequate evaluation of the total costs of oil shale development.

Issue: A cumulative socioeconomic analysis must be performed when more information is available. It does make sense to evaluate the magnitude and extent of the impacts at the project level, which it states in Chapter 2.6, however it is just as important to look at the cumulative impacts across all projects. 52837-160

Issue: The socioeconomic data is not broken down by county in the PEIS and it is therefore impossible to accurately evaluate the impacts. The counties in the ROI in Colorado are very different from each other and their current conditions and policies will influence how the potential growth from oil shale development will impact their county and municipalities. The distribution of the socioeconomic impacts is very important to consider because it will impact resources and costs to the counties and municipalities differently. 52837-161

Recommendation: Break the region of influence down by state and county to estimate the economic impacts.

Issue: One of the key assumptions is that the local economy in each ROI would minimally provide materials, goods, and services related to the construction and operation of oil shale facilities therefore reducing the risk of local inflation. The Draft PEIS makes the assumption that 50% of the materials and labor for the construction of temporary employer-provided housing and housing provided by local communities would come from each ROI. However, the price inflation created both in the labor market as well as in the housing materials/construction market are not included in the socioeconomic analysis. Current impacts from gas development in the ROI show that local factor price inflation does occur especially in the labor market, housing and housing/construction materials. Chapter 3 of the PEIS discusses the historical and current factor price issues yet it is not included in Chapter 4 of the PEIS. 52837-162

Recommendation: The socioeconomic analysis must include a component that reflects the impact of the oil shale development on local prices in the labor, goods and services, and construction materials markets.

Issue: The total employment impact from a direct construction or direct operation job is not complete. The socioeconomic sections of the PEIS present the direct and indirect employment and income impacts using IMPLAN as the model source. We do not see that the work has included the "induced"effect, the spending of the income earned locally. Chapter 3 of the PEIS which presents the history of the prior oil shale boom and acknowledges that when the direct oil shale jobs pulled out that there were the indirect suppliers effected as well as the local businesses that provided services to the workers. The PEIS states in Chapter 3 "Exxon decided to close leaving 2100 oil shale workers and 7500 support workers unemployed. Our current research using IMPLAN shows that the employment multiplier for an oil and gas job is around 2.5 (each 1 direct oil and gas job creates an additional 1.5 indirect and induced jobs). The data in the PEIS shows the multiplier closer to 1.6 which is underestimating the true total impact of oil shale jobs by almost 100%. 52837-163

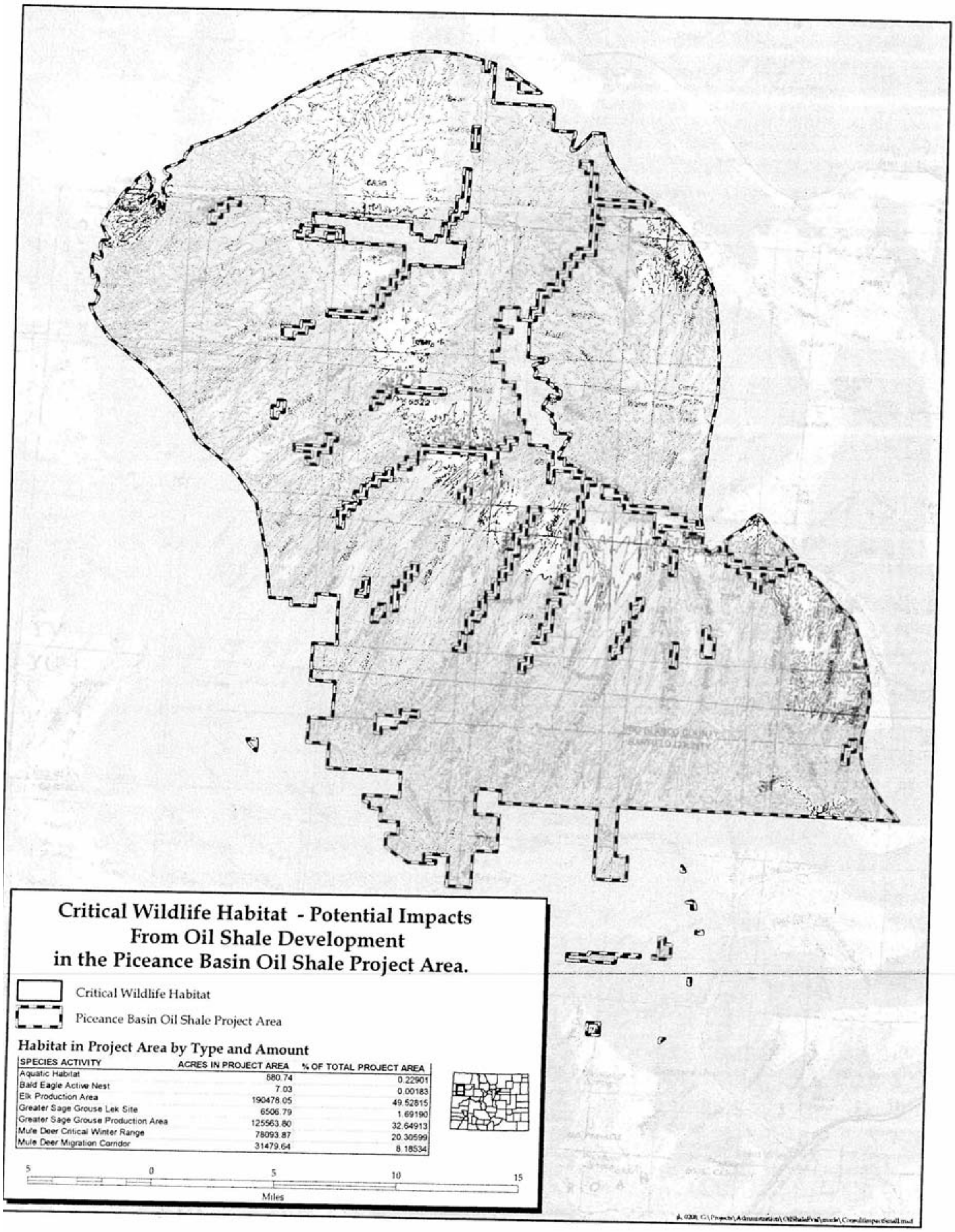
Recommendation: Review the work from IMPLAN and provide information supportive of the low multipliers being used or adjust the multiplier to acknowledge the true total impact.

Issue: The impact to an area from a large new project(s) is not just in the "Boom" but also in the risk of the "Bust". Chapter 3 of the PEIS describes the historic context of the oil shale "boom and bust" yet no attention is paid to the risk of a "bust" in the impact analysis sections or in terms of mitigation. The ROI suffered a 20 year recession due to the last oil shale boom/bust. 52837-164

Recommendation: The socioeconomic analysis must address the risk and impacts of a bust and what mitigation measures will be put in place to keep the ROI from suffering similar impacts from the previous oil shale boom and bust.

Issue: There is a cost to the loss of economic diversification which is related to the ability of a region to bounce back from either a bust or change in the business cycle. The socioeconomic analysis does discuss the impact of oil shale development on agriculture and on tourism in terms of total jobs and income but does not address how the loss of economic diversification increases the economic risks of the region. 52837-165

Recommendation: Address the risks and/or costs of the loss of economic diversification caused by oil shale development on tourism, agriculture or other industries.



SPECIES ACTIVITY	ACRES IN PROJECT AREA	% OF TOTAL PROJECT AREA
Aquatic Habitat	880.74	0.22901
Bald Eagle Active Nest	7.03	0.00183
Elk Production Area	190478.05	49.52815
Greater Sage Grouse Lek Site	6506.79	1.69190
Greater Sage Grouse Production Area	125563.80	32.64913
Mule Deer Critical Winter Range	78093.87	20.30599
Mule Deer Migration Corridor	31479.64	8.18534

Responses for Document 52837

52837-001: Pursuant to Congress's mandate in Section 369 of the Energy Policy Act of 2005, the original intent of the PEIS was to amend 12 existing BLM land use plans to support commercial oil shale and tar sands leasing. As preparation of the PEIS proceeded, and in consultation with BLM's cooperating agencies, it was determined that the analysis to support leasing decisions would require making many speculative assumptions regarding potential, unproven technologies. Consequently, the decision to offer specific parcels for lease was dropped from consideration in the PEIS. To still be responsive to Congress' direction, the focus of the PEIS was changed to only identify public lands to be opened or closed to application for commercial oil shale and tar sands leasing.

Nevertheless, there is sufficient information at the programmatic level to make a reasoned choice among the alternatives when considering lands open or closed for consideration of commercial leasing. The PEIS analyzes the environmental consequences of this allocation decision in sufficient detail for the decision maker to choose which lands would be available for further consideration for leasing. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development nor do they create any development rights. When applications to lease are received and additional information becomes available, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and possible mitigation measures, as well as what level of development may be anticipated.

52837-002: The BLM initiated the RD&D leasing process to provide important information that can be used as the BLM works with communities, states, and other federal agencies to develop strategies for managing any environmental effects and enhancing communities' ability to support the orderly development of the oil shale resource. The alternatives within the PEIS do not alter the intent of the RD&D program. Under each alternative, the RD&D lessees would continue their efforts to prove their oil shale technology and gather additional technical and environmental information. In Section 369 of the Energy Policy Act of 2005, Congress authorized a commercial leasing program for oil shale in addition to the RD&D program. Additional information about environmental impacts from commercial oil shale operations would be required before the BLM would issue commercial oil shale leases or approve plans of development.

52837-003: This PEIS is a programmatic-level document analyzing land use allocation decisions. Programmatic environmental impact statements are used to evaluate broad policies, plans, and programs and provide an effective analytical foundation for subsequent project-specific NEPA documents. The BLM believes there currently is sufficient information at the programmatic level to make a reasoned choice among the alternatives as to whether lands are suitable for future consideration for commercial oil shale leasing.

The PEIS presents, for the purposes of analysis, a cumulative analysis based on the nature and scope of the proposed action and on available nonspeculative information. It provides a summary of the extensive ongoing activities in the Piceance Basin and elsewhere in the study area, and considers these in its overview of potential cumulative impacts (see Sections 6.1.5 and 6.2.5). The PEIS analyzes the environmental consequence of an allocation decision that does not commit any resources or grant any lease rights.

Please see also the response to Comment 52837-018.

52837-004: The affected environment of the PEIS covers portions of three states and nine separate land use plans. It is important to note that the carrying capacity thresholds included in the WRFO RMP are unique to that plan. There are no comparable management prescriptions in the other eight land use plans. These thresholds are based on existing statutory requirements or site-specific analysis and are only applicable to oil shale. Prior to changing the proposed action to an allocation decision, the intent was to review and subsequently revise or remove the thresholds based on new information since 1989 when the thresholds were first established. However, after the purpose of the PEIS was changed from providing opportunities for commercial leasing to making only land use allocations, the revision or removal of the thresholds was no longer applicable. The PEIS does not modify or eliminate the carrying capacity thresholds for the protection of communities, the environment, and wildlife resources contained in the WRFO RMP. The statement regarding the WRFO RMP land use plan amendment, which would remove the thresholds, as described on page C-9 of the Draft PEIS, should have been deleted prior to the release of the draft. Any decisions concerning the application of thresholds will be made at the site-specific level where detailed information relevant to that determination can be made and where interagency consultation can be accomplished.

52837-005: The promulgation of regulations on environmental protection standards, setting royalty rates and addressing bonding, establishing standards for diligent development, and determining the allowable size of leases, are outside the scope of the PEIS.

52837-006: The decisions analyzed in the PEIS include no commitment by the BLM to offer for lease public lands within Colorado without additional site-specific NEPA analysis. This additional analysis will consider any new or site-specific information regarding proposed oil shale technology and any anticipated environmental consequences. New information on technologies may be a consequence of research on the RD&D leases or result from research or studies from other sources. Specific mitigation measures, management prescriptions, and the best available practices to minimize impacts will be applied as a result of site-specific NEPA evaluations. In addition, the BLM will involve the State, local communities, and the public throughout the NEPA processes. The Energy Policy

Act of 2005 requires the BLM to finalize this PEIS, knowing that results from the RD&D program would probably not be available for inclusion in this document. It is not necessary to await the results from the RD&D program prior to amending the land use plans under analysis in this PEIS.

As noted in the response to Comment 52837-005, the promulgation of regulations is outside the scope of the PEIS.

52837-007: The BLM acknowledges the commentor's preference for Alternative A.

52837-008: The BLM does recognize that additional NEPA analysis will be required and is committed to preparing the appropriate level of analysis prior to the issuance of any oil shale lease. (See page 2-19 of the Draft PEIS for the description of additional NEPA requirements.) A supplemental EIS as defined under the CEQ regulations, 40 CFR 1502.9, however, would not be appropriate for such additional NEPA analysis. This is because the nature and scope of the proposed action (i.e., leasing) will be different from the plan amendment action analyzed in the PEIS. Supplemental EISs are prepared when the agency makes substantial changes to a proposed action analyzed in an EIS or when there are significant new circumstances or information bearing on a proposed action analyzed in an EIS. Supplemental analyses focus on only those parts of the EIS that require updating before a decision on that proposed action is actually made. Since leasing will be an entirely different decision, a new NEPA analysis will be required. It is inappropriate to speculate at this stage whether such NEPA analysis will be programmatic in nature.

This new NEPA analysis will analyze whether to offer for lease parcels of land for commercial oil shale exploration and development and under what conditions or stipulations. The analysis will also contain any new information or circumstances relevant to the technology, the affected environment, and any associated environmental consequences. This information may be a consequence of research on the RD&D leases or a result of industry performing research or studies on nonfederal lands.

As required by NEPA, all subsequent NEPA documents will analyze the cumulative effects from other reasonably foreseeable future actions. The scope and nature of the specific proposed action will drive the type of NEPA analysis the BLM performs. As required by NEPA, the cumulative effects analysis would consider the present effects of past actions, to the extent that they are relevant, and present and reasonably foreseeable (not highly speculative) federal and nonfederal actions, taking into account the relationship between the proposed action and these reasonably foreseeable actions.

The affected environment of the action could vary greatly from a large regional area to a small discrete area. The scope of the analysis in the NEPA document would be dependent upon the number of applications received and the type and size of operations proposed by the applicant(s). This could result in a statewide, regional, basin-wide, or site-specific impact analysis. Overall, the geographic extent of the analysis would be limited to those areas that could experience a change in the pattern of land use as a consequence of a direct impact or other induced effects on the natural resources. The nature of the action can also vary greatly based on the type of technology or mining method. Another critical factor would be the type of infrastructure needed to support the operation, in particular, the source of electrical power.

Hypothetically, the proposal in subsequent NEPA documents could offer for commercial lease (1) only a limited number of parcels, (2) parcels located in a geologic basin, or (3) parcels located throughout a state. Estimated oil shale exploration and development activities assumed to occur as a result of issuing the leases would be based on actual applications; therefore, analyses of proposed operations, hypothetical development scenarios, and an RFDS could be developed. Depending on the information included in the applications, technologies whose impacts would be analyzed could include any or all of underground and surface mining with surface retort operations and/or in situ operations.

Based on the nature of the proposed action, existing sources of electrical power may be sufficient to power the operation, or electrical power may need to be generated on lease using either conventional energy sources like natural gas or renewable energy sources like wind or solar. A third hypothetical analysis may include the expansion of existing power plants or the construction of additional power plants (coal, gas, nuclear). In each case, the scope of the NEPA analysis would be limited to the extent of the direct and indirect effects from activities described in an RFDS.

For example, if the proposed action were to lease three tracts in Utah using underground mining technology only, the scope and scale of the analysis would vary from that which would be performed if the proposed action were to lease several parcels in all three states using a variety of technologies. The geographic extent of analysis for a leasing decision is based on the extent of the potentially affected resource(s). In the first instance, the NEPA analysis would most likely not be a programmatic EIS but would define the area subject to analysis as the area bounded by the three leases. The analysis may not necessarily include an analysis of building additional power plants (dependent on whether the additional mines could pull power off the existing grid or not). In the second instance, it may be appropriate for the BLM to perform a regional NEPA analysis that would look at leasing in all three states and would include an analysis of the power plants (coal, gas, nuclear) as well as refinery capacity that might be necessary for any development to occur.

In both instances, the NEPA analysis would be limited to the extent of effects from activities described in an RFDS. While the proposed leasing area may be the three Utah tracts, effects on some resources can be extensive, going beyond the boundaries of the proposed leasing area and determined by the distance over which effects remain significant (e.g., effects on air quality or effects on an entire watershed), while the effects on other resources remain within the leasing area boundary and are geographically limited by the resource itself (e.g., a specific species of threatened and endangered plant or a specific culturally significant feature). The impact zones of particular resources may be superimposed or may overlap only in part. All relevant effects, including those that extend outside the project, or even, in some cases, the planning area where the project is located, must be evaluated and considered in the leasing decision that is made for the planning area.

Thus, while the BLM is committed to performing NEPA analyses prior to leasing, we cannot commit to a certain type of NEPA analysis (regional, planning area, or local). The proposed action will drive what analysis must be performed to comply with the requirements of NEPA.

52837-009: Please see Comment 52837-001 above for the response regarding land use allocations.

Regarding regulatory issues, those are being considered in a separate rule-making process and are outside the scope of the PEIS.

52837-010: The comment contains a summary of issues identified in the technical sections of the State’s comment letter. Responses to the individual agency technical comments are provided later in this response, but it is important to note that many of the issues cannot be addressed without reference to site-specific locations and conditions. Additionally, many of the comments address compliance with existing law and regulation. This PEIS states repeatedly that lessees will be required to comply with applicable local, state, and federal laws and regulations. The specific methods of compliance will be established by the appropriate regulatory authorities when a specific proposal can be evaluated against those legal and regulatory requirements.

As described in the response to Comment 52837-001, the BLM has determined that there is sufficient information to support the land allocation decisions proposed in the PEIS. The local conditions identified in the State’s comment summary will be included in the NEPA analysis that will accompany future site-specific leasing and/or development applications if those conditions are present. Note also that activities occurring on nonfederal lands, though at times foreseeable, are usually beyond the authority of the BLM to regulate. The BLM will welcome the participation of local, state, and other federal agencies in the NEPA processes for those future decisions.

52837-011: Congress declared its intent in the Energy Policy Act of 2005 for the Nation to pursue the development of oil shale and tar sand resources among other unconventional fuels in an environmentally sound manner. As required by that Act, the BLM initiated this PEIS intending to provide the environmental analysis for issuance of commercial leases that would convey development rights to lease holders. As discussed in the Draft PEIS, because of various uncertainties regarding location of developments, technologies to be employed, and the lack of knowledge of specific impacts on various resources, the BLM decided not to analyze the environmental impacts of issuing particular leases at this time and instead decided to analyze amendments of land use plans. Amending those plans is necessary, but not sufficient, to proceed to commercial development of federal oil shale resources.

Thus, this PEIS: (1) identifies the most geologically prospective oil shale resources on public lands in Colorado, Utah, and Wyoming; (2) supports amendment of certain land use plans to identify areas as available for application for commercial leasing in the future; (3) supports amendment of certain land use plans to identify areas as off-limits to application for commercial leasing in the future; (4) supports amendment of land use plans to specify that the BLM will consider and give priority to the use of land exchanges to facilitate oil shale development; and (5) discloses what is known about oil shale development as well as what information and data must be obtained in order to be able to complete the NEPA analysis necessary to lease. This PEIS clarifies, to the extent possible, how potential oil shale development could proceed on public lands and stipulates that site-specific NEPA analysis will be required prior to leasing and development. This PEIS, therefore, facilitates subsequent environmental analysis but it does not convey any lease or development rights on public lands. For that reason, and coupled with the requirements for subsequent site-specific NEPA analysis prior to leasing and development, the BLM has determined that, other than potential impacts to property values, there will be no impact on the environment as a result of these allocation (land use plan amendment) decisions.

The PEIS, while not exhaustive in its identification of potential impacts of commercial development, has disclosed potential impacts of oil shale development based primarily on BLM experiences with surface-disturbing activities as a result of other types of mineral development, such as coal mining and oil and gas development. We cannot say for certain that those would be the impacts from commercial oil shale or tar sands development, but we can say, based on our experience with other types of mineral development, that those type impacts may occur. The result is that this PEIS fulfills three purposes: (1) it provides sufficient information for the decision maker to make a reasoned choice among the alternatives as to which lands should be open or closed to oil shale leasing; (2) it addresses additional information needed by industry, government, and the public to facilitate future environmental analysis of leasing and development actions; and (3) it allows operators to compare environmental impacts of their proposed operations with those identified in the PEIS and to include proposed mitigation measures (although not necessarily those potential mitigation measures discussed in the PEIS) as part of their proposed actions. It puts operators on notice that development of oil shale can only occur if it is done in an environmentally acceptable manner. It also reiterates the obvious requirements that any development will have to comply with existing laws and regulations regarding protection of the natural, social, and cultural environment.

The Rand Corporation testimony cited in the comment—that is, that commercial development will not occur for some time—is consistent with statements in the press and those heard during public open house meetings on the Draft PEIS. Industry is proceeding cautiously, which underscores the point that Rand was making; however, that commentary alone does not obviate the need for BLM to analyze the environmental impacts of amending land use plans to allow or to prevent leasing of oil shale and tar sands. Industry advocates for certainty about what a new government program will look like before it will invest several million dollars in development projects. The PEIS, along with oil shale regulations (such as those proposed separately by the BLM), would be the foundation for that program.

Finally, in the Energy Policy Act of 2005, Congress set a deadline for the BLM to complete this PEIS. That deadline has been exceeded, but that does not allow the BLM to postpone this PEIS until new information becomes available or until the industry is ready to invest in commercial operations.

52837-012: The PEIS analyzes the environmental consequences of proposed allocation decisions in sufficient detail for the decision maker to choose which lands would be available within the most geologically prospective areas for further consideration for leasing. The proposed allocations do not authorize the immediate leasing of lands for commercial development nor do they create any development rights. When applications to lease are reviewed, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects, reasonable alternatives, and mitigation measures, as well as what level of development may be anticipated. This future analysis will be done in the context of ongoing and anticipated future development of other resources within the area of influence of any proposed oil shale lease.

52837-013: There is a substantial amount of nonfederal land in the study area (see discussion in Section 3.1); however, the scale and timing of potential future oil shale and tar sands development on these lands, as well as the technologies that would be used for development, are highly speculative at this time. Text has been added in Sections 6.1.5 and 6.2.5 to clarify that future levels of commercial oil shale and tar sands development (both on public and private lands) are unknown.

As stated in Sections 6.1.5 and 6.2.5 of the PEIS, for the purposes of analysis, the cumulative impacts assessment looks at the incremental impacts of a single oil shale facility and a single tar sands facility, recognizing that there may be more than one of each type of these facilities brought into operation during the study period. Additionally, for the general cumulative analysis conducted for this PEIS, the impacts of potential development on nonfederal lands were included by assuming that the impacts of oil shale or tar sands facilities on nonfederal lands would be similar to the impacts of such facilities on federal lands (see text added in Sections 6.1.5.3 and 6.2.5.3). Therefore, the cumulative analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decision and the uncertainty of oil shale and tar sands development on private lands.

A more specific analysis of cumulative impacts of facilities on nonfederal lands in conjunction with impacts from facilities on federal lands may be conducted at a future step in the assessment process, when an RFDS for oil shale development would be included. An RFDS was not developed for this PEIS because most of the information necessary for producing an RFDS is unknown and not reasonably available at the present experimental stage of the oil shale and tar sands industries. Assumptions based on the limited available information would be too speculative to support a meaningful scenario. An RFDS at a future step in the assessment process would be based on a clear set of supportable assumptions associated with a leasing or development proposed action.

52837-014: As stated in the Energy Policy Act of 2005, the development of oil shale, tar sands, and other strategic unconventional fuels for research and commercial development should be conducted in an environmentally sound manner using practices that minimize impacts. The BLM believes that analyzing an allocation decision provides the opportunity to build on scientific, governmental, or industry research in order to analyze, in a general way, the possible impacts of commercial development of these resources. The analysis of this land use planning (allocation) decision is just one step, however. Prior to offering for lease any parcels of land for commercial oil shale exploration and development, further analysis will be carried out and documented in accordance with NEPA to support any decisions in this regard. That NEPA analysis will evaluate the environmental impacts of the oil shale exploration and development and develop specific mitigation measures to mitigate or eliminate the identified impacts. The BLM believes that such a phased approach ensures that commercial oil shale development programs both meet the intent of Congress and take advantage of the best available practices to minimize impacts, and that state, local communities, and the public have the opportunity to participate in the process. While uncertainty is an inherent part of planning in accordance with FLPMA’s multiple-use mandate, and delays are possible in bringing any new resource into commercial development, the BLM manages public lands in compliance with the FLPMA principles of sustained yield and multiple use, to protect the public lands, and to provide for domestic sources of minerals.

52837-015: With the passage of the Energy Policy Act of 2005, Congress recognized the importance of encouraging research and development of this resource, as well as of establishing a commercial leasing program to reduce the growing dependence on foreign oil imports. After beginning the analysis of a leasing program, and in consultation with cooperating agencies, the PEIS was modified from a leasing document to one analyzing the impacts of an allocation decision, creating a “staged” or “phased” approach to an oil shale program. This provides an opportunity to build on scientific, governmental, or industry research, including findings from the existing RD&D leases. Any new information and/or circumstances will be taken into consideration in the preparation of future NEPA analysis. Future analysis will consider a full range of alternatives, as well as specific mitigation measures, such as BMPs or stipulations to avoid or mitigate short-term or long-term adverse impacts to Colorado’s environment, public safety, wildlife, and local communities.

52837-016: The CEQ regulations at 40 CFR 1502.22 require an agency to disclose whether there is “incomplete or unavailable information” and to seek to acquire that information if it is “relevant to reasonably foreseeable significant adverse impacts” and is “essential to a reasoned choice among alternatives.” The purpose of the provision is to advance decision making even in the absence of complete information regarding environmental effects associated with the proposed action. Agencies are required to comply with this provision when evaluating “reasonably foreseeable significant adverse effects.”

The PEIS proposed action is to amend land use plans thereby allowing certain lands to be considered for future leasing. The decision does nothing more than remove the administrative barrier to BLM considering any application for leasing for some lands, while leaving other lands unavailable for leasing. The amendment does not commit any resources or grant any lease rights. For that reason and because there will be subsequent site-specific NEPA analysis prior to leasing and development, the BLM has determined that there will be no impact on the environment as a result of these allocation decisions and, therefore, does not trigger the requirements of 40 CFR 1502.22.

For the purposes of analysis, in the absence of more specific information on the technology and environmental consequences of commercial development of oil shale and tar sands, this PEIS employs information derived from other types of mineral development (i.e., oil and gas, and underground and surface mining of coal). The BLM has taken this approach because it anticipates, to the best of its knowledge, that the surface-disturbing activities involved with these other types of mineral development are comparable to those that may result from oil shale and tar sands development. There is a wealth of information concerning the consequences of oil and gas and underground and surface mining activities, and projecting on the basis of this information, to the extent that it is applicable, permits a decision maker to decide whether to open areas to future application for leasing or to protect the specific resources by closing areas. Therefore, it is not a case of information missing that is needed to make a land use allocation decision such as that contemplated here; rather, the BLM is engaged in a projection based on these anticipated similarities. To the extent that additional information will be required in order to analyze alternatives to a leasing or development decision, that is not a matter of information missing with respect to the land use allocation decision under consideration here, but a matter of information that will be developed in its proper place—during the NEPA analysis for these later decisions.

Therefore, the PEIS need not assess the relevance of the missing information needed to make an oil shale leasing or development decision. The PEIS, however, does disclose the fact that BLM will consider new information, such as that emerging from the RD&D leases, during subsequent NEPA analysis performed as the basis for making any leasing decisions.

Also, see the response to Comment 52837-015 above that describes the "staged" or "phased" approach that is expected to facilitate development of necessary additional information to support actual leasing and development activities.

52837-017: The prerequisite level of information necessary to make a reasoned choice among the alternatives is based on the scope and nature of the proposed action. An allocation decision is very limited in scope and, therefore, does not require an exhaustive gathering and monitoring of baseline data. See response to Comment 52837-001 regarding the level of information needed to support land allocation decisions.

The level of information necessary for subsequent NEPA analysis will be based on the nature and scope of the proposed action and gathered in full compliance with BLM's land use planning and NEPA procedures. The BLM's land use planning decisions and associated NEPA analysis guides decisions for every action on the public lands. A major component of the NEPA process associated with such planning is working with cooperating agencies to collect inventory data and analyze the current management situation (BLM Planning Handbook H1601-1, F.2.c.). In preparing a land use plan, amendment, or revision, a systematic interdisciplinary approach is used to provide accurate, objective, and scientifically sound environmental analysis based on the best available information to formulate management prescriptions, including mitigation measures to avoid or mitigate adverse impacts. The BLM uses a public scoping process to identify issues, concerns, and alternatives and to solicit information or identify information gaps concerning a wide range of topics, including water quality and quantity, air quality, wildlife resources, and socioeconomic impacts. Analysis of the information gathered through these processes provides the foundation for the decision maker to make informed decisions concerning the various management prescriptions. In addition, the BLM recognizes the merits of the oil shale RD&D program to provide information not only about technologies, but also about possible impacts to resources to ensure that oil shale technologies operate at economically and environmentally acceptable levels. The BLM believes this effort will significantly enhance the collective knowledge regarding the viability of innovative technologies for oil shale development on a commercial scale and provide additional information on environmental consequences and potential mitigation measures. Data will be collected, as appropriate, to ensure that operations are in compliance with state and federal statutes and regulations.

If there is incomplete or unavailable information regarding any particular decision, the BLM will comply with CEQ regulations (40 CFR 1502.22) and make it clear that such information is lacking. If the incomplete information relevant to reasonably foreseeable significant adverse impacts is essential to making a reasoned choice among alternatives and the overall costs of obtaining it are not exorbitant, the BLM will obtain the information. If overall costs of obtaining the information are exorbitant or the means to obtain it are not known, the BLM will provide the appropriate statements on the relevance of the information and a summary of any existing information.

52837-018: This PEIS is a programmatic-level document analyzing land use allocation decisions. Programmatic environmental impact statements are used to evaluate broad policies, plans, and programs and provide an effective analytical foundation for subsequent project-specific NEPA documents. The BLM believes there currently is sufficient information at the programmatic level to make a reasoned choice among the alternatives as to whether lands are suitable for future consideration for commercial oil shale leasing.

The PEIS does provide a summary of the extensive ongoing activities in the Piceance Basin and elsewhere in the study area and considers these in its overview of potential cumulative impacts. For example, Table 6.1.5-4 shows that over 30,000 oil and natural gas wells are planned for installation over the 20-year study period in the affected field offices. The approximate land disturbance for these well installations, as well as from other activities, was used to estimate total cumulative land disturbance from other activities in the study area over the next 20 years. Section 6.1.5.3.10 acknowledges that income in the recreation sector may be lost due to oil shale and tar sands development. Also, Sections 6.1.5.3.4 and 6.1.5.3.5 note that depending on the type and level of development, regional water and air impacts may limit oil shale and tar sands development.

The BLM anticipates that oil shale development would proceed in a three-step decision making process similar to that used for federal onshore oil and gas: land use planning (i.e., amending RMPs); leasing; and approval of a drilling permit or a plan of operations. In the present experimental stage of the oil shale and tar sands industries, however, the BLM believes that the stages of NEPA compliance will be different from those used in oil and gas.

As a result of the maturity of the oil and gas industry, the BLM is usually able to include sufficient site-specific analysis in its NEPA documentation for amendments to RMPs so that an additional NEPA document is not required prior to issuing an oil and gas lease in conformance with the RMP. Nonetheless, the BLM does prepare a NEPA analysis before approving a plan of operation or a drilling permit that would authorize significant disturbance of the leased area. The

NEPA analysis for both decision levels includes cumulative effects analysis. Analysis of each oil and gas decision is based on technical information associated with the particular proposed action, as well as information about other reasonably foreseeable future actions in and near the area of the proposal.

In contrast, the present experimental state of the oil shale and tar sands industries does not allow this PEIS for land use allocation to include sufficient site-specific information or cumulative impact analysis to support issuance of a lease. Accordingly, unlike in oil and gas leasing, prior to oil shale leasing, additional NEPA analysis that will be required. That NEPA analysis could result in decisions not to lease in specific areas, or to lease particular areas with stipulations, such as a stipulation precluding disturbance of the surface.

As with oil and gas leases, although the lease would grant the lessee the right to explore and develop the oil shale and tar sands resources, the lease would not authorize surface disturbance. Before disturbing the surface, the operator would have to obtain the BLM's approval of a plan of development through a project-level NEPA analysis.

NEPA analysis at the leasing and at the development approval stages of oil shale and tar sands decision making would be based on reasonably available technical information associated with the proposed action and on information about other reasonably foreseeable future actions in and near the area of the proposal.

The BLM believes that cumulative impacts would be adequately assessed at the leasing stage. As required under NEPA, all subsequent NEPA documents will also analyze the cumulative effects from other reasonably foreseeable future actions. The scope and nature of the specific proposed action will drive the type of NEPA analysis that the BLM performs. The cumulative effects analysis would consider the present effects of past actions, to the extent that they are relevant, and present and reasonably foreseeable (not highly speculative) federal and nonfederal actions, taking into account the relationship between the proposed action and these reasonably foreseeable actions.

As described in the proposed action in the PEIS, the BLM is committed to performing NEPA analyses prior to leasing and development, but until the scope of the potential leasing and/or development is known, we cannot commit to the scope of the NEPA analysis (regional, planning area, or local) that will be required. The proposed action will drive what analysis must be performed to comply with the requirements of NEPA.

52837-019: Before any activities can take place on public lands, such activities must be allowed for in the land use plan governing use of those lands. As explained in the document itself, this PEIS analyzes the environmental consequences of allocating certain lands for the possible commercial exploration and development of these resources. The allocation decisions to be made do not commit any resources or grant any lease rights. Therefore, in addition to the analysis of direct and indirect effects of these land allocation decisions, including consideration of alternative ways of making these decisions, the PEIS presents a cumulative impact assessment based on the nature and scope of this proposed action and on available nonspeculative information. Programmatic EISs such as this one are considered adequate without site-specific analysis when the federal action proposed, as here, does not involve a site-specific or critical decision. As explained in the document itself, as well as in responses to other comments (see, e.g., response to Comment 52837-018), prior to any commercial leasing, additional NEPA analysis will take place. Because it is still a matter of speculation as to whether leasing and development will ever take place, and because there will be additional environmental analysis prior to leasing, a cumulative analysis associated with the effects of the land use allocation decision contemplated here need not analyze the impacts of leasing and development.

In fact, if parcels are considered for potential leasing in the future, a NEPA analysis, including a cumulative analysis, appropriate to that action, will be required prior to any leasing. This cumulative analysis would include other Reasonably Foreseeable Future Actions, such as local oil and gas exploration and development, and any connected actions associated with the specific proposed action, such as, for instance, the establishment of a source of electrical power generation, if relevant. See response to Comment 52837-008 for a discussion on the scope of potential subsequent cumulative analyses.

The comment recommends preparation of a supplemental PEIS when additional information is available. Please see the response to Comment 52837-008, which contains a discussion of the use of a supplemental EIS.

52837-020: Please see the response to Comment 52837-004.

52837-021: The Energy Policy Act of 2005 directed the Secretary of the Interior to (1) complete a programmatic environmental impact statement for a commercial leasing program for oil shale and tar sands resources on public lands, and (2) publish a final regulation reestablishing such a program. The BLM, through its rulemaking process, is drafting a proposed set of regulations to outline the policies and procedure to implement a commercial leasing program. The BLM published a proposed rule for the management of a commercial oil shale leasing program in the *Federal Register* on July 23, 2008. The BLM rulemaking process is separate and apart from the drafting of the PEIS. The PEIS analyzes the environmental consequences of an allocation decision, and therefore comments concerning the regulatory process are outside the scope of the PEIS.

52837-022: The BLM does recognize that additional NEPA analysis will be required and is committed to preparing the appropriate level of analysis prior to the issuance of any oil shale lease. (See page 2-19 of the Draft PEIS for the description of additional NEPA requirements.) This new NEPA analysis will analyze whether to offer for lease parcels of land for commercial oil shale exploration and development and under what conditions or stipulations. The analysis will also contain any new information or circumstances relevant to the technology, the affected environment, and any associated environmental consequences. This information may be a consequence of research on the RD&D leases or a result of industry performing research or studies on nonfederal lands.

The affected environment of the action could vary greatly from a large regional area to a small discrete area. The scope of the analysis in the NEPA document would be dependent upon the number of applications received and the type and size of operations proposed by the applicant(s). This could result in a statewide, regional, basin-wide, or site-specific impact analysis. Overall, the geographic extent of the analysis would be limited to those areas that could experience a change in the pattern of land use, as a consequence of a direct impact or other induced effects on the natural resources. The nature of the action can also vary greatly based on the type of technology or mining method. Another critical factor would be the type of infrastructure needed to support the operation, in particular, the source of electrical power.

Thus, while the BLM is committed to performing NEPA analyses prior to leasing, we cannot commit to a certain type of NEPA analysis (regional, planning area, or local). The proposed action will drive what analysis must be performed to comply with the requirements of NEPA.

52837-023: The PEIS serves as the basis for land allocation and does not support leasing decisions. It is, therefore, premature and highly speculative to predict or assume power sources, when, at this time, definitive information about the technologies, including the amount of power needed, the size of the operations, the locations, etc., are unknown. The effects associated with a surface coal mine are different from those associated with an underground operation. Effects associated with a power plant could change drastically depending on where the plant is located and the power requirements of the operations. The assumptions made in the PEIS are based on the best information available. The PEIS analysis is a consequence of those assumptions, the available data, and an attempt to present the potential impacts that reflect known conditions or circumstances.

52837-024: Table 4.5.2-1 shows examples of how much water would be needed in oil shale development under different technologies. It does not imply that commercial oil shale development is committed or is functioning. The table also shows projected available water for the states of Colorado, Utah, and Wyoming. Therefore, a comparison of what is available to address the water needs using different oil shale development technologies could be made.

Information on groundwater availability is limited. A range of groundwater available is used in this PEIS and shown in the table.

Common impacts on the quality of water resources are described in Section 4.5.1.

52837-025: Withdrawal of groundwater that discharged to certain segments of Piceance and Yellow Creeks would generally decrease stream flow, especially during the summer seasons. The decrease of the stream flow depends on the amount of groundwater withdrawn, the location of project sites, the hydrologic connections between the creeks and aquifers, and any discharge of water from the project sites. As these are factors unknown, their impacts on the water resources, therefore, could not be evaluated. However, the impacts would be evaluated at the project levels when these unknown factors are better quantified.

The general impacts that could occur after the melting of the freeze wall are described in Section 4.5.1.

52837-026: The PEIS is a general document and is not intended to list all potential contaminants that may be associated with commercial leasing of oil shale and tar sands. Section 4.5.1.3 of the Draft PEIS recognizes that contaminants to water could be introduced through different means associated with commercial operations. Future site-specific NEPA analyses will consider potential contamination and mitigating measures.

Sections 4.7 and 5.7 contain analysis of noise issues, including information regarding different phases of commercial operations.

There are no areas in Colorado that were identified to have wilderness characteristics outside of Wilderness Areas and Wilderness Study Areas within the PEIS study area.

52837-027: The BLM does recognize that additional NEPA analysis will be required and, as described in the PEIS itself, is committed to preparing the appropriate level of analysis prior to the issuance of any oil shale lease. The BLM is conducting phased decision making—proceeding from land use planning, to leasing, to operational permitting—as the BLM does for other resources such as oil and gas. This first step—RMP amendment to allow the BLM to consider applications for leasing—may be followed by the subsequent steps of leasing and plans of development, if necessary. The locations, scales, and scopes of the later steps are too speculative at this point and will require their own distinct decision making process when the industry can provide the necessary information. Therefore, it is inappropriate to speculate at this stage whether such NEPA analysis will be programmatic in nature.

52837-028: The reference to the Colorado Mined Land Reclamation Act has been removed from Table D-3 but added to Tables D-4,-5,-6,-7,-10,-13, and-14.

52837-029: The mined land reclamation laws have been added to Appendix D of the Final PEIS.

52837-030: The best available information to define the geologically prospective area was used, and the deposits were sufficiently characterized so the BLM could delineate where the most geologically prospective resources are located. The specific reports used to delineate the most geologically prospective areas are cited in footnote 2 on page 1-6 of the Draft PEIS. In the Piceance Basin, the deposits were characterized using USGS data. The Green River, Washakie, and Uinta Basins were characterized by a BLM geologist using Fischer Assay data from existing exploration drill holes. It can be assumed that comparable procedures would be developed, as in the coal, oil, and gas program, etc., to explore the oil shale deposit in order to obtain geological, geophysical, environmental, and other pertinent data concerning the oil shale deposit, thereby gathering adequate information for subsequent stages of exploration and development.

52837-031: The information in Table 2.2.3-1 is supplemented in Section 3.1.1 of the PEIS where the existing ACECs included in the discussion of the Field Office in that they are located are discussed. The relevance and importance criteria that supported the designation as ACEC are included along with specific acreages.

52837-032: The referenced text has been revised to clarify the comparison.

52837-033: The referenced paragraph in Section 3.4.2.1 has been deleted.

52837-034: Thank you for your comment.

There is large potential variability in water use depending upon the technologies used, the source of the water, the economics of treatment versus injection disposal, and so forth. The question of water consumption versus water diversion must be dealt with in subsequent and site-specific NEPA analysis.

52837-035: Volume expansion comes from known and suspected sources. The referenced increase (30%) comes from all activities (including mining, crushing, and sizing in preparation for retorting) and compares the spent shale to the in situ condition of the raw shale.

Clarifications have been made to the text.

52837-036: The maturing oil shale industry will influence the placement of power generation sources and other supporting infrastructures. In the early years of the industry, however, the BLM believes it is reasonable to assume that oil shale developers will have to install their own power generating capabilities. Those developers are expected to rely on existing pipeline infrastructures, however, and must bear the cost of connecting their facility to that infrastructure. Additionally, with respect to pipeline conveyance of raw shale oil, shale oils that have not been sufficiently upgraded at the mine site to remove contaminants (especially nitrogen-bearing contaminants) may not be eligible for transport in existing conventional crude oil pipelines for fear of contamination of those conventional crudes, and a fully independent pipeline network for delivery of raw shale oil to refineries may be required.

52837-037: Tables in Section 4.1 of the PEIS present the acreage figures noted in the comment. The Tables' footnotes present the assumptions associated with the acreage figures. For example, Table 4.1.1-1 describes the assumed values for surface disturbance (and other factors) for one surface mine with retort that could be located in either Utah or Wyoming. Footnote b identifies the surface disturbance number as the estimated range of surface disturbance that could occur at any given time during the life of the project.

52837-038: The text in Section 4.5.1.2 has been modified accordingly.

52837-039: The text in Section 4.5.1.4 has been modified accordingly.

52837-040: You are correct that the areas considered in the PEIS and the three referenced RMPs overlap. All decisions related to land use planning for oil shale and tar sands resources in the PEIS study area will be made in the ROD for the PEIS. The ROD will amend the existing RMPs by making decisions on whether or not lands will be available for application for future leasing and development of oil shale on public lands for those areas where the resource is present. Additional site-specific NEPA analysis will be completed on any future lease application before any leases would be issued. If, as part of this preleasing NEPA analysis, the BLM determines that leasing and subsequent development of the oil shale resources would cause significant impacts, for example, to ACECs or important wildlife habitat, the BLM can require the applicant to: (1) mitigate the impact so that it is no longer significant, (2) move the proposed lease location, or if neither of these options resolves the anticipated conflicts, (3) the BLM can decide that development of the oil shale resource outweighs protection of the on-site resources and approve the application. This preleasing NEPA analysis would include opportunities for public involvement and comment that are part of the PEIS process and every other planning and NEPA process the BLM undertakes.

52837-041: Site- and species-specific analyses will be conducted for any proposed project. The purpose of these analyses is, in part, to identify any habitats or species that warrant special consideration during project siting, design, construction, operation, and decommissioning. The scope and approach for these analyses, as well as any particular species or habitats to be evaluated and additional mitigation measures to be incorporated as project stipulations, will be determined on a project-by-project basis in conjunction with input from federal, state, and local agencies and interested stakeholders.

52837-042: The BLM acknowledges the commentor's preference for Alternative A.

52837-043: It is important to recognize that the plan amendment being analyzed in the PEIS merely allocates certain land for future consideration of applications for commercial development of oil shale and tar sands resources. There is no commitment of resources or granting of any leases; therefore, there is no "irrevocable commitment" of resources made in the PEIS.

The FLPMA directs the BLM to manage public lands for multiple use (Section 102(a)(7)). As a multiple-use agency, the BLM is required to implement laws, regulations, and policies for many different and often competing land uses and to resolve conflicts and prescribe land uses through its land use plans. The FLPMA makes it clear that the term "multiple use" means that not every use is appropriate for every acre of public land and that the Secretary can "make the most judicious use of the land for some or all of these resources or related services over areas large enough to provide sufficient latitude for periodic adjustments in use." Wildlife resources, although important, do not necessarily have an absolute priority over other authorized uses of public lands.

At such time as applications to lease are accepted, and as additional information becomes available, an interdisciplinary team of resource specialists, with on-the-ground knowledge of the area, will analyze the current management situation, desired conditions, and the uses and activities to create alternatives or mitigation measures to resolve any issues raised or conflicts identified. That interdisciplinary team will use a balanced approach consistent with FLPMA's principles of multiple use and sustained yield. Furthermore, the BLM will seek the participation of CDOW and other agencies as cooperating agencies for providing the analyses required under NEPA.

52837-044: The definitions of moderate and large impacts have been modified in Tables 4.8.1-1, 4.8.1-2, 5.8.1-1, and 5.8.1-2 of the Draft PEIS, and some of the potential magnitude of impacts have also been changed to indicate that a number of impacts to wildlife species could be large if not mitigated. The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development. The potential for the Piceance Basin to meet the capacity requirements for infrastructure, power, or water would be determined at the project-specific level (i.e., on a lease-by-lease basis).

52837-045: The BLM is conducting a phased decision-making process—proceeding from land use planning to leasing to operational permitting. The land use planning or allocation decision does nothing more than remove an administrative barrier preventing the BLM from accepting applications. Therefore, subsequent NEPA analysis will be required prior to the leasing and development phases, and potential impacts to wildlife resources will be one of the areas addressed in any analysis. Part of that NEPA analysis will be to determine the cumulative impacts of the decisions, including determination of the potential cumulative impacts to wildlife populations. This additional analysis will consider any new or site-specific information regarding proposed oil shale technology and any anticipated environmental consequences. Specific mitigation measures, management prescriptions, and the best available practices will be applied to minimize or eliminate impacts as a result of the NEPA analysis.

52837-046: While there are many possible alternatives or actions, the BLM, in consultation with 14 cooperating agencies and as mandated by Congress in the Energy Policy Act of 2005, used the scoping process to determine a reasonable range of alternatives that best addressed the issues, concerns, and alternatives identified by the public. It was determined that the three alternatives provided a reasonable range because the allocation decisions, as being proposed in the PEIS, had a very narrow and limited scope—to allow certain lands to be considered for future leasing. This approach is in full compliance with NEPA since the purpose and need of the PEIS serves as the basis to determine the reasonable range of alternatives in a NEPA document. A broad “statement of need” may necessitate a wider range of alternatives, while a more limited and narrow scope would have a limited number of alternatives. The “No Action Alternative is the “no change” from current management direction or level of management intensity. Alternative B was structured to make the most geologically prospective lands available. Alternative C was structured to apply existing land use plan decisions to the planning area.

52837-047: The potential level of oil shale development that could occur in the near future is unknown and has made it impossible to prepare a nonspeculative assessment of the cumulative effects of ongoing oil and gas development. The cumulative impact analysis for the PEIS does include the potential oil and gas development being analyzed in the WRFO RMP amendment as well as other activities forecasted for BLM-administered lands.

Section 6.1.5.2 and 6.1.5.3 have been revised to acknowledge the potential for oil shale development on nonfederal (e.g., private, state, Tribal) lands. However, the extent and impacts of such development, just as on public land, are unknown at this time. It is assumed that development of oil shale or tar sands facilities on nonfederal lands would have impacts similar to such facilities located on federal lands, as described in Chapters 4 and 5 of the PEIS.

52837-048: The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development. The impact analyses provided in the PEIS qualitatively indicate the types of impacts that could occur to wildlife, including the greater sage-grouse, based on BLM experience with other types of mineral development. Sections 6.1.5 (oil shale) and 6.2.5 (tar sands) provide an overview of impact-producing factors and potential cumulative impacts, including cumulative impacts to ecological resources (see Sections 6.1.5.3.7 and 6.2.5.3.7).

Tables 6.1.5-4, 6.1.5-5, and 6.1.5-6 of Section 6.1.5.2.1 summarize potential oil and gas development that could occur within the oil shale and tar sands region of the three states.

Quantitative analyses of potential impacts to greater sage-grouse and other wildlife species would be conducted for any proposed project. Project-specific NEPA analyses would also identify and assess any cumulative impacts that are beyond the scope of the cumulative impacts addressed in the PEIS. Policies and BMPs that would be implemented at the project-specific level are expected to avoid sage grouse habitat and, where not possible, minimize and mitigate impacts to sage grouse to the extent practicable. Sage grouse mitigation would be incorporated as project stipulations, as needed. The need for these mitigation measures would be determined on a project-by-project basis in conjunction with input from federal, state, and local agencies and interested stakeholders. Mitigation of impacts to sage grouse would include recommendations included in the BLM's National sage grouse habitat conservation strategy, as well as those contained in state-wide and regional sage grouse conservation strategies and management plans that have been prepared by state agencies.

52837-049: Chapters 4 and 5 of the PEIS contain substantial discussion of the types of impacts that might occur to both wildlife and water resources from commercial oil shale or tar sands development, including discussions of effects of displacement of big game from winter range and impacts to sensitive and threatened and endangered fish species.

52837-050: The impact analyses provided in the PEIS qualitatively evaluate the water quality impacts mentioned in the comment to fish and wildlife species based on BLM experience with other types of mineral development (see Sections 4.8.1.1, 4.8.1.3, 5.8.1.1, and 5.8.1.3).

The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development. Therefore, the specific number and locations of projects within the Piceance Basin or elsewhere cannot be identified within the PEIS. Sections 6.1.4.7 and 6.2.4.7 of the PEIS compare potential impacts of the allocation decisions on ecological resources but are based on a comparison of lands available for leasing among alternatives with key aquatic and terrestrial habitats that overlap the lease areas. Subsequent project- or site-specific NEPA documents will be prepared to determine whether or not a lease will be offered in a specific area. These will include quantitative analyses of water quality impacts to fish and wildlife species that occur within the project area, including considerations of direct, indirect, and cumulative effects (including other infrastructure required to support oil shale and tar sands development), reasonable alternatives, and possible mitigation measures to protect fish and wildlife habitats. Mitigation measures would be determined in conjunction with input from federal, state, and local agencies and interested stakeholders.

52837-051: Tables 4.8.1-1 and 5.8.1-1 of the Draft PEIS have been modified to add water depletion as an impact category that could potentially affect wildlife. A paragraph has been added to the discussion of habitat disturbance (Sections 4.8.1.3.1 and 5.8.1.3.1) that qualitatively assesses the impacts of water depletions to wildlife.

52837-052: The BLM is evaluating the amendment of land use plans in parts of Colorado, Utah, and Wyoming to identify public lands that would be available for future application for leasing for oil shale or tar sands development. The proposed action is a land use allocation and does not commit any resources or authorize any BLM action that would have a direct, indirect, or cumulative impact on migratory or other wildlife species.

Cumulative impacts to wildlife species (including migratory species) are discussed qualitatively in Sections 6.1.5.3.7 and 6.2.5.3.7 of the PEIS. At this time, it is not possible to provide a quantitative evaluation of cumulative effects as requested in the comment because there are many uncertainties regarding the amount of development that is reasonably foreseeable, the types of technologies that might be deployed, and the locations of potential projects. These details would be needed to perform the type of analysis requested in the comment. Cumulative impacts will be evaluated in greater detail in project-specific NEPA assessments and consultations conducted prior to leasing and development. These cumulative impact analyses will take into consideration other reasonably foreseeable oil shale and tar sands developments.

52837-053: The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development. Therefore, it is justifiable that the evaluation of specific occurrences of resources and supporting facilities, analyses of the environmental consequences of oil shale or tar sands development, and the assessment of the cumulative effects of oil shale and tar sands development together with the other factors mentioned in the comment be included in subsequent project- or site-specific NEPA documents rather than in this PEIS.

As stated in Sections 6.1.5 and 6.2.5 of the PEIS, for the purposes of analysis the cumulative impacts assessment looks at the incremental impacts of a single oil shale facility and a single tar sands facility, recognizing that there may be more than one of each type of these facilities brought into operation during the study period. This cumulative analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decision and the uncertainty of oil shale and tar sands development on private lands. Most of the topics identified in the comment are addressed in the PEIS. Section 3.7.3 describes existing wildlife resources in the study areas. Section 4.8.1.3 describes the types of impacts that are known to affect or that could affect wildlife resources. Sections 6.1.1.7, 6.1.2.7, 6.1.3.7, 6.2.2.7, and 6.2.3.7 present maps showing crucial habitats relative to oil shale basins and STSAs. Sections 6.1.5.2 and

6.2.5.2 present an inventory of other disturbances that could contribute to cumulative impacts to wildlife species. Other requested items (e.g., overlays of areas to be developed, an assessment of the magnitude and extent of crucial habitat that will be affected) are not sufficiently well known at this time.

A more specific analysis of cumulative impacts of oil shale and tar sands facilities in the study area may be conducted at a future step in the assessment process, when an RFDS for oil shale and/or tar sands development would be included. An RFDS was not developed for this PEIS because most of the information necessary for producing an RFDS is unknown and not reasonably available at the present experimental stage of the oil shale and tar sands industries. Assumptions based on the limited available information would be too speculative to support a meaningful scenario. An RFDS at a future step in the assessment process would be based on a clear set of supportable assumptions associated with a leasing or development proposed action. Information pertinent to developing an RFDS will be gained from RD&D projects.

Additionally, the NEPA analyses at the leasing and development stages will consider effects from Reasonably Foreseeable Future Actions (RFFAs) (40 CFR 1508.7). If the proposed action would impact a particular resource that one or more RFFAs would also impact, the impacts of those RFFAs would be included in the cumulative effects analysis for the proposed action. At the leasing or development stage, the scope of a cumulative effects analysis will be determined by the location and number of potential leases/projects and the specific resources that may be affected by those leases/projects. For example, the geographic extent of a cumulative effects analysis for leasing or for a proposed development project will reflect not only the geographical limits of the proposed lease/projects, but also the geographical limits of the resource being affected (e.g., elk winter range).

52837-054: The comment expresses concern for impacts on a number of federally protected species or other species of national concern. The impacts of leasing and development on these species are presented and discussed in the PEIS. The text box on greater sage-grouse presented in both Sections 4.8.1.3.1 and 5.8.1.3.1 has been modified to include reference to state and regional greater sage-grouse conservation and management plans that contain mitigation measures to minimize potential impacts to the species. Additional information pertaining to the occurrence and distribution of fish species (especially sensitive native fish species) within the Piceance Oil Shale Basin has been added to Sections 3.7.1 and 3.7.1.1.4 of the PEIS, including information about Colorado River cutthroat trout, roundtail chub, bluehead sucker, flannelmouth sucker, and mountain sucker. The existence of conservation agreement documents for these species has been noted and referenced in these sections as well. Appendix F of the PEIS identifies conservation measures that would be applied to listed and sensitive species.

The BLM is evaluating the amendment of land use plans in parts of Colorado, Utah, and Wyoming to identify public lands that would be available for future application for leasing for oil shale or tar sands development. The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of the lands for commercial development. Subsequent project- or site-specific NEPA documents will be prepared to determine whether or not a lease will be offered in a specific area. These documents will evaluate specific occurrences of the species mentioned in the comment, analyze the environmental consequences of leasing (including consideration of direct, indirect, and cumulative effects) to these species, evaluate reasonable alternatives, and consider mitigation measures to protect the species and their habitats.

52837-055: The PEIS is a programmatic-level document, analyzing allocation decisions. Programmatic environmental impact statements are used to evaluate broad policies, plans, and programs and provide an effective analytical foundation for subsequent project-specific NEPA documents. Currently, there is sufficient information on a programmatic level to make a reasoned choice among the alternatives as to whether lands are suitable for future consideration for commercial oil shale leasing. Depending on the situation in the area being considered for future leasing, wildlife- and landscape-level issues may be included in subsequent NEPA analysis. At that time, the BLM will strive to ensure that the goals and objectives of each program (representing resource values and uses) are consistent and compatible for a particular land area. Not all uses and values can be provided for on every acre. That is why land use plans are developed through a public and interdisciplinary process. The interdisciplinary process helps ensure that all resource values and uses are considered to determine what mix of values and uses is responsive to the issues identified, such as carrying capacity, water rights, and impacts to wildlife and wildlife habitat.

52837-056: An evaluation of reclamation success following oil shale development is presented in Section 4.8.1.2. The PEIS acknowledges that reestablishment of some vegetation types (e.g., shrubland communities) may require several decades. The PEIS also states that reestablishment of native plant communities in particularly arid regions (e.g., Uinta Basin Floor ecoregion in Utah and portions of the Rolling Sagebrush Steppe and Salt Desert Shrub Basins ecoregions in Wyoming) may not be successful. The loss of intact native plant communities could result in increased habitat fragmentation, even with the reclamation of impacted areas.

52837-057: The presence of non-native invasive species in potential oil shale lease areas and the potential introduction and spread of such species into uninfested areas as a result of oil shale development are discussed in Section 4.8.1.2 of the PEIS.

52837-058: The BLM is preparing a programmatic-level document analyzing land use allocation decisions. Information needed to support those decisions is general in nature. The BLM has disclosed in the PEIS information regarding potential impacts of commercial development on wildlife populations. At this time, however, there is no way to accurately predict those impacts or the magnitude of those effects.

Nevertheless, there is sufficient information at the programmatic level to make a reasoned choice among the alternatives when considering lands open or closed for consideration of commercial leasing. The PEIS analyzes the environmental consequences of this allocation decision in sufficient detail for the decision maker to choose which lands would be available for further consideration for leasing. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development nor do they create any development rights. When applications to lease are received and additional information becomes available, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and possible mitigation measures, as well as what level of development may be anticipated.

52837-059: Thank you for your comment. The BLM looks forward to continuing its strong working relationships with the Department.

52837-060: Please see the response to Comment 52837-040. Additionally, although decisions regarding whether or not public lands will be available for application for commercial oil shale leasing and development, all three RMPs mentioned will, as part of the planning and NEPA process, include an analysis of the cumulative effects of actions relevant to each of the plan areas. This cumulative analysis would include analysis of the effects of other RFFAs, such as local oil and gas exploration and development, anticipated oil shale development, and any actions associated with the proposed actions.

52837-061: Geologic resources in Colorado's Piceance Basin are described in general in Section 3.3.1.5. Resources at the local scale are not addressed in the PEIS. Seismic risk is described in Section 3.3.1.4 as fairly low. Whether operations would increase seismic risk would be addressed in leasing and project-specific NEPA analyses, including the analysis of the key aspect of any potential permitted deep injection of wastewater. If significant impacts are identified as part of these NEPA analyses, mitigation, in the form of constraints on leasing and/or operations, would be applied to lessen or eliminate those impacts.

52837-062: The BLM is taking a measured approach to oil shale development where each step builds upon a prior step. This staged approach ensures that any commercial oil shale program meets the intent of Congress and takes advantage of the best available information and practices to minimize impacts and offer opportunities for states, Tribes, local communities, and the public to be involved at each decision point. At future stages of environmental evaluation (i.e., leasing and/or plan of development), a landscape-level analysis will be performed if appropriate.

This analysis would consider effects from Reasonably Foreseeable Future Actions, including other oil shale/tar sands leases/projects. Please also see the response to Comment 52837-027. The BLM notes the State of Colorado's preference for Alternative A.

The BLM is aware of the requirements of the Energy Policy Act of 2005. Consistent with those mandates, the BLM is moving forward with this broad-scale PEIS that reviews the reasonably available information. As pointed out by the cooperating agencies, the BLM cannot acquire information at this time to project the number, locations, or technologies of future commercial oil shale operations. Congress has not authorized the BLM to delay this PEIS until technologies have been proven commercially viable. Thus, this PEIS supports the programmatic decisions to amend land use plans to open certain lands to further consideration of oil shale or tar sands leasing and to close other lands to such leasing.

52837-063: The sources of projected demands and water uses are from the states of Utah and Wyoming in their water plan documents (see footnotes of Tables 3.4.1-2 to 3.4.1-4) and the *Statewide Water Supply Initiative* study of Colorado (CWCB 2004). These documents provide information on water demands of different sectors over the next 20 to 40 years. The PEIS uses the best available information for its analyses. Any pending, planning, or ongoing study results would not be included unless they formally have been made publicly available.

52837-064: Section 3.4.1.4 of the PEIS describes Colorado's tributary and non-tributary groundwater nomenclature. The discussions of potential impacts and cumulative effects do not distinguish whether groundwater at a potential commercial site is tributary or non-tributary, because that is site-specific information, and the document is programmatic in its coverage. Instead, the document considers groundwater use as a whole. Groundwater usage, whether pumped for mine dewatering, in situ zone dewatering, operations support, or other purposes, would affect cumulative water impacts whether the groundwater is tributary or non-tributary.

52837-065: This PEIS is a programmatic-level document, analyzing allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of the lands for commercial development. Subsequent NEPA documents will be prepared to analyze the environmental consequences of leasing and future exploration and development, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and possible mitigation measures to protect resources and resource values, as well as what level of development may be anticipated.

The amount of water to be needed for oil shale development, if it occurs, would depend on the scale of the development, technologies, economy, acceptable environmental impacts, and many other factors. Subsequent NEPA assessments will also consider the results of the needs assessments cited in the comment.

52837-066: Additional power needs for in situ oil shale development are considered in the cumulative impact assessment (e.g., the ground disturbance and water needs for power generation are included in estimates for individual in situ oil shale facilities; see Section 6.1.5.3). However, at this time it was considered too speculative to assume that the coal used would be mined within the study area (e.g., it could come from northeast Wyoming). More specific data would be available when NEPA documents are prepared to analyze the environmental consequences of leasing and future exploration and development.

52837-067: The types and amounts of hazardous waste that would be generated vary with the various oil shale technologies and would also depend on the scale of the development. The BLM believes that the RD&D program will be a source of additional useful information regarding commercially viable oil shale technologies and their impacts, including hazardous waste generation and management.

This PEIS is a programmatic-level document, analyzing allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of the lands for commercial development. Subsequent NEPA documents will be prepared to analyze the environmental consequences of leasing and future exploration and development, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and mitigation measures to protect resources and resource values, as well as what level of development may be anticipated. These analyses will incorporate new technology-specific data where available.

52837-068: Thank you. The “units” were omitted by accident. The text has been appropriately modified.

52837-069: Injection is permitted by the EPA, as noted in the text. The text in the PEIS has been modified to include mention of the possibility of induced seismicity due to injection.

The potential mitigation measures (Sections 4.3.2 and 5.3.2) have been modified to recommend literature studies focused on faulting; however, specific faults are not mentioned. A recent publication by the Colorado Geological Survey shows no faults in northwest Colorado. See B.L. Widmann, R.M. Kirkham, M.L. Morgan, W.P. Rogers, 2002, *Colorado Late Cenozoic Fault and Fold Database and Internet Map Server Part I*, Colorado Geological Survey, IS-60A, with mapping updated in 2007, available at http://geosurvey.state.co.us/Portals/0/co_eq_map_2006v7.pdf. This map marks the estimated location of the 1882 earthquake as a location in central Colorado, 150 miles east-northeast of the Dudley Bluffs of the Piceance. Also, the Cimarron fault is 70 miles southeast of the portion of the Piceance under consideration.

Regarding the seismic hazard, the 2005 USGS reference cited in the PEIS does not support the commentor's claim of 20–30% g accelerations with a 2% probability, but rather 14–16%. The 2% probability information has been added to the seismic description of each of the four basins.

52837-070: The commentor has echoed many of the potential impacts identified in Section 4.5 of the PEIS, including mining-enhanced groundwater movement, mine dewatering, spring source water, drainage modification, increased porosity and permeability, changes in groundwater/surface water interaction, and changes in groundwater and surface water flow patterns. The commentor would like discussion of the magnitude and mitigation of these potential impacts. The PEIS is a programmatic-level document, and it cannot address or quantify issues at the site-specific level. It is expected that groundwater monitoring at the RD&D sites will provide information at a pilot scale on the degree of impact from different technologies and that this information would be used to determine mitigation measures and also decisions regarding possible future developments. It should be noted that an in situ approach relying on freeze wall technology would require dewatering within the treated volume only, rather than throughout the much larger volume that would be affected by a cone of depression. Also, note that the drawdown associated with typical dewatering (without bounding freeze walls) is dependent on the pumping rate and hydrogeological factors. The theoretical extent of drawdown is unbounded, although the drawdown is practically immeasurable at increasing distances from a pumping well.

If the policy of oil shale development is adopted, a development plan for each project would be prepared. At the project levels, specific infrastructure, roads, and facilities are better defined. Project locations, technologies to be deployed, and anticipated activities would be specified. With this information, more detailed environmental impact analyses would then be conducted. The results would be reported in project-specific NEPA documents.

52837-071: This PEIS is programmatic in scope. The document provides a range of water availability estimates, options (surface water and groundwater), and demands (varied with technologies) and potential impacts. The magnitudes of various impacts and specific types of impacts, would be provided at project-specific NEPA documents in the next phase.

52837-072: The PEIS is a programmatic-level document that analyzes allocation decisions and their consequences. The PEIS does not commit any resources or grant any lease rights. When applications to lease are reviewed, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and mitigation measures, as well as what level of development may be anticipated.

The water estimates used in the PEIS are what an oil shale project plan could use, based upon today's knowledge of oil shale development and assumed plant capacity. Although the PEIS estimates water availability, water rights are not evaluated as that issue is outside the scope of the PEIS. Water rights are also tradable and are going to change with time. They are more appropriately addressed in site- and project-specific NEPA documents.

The Upper Colorado River Endangered Fish Recovery Program uses instream flow water rights to protect endangered fish species. CWCB is the sole agent administrating the instream flows and has acquired water rights to maintain instream flows since the program started. The potential oil shale developers need to follow applicable laws and adhere to existing instream flow water rights to acquire enough water resources for their uses.

52837-073: The comment appears to deal with specific compliance with state water law. The BLM has stated in the PEIS in many places that "commercial development of oil shale or tar sands resources on public lands will be subject to existing federal, state, and local laws and regulatory requirements as well as established BLM policies" (e.g., see Section 2.2 of the PEIS). Appendix D has been amended to include the referenced CRS citations.

52837-074: Please see Comment 52837-081 regarding the level of information required for this PEIS. To reiterate, the BLM is committed to preparing the appropriate level of analysis prior to the issuance of any oil shale or tar sand lease or approval of a plan of development in full compliance with the requirements of NEPA. The BLM will work with any cooperating agencies to determine a reasonable range of alternatives that best address the issues, concerns, and alternatives identified by the public such that a balanced mix of uses results.

52837-075: The PEIS is a programmatic-level document that analyzes allocation decisions and their consequences. The PEIS does not commit any resources or grant any lease rights. When applications to lease are reviewed, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and mitigation measures, as well as what level of development may be anticipated. Such analysis covers the impacts on water resources.

The *Statewide Water Supply Initiative Phase I* study was one of many references used to prepare the PEIS. Based on the study, the projected and current water availabilities in Colorado are evaluated. As the water allocation of Colorado under the Colorado River and Upper Colorado River Basin Compacts is dictated by the compacts, the allocation would not be affected by oil shale development.

Oil shale and/or tar sand development is at the very beginning stage. The water use is going to change with developing technologies. Similarly, the landscape of water use and demand in the Upper Colorado River basin changes with time. Any evaluation of impacts on water resources must consider supply, demand, and legal issues. By the time a leasing application is submitted, it would be at least 3 to

5 years away. At that time, the water use environment will have changed. Any elaborate evaluation based on today's water use conditions and the many uncertain assumptions used in the development eventually would produce results with questionable reliability. Therefore, it is better to make such evaluation at the project level later when there is less uncertainty.

52837-076: Water availability is discussed in Section 3.4.1 by hydrologic basins and by states in the oil shale and tar sand regions. The range of water needed for oil shale and tar sands development and the water remaining available to a state under the compacts are described in Sections 4.5.2 and 5.5.2 and summarized in Tables 4.5.2-1 and 5.5.2-1.

This PEIS assumes that 6,000 thousand ac-ft per year is available for use in the Upper Colorado River Basin. The same amount was used in Colorado's *Statewide Water Supply Initiatives* study (CWCB 2004). It was based on long-term historical hydrologic data with a mean undepleted flow at Lees Ferry of about 15,000 thousand ac-ft/year and was confirmed by another CWCB study (2007). The data were collected from 1906 to 2005 within which wet and drought years existed. Other studies (Kuhn 2005, Tipton 1965) suggested that a mean undepleted flow of 13,500 thousand ac-ft/year be used. The Tipton study was based on historical data from 1930 to 1964. A tree-ring study supported the 13,500 thousand ac-ft/year figure (Kuhn 2005).

The assumed 6,000 thousand ac-ft/yr is the amount legally available for the Upper Basin states and has to be consistent with the flow at the Lees Ferry site. For example, the Lees Ferry is 15 million ac-ft; at least 7.5 million ac-ft has to be sent to Lower Basin states and 0.75 million ac-ft to Mexico. The maximum water available to the Upper Basin states has to be less than 6.75 million ac-ft (15 million ac-ft minus 7.5 million ac-ft minus 0.75 million ac-ft) to meet the requirements of various compacts of the Colorado River. The legal entitlement issue has been discussed in Section 3.4.

To evaluate the water supply of the Colorado River Basin, the BLM prefers the use of long-term historical data over relatively short-term data. Historically, we learned that short-term historical data fluctuates and is less reliable than long-term data, resulting in biased assumptions. That happened in the Colorado River Compact of 1922 that assumed a mean flow of 16,400 thousand ac-ft/year (Smerdon et al. 2007). Similarly, if we select the drought years of early 2000s data for our evaluation, we would likely produce another kind of biased results.

The shares of the Colorado River Basin states are specified in the various compacts of the Colorado River. It is inappropriate for the PEIS to speculate on the outcome of future compact development and consider that outcome to evaluate water availability.

The most geologically prospective areas of oil shale are shown in Figure 2.3-1. The water resources of various oil shale basins are described in Section 3.4.2 and shown in the maps of that section.

Water rights ownership is quite dynamic and is changing rapidly in the last several years. By the time an oil shale and/or tar sand project is developed, the ownership may differ greatly from what we have today. Therefore, the issue is more appropriately addressed in subsequent project-specific NEPA documents.

See also response to Comment 52837-075.

52837-077: The PEIS is a programmatic-level document that analyzes allocation decisions and their consequences. The PEIS does not commit any resources or grant any lease rights. When applications to lease are reviewed, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and mitigation measures, as well as what level of development may be anticipated.

Development of oil shale and/or tar sand projects could create local sources of salts for water resources through ground disturbance and soil erosion, generally in the vicinity of project sites, access roads, and rights-of-way. Salinity impacts are closely related to the types of project activities and would be evaluated in subsequent project-specific NEPA documents. Specific BLM salinity control projects and measures to protect these projects near oil shale and/or tar sand sites would be addressed.

The development of oil shale and/or tar sand projects would require compliance with existing applicable regulations, including NPDES. It is described in Section 3.4.1. In Section 4.5.1.3, the PEIS showed that surface runoff at a mining site could be exempted from NPDES permits, provided that the runoff not be contaminated by contact with any overburden, raw material, intermediate product, finished product, by-product, or waste product located on the site of operation. Surface runoff not intercepted at these sites could create a non-point source of contaminants.

52837-078: The Upper Colorado River Endangered Fish Recovery Implementation Program and conservation measures to protect the Colorado River endangered fish species are discussed in Appendix F of the PEIS.

52837-079: The stream segments with instream flow water rights in Water Divisions 5 (Colorado River Basin) and 6 (White River Basin) have been listed in Appendix I. Unfortunately, we could not show their locations on a map because their graphical location information is not available. Specific impacts on instream flows of these streams would be evaluated in subsequent project-specific NEPA documents.

52837-080: Increase in flooding potential resulting from oil shale development is unlikely, as works in streams are very limited. Under the arid and semiarid environment, flooding is more likely triggered by thunderstorms and snowmelts.

52837-081: As is described in Chapter 1 of the PEIS, commercial leasing will not be authorized by this PEIS. Lands are only being identified as available for application for leasing. Monitoring of the RD&D activities is an ongoing activity that is required as part of the RD&D EA approvals.

52837-082: At this time, it is neither required nor possible for this PEIS to present a cumulative effects analysis showing the impacts of leasing and development of these resources across the entire landscape of these three states. First, the decisions to be made on the basis of this PEIS are limited in character, consisting as they do only of planning/allocation of lands where nominations to lease can be considered. Second, the locations, scope, and scale of future oil shale and tar sands development are highly speculative, and because there will be additional NEPA prior to leasing. These points have been clarified in the introduction to the cumulative impacts sections (Sections 6.1.5 and 6.2.5).

A more specific analysis of cumulative impacts of multiple oil shale and tar sands facilities in the study area may be conducted at a future step in the assessment process, when an RFDS for oil shale and/or tar sands development would be included. An RFDS was not developed for this PEIS because most of the information necessary for producing an RFDS is unknown and not reasonably available at the present experimental stage of the oil shale and tar sands industries. Assumptions based on the limited available information would be too speculative to support a meaningful scenario. An RFDS at a future step in the assessment process would be based on a clear set of supportable assumptions associated with a leasing or development proposed action. Such an analysis may include comparison of impacts with and without consolidation of infrastructure development.

The projected water needs for population growth related to oil shale development have been included in PEIS water needs projections (see Table 4.5.2-1). Oil shale project sites generally have facilities to treat sewer on-site. The need for new infrastructure in communities is addressed qualitatively in the socioeconomics sections (Sections 4.11 and 5.11) of the PEIS. The overall impacts of oil shale/tar sands development on water resources are difficult to evaluate at the programmatic level because of the dependence on the scale of development but would be addressed in more detail (possibly including numeric modeling) in future NEPA assessments.

52837-083: The comment addresses issues that must be dealt with at the site-specific level. Since this PEIS is programmatic in nature, the information provided is general, but Section 4.5 provides extensive discussions on water demands and water quality associated with oil shale technologies and also addresses water demands that arise from the coincident growth of support industries and communities.

52837-084: The PEIS cumulative impacts analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decisions being proposed in the PEIS (i.e., amending land use plans to allow certain lands to be considered for future leasing). A more specific cumulative analysis would be more appropriate prior to a leasing or development decision if and when specific technical and environmental information becomes available.

This PEIS does include in the cumulative impacts analysis a discussion of the possibility of land disturbance and other impacts from planned power lines, both those required for oil shale/tar sands facilities and those planned for other purposes (e.g., the transmission and pipeline rights-of-way are included in the total acreage estimate of 14,000 acres for an oil shale facility [Table 6.1.5-9 of the PEIS]), and the potential impacts from other energy corridors are also acknowledged in Section 6.1.5.3.1

A more specific analysis of cumulative impacts of oil shale and tar sands facilities in the study area may be conducted at a future step in the assessment process, when an RFDS for oil shale and/or tar sands development would be included. An RFDS was not developed for this PEIS because most of the information necessary for producing an RFDS is unknown and not reasonably available at the present experimental stage of the oil shale and tar sands industries. Assumptions based on the limited available information would be too speculative to support a meaningful scenario. An RFDS at a future step in the assessment process would be based on a clear set of supportable assumptions associated with a leasing or development proposed action and could include numeric modeling of surface and groundwater impacts as suggested in the comment.

52837-085: As the scale of development and project locations associated with oil shale and tar sands resource and ancillary development are not known, the analysis described in the PEIS was limited to estimating impacts for a region-of-influence in each state based on the likely residential location of project workers. As described in Section 4.11.1.1 of the PEIS, the in-migrating population assumed with each facility was assigned to local communities in each ROI based on a facility's direct workforce, community population, and intervening distances. Expenditure levels to support the in-migrating population at existing levels of service are then estimated for each community and aggregated for each ROI. Estimates of the impact of oil shale and tar sands development on local government expenditures are presented in Section 4.11.1.2 of the PEIS.

When commercial-scale oil shale and tar sands resource development occurs, additional NEPA analyses would be undertaken, where project locations, employment levels, and the number of in-migrating workers in each phase of development would be known, enabling a detailed analysis of oil shale and tar sands and ancillary facility impacts on local tax revenues, facility and infrastructure capacity, and expansion costs, and on the state and local government expenditures required to maintain different levels of service.

52837-086: The water from major rivers (and reservoirs along the rivers) has multiple uses, including as drinking water supplies. Any impacts on the major rivers, as described in this PEIS, have implications on drinking, agricultural, and industrial water supplies. Treating drinking water supplies differently becomes artificial and unnecessary.

The PEIS is a programmatic-level document that analyzes allocation decisions and their consequences. The PEIS does not commit any resources or grant any lease rights. When applications to lease are reviewed, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and mitigation measures, as well as what level of development may be anticipated.

52837-087: Our apologies. CDPHE was included in the list in Chapter 1 but was inadvertently not included in Chapter 7. The text has been corrected in Chapter 7.

52837-088: The sentence has been changed to state that the discharge of wastewater or the discharge of spent leachate into waters of the United States or a state will require an NPDES permit or state equivalent.

52837-089: This section of the PEIS is designed to provide a summary level discussion of the categories of possibly applicable legal requirements. The suggested addition provides detailed information, which would be more appropriate during a site-specific NEPA analysis.

52837-090: The source of selenium in the Colorado River Basin is from Mancos Shale, which is stratigraphically much lower than the Green River Formation (the productive zone of oil shale). Mancos Shale is not exposed in the Piceance Basin or other oil shale prospective basins examined in this PEIS. It does occur in Gunnison Basin south of the Piceance Basin. Given the above situation, the issue of selenium is not emphasized in the PEIS.

Low levels of selenium are found in a few streams. These streams impaired with selenium are shown in Table 3.4.1-1, which lists all impaired streams in the three states in the Upper Colorado River Basin.

52837-091: The most recent 303(d) streams within the oil shale and tar sands regions are listed in Table 3.4.1.3. Because the locations of potential project sites are still uncertain under alternatives B and C, potential impacts on specific 303(d) streams due to oil shale development, therefore, could not be evaluated. Such evaluation would be provided in project-specific NEPA documents. Similarly, impacts on future (303)d river segments would be addressed in the NEPA documents.

52837-092: Colorado, Utah, and Wyoming have been granted NPDES implementation authorization. The states' NPDES programs must be at least as stringent as the federal program. Text has been added to the PEIS to reflect this.

The nonpoint source runoff and sedimentation impacts are described qualitatively in Section 4.5. At this time, such impacts cannot be quantified, because the locations, scope, and scale of future oil shale and tar sands development are highly speculative. However, because the decisions to be made on the basis of this PEIS are limited in character, consisting as they do only of allocation of lands where applications to lease can be considered, and because there will be additional NEPA analyses prior to leasing, a quantitative analysis of the cumulative impacts of nonpoint source runoff and sedimentation is not required at this time. These points have been clarified in the introduction to the cumulative impacts sections (Sections 6.1.5 and 6.2.5).

52837-093: The bullets in Section 4.5.1 have been clarified.

The surface disturbances in the two bullets are referring to disturbances associated with access roads and rights-of-way.

Airborne dust from various disturbed areas and vehicle traffic could be nonpoint sources of sediment and dissolved salt to surface water bodies.

52837-094: If commercial development were to take place, groundwater withdrawals would take place for various purposes to support the various oil shale technologies. The cumulative effect of this pumping on the hydrologic cycle would depend on a combination of the site-specific conditions across all commercial lease areas and the choice of technology at each lease area, as well as other past, present and reasonably foreseeable use of the groundwater. Because the level of development is unknown and highly speculative, only a generic analysis can be provided on the effects of groundwater pumping (see Sections 4.5.1.4 and 5.5.1.4).

52837-095: Colorado has been delegated permit authority for the NPDES permit program including stormwater permits for all areas except Indian lands and federal facilities. Therefore, the State of Colorado has the permitting authority for point sources on BLM lands. The state has also been delegated authority for the §404 dredge and fill program. However, in the 1987 amendments to the CWA, Congress explicitly excluded stormwater runoff from the definition of a point source. Runoff from mining operations or oil and gas exploration, production, or treatment operations is exempt from the NPDES permit program if that runoff is composed entirely of flows from conveyances or conveyance systems used for collecting and transporting precipitation runoff. To qualify for the exemption, however, the runoff must not be contaminated by contact with any overburden, raw material, intermediate product, finished product, by-product, or waste product located on the site of operation. (Source: BLM, Western States Water Laws, available at: http://www.blm.gov/nstc/WaterLaws/Chap2.html, accessed 4/11/08.)

In the text, it has been clarified that Colorado, Utah, and Wyoming have been granted NPDES authorization. The states' NPDES programs must be at least as stringent as the federal program.

52837-096: The text in Section 4.5.1.3 has been modified to reflect the differing UIC approach in the three states. Regarding the concern about Colorado's groundwater contaminant list, each state has its own limits on particular contaminant concentrations, and these details would be appropriate for a project-level NEPA analysis rather than this PEIS.

52837-097: In Section 4.5.1, the PEIS describes the commentor's concerns about increased permeability and the potential for groundwater contamination. It is expected that the monitoring of results from RD&D projects would be useful in future, site-specific NEPA decisions regarding any developments.

52837-098: The extent of mine dewatering necessary would be subject to site-specific factors (e.g., the location of saturated zones relative to mine access shafts and adits (and how well they are sealed) and the portion of the formation being actively mined) and, while it is safe to assume that dewatering would occur throughout the period of active mining, it is highly speculative to attempt to identify the extent to which it would take place or the associated power requirements. At the leasing or plan of development stage, when site-specific information is available and when the scope of the proposed action is determined, the appropriate level of additional analysis will be performed, including assumptions on power use for mine dewatering, if applicable.

52837-099: Please see Comment 52837-081 regarding the level of information required for this PEIS.

The decisions analyzed in the PEIS include no commitment by the BLM to offer for lease public lands within Colorado without additional site-specific NEPA analysis. This additional analysis will consider any new or site-specific information regarding proposed oil shale technology and any anticipated environmental consequences. New information on technologies may be a consequence of research on the RD&D leases or result from research or studies from other sources. Specific mitigation measures, management prescriptions, and the best available practices to minimize impacts will be applied as a result of site-specific NEPA evaluations. In addition, the BLM will involve the state, local communities, and the public throughout the NEPA processes. The Energy Policy Act of 2005 requires BLM to finalize this PEIS, knowing that results from the RD&D program would probably not be available for inclusion in this document. It is not necessary to await the results from the RD&D program prior to amending the land use plans under analysis in this PEIS.

52837-100: This section of the PEIS is designed to provide a summary level discussion of the categories of possibly applicable legal requirements. The suggested addition provides detailed information, which would be more appropriate during a site-specific NEPA analysis.

52837-101: See response to Comment 52837-100.

52837-102: Thank you for your comment. Section A.3.2.2 discusses the advantages and disadvantages of in situ retorting. Contamination of groundwater aquifers by heavy metals leaching from spent shales and residual organic pyrolysis products not recovered from the retort zone is noted as a potential problem. Using solvents to recover the retort products could introduce additional contamination potential. Section 4.5 provides additional discussions on possible impacts to groundwater resources. Future applications for oil shale processing must include detailed plans for avoiding or mitigating groundwater contamination, irrespective of the aquifer's proximity to drinking water supplies; such plans must specifically address protection of drinking water supplies that lie within or proximate to the potential area of impact.

52837-103: Thank you for your comment. Compliance with drinking water standards is implicit for "potable" water being delivered to an oil shale facility for consumption.

52837-104: As noted in the introductory material of Appendix D, the citations in the tables are only those of general statutory authority; they do not convey which states have primacy.

52837-105: As noted in the introductory material of Appendix D, the citations in the tables are only those of general statutory authority. The tables do not list any state or federal regulations.

52837-106: Thank you for your comment. Section 2.2 provides, in very general terms, an overview of existing federal, state, and local laws and regulatory requirements for, as well as established BLM policies that would be associated with, oil shale and tar sands development. Additional information on some of the statutes and regulatory requirements was provided in Appendix D for a limited number or resources. It was not meant to be all inclusive.

52837-107: Although examples of potential types of mitigation measures to protect water resources are provided for consideration (see Sections 4.5.3 and 5.5.3), this discussion is fairly general in nature, because the appropriate place to develop specific BMPs to protect environmentally sensitive areas is at the time that site-specific NEPA evaluations are performed, whether that is at the lease or plan of development stage as a result of those evaluations. In all such cases, the BLM will involve the state, local communities, and the public throughout the NEPA processes. The comment also raises regulatory issues that may be answered in final regulations governing oil shale leasing and operations but are not within the scope of this PEIS.

52837-108: Please see the response to Comment 52837-097 regarding contamination of groundwater.

Groundwater contamination resulting from oil shale and tar sands development is a key concern identified in the PEIS. Section 4.5.1.2 includes a discussion of changes in permeability and leaching potential, and Section 4.5.1.3 contains a discussion of the organic contaminants that are possible from in situ processes based on field and lab studies. It is expected that groundwater monitoring at the RD&D sites will provide information at a pilot scale on the degree of impact from in situ technologies, and that this information would be used to determine mitigation measures and also decisions regarding possible future developments.

Coordination on water issues would take place in at least two ways. First, the BLM's NEPA process is an open process that encourages participation by stakeholders, similar to the current process with the PEIS. These formal processes are initiated whenever there is a new proposed action requiring NEPA analysis, such as any future commercial lease applications. Second, the BLM encourages ongoing, informal coordination between the various levels of government in the normal day-to-day implementation of our respective responsibilities.

52837-109: The BLM has specific policies and guidelines for the establishment and management of ACECs (BLM 1600 Planning Handbook and 1612 Manual). Local BLM offices, during the land use planning process, designate areas as ACECs, as well as develop specific management prescriptions to protect the relevant and important values of the ACECs. The specific management prescriptions in the local RMP guide the day-to-day management of the areas.

52837-110: The format of the PEIS allows readers to easily find information about the purpose and need for the action (Chapter 1), the alternatives (Chapter 2), the study area (Chapter 3), and the potential impacts (Chapters 4, 5, and 6). All elements required under NEPA are included (e.g., cumulative impact analysis, presentation of alternatives, and addressing irreversible and irretrievable commitment of resources, if any). The .pdf format of the electronic versions is searchable by key terms, allowing readers to quickly locate topics of interest.

52837-111: As stated in Section 1.1 of the Draft PEIS, the BLM proposes to amend 12 land use plans in Colorado, Utah, and Wyoming to describe the most geologically prospective areas administered by the BLM in these states where oil shale and tar sands resources are present, and to decide which of those areas will be open to application for commercial leasing, exploration, and development. Additionally, the analysis conducted in preparation of this PEIS was based on available and credible scientific data. As a programmatic evaluation, conducted in support of land use plan amendments, this PEIS does not address site-specific issues associated with individual oil shale or tar sands development projects. A variety of location-specific factors (e.g., soil type, watershed, habitat, vegetation, viewshed, public sentiment, the presence of threatened or endangered species, and the presence of cultural resources) will vary considerably from site to site. In addition, the variations in extraction and processing technologies and project size will greatly determine the magnitude of the impacts from given projects. The combined effects of these location-specific and project-specific factors cannot be fully anticipated or addressed in a programmatic analysis. As a result, additional, site-specific NEPA analyses will be conducted prior to the issuance of commercial leases and the approval of specific plans of development. The BLM would invite other federal, state, local, and Tribal agencies to participate as cooperating agencies on these site-specific project-level NEPA documents.

The proposal (describing where oil shale and tar sands resources are present, and to decide which of those areas will be open to application for commercial leasing, exploration, and development) would not result in the emissions of any climate change-related (or other) air pollutants. Speculation about project locations and how development might occur would require many assumptions that are premature at this stage in the process. If a decision is made to make oil shale and/or tar sands available for future leasing, detailed potential air quality and climate impacts will be appropriately evaluated in detailed, site-specific NEPA analyses (including potential direct, indirect, and cumulative impacts) before issuing leases and approving plans of development.

52837-112: See response to Comment 52837-111.

52837-113: See response to Comment 52837-111.

Speculation regarding the quantity and potential impacts from "Community Exposure to Hazardous Air Pollutants" is premature at this stage in the process.

52837-114: The discussion of additional power requirements is consistent with the needs of the PEIS to identify lands as available for application for leasing. Chapter 4 of the PEIS in Section 4.1.6 contains information on the size of a power facility needed to support an assumed 100,000 bbl/day in situ oil shale operation. This information and information on expected water needs, employment, and land needed for plant construction are included to disclose the general magnitude of the impacts of this size plant on the resources listed.

Please see Comment 52837-008 regarding the extent of future NEPA analysis that would be required to consider such a development.

52837-115: See response to Comment 52837-111.

52837-116: It would be useful to conduct additional background meteorology and air quality related values monitoring throughout the study area. The BLM would like to meet with the states of Colorado, Utah, and Wyoming (along with other federal land management agencies) to pursue how such monitoring could be financed and conducted. All air quality and climate data gathered by the BLM is made available to the public upon request.

Table 3.5.3-2 in Section 3.5.3 provides a detailed list of representative criteria air pollutant concentrations. All values are cleaner than the ambient air quality standards applicable when the analysis was prepared, although as indicated in Table 3.5.3-2, certain ozone and particulate matter values were greater than 50% of the applicable standard (up to 93% of the 8-hour ozone standard based on CASNET monitoring at the Mesa Verde, Canyonlands, and Gothic stations). EPA has recently lowered the ambient ozone standards and will make formal determinations as to whether or not the study area continues to achieve the applicable National Ambient Air Quality Standards. The BLM will not conduct activities that would be in violation of the air quality standards, and will require lessees to obtain and to abide by all necessary permits and to abide by all other applicable laws and regulations. Speculation about project locations and how development might occur would require many assumptions that are premature at this stage in the process.

52837-117: When applications to lease are received and additional information regarding technologies and impacts becomes available, the BLM will conduct further NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and mitigation measures, as well as what level of development may be anticipated.

The BLM's NEPA process is an open process that encourages participation by stakeholders, similar to the current process with the PEIS. These formal processes are initiated whenever there is a new proposed action requiring NEPA analysis, such as any future commercial lease applications. Additionally, the BLM encourages ongoing, informal coordination between the various levels of government in the normal day-to-day implementation of our respective responsibilities.

52837-118: See response to Comment 52837-008.

52837-119: Permitting for future oil shale and tar sands projects would require compliance with state and federal regulations and programs, including any mandatory Renewable Portfolio Standard Programs in effect at that time. Currently, estimating the impacts of power requirements is very speculative because the amount of power required varies with the technology to be implemented, and also because the source of the power (and therefore the impacts) is unknown. Required power could come from coal-fired plants, nuclear plants, natural gas, or renewable energy sources. The commentor should note also that there are limits to the BLM's authority to impose requirements on activities taking place off federal lands. An example would be that the BLM has no regulatory authority over electric generating facilities located outside of the BLM's lands.

52837-120: Figure 3.5.1-1, Section 3.5.1.1, provides both prevailing wind information at several monitoring locations throughout the study area, and a citation for where the information was obtained. Speculation about project locations and how development might occur would require many assumptions that are premature at this stage in the process.

52837-121: Thank you for your comment.

52837-122: The future NEPA analysis described in Comment 52837-001 will consider the relative resource values present in any proposed lease area and will be used by the BLM to support a decision on whether to offer specific parcels of land for lease. As the specific alternatives associated with the lease sale NEPA document are formulated, areas identified to be offered for leases would be overlaid with other existing program decisions in the RMP. Inconsistencies or conflicts would be identified and alternatives formulated so that ultimately a balanced mix of areas to be offered for leases and protection of natural resource values or uses result. While there are many possible management options, the BLM will use the scoping process to determine a reasonable range of alternatives that best address the issues, concerns, and alternatives identified by the public.

52837-123: See responses to Comments 00007-002 and 00036-013.

52837-124: The potential emissions of any air pollutant (including mercury) would not result from the alternatives examined for making BLM-administered lands available for potential future commercial leasing of either oil shale or and tar sands resources. Site-specific NEPA review would be the appropriate stage for analysis of mercury emissions.

52837-125: The statement in Section 6.1.1.5 is an accurate summation of the EAs for the RD&D projects. The summaries of the EAs are provided for information. The BLM will not conduct or authorize activities that would not comply with applicable local, state, Tribal, or federal air quality laws, statutes, regulations, standards, or implementation plans. Speculation about project locations and how development might occur would require many assumptions that are premature at this stage in the process. Site-specific NEPA analysis will address air quality impacts of particular proposals.

52837-126: Thank you for your comment. Revisions of the RD&D leases is outside the scope of this PEIS. The state offices of the BLM are always willing to work with operators and other regulating agencies to promote improvement of environmental performance on BLM leases.

52837-127: Speculation regarding the quantity and potential impacts from "Community Exposure to Hazardous Air Pollutants" is premature at this stage in the process. The commentor is invited to submit estimates and data in the NEPA process for specific proposals.

52837-128: Although the commentor concludes that Alternative A is environmentally preferable, the PEIS adequately supports a decision in the Record of Decision to allow future consideration of certain federal lands for leasing oil shale or tar sands. The NEPA analysis for proposals that can be analyzed as to location and technologies will address regional air quality impacts.

52837-129: Project-specific NEPA will be done before any leases are issued. The NEPA process will be open pursuant to applicable regulations. The BLM state offices will be willing to meet with state, local, and federal government agencies to discuss concerns and to share information. If the State of Colorado is seeking establishment of a Federal Advisory Board, that is beyond the scope of this PEIS.

52837-130: One of the major reasons that the decision to offer specific parcels for lease was dropped from consideration in the PEIS is the uncertainty related to future power requirements needed to supply the industry. The allocation decisions now being made in the PEIS do not approve immediate leasing and consequently do not have any indirect effects associated with power generation. At the time commercial lease or development applications are considered in subsequent NEPA analysis, information regarding power sources, including their type, location, and size, will be considered. Renewable energy sources could also be considered at that time.

52837-131: Thank you for your comment. All future analysis will be performed in full compliance with NEPA, CEQ's regulations implementing NEPA, and the BLM's land use planning regulations and policies. Also note that the proposed leasing regulations would not require the BLM to accept applications for leasing that were not responsive to a call for nominations.

52837-132: See response to Comment 52837-118.

52837-133: Table 3.5.3-2 in Section 3.5.3 provides a detailed list of representative criteria air pollutant concentrations. All values are cleaner than the ambient air quality standards applicable when the analysis was prepared, although as indicated in Table 3.5.3-2, certain ozone and particulate matter values were greater than 50% of the applicable standard (up to 93% of the 8-hour ozone standard based on CASNET monitoring at the Mesa Verde, Canyonlands, and Gothic stations). EPA has recently lowered the ambient ozone standards, and will make formal determinations as to whether or not the study area continues to achieve the applicable National Ambient Air Quality Standards. The BLM will not conduct or authorize activities that would not comply with applicable local, state, Tribal, or federal air quality laws, statutes, regulations, standards, or implementation plans.

Speculation about project locations and how development might occur would require many assumptions that are premature at this stage in the process.

It would be useful to conduct additional background meteorology and air quality related values monitoring throughout the study area. The BLM would like to meet with the states of Colorado, Utah, and Wyoming (along with other federal land management agencies) to pursue how such monitoring could be financed and conducted. All air quality and climate data gathered by the BLM is made available to the public upon request.

52837-134: Section 3.5.1.2 describes the existing state of knowledge regarding climate change. However, no climate change-related pollutant emissions would result from the alternatives examined for making BLM-administered lands available for potential future commercial leasing of either oil shale or tar sands resources. Also, no conclusions regarding the potential significance of climate change air pollutants as compared to local or regional emissions were made.

52837-135: Thank you for your comment. The PEIS is analyzing the environmental consequences of an allocation decision. As a result, the ROD will not commit any resources or grant any lease rights. This process provides an opportunity for a subsequent level of NEPA analysis of specific parcels that may be offered for lease and to develop specific mitigation measures to protect the resources and resource values present.

Only those ACECs that are open to mineral entry can be considered for leasing; however, management prescriptions are crafted to protect the relevant and important values. The site-specific NEPA analysis would consider any impact on ACECs before any leases would be issued. If, as part of this NEPA analysis, the BLM determines that leasing and subsequent development of the oil shale or tar sands resources would cause significant impacts to ACECs, the BLM can require the applicant to: (1) mitigate the impact so that it is no longer significant, (2) move the proposed lease location, or if neither of these options resolves the anticipated conflicts, (3) the BLM can decide that development of the oil shale or tar sands resources outweighs protection of the on site resources and approve the application. This NEPA analysis would include opportunities for public involvement and comment that are part of the NEPA process.

52837-136: In the Energy Policy Act of 2005, Congress directed the Secretary of the Interior to make lands available to conduct research and development activities with respect to technologies for the recovery of liquid fuels from oil shale and tar sands resources. This provision of the Energy Policy Act is specifically referring to a research and development program and not the establishment of commercial oil shale or tar sands leasing program. The CEQ regulations (40 CFR 1502.1) require the BLM to consider reasonable alternatives, including the No Action Alternative. Each alternative in the PEIS will be given equal consideration by the decision maker.

52837-137: The BLM acknowledges the commentor's policy preference, but critique of the policy choices embodied in the Energy Policy Act of 2005 is beyond the scope of this PEIS.

52837-138: The description of the existing RD&D leases and their relationship to each of the alternatives has been clarified in the Final PEIS (see Sections 1.2, 1.4.1, and 2.3). The RD&D leases are valid existing rights and will be administered under the terms and conditions of the existing leases. The obligations of both parties are spelled out in those leases. As stated previously, approval of conversion of any RD&D lease to a commercial lease with preference right acreage would be subject to review under NEPA.

52837-139: Permitting for future oil shale and tar sands projects would require compliance with state and federal regulations in effect at that time.

52837-140: The BLM notes the preference of the State of Colorado for Alternative A, the No Action Alternative. The BLM is amending the land use plans in compliance with the provisions of the Energy Policy Act and the intent of Congress as clarified in the responses to Comment 52837-011. As explained in the PEIS itself, the proposed amendment of the land use plans only effectuates an allocation—opening or closing lands to further consideration of the possibility of leasing for commercial development of these resources. As set forth in this PEIS, the BLM concludes that the available information is sufficient for amending the land use planning decisions. As required by the NEPA regulations, the BLM will analyze no action alternatives in subsequent NEPA documents for actual proposed developments.

52837-141: The BLM does recognize that additional NEPA analysis will be required, and is committed to preparing the appropriate level of analysis prior to the issuance of any oil shale lease. (See page 2-19 of the Draft PEIS for the description of additional NEPA requirements.) A supplemental EIS as defined under the CEQ regulations, 40 CFR 1502.9, however, would not be appropriate for such additional NEPA analysis. This is because the nature and scope of the proposed action (i.e., leasing) will be different from the plan amendment action analyzed in the PEIS. Supplemental EISs are prepared when the agency makes substantial changes to a proposed action analyzed in an EIS or when there are significant new circumstances or information bearing on a proposed action analyzed in an EIS. Supplemental analyses focus on only those parts of the EIS that require updating before a decision on that proposed action is actually made. Since leasing will be an entirely different decision, a new NEPA analysis will be required. It is inappropriate to speculate at this stage whether such NEPA analysis will be programmatic in nature.

52837-142: The BLM agrees that a piecemeal or segmented approach to analysis of the environmental effects resulting from several projects without consideration of other past, present, or reasonable foreseeable future projects that may cumulatively affect the quality of the human environment should be avoided to the extent possible. At the leasing or development stage, however, the scope of a cumulative effects analysis will be determined by the location and number of potential leases/projects and the specific resources that may be affected by those leases/projects. As a result, the BLM believes that “piecemealing” or “segmenting” is unlikely to occur.

The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of the lands for commercial development. As stated in Sections 6.1.5 and 6.2.5 of the PEIS, for the purposes of analysis the cumulative impacts assessment looks at the incremental impacts of a single oil shale facility and a single tar sands facility, recognizing that there may be more than one of each type of these facilities brought into operation during the study period. This cumulative analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decision and the uncertainty of oil shale and tar sands development on private lands.

A more specific analysis of cumulative impacts of oil shale and tar sands facilities in the study area may be conducted at a future step in the assessment process, when an RFDS for oil shale and/or tar sands development would be included. An RFDS was not developed for this PEIS because most of the information necessary for producing an RFDS is unknown and not reasonably available at the present experimental stage of the oil shale and tar sands industries. Assumptions based on the limited available information would be too speculative to support a meaningful scenario. An RFDS at a future step in the assessment process would be based on a clear set of supportable assumptions associated with a leasing or development proposed action. Information pertinent to developing an RFDS will be gained from RD&D projects.

52837-143: The promulgation of regulations on environmental protection standards (i.e., setting royalty rates and addressing bonding, establishing standards for diligent development, and determining the allowable size of leases) is outside the scope of the PEIS.

The BLM published a proposed rule for the management of a commercial oil shale leasing program in the *Federal Register* on July 23, 2008. This process has its own public comment period.

52837-144: The BLM acknowledges the commentor’s preference for Alternative A.

52837-145: Thank you for your comments. You are correct that characterization of wastes and estimations of their volumes will be critical to their proper management. At this point in time, the experiences of ongoing research efforts give some general indications of the types of wastes that can be expected. However, a much more detailed analysis of waste types and volumes will be required as part of a detailed plan of operation for commercial-scale operations that applicants will be required to provide. On-site waste management strategies, as well as identification of final treatment and disposal facilities to be used, will all need to be specified, and all necessary permits will need to be secured. As for concerns related to the original RD&D projects, it is important to remember that the RD&D projects are outside the scope of this PEIS and were analyzed in separate NEPA documents. However, those same waste management issues have relevance in those instances where the RD&D efforts evolve to commercial scale operations and will be addressed by separate NEPA analyses when and if those transitions occur for any of the RD&D projects.

52837-146: Thank you for bringing this error to our attention. Yes, regulatory constraints are applicable to RD&D projects and thus are applicable under Alternative A (No Action). Table 2.3.2-1 has been revised to show how Alternative A varies compared to the other alternatives.

52837-147: The BLM is evaluating the amendment of land use plans in parts of Colorado, Utah, and Wyoming to identify public lands that would be available for future application for leasing for oil shale or tar sands development. The proposed action is primarily a land use allocation and does not commit any resources or authorize any BLM action that would have a direct, indirect, or cumulative impact on public or worker health.

When actual exposure doses due to a process are known or can be estimated, it is possible to conduct quantitative health risk assessments that estimate the probability of health effects such as cancer, or provide an indicator of the likelihood of other types of health effects. Because the locations of residences and populations with respect to future oil shale and tar sands development are unknown, and the type and quantity of emissions to air and water from future facilities are also unknown, such a quantitative risk assessment is not possible as a part of this PEIS, which supports amending land use plans to allow certain lands to be considered for future leasing. Quantitative risk assessment would likely be possible as a part of NEPA analyses conducted for site- and technology-specific plans of development.

52837-148: The BLM is conducting a phased decision making process—proceeding from land use planning, to leasing, to operational permitting—as the BLM does for other resources such as oil and gas. This first step—RMP amendment to allow the BLM to consider applications for leasing—may be followed by the subsequent steps of leasing and plans of development. As explained in the PEIS, the proposed amendment of the land use plans is a land allocation decision—opening or closing lands to further consideration of the possibility of leasing for commercial development. Development of lease stipulations will occur in the subsequent NEPA analyses that are evaluating proposed commercial leases or plans of operations.

52837-149: The BLM is evaluating the amendment of land use plans in parts of Colorado, Utah, and Wyoming to identify public lands that would be available for future application for leasing for oil shale or tar sands development. The proposed action is primarily a land use allocation and does not commit any resources or authorize any BLM action that would have a direct, indirect, or cumulative impact on public or worker health.

When actual exposure doses due to a process are known or can be estimated, it is possible to conduct quantitative health risk assessments that estimate the probability of health effects, such as cancer, or provide an indicator of the likelihood of other types of health effects. Because the locations of residences and populations with respect to future oil shale and tar sands development are unknown, and the type and quantity of emissions to air and water from future facilities are also unknown, such a quantitative risk assessment is not possible as a part of this PEIS, which supports amending land use plans to allow certain lands to be considered for future leasing. Quantitative risk assessment would likely be possible as a part of NEPA analyses conducted for site- and technology-specific plans of development.

52837-150: The assessment of potential health and safety impacts of oil shale and tar sands development provided in the PEIS is a preliminary discussion of the types of health effects associated with likely types of contaminants, and general safety issues associated with mining and in situ production. This is appropriate for the proposed action, which is primarily a land use allocation and does not commit any resources or authorize any BLM action that would have a direct, indirect, or cumulative impact on public or worker health. The technology-specific type of health effects data analysis requested in the comment would be included as a part of NEPA analyses conducted for site- and technology-specific plans of development.

52837-151: The BLM is evaluating the amendment of land use plans in parts of Colorado, Utah, and Wyoming to identify public lands that would be available for future application for leasing for oil shale or tar sands development. The proposed action is a land use allocation and does not commit any resources or authorize any BLM action that would have a direct, indirect, or cumulative impact on public or worker health. Operators would be subject to all applicable worker safety and health regulations.

When actual exposure doses due to a process are known or can be estimated, it is possible to conduct quantitative health risk assessments that estimate the probability of health effects such as cancer, or provide an indicator of the likelihood of other types of health effects (i.e., systemic effects). Because the locations of residences and populations with respect to future oil shale and tar sands development are unknown, and the type and quantity of emissions to air and water from future facilities are also unknown, such a quantitative risk assessment is not possible as a part of this PEIS, which supports amending land use plans to allow certain lands to be considered for future leasing. Quantitative risk assessment would likely be possible as a part of NEPA analyses conducted for site- and technology-specific plans of development.

52837-152: The BLM is evaluating the amendment of land use plans in parts of Colorado, Utah, and Wyoming to identify public lands that would be available for future application for leasing for oil shale or tar sands development. The proposed action is a land use allocation and does not commit any resources or authorize any BLM action that would have a direct, indirect, or cumulative impact on public or worker health.

When actual exposure doses due to a process are known or can be estimated, it is possible to conduct quantitative health risk assessments that estimate the probability of health effects, such as cancer, or provide an indicator of the likelihood of other types of health effects. Because the locations of residences and populations with respect to future oil shale and tar sands development are unknown, and the type and quantity of emissions to air and water from future facilities are also unknown, such a quantitative risk assessment is not possible as a part of this PEIS, which supports amending land use plans to allow certain lands to be considered for future leasing. Quantitative risk assessment would likely be possible as a part of NEPA analyses conducted for site- and technology-specific plans of development.

52837-153: The items the reviewer cites as not being addressed in the document are not addressed because the BLM has no statutory or regulatory oversight relative to the licensing, inspection, and enforcement specific to labor camps (man camps), retail food establishments, wholesale food firms, schools, childcare, mobile home parks, public accommodations (hotels/motels), and campgrounds. The document does state in Section 2.2 that, “Commercial development of oil shale or tar sands resources on public lands will be subject to existing Federal, state, and local laws and regulatory requirements as well as established BLM policies.”

52837-154: To reiterate the response from previous comments, the BLM is analyzing the effects of amending land use plans to identify public lands available for application for future commercial oil shale development, and this land allocation decision does not authorize the immediate leasing of lands for commercial development nor does it create any development rights. The PEIS analyzes the environmental consequences of this allocation decision and has determined that with the possible exception of an effect upon property values, there are no adverse environmental effects of this decision, including other socioeconomic effects. If and when applications to lease are received and additional information becomes available, the BLM will conduct further site-specific NEPA analysis, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and possible mitigation measures, as well as what level of development may be anticipated. Potential socioeconomic impacts will be an important part of this future analysis.

52837-155: Uncertainty over the amount and timing of future commercial leasing has prevented development of an RFDS for oil shale and tar sands development which would project the level of activity over the life of the RMP based on estimates of the amount of resources that might be developed. Therefore, a reasonable assumption was made to analyze one hypothetical project of specified size for all three primary technologies considered in the PEIS. This analysis provides the decision maker with the requisite level of detail associated with the environmental consequences with a likely commercial development to make an informed decision.

52837-156: Text has been added to the PEIS describing in more detail the nature of temporary housing. It should be noted that the analysis of impacts of construction of temporary housing in each ROI is not dependent on its location, and assumes a generic housing construction type.

When commercial-scale oil shale and tar sands resource development occurs, additional NEPA analyses would be undertaken to analyze in detail the extent of regional economic impacts, including impacts on housing markets and applicable mitigation measures. Site-specific reviews would take into account actual worker residential locations by county, the extent of wage and salary spending, and equipment material and service procurement patterns in each county by housing developers when these details are known. If it is determined that additional impacts may occur in other counties outside each ROI, particularly with regard to workforce commuting patterns and the impacts on local housing markets, these counties would be included in any future site-specific assessment.

52837-157: The text in the PEIS has been changed to address the issues raised in the comment.

52837-158: Given the programmatic nature of the PEIS, the purpose of the analysis of socioeconomic impacts is to provide an overview of the type and magnitude of impacts that would likely occur with the construction and operation of oil shale and tar sands facilities. As the scale of development and project locations associated with oil shale and tar sands resource and ancillary development are not known, the analysis described in the PEIS was limited to estimating impacts for a region-of-influence in each state, based on the likely residential location of project workers. As described in Section 4.11.1.1 of the PEIS, the in-migrating population assumed with each facility was assigned to local communities in each ROI based on a facility's direct workforce, community population, and intervening distances. Expenditure levels to support the in-migrating population at existing levels of service are then estimated for each community and aggregated for each ROI.

If commercial-scale oil shale and tar sands resource development occurs, additional NEPA analyses would be undertaken, where project locations, employment levels, and the number of in-migrating workers in each phase of development would be known, enabling a detailed analysis of oil shale and tar sands and ancillary facility impacts on local tax revenues, facility and infrastructure capacity and expansion costs, and on the local government expenditures required to maintain different levels of service.

52837-159: Please see response to Comment 52837-085.

52837-160: The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of the lands for commercial development. Therefore, it is justifiable that the evaluation of specific occurrences of resources and supporting facilities, analyses of the environmental and socioeconomic consequences of oil shale or tar sands development, and the assessment of the cumulative effects of oil shale and tar sands development be included in subsequent project- or site-specific NEPA documents rather than in this PEIS.

As stated in Sections 6.1.5 and 6.2.5 of the PEIS, for the purposes of analysis the cumulative impacts assessment looks at the incremental impacts of a single oil shale facility and a single tar sands facility, recognizing that there may be more than one of each type of these facilities brought into operation during the study period. This cumulative analysis was conducted to the extent appropriate, as dictated by the limited scope and narrow allocation decision and the uncertainty of oil shale and tar sands development on private lands.

A more specific analysis of cumulative impacts of oil shale and tar sands facilities in the study area may be conducted at a future step in the assessment process, when an RFDS for oil shale and/or tar sands development would be included. An RFDS was not developed for this PEIS because most of the information necessary for producing an RFDS is unknown and not reasonably available at the present experimental stage of the oil shale and tar sands industries. Assumptions based on the limited available information would be too speculative to support a meaningful scenario. An RFDS at a future step in the assessment process would be based on a clear set of supportable assumptions associated with a leasing or development proposed action.

52837-161: As the scale of development and project locations associated with oil shale and tar sands resource and ancillary development are not known, the analysis described in the PEIS was limited to estimating impacts for a region-of-influence in each state, based on the likely residential location of project workers. As described in Section 4.11.1.1 of the PEIS, the in-migrating population assumed with each facility was assigned to local communities in each ROI based on a facility's direct workforce, community population, and intervening distances. Expenditure levels to support the in-migrating population at existing levels of service are then estimated for each community and aggregated for each ROI. Estimates of the impact of oil shale and tar sands development on local government expenditures are presented in Section 4.11.1.2 of the PEIS.

The comment that the localities have significantly different socioeconomic conditions is well taken. That is one reason why it would be speculative to assume precise socioeconomic impacts before there is a leasing of development proposal with locations, proposed technology, and scale of operation.

52837-162: As the technologies, scale of development, and project locations associated with oil shale and tar sands and ancillary development are not known, the analysis described in the PEIS was based on a series of assumptions regarding the retention of wages associated with housing construction, facility construction, and operation are presented in Section 4.11 of the PEIS. These assumptions were based on publicly available NEPA reviews, past experience with oil shale and tar sands and other energy-related projects, and industry data on power generation and coal mining. These assumptions are reasonable for a programmatic review of potential socioeconomic impacts.

If commercial-scale development occurs, additional NEPA analyses would be undertaken to analyze in detail the extent of regional economic impacts, including impacts on local wholesale and retail price inflation. Site-specific reviews would take into account actual worker residential locations by county, the extent of wage and salary spending, and equipment material and service procurement patterns in each county by oil shale and tar sands resource developers and operators when these details are known.

The BLM is also aware that changes in local wages and prices as a result of any oil shale and tar sands development projects will depend in part on the local supply of labor and materials, and that those supplies may change between the date of this PEIS and issuance of any commercial lease or approval of any plans of development.

52837-163: In the analysis reported in the PEIS, the “induced” effect resulting from household spending is included in the “indirect” effect.

Data on indirect employment losses resulting from the closure of the Colony Project were stated in Gulliford (1989) and were not estimated as part of the analysis undertaken for the PEIS. Multiplier estimates used in the PEIS for OSTS developments reflect the assumptions regarding the ability of each ROI to retain procurement and wage and salary spending, and as a result may differ from the estimates stated in the comment.

52837-164: The role of tax revenues in attempts to diversify local economies and reduce dependency on natural resource extraction industries, thereby reducing the susceptibility of local communities to the boom-and-bust economic cycle associated with energy development in rural areas, is included in the Sections 4.11.2 and 5.11.2 covering potential mitigation measures.

As the analysis included in the PEIS is intended only to support land allocation decisions, not leasing decisions, additional analysis addressing the risk and impacts of a "bust" and the appropriate mitigation measures will occur as part of future NEPA assessments.

52837-165: Text has been added to Section 4.10 and 5.10 of the PEIS covering the impact of oil shale and tar sands developments on the diversification of local economies and their attempts to reduce dependency on natural resource extraction industries, thereby reducing the susceptibility of local communities to the boom-and-bust economic cycle associated with energy development in rural areas. The role of tax revenues in attempts to diversify local economies away from natural resource development is included in Sections 4.11.2 and 5.11.2 covering potential mitigation measures.

52837-166: As stated in Section 1.1 of the Draft PEIS, the BLM proposes to amend 12 land use plans in Colorado, Utah, and Wyoming to describe the most geologically prospective areas administered by the BLM in these states where oil shale and tar sands resources are present, and to decide which of those areas will be open to application for commercial leasing, exploration, and development. Additionally, the analysis conducted in preparation of this PEIS was based on available and credible scientific data. As a programmatic evaluation, conducted in support of land use plan amendments, this PEIS does not address site-specific issues associated with individual oil shale or tar sands development projects. A variety of location-specific factors (e.g., soil type, watershed, habitat, vegetation, viewshed, public sentiment, the presence of threatened or endangered species, and the presence of cultural resources) will vary considerably from site to site. In addition, the variations in extraction and processing technologies and project size will greatly determine the magnitude of the impacts from given projects. The combined effects of these location-specific and project-specific factors cannot be fully anticipated or addressed in a programmatic analysis. As a result, additional site-specific NEPA analyses will be conducted prior to the issuance of commercial leases and the approval of specific plans of development. The BLM would invite other federal, state, local, and Tribal agencies to participate as cooperating agencies on these site-specific project-level NEPA documents.

The proposal (describing where oil shale and tar sands resources are present, and to decide which of those areas will be open to application for commercial leasing, exploration, and development) would not result in the emissions of any climate change-related (or other) air pollutants. Speculation about project locations and how development might occur would require many assumptions that are premature at this stage in the process. If a decision is made to make oil shale and/or tar sands available for future leasing, detailed potential air quality and climate impacts will be appropriately evaluated in detailed, site-specific NEPA analyses (including potential direct, indirect, and cumulative impacts) before issuing leases and approving plans of development.

Section 3.5.1.2 in the Draft PEIS describes the existing state of knowledge regarding climate change. However, no climate change-related pollutant emissions would result from the alternatives examined for making BLM-administered lands available for potential future commercial leasing of either oil shale or tar sands resources.

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Thank you for your comment, Michael Braaten.

The comment tracking number that has been assigned to your comment is OSTSD52850.

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Oil Shale and Tar Sands
Comment ID: OSTSD52850

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Comment Submitted:

March 20, 2008

BLM Oil Shale and Tar Sands PEIS Argonne National Laboratory EVS/900 9700 S. Cass Avenue Argonne, IL 60439

Submitted electronically at osts.anl.gov.

As a participating coordinating agency, the City of Rifle maintains its position of recommending No Action on oil shale leasing and recommends Alternative A of the Draft Oil Shale Programmatic Environmental Impact Statement. The City's preferred alternative allows activities on the existing research, development and demonstration leases to continue, but precludes industry expansion at this time. 52850-001

The City's reasons for continued opposition of oil shale leasing at this time is that there remains a lack of understanding of proposed extraction technology or true environmental and social impact data because of the unknowns associated with oil shale development.

Federal mandate or not, the preparation of this Programmatic Environmental Impact Statement for the sake of letting oil shale leases at this time makes no sense, especially as the RD&D projects are on-going and far from completion. Until the City can reasonably understand how it will be impacted by the development of oil shale, it cannot support an alternative that allows leasing. Comments specific to the Draft PEIS document's contents from the City will not be submitted. 52850-002

As noted above, this position is consistent with past recommendations made as a coordinating agency and the City continues to believe that it is necessary to wait for the outcomes of the RD&D projects before making additional oil shale resources available for commercial lease applications.

Respectfully submitted on behalf of the City Council of the City of Rifle,

Keith Lambert, Mayor City of Rifle

Responses for 52850

52850-001: The BLM acknowledges the commentor's preference for Alternative A.

52850-002: The BLM believes that the RD&D program will be a source of additional useful information regarding commercially viable oil shale technologies and their impacts. In the Energy Policy Act of 2005, however, Congress did not authorize the BLM to wait for additional information from the RD&D program before completing this PEIS. The BLM will analyze all available, relevant information in an appropriate NEPA document before issuing leases for oil shale or tar sands. That analysis will include any new information from research or lessons learned on the RD&D leases or from studies or operations on nonfederal lands.

As explained in the document itself, this PEIS analyzes the environmental consequences of allocating certain lands for the possible commercial exploration and development of these resources. The allocation decisions to be made do not commit any resources or grant any lease rights. Therefore, in addition to the analysis of direct and indirect effects of these land allocation decisions, including consideration of alternative ways of making these decisions, the PEIS presents a cumulative impact assessment based on the nature and scope of this proposed action and on available nonspeculative information. Programmatic EISs such as this one are considered adequate without site-specific analysis when the federal action proposed, as here, does not involve a site-specific or critical decision. As explained in the document itself, as well as in responses to other comments (see, e.g., response to Comment 52837-018), prior to any commercial leasing, additional NEPA analysis will take place. Because it is still a matter of speculation as to whether leasing and development will ever take place, and because there will be additional environmental analysis prior to leasing, a cumulative analysis associated with the effects of the land use allocation decision contemplated here need not analyze the impacts of leasing and development.

Since the alternatives in the PEIS do not authorize the immediate leasing of lands for commercial development, any future leasing will require subsequent NEPA analysis, as described in Section 1.1.1. The BLM's analysis in the PEIS provides the decision maker with information to make an informed decision on which lands are suitable for future consideration for commercial oil shale leasing. Currently, there is sufficient information on a programmatic level to rigorously explore and objectively evaluate all reasonable alternatives associated with an allocation decision. As required by CEQ regulations (40 CFR 1508.7 and 1508.8), this document, and all subsequent NEPA documents, will analyze the direct, indirect, and cumulative effects of the proposed action. That analysis will also help to form the basis for the development of mitigation measures, such as BMPs to avoid or mitigate short-term and long-term adverse impacts.

Thank you for your comment, Maurice Dechant.

The comment tracking number that has been assigned to your comment is OSTSD52870.

Comment Date: March 20, 2008 17:14:40PM
Oil Shale and Tar Sands
Comment ID: OSTSD52870

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Attachment: Mesa County Comments - Draft PEIS.pdf

Comment Submitted:

Please see the attached comments. See Attachment.

Mesa County Attorney's Office

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March 20, 2008

DELIVERY BY WEB, E-MAIL, AND US MAIL

BLM Oil Shale and Tar Sands PEIS
Argonne National Laboratory EVS/900
9700 S. Cass Avenue
Argonne, IL 60439

Re: Comments of Mesa County, Colorado Regarding the BLM Oil Shale and Tar Sands PEIS.

To The Bureau of Land Management:

Mesa County appreciates the opportunity to submit comments on the Draft PEIS. The Mesa County Board of County Commissioners has requested that I prepare and submit our comments. We have followed the preparation of the PEIS as a Cooperating Agency. Although the areas being considered for commercial leasing of oil shale resources are not necessarily located within the boundaries of Mesa County, experience with the previous development of the Colony Project in the late 1970's and early 1980's confirms that the impacts of oil shale development will fall heavily on Mesa County and its municipalities. We remember the impacts and difficulties of the "boom" era and we remember even more clearly the impacts and difficulties of the "bust" era following Black Sunday. Our comments are as follows:

We are concerned with the change in scope of the PEIS. The original intent of the PEIS was to provide analysis not only for amendment of land use plans (RMP's) but also for the issuance of leases for the commercial development of oil shale and tar sands resources. That scope has now been changed to utilize the PEIS only for amendment of the RMP's. We realize that during the development of the Draft PEIS, concerns were raised that there was a lack of information about specific technologies and that much of the information about specific technologies and the resulting impacts was historic and based on technologies that are now over thirty years old. However, typically, a PEIS is completed to modify the RMP's and leases are then issued on nominations. Site specific NEPA analyses are completed after the leases are issued and are based on company-specific development technology and plans, which will reflect current technologies and impacts. Conditions are placed on a lease as an outcome of the site specific NEPA analysis. In this regard, we strongly support the RD&D approach and program currently being undertaken. To the extent it can be expanded with the issuance of additional leases and the evaluation of additional technologies, we would support such expansion. 52870-001

Information and techniques presently being developed on the RD&D leases will be valuable in the site-specific process. 52870-001 (cont.)

We strongly support the use of site-specific NEPA analysis, where the PEIS is used to amend the RMP's and issue the leases and the NEPA analysis is conducted after the lease is issued. Under the current Draft PEIS, only the RMP's would be amended. Leasing would follow another NEPA analysis and development would follow a third NEPA analysis. We are concerned that no applicant will be willing to conduct a very expensive NEPA analysis prior to leasing, with no guarantee that the applicant will be the successful bidder on the lease, and then conduct a subsequent expensive NEPA analysis if they win the lease based on the first NEPA analysis. We believe this process will be economically onerous on the applicants, the Cooperating Agencies, and the impacted local governments. As previously stated, we support thorough and specific NEPA analyses at the appropriate time. However, we urge BLM to consider the capacity of the Industry, the Cooperating Agencies, and the impacted local governments to effectively and economically participate in the process as presently contemplated. 52870-002

We note at various sections of the Draft PEIS the consideration of Regulatory and operational constraints. With regard to Alternatives B and C, Table ES-1 states "All commercial development would be conducted in compliance with federal, state, and local regulatory requirements and established BLM policies." Paragraph 4.1 states "A key assumption is that all applicable federal, state, and local regulatory requirements will be met (see Section 2.2 and Appendix D)." It is respectfully suggested that this should not only be an assumption, but a commitment by the BLM. This commitment should extend not only to the regulations of counties which are the physical site of the lease and the project, but to the regulations of counties such as Mesa County which will be impacted by the lease and project. Specifically, without limitation, roads, pipeline ROW's, air and water quality, wildlife, tourism, housing, sanitation, social and economic impacts and, in fact, the entire lists of impacts and concerns set out in Chapters 4, 5, and 6, are of concern to Mesa County in the issuance of leases and the development of projects, even if the physical site of the lease and project is in a neighboring county. 52870-003

On occasion, we run into and consider the concept of Federal Preemption of local regulations. As a specific note regarding honoring local regulatory requirements, Mesa County has a long history of cooperation with the Forest Service and BLM through a variety of methods, including agreements for joint planning, etc. We very much appreciate the efforts and cooperation of the Forest Service and BLM in this regard.

Specifically regarding the three oil shale alternatives, we believe that Alternative A, No Action Alternative, is not in the best interest of the United States, the State of Colorado, and/or Mesa County. The thoughtful and carefully regulated exploration and development of oil shale reserves is a vital component of energy development for our country and our local area. Regarding Alternatives B and C, we note that many of the impacts are of the same nature in Alternative C as in Alternative B, they are simply more 52870-004 limited in extent in Alternative C because of its significantly smaller size. We note that the lands available for leasing in Alternative C appear to be smaller and more scattered and we question whether Alternative C would result in a situation in which development of the oil shale reserves becomes economically impossible. With this in mind, and with the basic assumption that the NEPA process will result in leases and projects which minimize and mitigate their negative impacts, we concur that Alternative B should be the Preferred Alternative. 52870-004 (cont.)

Mesa County's experience with the impacts of the Colony Project and with other energy related development is that the negative impacts of the development occur significantly in advance of the tax revenues and other revenues that assist to mitigate the negative impacts. Our economy in Mesa County and in this general region is significantly different than it was in the late 1970's and early 1980's. However, although the energy industry has attempted to assist in many ways, impacts from the current exploration and development of natural gas have stretched local resources. We strongly believe that government and industry need to make significant, early, up-front investments in and contributions to the infrastructures of local entities which will be impacted by oil shale development. These investments and contributions can be later credited against severance and/or other taxes and impact fees as they come due. We believe that these investments and contributions should be considered in and required by the NEPA process. In this regard, we join in, and respectfully refer the BLM to, the March 20, 2008 comments submitted by Club 20. 52870-005

We appreciate the opportunity to participate in the PEIS process and we look forward to cooperating with the BLM and participating in the site specific NEPA project analyses as oil shale development proceeds.

Sincerely,

Maurice Lyle Dechant

Maurice Lyle Dechant
Mesa County Attorney

Responses for Document 52870

52870-001: The experimental state of the oil shale and tar sands industries prevents the BLM from completing a NEPA analysis of the amendments to the RMPs that would be sufficiently detailed to allow oil shale or tar sands leasing to proceed without additional NEPA analysis. The BLM acknowledges the commentor's support for the RD&D program and the recommendation for additional RD&D leases. Although future rounds of RD&D leasing are possible, no decision has been made whether there will be additional opportunities to compete for RD&D leases on federal lands.

52870-002: Thank you for your comment. Site-specific impacts of potential development will be identified in future NEPA analysis prior to leasing, which will be used to make decisions regarding lease stipulations. Unlike oil and gas, and both surface and underground mining, the nature of oil shale and tar sands development is still not understood well enough to support lease issuance.

52870-003: The BLM's intent is that future development would be conducted in compliance with federal, state, and local regulatory requirements, and established BLM policies, as is stated in the PEIS. The particular reference cited in Chapters 4 and 5 has been changed to clarify this intention.

52870-004: The BLM acknowledges the commentor's preference for Alternative B.

52870-005: Given the programmatic nature of the PEIS, the purpose of the analysis of socioeconomic impacts is to provide an overview of the type and magnitude of impacts that would likely occur with the construction and operation of oil shale and tar sands facilities. As the scale of development and project locations associated with oil shale and tar sands resource development are not known, the analysis described in the PEIS is limited to estimating impacts for an ROI in each state, based on the likely residential location of project workers. As described in Section 4.11.1.1 of the PEIS, the in-migrating population assumed with each facility was assigned to local communities in each ROI based on facility direct workforce, community population, and intervening distances. Expenditure levels to support the in-migrating population at existing levels of service are then estimated for each community and aggregated for each ROI.

If commercial-scale resource development occurs, additional NEPA analyses would be undertaken, where project locations, employment levels, and the number of in-migrating workers in each phase of development would be known, enabling a detailed analysis of oil shale, tar sands, and ancillary facility impacts on local tax revenues, facility and infrastructure capacity, and expansion costs, and on the local government expenditures required to maintain different levels of service.

Text has been added to the PEIS indicating that the BLM cannot direct that government funds be paid to state and local governments to mitigate impacts from oil shale development. The BLM can only show those impacts in NEPA documents and address how those impacts were mitigated in the past by direction from Congress to use the bonus bids from the federal leases.

Thank you for your comment, John Harja.

The comment tracking number that has been assigned to your comment is OSTSD53001.

Comment Date: April 21, 2008 17:58:51PM
Oil Shale and Tar Sands
Comment ID: OSTSD53001

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Comment Submitted:

See Attachment.

State of Utah

JON M. HUNTSMAN, JR.
Governor

GARY R. HERBERT
Lieutenant Governor

Office of the Governor
PUBLIC LANDS POLICY COORDINATION

JOHN HARJA
Director

April 21, 2008

BLM Oil Shale and Tar Sands Programmatic EIS
Argonne National Laboratory
9700 S. Cass Avenue
Argonne, Illinois 60439

SUBJECT: Oil Shale and Tar Sand Programmatic EIS

To Whom It May Concern:

The State of Utah appreciates the opportunity to work with the Department of Energy (DOE) and Bureau of Land Management (BLM) as a formal cooperating agency in the preparation of this Programmatic Oil Shale and Tar Sands Environmental Impact Statement (PEIS). The state also appreciates the DOE and BLM's extension of similar status to local governmental entities that have a stake in the planning area under consideration. The state firmly believes that cooperative discussions among the various landowners and regulatory agencies will lead to the best possible final product.

The state, local governments, DOE and BLM have invested considerable time and effort working together in this impact analysis. The state's expectation is that this process will continue and lead to a well-reasoned and well-formulated oil shale and tar sands leasing plan. Further, while the state considered local governments' input during preparation of its comments, the BLM should also fully consider the comments submitted directly by local governments.

The comments and concerns raised below are offered in the spirit of cooperation through disclosure, analysis and adherence to the provisions of law, regulation, good governance and common sense. The state recognizes impact analyses as a dynamic process that will continue into the future, and reserves the right to supplement these comments as necessary. The state looks forward to resolution of these issues as a cooperating agency through the preparation of the Final Programmatic EIS 53001-001

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Air Quality

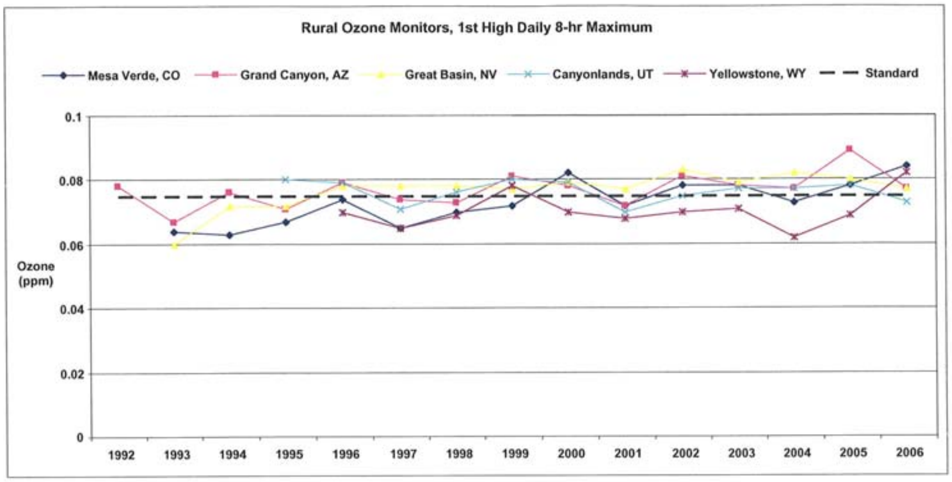
The state appreciates the thorough and comprehensive evaluation of the impacts on various aspects of the environment in the Oil Shale and Tar Sands PEIS. Notably, the PEIS provides a fairly comprehensive description of some of the long term impacts on air quality that could be anticipated. (page 4-46).[1] The PEIS further provides a summary of cumulative impacts across the various effected areas of the environment including air quality. (page 6-154).[2] However, the PEIS states that prior to the development of oil shale, "additional project-specific NEPA analyses would be performed, subject to public and agency review and comment." (page 4-47). Despite this additional level of review, there is some concern that these project-specific NEPA analyses may not appropriately address the cumulative impacts that occur when regional and sub-regional transport of precursor emissions is involved.

The National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$ and Ozone are of concern for the State of Utah. The Ozone standard was lowered earlier this month and the $PM_{2.5}$ NAAQS was lowered in September of 2006. With these revisions, the potential for violating standards increases over a wider geographic area. More specifically, high elevation valleys in the Intermountain West, even those with relatively small population centers, can be susceptible to elevated $PM_{2.5}$ levels during strong, cold inversions. 53001-002

Ozone, which is usually a summer time problem, has become a puzzling winter time problem in the Pinedale area of Wyoming where large natural gas fields exist. The Wyoming Department of Environmental Quality issued an air pollution advisory during the last week of February, 2008 for the Upper Green River Basin, in Sublette County after monitoring very high 8-hour average ozone concentrations. During summer months, regional ozone levels, as measured by the CASTNET monitors show an increasing trend in what might be considered background levels of ozone throughout the Intermountain West (see Rural Ozone Monitors graph).

[1] Long-term, regional impacts (primarily CO and NOx, with lesser amounts of PM, SO2, and VOCs) would result from oil shale processing, upgrading, and transport (pipelines). Depending on site-specific locations, meteorology, and topography, NOx and SO_2 emissions could cause regional visibility impacts (through the formation of secondary aerosols) and contribute to regional nitrogen and sulfur deposition. In turn, atmospheric deposition could cause changes in sensitive (especially alpine) lake chemistry. In addition, depending on the amounts and locations of NOx and VOC emissions, photochemical production of O3 (a very reactive oxidant) is possible, with potential impacts on human health and vegetation. Similar impacts could also occur from the additional coal-fired power plants that would be needed to supply electricity for in situ oil shale extraction. (Section 4.6 Air Quality and Climate, page 4-46.)

[2] "Oil and gas development, other minerals development, and other activities (e.g., agricultural development and residential development) would all involve impacts on local air quality during land clearing and construction because of increased PM emissions and exhaust emission from construction equipment. There could also be regional air quality impacts if these activities involve long-term emissions of criteria pollutants or hazardous air pollutants at substantial levels. The incremental impact of oil shale development activities on total cumulative impacts would be assessed during future site-specific NEPA analyses." Section 6.1.5.3.5 Air Quality, page 6-154. 6.1.5, beginning on page 6-126.



Ultimately, a comprehensive analysis of the cumulative impacts on air quality—specifically the effects of secondary photochemistry and the ability to maintain the NAAQS for $PM_{2.5}$ and Ozone—is outside the scope of this Programmatic EIS. Moreover, the state recognizes the limitations on defining and quantitatively analyzing the scope of potential impacts when the scale, location, and method of development are uncertain. Nonetheless, in light of the foregoing issues, we request the BLM work with the state on a combined analysis of the effects of all emission sources upon completion of the pending baseline study. 53001-002 (cont.)

Relationship of PEIS to RMPs

Under the Programmatic EIS's preferred alternative "B" and alternative "C," seven land use plans in Utah would be amended. (page 1-11). Many of these land use plans are currently undergoing revision and Final RMPs are anticipated within the year. Management decisions made in each of the RMP revisions may directly affect the availability of lands within the analysis area. The State of Utah seeks clarification as to the relationship of the PEIS to the draft RMPs. Specifically, how will decisions made in each RMP amendment affect the analysis and disclosures made in the oil shale and tar sands EIS? 53001-003

Appendix C of the PEIS identifies proposed land use plan amendments associated with alternatives B and C for oil shale and tar sands. (page C-3). Appendix C indicates that under PEIS alternatives B and C, "all lands within the most geologically prospective oil shale areas that are not excluded from commercial leasing by existing law and regulation, Executive Orders, or administrative land use designation, or have not been specifically excluded by the BLM for other reasons, will be available for application for commercial leasing." (page C-11). The state appreciates this statement. However, the PEIS states lands that would be excluded from leasing under both programmatic alternatives include the following:

- Wilderness Areas
- WSAs
- Areas within the NLCS
- existing ACECs that are currently closed to mineral development
- segments of rivers determined to be eligible for WSR status by virtue of a WSR inventory. (page 2-17).

Wild and Scenic Rivers

The PEIS proposes to exclude segments of rivers administratively determined to be an eligible river segment. The state acknowledges the completion of the eligibility phase of the WSR studies as part of the RMP process. The state is also committed to exploring segments of rivers which may make a suitable inclusion in the Wild and Scenic River System. However, protections do not arise until segments are congressionally designated. The state is concerned that the proposed management of "eligible" segments is equivalent to agency designation that impermissibly shortcuts the statutory process. The state believes that exclusion of lands from leasing is not warranted by the eligibility finding, and requests a consistency review of this issue. Further, the Utah BLM is proposing to make suitability findings as part of the record of decision for the RMPs. The state requests clarification regarding treatment of segments found ineligible or unsuitable as part of the RMP revision process and their leasing availability. 53001-004

Areas of Critical Environmental Concern

The PEIS excludes ACECs that are **currently** closed to mineral development. The state requests clarification regarding treatment of potential ACECs that may be designated as part of ongoing RMP revisions. Would newly created ACEC that are closed to mineral development be available for leasing? Also, it is not clear whether "closed to mineral development" encompasses ACECs that are withdrawn for mineral development. To that end, the state requests a distinction be made between ACECs that have been withdrawn from mineral development and ACECs that are closed to mineral development , as well as clarification of how these designations may impact potential leases for oil shale and tar sands development. 53001-005

National Landscape Conservation System ("NLCS")

The PEIS excludes from leasing areas that are part of the NLCS. Please clarify BLM's authority to create a management category and subsequent basis for exclusion of lands for leasing based solely on the designation under the NLCS. 53001-006

Ongoing RMP Revisions

Appendix C designates oil shale acreage estimates for each RMP representing "those lands not excluded from commercial leasing under Alternative "B"." (page C-11). The same is done for tar sands. (pages C-20—C-22). The state requests clarification as to whether the RMPs will reflect the acreage made available for oil shale and tar sands leasing as provided for 53001-007 in the PEIS. If Final RMPs include special designations that differ from those anticipated and discussed in the PEIS, what process will be used to revise the PEIS in light of new information and changed conditions? 53001-007 (cont.)

Adaptation to Technological Innovation

Please clarify whether additional lands may be considered for leasing notwithstanding their lack of inclusion in the PEIS. The state asks the BLM to consider defining how additional lands might be made available for leasing in the event new data supports the feasibility of developing additional land not considered in the PEIS. 53001-008

Leasing

The state wishes to clarify the BLM's approach to issuing leases. Regarding oil shale leasing, the PEIS states:

> [I]f and when applications to lease are received and additional information becomes available, the BLM will conduct NEPA analyses, including consideration of direct, indirect, and cumulative effects, reasonable alternatives, and possible mitigation measures, as well as what level of development may be anticipated. On the basis of this NEPA analysis to be conducted at the lease stage, the BLM will consider further amendment of one or more plans, including, but not limited to, the establishment of general lease stipulations and BMPs. (page 2-16).

With respect to tar sands, the PEIS provides that leasing would occur on a lease-by-application process. More specifically:

> The BLM would issue a call for applications for commercial leases. In response, companies would be required to identify the specific lands that they are interested in as part of their lease application package. It is also possible that the BLM would identify specific tracts to be leased in the call for applications. This process would require that NEPA analyses be conducted prior to lease issuance. Information collected as part of the lease application process would be incorporated into the NEPA analysis. Applicants would be required to identify key information regarding aspects of the proposed development needed to support a complete NEPA review. . . During this NEPA review, the BLM would identify and establish appropriate lease stipulations to mitigate anticipated impacts. (page 2-42).

53001-009

The state requests clarification as to how the leases will be awarded to applicants. Under the current PEIS, it appears that all potential applicants would be required to submit and/or conduct NEPA analyses prior to being awarded a lease. Please clarify the timing, content, and scope of NEPA analysis associated with lease issuance. Please also clarify whether the BLM follow the coal, fluid mineral, or a hybrid leasing model?

Water Issues

The effects of water utilization for tar sands and oil shale development have been skirted in this PEIS. The state recommends an analysis of the impacts of water withdrawal for this development. The state is concerned that the degree of industrial water use may diminish flows in the Colorado River, further harming sensitive and endangered fishes inhabiting the river. We do not understand if there is sufficient physical water, let alone water rights, available to support the scale of development contemplated in the PEIS and the effects this level of water demand might have on agriculture, wildlife (especially endangered fish), or wildlife inhabiting lands and waters in the area.

The state believes it is possible to demonstrate varying scenarios of potential wildlife and environmental impacts from water utilization for tar sands and oil shale development. If, under a set of "high hydrocarbon production/high water demand" assumptions, the public might expect to encounter a 43% reduction throughout the Uinta Basin on farm irrigation, then we may expect to see a commensurate reduction in associated wildlife habitat on private lands. If, in another scenario, the forecast is for "*in situ* development only/moderate water demand" leading to a 9% reduction in lower Colorado River flows as a result of the development, then state biologists would begin to develop an understanding of the potential impacts to endangered fishes on a small reduction in river flows. There might be different ways to package the description of a quantified range of impacts, either among alternatives or within an effects matrix later in the document. This PEIS should attempt to predict precisely how much water will be needed to develop oil shale and tar sands resources under a suite of different development thresholds. An appropriate impact analysis of the loss of water on wildlife and their habitats should follow each development scenario. 53001-010

Visual Impacts

To assess the development impacts involving tar sands in Utah, the PEIS based many of its assumptions on published information for a proposed 20,000 bbl/day- capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit in California. (page 5-2). For purposes of analysis and to provide a range of impact, the PEIS scaled bitumen production in Utah to 100,000 bbl/day. (page 5-2). As part of its visual impact analysis, the PEIS shows photos of Canadian tar sands operations. (pages 5-97 – 5-99). However, the Canadian operations depicted are likely an order of magnitude larger than those operations contemplated for development in the United States. Operations in Utah are not likely to include upgraders because Utah projects will probably be too small to support an integrated upgrader. In contrast, the Canadian operations tend to have an integrated upgrader. Given the major differences between the operations likely to occur in Utah and those currently underway in Canada, the state requests additional clarification regarding the use of the large scale Canadian operations in its assessment of visual impacts in the PEIS. 53001-011

Socioeconomic Impacts

The employment data relied on in the PEIS is extrapolated from a number of NEPA documents covering impacts of large energy resource development projects. It appears the 53001-012 estimated employment numbers for a hypothetical tar sands project may be overstated by a factor of at least two. (page 6-202). Workforce estimates are also based on operations much larger than those anticipated in the project area. As such, the state requests the BLM consider this possibility in evaluating the socioeconomic impacts of hypothetical tar sands projects and to consider modifying dependent analyses to reflect the impacts of a smaller operation. 53000-012 (cont.)

The state also asks the BLM to consider the additional jobs that would be created through oil shale and tar sands development in its assessment of the impacts on recreational employment. Studies containing information on the economics of Utah's oil and gas exploration and production industry are provided for the BLM's review. 53001-013

Energy and Mineral Developments Within Utah

The state noted the following factual or typographical errors in the section of Chapter 6 discussing energy and mineral developments for Utah.

Oil and Gas Development

For the past four years (2004 through 2007), Utah's Division of Oil, Gas and Mining reported an average of 811 well spuds per year within Uintah and Duchesne counties. Projecting only 580 wells per year for the Vernal PA may be conservative for the area long term. Necessary revisions should be reflected in section 6.2.5.2.1 as well. 53001-014

Coal Mining

The largest undeveloped coal resources are in the Henry Mountain Planning Area, with smaller amounts in the San Rafael Planning Area. (see Table 6.1.5-5). Predicted production for all field offices combined is about 30 to 34 million tons/yr. About 13% of this production would be from surface mines, and 87% would be from underground mines. These changes should be reflected in section 6.2.5.2.2. 53001-015

In Table 6.1.5-5 under the section entitled Coal, in the columns for the Henry Mountain and San Rafael PAs, the description refers to coal reserves in the Wasatch Formation, but should say the Wasatch Plateau coal field. The Henry Mountains column also needs to include coal in the Sevier County portion of the Emery coal field. The section on predicted production for the Henry Mountains also needs to change from Wasatch Formation to Wasatch Plateau coal field and include the Emery coal field as well. Similar errors are repeated in Table 6.2.5-4. 53001-016

Other Minerals Development

Metals produced in Utah include copper (one mine), iron (two mines), phosphate (one mine), molybdenum (one mines), potash (three mines), silver (four mines), and uranium (one mine). (EPA 1997). In the ROI counties (Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah, and Wayne), only sand and gravel, gilsonite, clay, gypsum, dimension sandstone, lime, helium, and gold are produced. (USGS 2004b). Phosphate production occurs in the Diamond Mountain area, and gilsonite in the Book Cliffs area. Uranium/vanadium has a high potential for 53001-017 development in the Henry Mountain and San Juan Planning Areas; it would result in at least 30 acres/yr of surface disturbance. A limited amount of other minerals development is expected. (see Table 6.1.5-5). These changes need to be reflected in section 6.2.5.2.3. 53001-017 (cont.)

Water Quality

A significant, long-term threat for water pollution could arise from poorly managed oil shale mining. As the oil shale exists right now, it is a sedimentary layer of low permeability (aquitard) that is located either in the unsaturated (vadose) zone or within the relatively shallow saturated zone. To extract kerogen from the rock, it must either be mined using conventional techniques, or new in-situ techniques may be used. Either process will increase the permeability of the formation, and allow infiltrating precipitation to leach salts and possibly other contaminants from the rock at a much greater rate than the undisturbed materials would.

The spent shale from mining has a greater volume then the original rock and backfilling the mine workings would not dispose of all of it. Underground mine workings may change the ground water flow regime within the oil shale by causing fractures in the overlying rock. This by itself could cause increased leaching of salts from the surrounding rock. If the workings are backfilled with spent shale, the increased permeability of the surrounding rock will allow infiltrating water to create a long-term source of salts leaching into ground water that will eventually discharge to surface water. Mine pits backfilled with spent shale would also allow precipitation to react with spent shale in the subsurface, and eventually result in discharge of salts to ground water and eventually surface water. The spent shale will be very dry upon disposal and large bodies of it will require a long time to get saturated in the dry climate, but there may eventually be a breakout of ground water that has been in contact with the shale waste. 53001-018

The Ground Water Protection Regulations specifically exempt operations that have "natural ground water seeping or flowing into conventional mine workings which re-enters the ground by natural gravity flow prior to pumping or transporting out of the mine and without being used in any mining or metallurgical process" from having to apply for a ground water discharge permit. However, the regulations do allow permitting of waste piles, which could possibly apply to backfilled spent shale.

In situ extraction operations will necessarily involve fracturing the rock to extract the formerly solid hydrocarbons that have been liquefied by the process. Because the rock has a high content of hydrocarbons, removing it will also increase its permeability. After extraction, precipitation will infiltrate the mined area and cause increased leaching of salts to ground water, eventually discharging to surface water. A risk assessment should be conducted that quantifies the effects of increased salinity to the Colorado River watershed or any potentially affected surface waters of this state that may result from the proposed project.

Utah Division of Oil Gas and Mining has jurisdiction over surface effects of in situ recovery activity, requiring certain plugging techniques for drill holes. For mines over 5 acres, operators are required to show what effects the operations will have on surface and ground water systems and the actions to be taken to mitigate those effects. Therefore, the Utah Division of

Water Quality will not issue UIC permits for reinjection wells for in situ mining of shale oil or tar sands at this time. 53001-018 (cont.)

It is also important to note that Region 8 directly implements the UIC Program on tribal lands so it is critical to have an accurate map of land ownership. The land ownership data layer in the State Geographic Information Database (SGID) is the best general surface ownership layer.

UIC Oil Shale Permitting Related to Injection Wells

Well Activity	Well Class	Permitted or Rule Authorized?
Hydraulic fracturing test *(convert to injection well after test)*	Class I	P
Air injection	Class V - exp	P or RA
Aquifer Remediation	Class V	P or RA
Tracer Testing	Class V	P or RA
Storm water trenches	Class V	P or RA
Closed-loop heat (not likely injection)		
Post-retorting water disposal	Class I or Class V	P
Aquifer Recharge / Drainage	Class V	P or RA
Nahcolite mining (solution mining) (then convert to de-watering wells, then convert to oil production wells)	Class III	P
Closed-loop freeze wall (not likely injection)		
Steam Stripping Hydrocarbons	Class V	P or RA

53001-019

Type of Analysis

A mechanism should be employed to allow the public to gain a better sense of the scale and potential variability among discernible environmental impacts. Deferring meaningful, quantified analysis of environmental impacts to the leasing-by-application determination does not answer the question of possible environmental outcomes. A response to difficult quantification challenges is to make explicit assumptions and lay out a range of realistically foreseeable outcomes; the final answer may fall between projected outcomes, but the public would have the opportunity to consider the scale of environmental effects associated with the alternatives. We recommend developing such a quantified range of outcomes, with assumptions inherent, as the only viable mechanism we can envision for allowing the public to understand the scale of the potential impacts to the environment. The Draft Oil Shale and Tar Sands PEIS provides the groundwork, but in repeated instances, does not lay out realistic impact scenarios with a quantification of impacts. The quantified analysis should not be left out of the PEIS because of its programmatic orientation. The present document is the public's only opportunity to provide input to the decision, programmatically and cumulatively. Therefore, BLM should provide the public with sufficiently quantified scenarios in tar sands and oil shale production. 53001-020

Issues of water availability, water quality, air quality, climate change, loss of wildlife habitat, are all worthy of quantification. 53001-020 (cont.)

Wildlife Concerns

The open-pit mining contemplated for major portions of the Book Cliffs area within Utah, coincides with crucial winter ranges for mule deer, and is also used by elk. Open-pit mining would impact mule deer populations in a herd recognized by many entities as "world class." Given the effects of open pit mining, and given the high degree of coincidence of the Book Cliffs oil shale deposits occurring less than 500 feet below ground surface with the mapped crucial winter habitat for mule deer, and to a lesser extent elk and pronghorn, mining must be accompanied by a strong reclamation program. The state asks that the PEIS require coordination of mining plans and reclamation with Utah's Division of Wildlife Resources. 53001-021

Cumulative Impacts

Evaluating the development impacts for oil shale and tar sands resources with those of other oil and natural gas development impacts will require a future, more exhaustive cumulative impacts analysis. Oil and natural gas development in the Book Cliffs of Utah has been fairly extensive, and there are clear indications of present intentions documented in recent BLM and U.S. Forest Service NEPA documents for companies to further develop these resources. Such impacts must be considered cumulatively in association with oil shale development. 53001-022

The State of Utah appreciates the opportunity to review this proposal. Please direct any other written questions regarding this correspondence to the address listed above, or call me at (801) 537-9801. Thank you.

Sincerely,

John Harja
Director

Response for Document 53001

53001-001: Thank you for your comment. The BLM looks forward to the partnership.

53001-002: The BLM is interested in pursuing these issues with the States of Colorado, Utah, and Wyoming.

It would be useful to conduct additional background meteorology and air quality-related values monitoring throughout the study area. The BLM would like to meet with the States of Colorado, Utah, and Wyoming (along with other federal land management agencies) to pursue how such monitoring could be financed and conducted. All air quality and climate data gathered by the BLM are made available to the public upon request.

53001-003: All decisions related to land use planning for oil shale and tar sands resources in the ongoing RMPs will be made in the ROD for the PEIS. The ROD will amend the existing plans (MFP or RMP or ongoing RMP if completed first) by making land use planning decisions on whether or not lands will be available for application for future leasing and development of oil shale or tar sands on public lands for those areas where the resource is present. Additional site-specific NEPA analysis will be completed on any future lease applications before leases would be issued. If, as part of this NEPA analysis, the BLM determines that leasing and subsequent development of the oil shale or tar sands resources would cause significant impacts, the BLM can require the applicant to: 1) mitigate the impact so that it is no longer significant or 2) move the proposed lease location, or if neither of these options resolves the anticipated conflicts 3) the BLM can decide that development of the oil shale or tar sands resources outweighs protection of the on-site resources and approve the application. This NEPA analysis would include opportunities for public involvement and comment that are part of the NEPA process.

53001-004: As described in the PEIS in Section 2.2.3, a river or river section may be designated as a WSR by Congress or the Secretary of the Interior under the authority of the Wild and Scenic Rivers Act of 1968. Land management agencies conduct inventories of rivers and streams within their jurisdictions and make recommendations to Congress regarding the potential inclusion of suitable rivers into the WSR system as part of their land use planning process. These special areas are managed to protect outstanding scenic, recreational, geologic, fish and wildlife, historic, cultural, or other values, and to preserve the river or river section in its free-flowing condition. WSR boundaries are established to include a corridor of land along either side of the river as determined to be appropriate for protection of the river's values. The law recognizes three classes of rivers: wild, scenic, and recreational. It is the BLM's policy to manage potentially eligible and suitable WSRs in a manner to prevent impairment of the river's suitability for WSR designation until Congress or the Secretary makes a final determination regarding the river's status. During this interim period, a corridor extending at least 0.25 mi from the "high water" mark on each bank of the river is established.

Segments of rivers that have been found to be unsuitable as part of the RMP process will no longer receive the interim protections afforded them during the period of their consideration for suitability. After the unsuitability decision, the lands adjoining the river segment may be managed, just as are other public lands, consistent with whatever management prescription is adopted through the land use planning process.

53001-005: Under the provisions of FLPMA, the BLM has designated ACECs where special management attention is required to protect and prevent irreparable damage to important cultural, historic, scenic values, fish and wildlife resources, or other natural systems or processes, or to protect life and safety from natural hazards. In ACECs not closed to mineral entry, the BLM has specific management prescriptions outlined in the local land-use planning document to protect the relevant and important values. However, the ACEC Manual (BLM Manual 1613) states: "Normally, the relevance and importance of resource or hazards associated with an existing ACEC are reevaluated only when new information or changed circumstances or the results of monitoring establish a need." Therefore, if there is new information or changed circumstances associated with the leasing of lands within ACECs open to mineral development (for example, if the RMP that designates an ACEC is amended by the PEIS to open the area including the ACEC to consideration for application for commercial lease), the ACEC will be reevaluated to consider whether to retain the ACEC designation or to develop additional management prescriptions in the NEPA analysis associated with the proposed leasing decision. This also applies to newly designated ACECs in the Utah RMPs.

Closed to "mineral development" and closed to "mineral entry" could mean the same thing. It depends upon the context in the document where it is found. However, unless an area has been officially designated on the public land records as "withdrawn from mineral entry," the area would fall into the category described in the first paragraph of this response.

53001-006: Congress granted the President authority to designate national monuments in the Antiquities Act of 1906, which specifies that the law's purpose is to protect "objects of historic or scientific interest." In addition to the presidentially created national monuments, Congress has established national monuments by passing laws to create individual monuments with their own purposes (generally to protect natural or historic features). For example, the Grand Staircase–Escalante National Monument was established by Presidential Proclamation on September 18, 1996, under the authority of Section 2 of the Act of June 8, 1906 (34 Stat. 225, 16 U.S.C. 431). In part, the proclamation said, "All Federal lands and interests in lands within the boundaries of this monument are hereby appropriated and withdrawn from entry, location, selection, sale, leasing, or other disposition under the public land laws…"

53001-007: Please see response to Comment 53001-003 regarding RMP revisions.

53001-008: Should industry come forward with an economically and environmentally sound proposal for commercial oil shale or tar sands leasing, the BLM and the Secretary of the Interior have the authority to undertake another EIS that would consider additional modification of land use plans to allow leasing for such a proposal. Excluded lands under each alternative can only be made available for leasing after the appropriate RMP is amended to consider the excluded area for potential leasing.

53001-009: The excerpt from the PEIS quoted in the comment is an accurate statement of the general process that will be used to accept applications for lease. The BLM, through its rulemaking process, is drafting a proposed set of regulations to outline the policies and procedures to implement a commercial oil shale leasing program. The BLM published a proposed rule for the management of a commercial oil shale leasing program in the *Federal Register* on July 23, 2008. The regulations for tar sands resources are already promulgated at 43 CFR, Part 3140. The BLM rulemaking process is separate and apart from the drafting of the PEIS. The PEIS analyzes the environmental consequences of an allocation decision and, therefore, questions concerning the regulatory process are outside the scope of the PEIS.

53001-010: This PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of lands for commercial development. Subsequent NEPA documents will be prepared to analyze the environmental consequences of leasing and future exploration and development, including consideration of direct, indirect, and cumulative effects; reasonable alternatives; and mitigation measures to protect resources and resource values, as well as what level of development may be anticipated. The PEIS provides an effective analytical foundation for subsequent project-specific NEPA documents.

The amount of water needed would be better understood at the future project-specific level when the scale of development, the technologies used in the development, the national agricultural economy, and the locations and hydrologic conditions of project sites are known.

The source of water needed for any oil shale and/or tar sands development projects would be specified in the project-specific NEPA documents and not in this PEIS. The water is unlikely to be diverted from public use water. Agricultural water might be a candidate for sources of water rights. Impacts on water resources caused by transfers of water from agricultural uses to oil shale and tar sands development on water resources have been added to Sections 4.5 and 5.5 of the PEIS. It would be a lessee's responsibility to obtain and maintain water rights necessary for its operations in accordance with state law. Thus, it would be conjecture to attempt an analysis of impacts from water demands for operations that might not obtain water rights.

Using different scenarios to project water utilization is a useful tool in evaluating impacts. However, there are many controlling factors in determining water uses. This approach could produce many highly speculative scenarios and unreliable results. Instead, it is more appropriate to evaluate the impacts of water resources on wildlife and their habitats at the project level. The BLM does not have a forecast “scale of development” for oil shale or tar sands. The BLM agrees with the cooperating agencies that there is not enough information at the experimental stage of the industries to support a development scenario that would be better than speculative.

53001-011: Canadian oil sands operations did not form the basis for the visual impact assessment in the Draft PEIS and were not considered in the visual impact analysis conducted for the Draft PEIS.

The photos of Canadian oil sands operations included in the Draft PEIS were intended to illustrate at a general level the types of visual impacts associated with tar sands development. They show visual impacts typical of surface mining operations and visual impacts associated with tar sands processing facilities. They illustrate the strong contrasts in form, line, color, and texture associated with mining operations and the built structures’ rectilinear geometry, symmetry, and surface characteristics. The scale of tar sands facilities that might be built in the future is not known precisely at this time; the photos in the PEIS include a range of scales, including a pilot-scale facility near Vernal, Utah.

The basis of the visual impact analysis for the Draft PEIS is a determination, based solely on distance from the STSA, of sensitive visual resources that might be affected by tar sands development, if the development and/or associated project components or activities, such as lighting, dust, or smoke, were visible from the locations of the sensitive visual resources. The analysis did not account for topography, which in some cases might obscure some or all views of the tar sands development and associated activities. Because precise information about the location of the development, its size, the technologies employed, and other site-specific information is not known at this point, this level of analysis is appropriate for this PEIS. When a specific tar sands development project is proposed for a specific location, a site-specific NEPA analysis would be conducted that would incorporate information about the size and nature of the development that was proposed, the precise location of the project components, and local topography to determine the visual impacts associated with the proposed development.

53001-012: Given the programmatic nature of the PEIS, the purpose of the analysis of socioeconomic impacts is to provide an overview of the type and magnitude of impacts that would likely occur with the construction and operation of representative oil shale and tar sands facilities. As the technologies, scale of development, and project locations associated with tar sands development are not known, the analysis described in the PEIS was based on a series of assumptions regarding project production levels and direct project employment during both construction and operations phases. These assumptions, described for both oil shale and tar sands development in Section 4.11 of the PEIS, were based on publicly available NEPA reviews of oil shale and tar sands projects. These assumptions are reasonable for a programmatic review of potential socioeconomic impacts. The BLM does, however, acknowledge the possibility that the estimate in this PEIS might be higher than actual impacts to employment or other socioeconomic values.

As the commentor suggests, the facility direct employment estimates are based on larger projects, in this case those analyzed in the Combined Hydrocarbon Leasing EIS. Direct construction and operations employment associated with two facilities, a surface mine (190,000 bbl/day, 9,600 construction employment and 6,566 operations employment) and an in situ facility (175,000 bbl/day, 12,060 construction employment, 2,235 operations), was averaged, and then scaled for the 20,000 bbl/day facility analyzed in the PEIS.

53001-013: Potential employment created by oil shale and tar sands facilities in each state ROI is presented in Sections 4.11 and 5.11 of the PEIS. The potential impacts of oil shale and tar sands developments on recreation, and the consequent loss of employment in each ROI, are presented in Section 4.11.1.5 and 5.11.1.4.

53001-014: The cumulative impacts assessment in the PEIS relied on the RFDSs for oil and gas development as presented in draft and final RMPs for each BLM Field Office. In the case of Vernal, the information was published in 2005. The total number of producing wells estimated in the Vernal RMP is still valid, although the anticipated life of the projected development scenario has been scaled back to 4 years, instead of the standard 15–20 years. The BLM does, however, acknowledge the possibility that the estimated oil and gas development presented in this PEIS might be less than the actual number of oil and gas wells developed in the future.

In general, the RFDS is an estimate based on past and present development projected into the future. The RFDS uses variables or factors to make an informed estimate of the number of oil and gas wells needed to produce the resource. These variables include the price of oil and gas, the success or failure of exploration in unproven areas, availability of exploration and development equipment, availability of infrastructure including the pipeline transportation network, technology, economics and the willingness of investors to invest in exploration for oil and gas, and the advancement of primary, secondary and tertiary recovery methods. After considering all information, the number of wells actually drilled could fluctuate, especially when determining activities over the life of an RMP.

However, variances in the number of wells, either up or down, does not alter the RFDS's usefulness as an analytical tool for NEPA analysis associated with planning-level decisions. It is the level of impacts disclosed, individually and cumulatively, that determines the validity of the NEPA analysis associated with specific planning decisions.

Given the limited scope and narrow allocation decisions being proposed in this PEIS (i.e., amending land use plans to allow certain lands to be considered for future leasing), the estimate of extensive oil and gas development given in the PEIS is considered a sufficient indicator of the magnitude of potential cumulative impacts. At the leasing or plan of development stage when the scope of the proposed action is determined, the appropriate level of additional analysis will be performed, including updated estimates of other activities occurring in the study area.

53001-015: The information presented in Sections 6.1.5.2.2 and 6.2.5.2.2 seems to agree with the information provided by the commentor. For example, in Table 6.1.5-5, the predicted coal production for all field offices given is 30 to 34 million tons/yr, as stated in the comment (most occurring in the Henry Mountain Planning Area). The information that about 13% of the production would be from surface mines and 87% from underground mining has been added to Tables 6.1.5-5 and 6.2.5-4.

53001-016: Thank you for your comment. The suggested changes have been made in the tables.

53001-017: The commentor is correct. The statements in Sections 6.1.6.2.2 and 6.2.5.2.4 have been changed to state that gilsonite is produced in the Book Cliffs area.

53001-018: The concerns above are discussed in Section 4.5 of the PEIS. Any proposed commercial development would have site-specific NEPA analyses, including determination of salinity impact, and would address state and local regulations on waste streams.

53001-019: The text in Sections 4.5.1.3 and 5.5.1.3 has been modified to account for the EPA administration of UIC on tribal land and the potential for UIC self-enforcement by Tribes.

53001-020: The PEIS is a programmatic-level document that analyzes allocation decisions. It is important to note that these allocations do not authorize the immediate leasing of the lands for commercial development. A more specific analysis of cumulative impacts of multiple oil shale and tar sands facilities in the study area may be conducted at a future step in the assessment process, when an RFDS for oil shale and/or tar sands development would be included. An RFDS was not developed for this PEIS because most of the information necessary for producing an RFDS is unknown and not reasonably available at the present experimental stage of the oil shale and tar sands industries. Assumptions based on the limited available information would be too speculative to support a meaningful scenario. An RFDS at a future step in the assessment process would be based on a clear set of supportable assumptions associated with a leasing or development proposed action, and would address the issues of water availability and quality, air quality, climate change, and loss of wildlife habitat.

53001-021: The BLM has a long history of cooperation with the Division of Wildlife Resources and it is our intent that this will continue when considering any future applications to lease or plans of development in the Book Cliffs area.

53001-022: See response to Comment 53001-014.

8 LIST OF PREPARERS

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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 ft^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.

Areas recognized as having wilderness characteristics (WCAs): Areas that are not officially identified as "wilderness" under the meaning of the Wilderness Act of 1964; nor are they "wilderness study areas" (WSAs) that were identified by BLM inventories in the 1970s and 1980s under the authority of FLPMA. Generally, they are areas that were identified by the BLM or others and that were inventoried by the BLM to determine whether they possessed the characteristics of wilderness as described in the Wilderness Act. The BLM may manage the lands to protect and/or preserve some or all of those characteristics through the land use planning process. In addition, under the land use planning process, the BLM must consider a range of alternatives for the land identified with wilderness characteristics. This gives the public the ability to fully compare the consequences of protecting or not protecting the wilderness characteristics on these non-WSA lands.

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

Atmospheric Deposition: The process by which trace gases and particulate matter in the atmosphere are deposited on vegetation, soils, and water bodies. Key concerns are total (wet and dry) deposition of sulfur and nitrogen compounds, and especially their potential impacts on sensitive lake systems.

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”: *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development* provides comprehensive guidance on the design, construction, maintenance, and reclamation of sites and access roads. The Gold Book promotes conduct of environmentally responsible oil and gas operations on federal lands.

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 (dBA): 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: Sets forth policy that public lands will be managed to secure, protect, and preserve significant caves.

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.

Reasonably Foreseeable Future Action: A projection of activities (industrial and minerals development, recreational activities and development, wildlife management, air and water resource management, urban development, transportation, etc.) within a defined geographic area and for a specified time frame. Reasonably foreseeable future actions are defined by available information on resource occurrences, past and present activities or uses and trends, economics, existing project proposals and other reliable indications of anticipated activities, and other identified factors specific to the area of analysis.

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 from 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.

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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, and the history of oil shale development in the western United States, and it 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 *Proposed Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Final 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. Finally, Attachment A1 provides an analysis of how the refinery industry may adjust to the availability of syncrude feedstocks derived from oil shale.

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

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1 Retorting and pyrolysis are key steps in oil shale processing. Retorting is a process that causes thermal decomposition of the organic fraction of the oil shale (kerogen). The recovered organic fraction is then distilled, or pyrolyzed, to produce three products: crude shale oil, flammable gases (including hydrogen), and char (deposited on spent shale). These processes are described further in Section A.3.2.

Eocene age. These deposits exist in the greater Green River Basin (including Fossil Basin and 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).

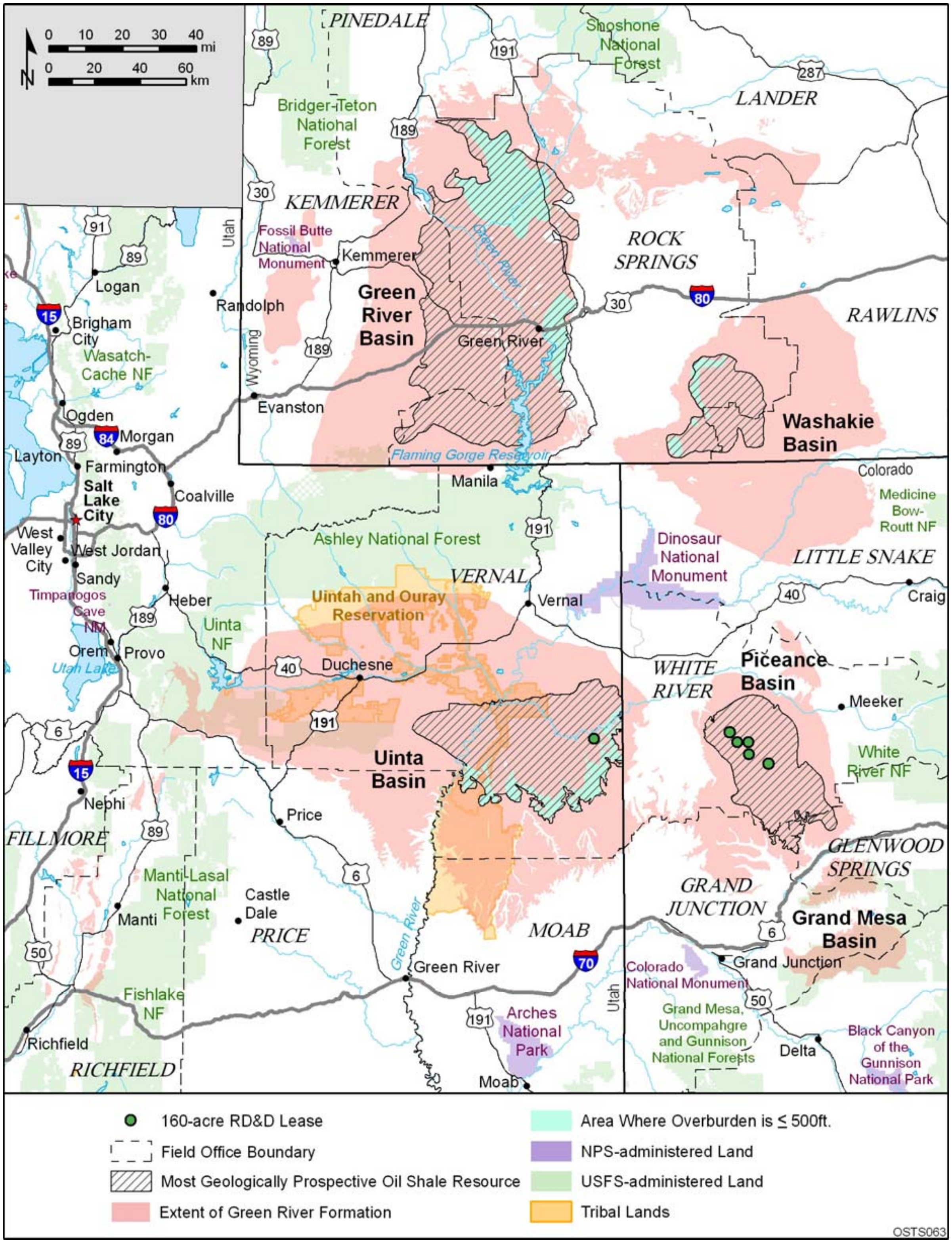

FIGURE A-1 Green River Formation Basins in Colorado, Utah, and Wyoming; Most Geologically Prospective Oil Shale Resources; Areas Where the Overburden above the Oil Shale Resources is ≤500 ft; and Locations of the Six RD&D Projects

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 and aluminum, respectively. 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 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 (Trudell at al. 1973), based on a greater amount of drilling data but limited to the southeastern

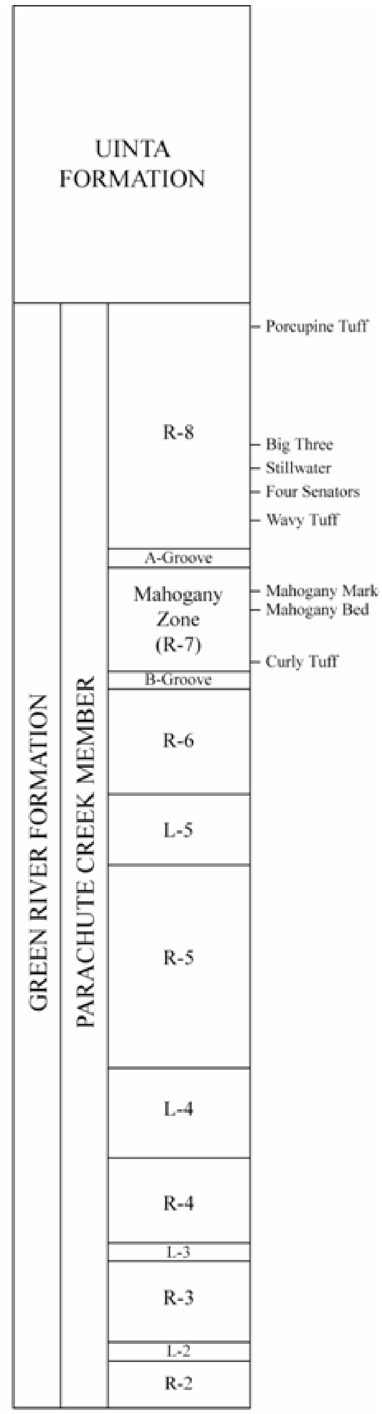

FIGURE A-2 Generalized Stratigraphic Section of the Parachute Creek Member of the Green River Formation in the Uinta Basin, Utah ("R" = rich oil shale zone; "L" = lean oil shale zone [adapted from Young 1995])

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 shale oil = 42 gal.

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

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 Wasatch 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 shale oil = 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 shale oil = 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 the development of oil shale 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 shale oil = 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 withdrawal 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, Retorts 7, 8, and 8x, were constructed at Logan Wash. Retorts 7 and 8 were fired and successfully 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 1986. Union was able to produce shale oil and upgraded this shale oil to syncrude at its commercial oil shale production facility 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 1960s, 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. 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 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 or 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 totalling 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 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); it does, however, typically utilize 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 (i.e., high resource recovery efficiencies);

- Previously mined areas that provide storage areas for future overburdens or disposal areas for spent shale; and

- Technologies that are well established, and operating logistics that 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);

- Substantial amounts of overburden and spent shale requiring management;

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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.

- 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 that may be high (necessarily very large mining/haulage equipment) to ensure high productivity; and
- Land reclamation programs that 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 by 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, adit, or a combination thereof.

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 causes decomposition of kerogen to liquid and gaseous organic fractions of value that have sufficient mobility 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 decomposition products 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, sometimes by injection of steam or other materials into either vertically or horizontally oriented boreholes or wells, but also by the application of alternative energy technologies such as microwave heating, radio-frequency (RF) 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 by using conventional liquid extraction technologies.

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

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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.

the flow of kerogen decomposition products 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 condensates. Steam injections are repeated over time until all of the bitumen is recovered.

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[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.

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 because of 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 as a follow-on to in situ retorting and has two distinct advantages: displacement and removal of additional kerogen decomposition products not recoverable through conventional mining techniques or in situ heating techniques, and the possible sequestration of CO_2 released from 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. However, solvent injection also has some drawbacks. The solvent must be recoverable for the process to be economically viable, and any solvent not recovered represents a potential for groundwater contamination.

- ***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; thus, it 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 RF heating technology for application to oil shale recovery (Cogliandro 2006; see also Raytheon 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%.[8]

- ***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

8 See http://www.Raytheon.com/newsroom/feature/oil_shale06/.

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. These might involve separating the oil shale from other extraneous materials and free water and crushing it to the uniform particle size specified by the retorting process being used. Primary and secondary crushing can 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., the small amount of formation water that entered the retort zone after heating commenced, as well as the water produced in kerogen pyrolysis and 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 the subsequent destructive distillation or pyrolysis of kerogen, which produces three product streams: crude shale oil (a collection of condensable organic liquids); flammable hydrocarbon 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 for production of distillate fuels 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, char-bearing spent shale from previous retorting cycles, or some other fuel is combusted to provide heat for pyrolysis of the remaining oil shale, 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; in some cases, they even convert 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 OTA (DOE 1982, 1983, 1988, 2004a,b; EPA 1977, 1979; NTIS 1979; OTA 1980a). Other technical reviews of AGRs also exist in the open literature (Heistand and Piper 1995).

Government-sponsored 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 of 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 Environmental 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 B Retort 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 one of only a few retorts that have operated in the United States that employ a solid-to-solid heat exchange process, and it is 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,[9] 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

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9 "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).

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.

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 fuel gas 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). Finally, the Paraho retort can also be operated in a direct/indirect hybrid mode.

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 devolatilization of coal fines. The technology has operated at commercial scales for the devolatilization 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 not only to retort kerogen but also to refine the resulting hydrocarbons into saleable liquid and gaseous petroleum fractions.

In this process, crushed and sized (–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, make up 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.[10] 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 raw shale oil and combustible gases 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.[11]

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.[12] Both TIS and MIS recovery techniques have been explored for their compatibility with in situ retorting. While most past

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[10] Many other AGRs could also be fitted with air pollution control equipment.

[11] 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.

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

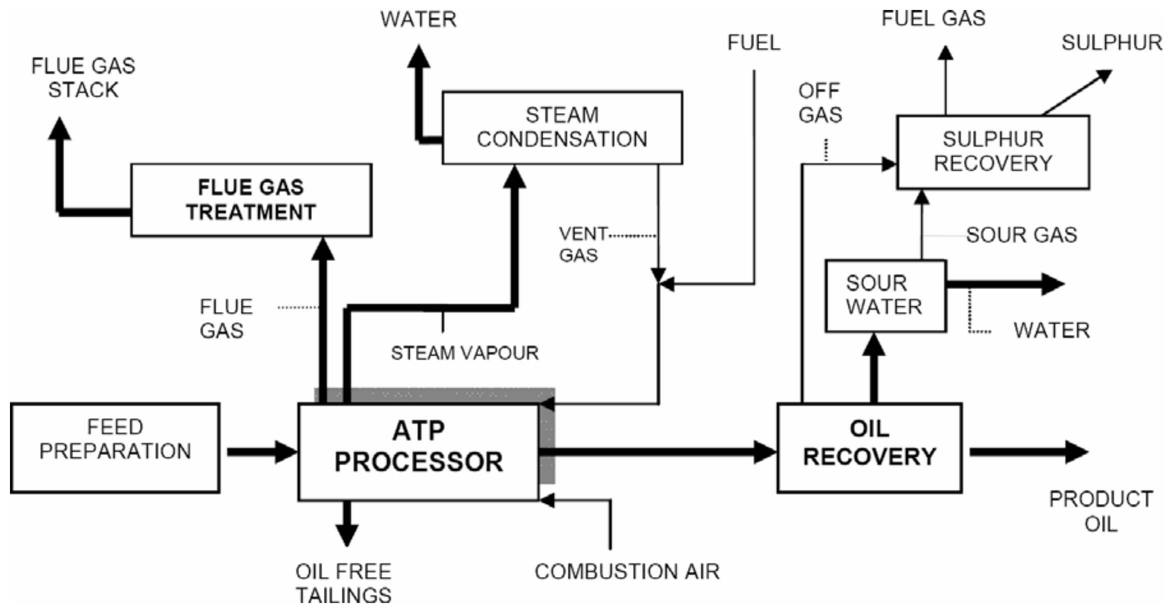

FIGURE A-3 ATP System Flow Diagram Processor (Source: UMATAC Industrial Processes; reprinted with permission)

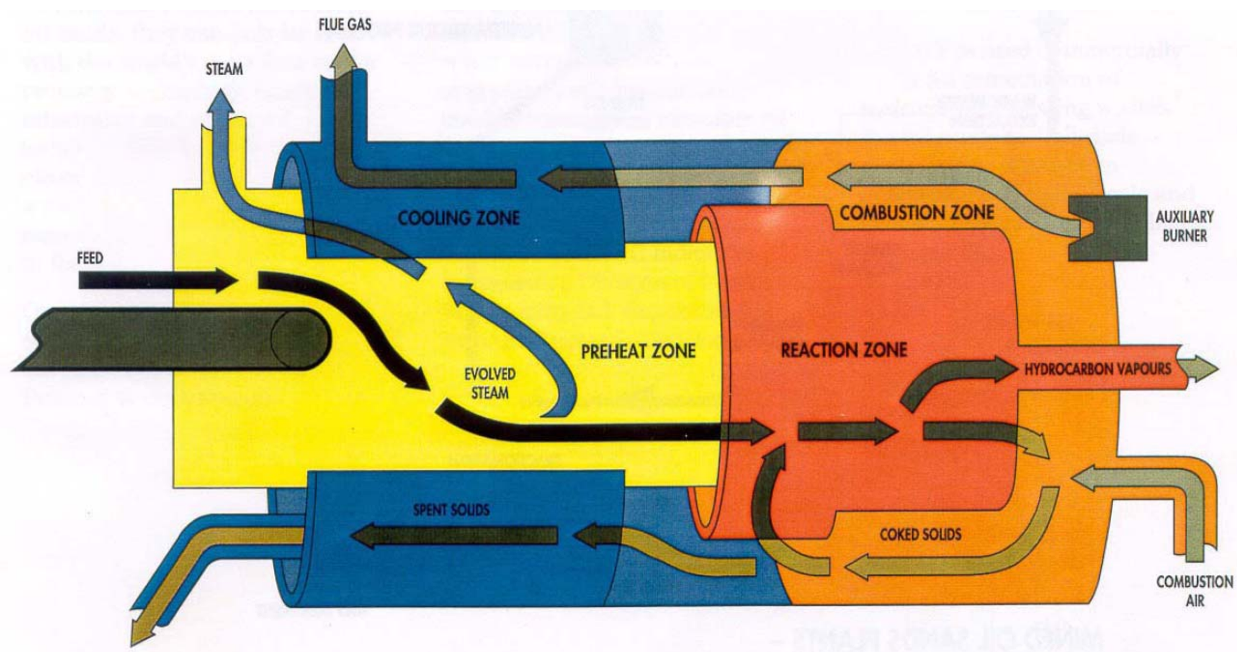

FIGURE A-4 Pictorial Representation of ATP Processor (Source: UMATAC Industrial Processes; reprinted with permission)

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 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.[13] The condensable liquid fraction, however, generally tends to be of 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 that results when heat is introduced to the formation by injection of combustion gases and/or steam, by advancement of a flame front as a result of 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)

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[13] However, gases recovered from in situ retorting that does not involve combustion are expected to be equivalent in quality to gases recovered from AGRs.

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 perhaps at a lower overall recovery efficiency);

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

- Overall energy efficiencies may 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 that allows portions of the formation to reach 1,100°F can result in technological problems, as well as the thermal decomposition of mineral carbonates and the formation and 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. However, in situ retorting with good thermodynamic controls can product pyrolysis products of equal or even greater quality than AGR.

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.[14] Explosives (ammonium nitrate and fuel oil [ANFO]) were then introduced to cause the "rubblizing" of some of the shale on the walls of the

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[14] 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.

void and to expand existing fractures in the formation, improving its permeability.[15] 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.[16] The resulting heat expanded downward into the surrounding formation, heating and retorting the kerogen. Retort 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.[17] 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°[18]), 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

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15 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).

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

17 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.

18 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.

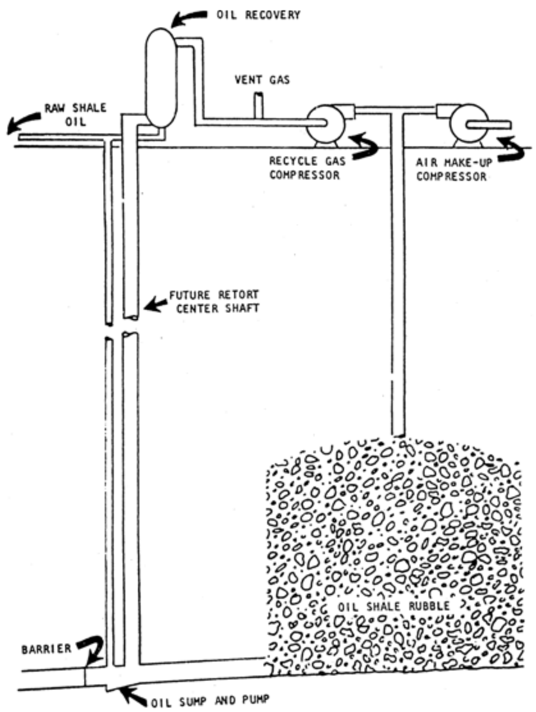

FIGURE A-5 Conceptual Design of the Occidental Oil Shale, Inc., MIS Retorting Process (Source: EPA 1979)

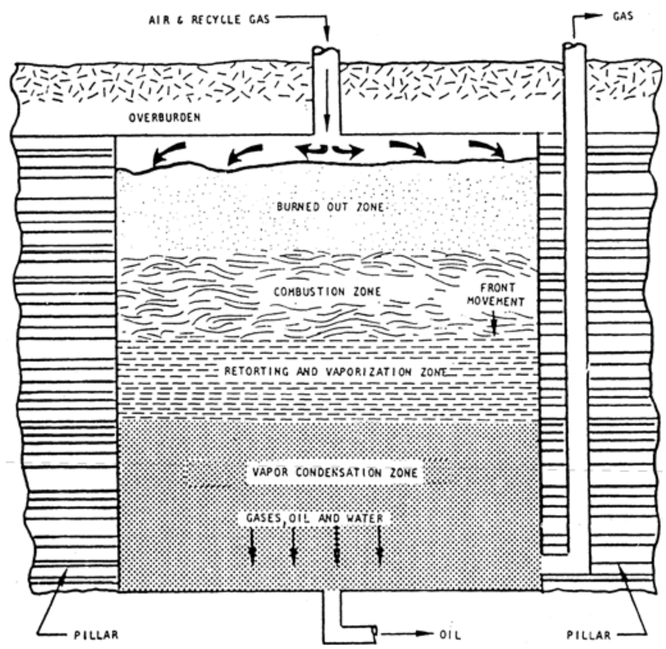

FIGURE A-6 Conceptual View of the Downward Movement of the Heat Front through the Formation in the Occidental Oil Shale, Inc., Vertical In Situ Retort (Source: EPA 1979)

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 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). 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 composed 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.[19] 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,[20] 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.[21] 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

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[19] 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).

[20] 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).

[21] 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.

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 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 increased, 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,[22] 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 cause 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.[23]

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[22] Butanes formed during upgrading of shale oil are typically mixtures of butane and butylenes. Although potentially saleable products (generally within the boiling range of commercial LPG), these mixtures are more typically used as fuel at the plant site.

[23] 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 that 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.

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, 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 with respect to leaching, autoignition, or fugitive dusting.[24] Average structural properties for spent shale from a Paraho AGR are shown in Table A-5.

It has been reported in the literature that as much as 30% expansion in volume can occur in spent shales over the parent raw shale (DOE 1988; Argonne 1990). 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, and the 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

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/s (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).

24 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.

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 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 et al. 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[25] 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 alkylpyridines 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.

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25 The parent compound, pyridine, is a cyclic polar hydrocarbon with the formula C_5H_5N. 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[a]

Constituent	Simulated In-Situ Retorts	Surface Retorts[b]
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	–[c]
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] Concentrations are in mg/L unless otherwise noted.

[b] TOSCO, U.S. Bureau of Mines, and Union Oil Company processes.

[c] A dash indicates data not available.

Source: EPA (1980).

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).

A.5.1 Shell Oil Mahogany Research 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 1996, Shell has been working in the Mahogany Zone of the Parachute Creek member 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.[26] 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

[26] 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.

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.

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 of relatively high quality (typically API 36°); approximately two-thirds by weight. 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 bbl/acre (i.e., heating of 1 acre of aerial extent of the

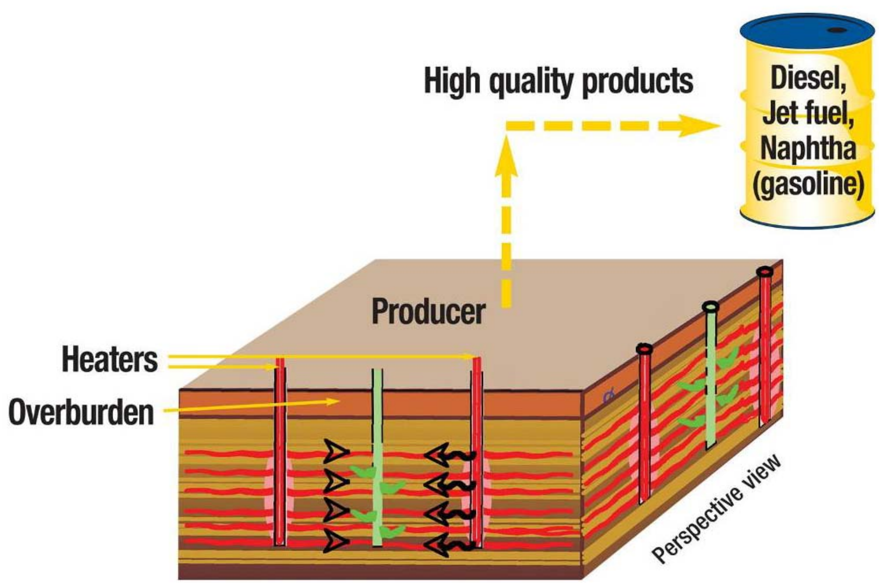

FIGURE A-7 Cross Section of Shell's Patented ICP Technology (Courtesy: Shell Exploration & Production; reprinted with permission)

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

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) 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, by 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 of 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.[27]

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 development 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

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[27] 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.

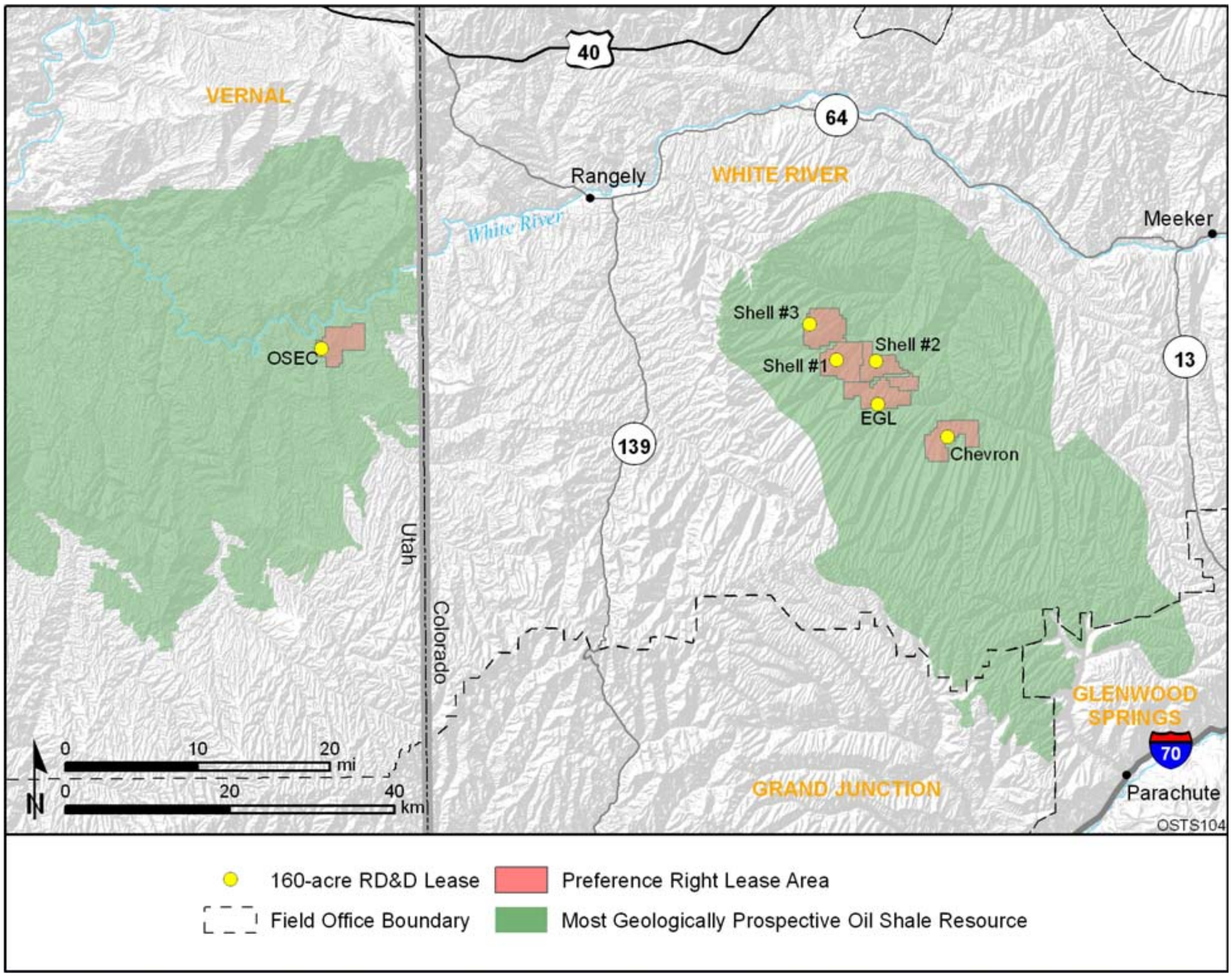

FIGURE A-9 Locations of Six RD&D Tracts and Associated Preference Right Lease Areas

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.[28]

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 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

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28 The following discussions are based on detailed plans of development submitted by each of the RD&D leaseholders. It is understood that those places may be refined or amended (with BLM approval) as research progresses.

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).

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 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 it is 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 (each of which would consist of 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 and guidelines (DOI and USDA 2006), 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-bbl 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 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.5.3.1.8 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)[29]

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.

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29 Since the preparation of this PEIS, EGL Resources, Inc. is now American Oil Shale, LLC.

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. 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 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 $PM_{2.5}$[30] emissions associated with EGL's project for both construction and RD&D

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).

30 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.

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 and 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 by 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.

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.

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 was available during construction and drilling, 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

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 development 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.

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 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, respectively). 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 I Estimated Emissions

TABLE 4-3 Phase I Estimated Emissions							
Emission Point	**Estimated Emissions Summary (tons/Phase I)**						
	NO_x	**SO_2**	**CO**	**VOC**	**PM_{10}**	**CO_2**	**HAPs**
Diesel Vehicle Emissions[1]	3.17	0.50	0.78	0.22	0.11	0.00	0.00
Truck Loading/Unloading[2]	--	--	--	--	0.000008	--	--
Storage Pile[2]	--	--	--	--	0.06	--	--
Total	**3.17**	**0.50**	**0.78**	**0.22**	**0.17**	**0.00**	**0.00**

1 Emission factors from http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html

2 Emission factors from USEPA AP-42 Chapter 11.19.2, *Crushed Stone Processing and Pulverized Mineral Processing*, August, 2004 for truck unloading of fragmented stone. Assumed controlled emissions using wet suppression. Aggregate storage emission factor from US EPA FIRE 6.25

Source: This table is reproduced as contained in BLM (2007).

TABLE A-13 Phase 2 Estimated Emissions

TABLE 4-4
Phase 2 Estimated Emissions

Emission Point	Estimated Emissions Summary (tons/Phase 2)					
	NO_x	SO_2	CO	VOC	PM_{10}	HAPs
ATP System Operation[1]	0.55	1.23	8.21	0.14	0.55	--
Start-Up Burner[2]	0.086	0.000072	0.014	0.0023	0.0027	0.000033
Flaring of flue gas[3]	--	--	0.26	5.98	--	--
Diesel Generator[4]	7.73	1.44	0.86	0.91	1.44	0.27
Diesel Storage Tank[5]	--	--	--	0.0062	--	--
Shale Crushing/Screening[6]	--	--	--	--	0.026	--
Truck Loading/Unloading[6]	--	--	--	--	0.00008	--
Stockpiled Shale[6]	--	--	--	--	0.48	--
ANFO Blasting[7]	0.032	0.004	0.126	--	--	--
Shale Oil Storage Tank[8]	--	--	--	0.73	--	--
Unpaved On-site Roads[9]	--	--	--	--	0.48	--
Total	**8.40**	**2.67**	**9.47**	**7.77**	**2.98**	**0.27**

1 Estimated concentration data provided by UMATAC based on a pilot project in Canada. Emissions assumed a 95% control on CO, VOC, and SO_2, and a filter bag for PM control. The CO_2 formed 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 will be due to the start-up burner. To be conservative, assumed the start-up burner emissions are separate.

2 Assumed a 24 hour start-up period, required 15 times over the course of the phase. Assumed a natural gas burner consuming 48 MMBtu per start-up. A portion of these emissions may be included in the ATP data; however, to be conservative, assumed the start-up burner emissions are separate. Emission factors are from USEPA AP-42, Chapter 1.5, *Liquified Petroleum Gas Combustion*, October 1996; HAP emissions were taken from USEPA AP-42 Chapter 1.4, *Natural Gas Combustion*, July 1998.

3 Estimated based on flare gas from previous pilot study conducted on similar ATP60 plant. Assumed a 98% destruction efficiency based on USEPA AP-42 Chapter 13.5, *Industrial Flares*, September 1991. The amount of CO converted to CO_2 in the flare is included in the CO_2 emission value.

4 Estimated assuming 592,000 gal of diesel will be needed for length of Phase 2. To be conservative, assumed all diesel is used in diesel-fired generators; however, some (~22,000 gal) will be used in the haul trucks and other unknown underground equipment. In order to comply with concentration thresholds, a CO and NO_x APCD device may need to be installed; therefore, a 85% and 90% control efficiencies for NO_x and CO were assumed. Emissions factors were obtained from typical Cummins 1 MW diesel generator specifications; CO_2 emission factor was from USEPA AP-42, Chapter 3.3, *Gasoline and Diesel Industrial Engines*, October 1996.

5 Working and breathing losses for 15,000 gal. tanks with a total throughput of 592,000 gallons (570,000 gal for power generation, 22,000 gal for the mine work) for the Phase, estimated using EPA Tanks4.0 program.

6 Emission factors from USEPA AP-42 Chapter 11.19.2, *Crushed Stone Processing and Pulverized Mineral Processing*, August, 2004. Assumed controlled emissions using wet suppression. Assumed 2 intermediate conveying transfer points between one primary crusher, one secondary crusher, and one screener. Aggregate storage emission factor from US EPA FIRE 6.25

7 Emission factors are from USEPA AP-42 Chapter 13.3, *Explosives Detonation*, February 1980.

8 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, estimated using EPA Tanks4.0 program.

9 Estimated PM_{10} emissions from unpaved vehicle traffic on-site using USEPA AP-42, Chapter 13.2.2, *Unpaved Roads*, December 2003; assumed a total of 50 miles traveled during Phase 2 for a 200 ton truck to gather 10,000 tons of shale oil (200 tons at a time) and transport it back to the ATP. Although $PM_{2.5}$ were not modeled due to lack of emission factors, even if all PM_{10} emissions were in the form of $PM_{2.5}$ emissions would be well below the $PM_{2.5}$ NAAQS.

Source: This table is reproduced as contained in BLM (2007).

TABLE A-14 Phase 3 Estimated Emissions

TABLE 4-7
Phase 3 Estimated Emissions

Emission Point	Estimated Emissions Summary (tons/Phase 3)					
	NO_x	SO_2	CO	VOC	PM_{10}	HAPs
ATP System Operation[1]	126.97	285.67	1,904.49	31.74	13.34	--
Start-Up Burner[2]	17.75	0.015	2.99	0.47	0.56	0.0068
Electrical Needs (14 MW)[3]	207.79	34.94	--	--	--	--
Hydrogen Plant Reformer[4]	5.15	0.06	8.64	0.57	0.78	0.00
Flaring of flue gas[5]	--	--	8.19	186.94	--	--
Diesel Storage Tank[6]	--	--	--	0.024	--	--
Shale Crushing/Screening[7]	--	--	--	--	7.14	--
Stockpiled Shale[7]	--	--	--	--	132.00	--
Truck Loading/Unloading[7]	--	--	--	--	0.02	--
ANFO Blasting[8]	14.88	1.75	58.63	--	--	--
Diesel Combustion[9]	870.81	24.25	145.50	15.43	24.25	4.52
Shale Oil Storage Tank[10]	--	--	--	9.19	--	--
Unpaved On-site Roads[11]	--	--	--	--	167.66	--
Total	**1243.34**	**346.69**	**2,128.44**	**244.36**	**345.75**	**4.52**

1 Estimated concentration data provided by UMATAC based on a pilot project in Canada. Emissions assumed a 95% control on CO, VOC, and SO_2, and a filter bag for PM control. The CO_2 formed 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 will be due to the start-up burner. To be conservative, assumed the start-up burner emissions are separate.

2 Assumed a 24 hour start-up period, required 50 times over the course of the phase. Assumed a natural gas burner consuming 3,000 MMBtu per start-up. A portion of these emissions may be included in the ATP data; however, to be conservative, assumed the start-up burner emissions are separate. Emission factors are from USEPA AP-42, Chapter 1.5, *Liquified Petroleum Gas Combustion*, October 1996; HAP emissions were taken from USEPA AP-42 Chapter 1.4, *Natural Gas Combustion*, July 1998.

3 Emissions were estimated based on the average 2000-2005 Bonanza I Power Plant emissions data from the USEPA Clean Air Markets. Between 2000 and 2005, the power plant required on average 4,996 MMBtu/hr. The additional power needed for Phase 3 would result in a maximum increase in usage of 3%. Assumed 3% of the average power plant emissions provided on the Clean Air Markets website would be emitted due to operation of Phase 3. Data on CO, VOC, PM_{10} and HAPs was not provided on the website.

4 Emissions were estimated assuming a 5.8 MW reformer fueled on natural gas and USEPA AP-42 Chapter 1.4, *Natural Gas Combustion*, July 1998. These emissions only account for an estimate of the hydrogen reformer; additional combustion devices that may 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 emissions estimate.

5 Estimated based on previous test run conducted on similar ATP60 plant scaled up for the 250 ton/yr processor, assuming only 50% of the off-gas is flared. This value is highly conservative given the flaring may only occur during emergency situations and/or the off-gas may be used instead to further fuel the ATP.

6 Working and breathing losses for 15,000 gal. tanks with a total throughput of 10,000,000 gallons for the Phase, estimated using EPA Tanks 4.0 program.

7 Emission factors from USEPA AP-42 Chapter 11.19.2, *Crushed Stone Processing and Pulverized Mineral Processing*, August, 2004. Assumed controlled emissions using wet suppression. Assumed 2 conveying transfer points. Aggregate storage emission factor from US EPA FIRE 6.25

8 Emission factors are from USEPA AP-42 Chapter 13.3, *Explosives Detonation*, February 1980.

9 Diesel fuel will be used mostly in underground haul trucks and other mining equipment. Some surface equipment or standby emergency generator may be used. To be conservative, the estimated 10 million gallons of diesel was assumed to be burned in a generator.

10 Working and breathing losses for shale oil storage tanks with a total project throughput of 75,348,000 gal, estimated using EPA Tanks4.0 program.

Source: This table is reproduced as contained in BLM (2007).

TABLE A-15 Phase 2 Greenhouse Gas Emissions

TABLE 4-5. Phase 2 Greenhouse Gas Emissions			
Emission Point	**Phase 2 (tons\Phase 2)**		
	CO_2	**Methane**	**Carbon Equivalence**
ATP Processor Operation[1]	2,296.86	--	626.42
Start-Up Burner[2]	56.56	--	15.42
Flaring of flue gas[3]	128.16	--	34.95
Diesel Generator[4]	6,807.48	--	1,856.58
Mine Opening Methane[5]	--	10.52	7.89
Total	**9,289.05**	**10.52**	**2,541.27**

[1] Estimated concentration data provided by UMATAC based on a pilot project in Canada. The CO_2 formed during oxidation of CO, assuming 100% conversion, was added to the total amount of CO_2. A portion of these emissions will be due to the start-up burner. To be conservative, assumed the start-up burner emissions are separate.

[2] Assumed a 24 hour start-up period, required 15 times over the course of the phase. Assumed a natural gas burner consuming 48 MMBtu per start-up. A portion of these emissions may be included in the ATP process data; however, to be conservative, assumed the start-up burner emissions are separate.

[3] Estimated based on flare gas from previous pilot study conducted on similar ATP60 plant. Assumed a 98% destruction efficiency based on USEPA AP-42 Chapter 13.5, *Industrial Flares*, September 1991. The amount of CO converted to CO_2 in the flare is included in the CO_2 emission value.

[4] Estimated assuming 592,000 gal of diesel will be needed for length of Phase 2. To be conservative, assumed all diesel is used in diesel-fired generators; however, some (~22,000 gal) will be used in the haul trucks and other unknown underground equipment. CO_2 emission factor was from USEPA AP-42, Chapter 3.3, *Gasoline and Diesel Industrial Engines*, October 1996.

[5] Estimated value provided by OSEC, assumes 5,000 cf CH_4/day over the course of the Phase 2.

Source: This table is reproduced as contained in BLM (2007).

TABLE A-16 Phase 3 Greenhouse Gas Emissions

TABLE 4-8
Phase 3 Greenhouse Gas Emissions

Emission Point	Phase 3 (tons\Phase 3)		
	CO_2	Methane	Carbon Equivalence
ATP Processor Operation[1]	532,985.79	--	145,359.76
Start-Up Burner[2]	11,680.33	--	3,185.54
Electrical Needs (14 MW)[3]	126,049.52	--	34,377.14
Hydrogen Plant Reformer[4]	12,349.23	--	3,367.97
Flaring of flue gas[5]	4,004.99	--	1,092.27
Diesel Combustion[6]	114,991.18	--	31,361.23
Mine Opening Methane[7]	--	472.73	354.55
Total	**802,061.04**	**472.73**	**219,098.46**

1 Estimated concentration data provided by UMATAC based on a pilot project in Canada. The CO_2 formed during oxidation of CO, assuming 100% conversion, was added to the total amount of CO_2. A portion of these emissions will be due to the start-up burner. To be conservative, assumed the start-up burner emissions are separate.

2 Assumed a 24 hour start-up period, required 50 times over the course of the phase. Assumed a natural gas burner consuming 3,000 MMBtu per start-up. A portion of these emissions may be included in the ATP process data; however, to be conservative, assumed the start-up burner emissions are separate.

3 Emissions were estimated based on the average 2000-2005 Bonanza I Power Plant emissions data from the USEPA Clean Air Markets. Between 2000 and 2005, the power plant required on average 4,996 MMBtu/hr. The additional power needed for Phase 3 would result in a maximum increase in usage of 3%. Assumed 3% of the average power plant emissions provided on the Clean Air Markets website would be emitted due to operation of Phase 3.

4 Emissions were estimated assuming a 5.8 MW reformer fueled on natural gas and USEPA AP-42 Chapter 1.4, *Natural Gas Combustion*, July 1998. These emissions only account for an estimate of the hydrogen reformer; additional combustion devices that may 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.

5 Estimated based on previous test run conducted on similar ATP60 plant scaled up for the 250 ton/yr processor, assuming only 50% of the off-gas is flared. This value is highly conservative given the flaring may only occur during emergency situations and/or the off-gas may be used instead to further fuel the ATP.

6 Diesel fuel will be used mostly in underground haul trucks and other mining equipment. Some surface equipment or standby emergency generator may be used. To be conservative, the estimated 10 million gallons of diesel was assumed to be burned in a generator.

7 Estimated value provided by OSEC, assumes 50,000 cf CH_4/day over the course of the Phase 3.

Source: This table is reproduced as contained in BLM (2007).

A.6 REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

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ATTACHMENT A1:

ANTICIPATED REFINERY MARKET RESPONSE TO FUTURE OIL SHALE PRODUCTION

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ATTACHMENT A1:

ANTICIPATED REFINERY MARKET RESPONSE 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 on the basis of 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 those of 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 distillate fuel 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). 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.[1]

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 that has 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.

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[1] However, operators of existing pipelines may be reluctant to accept crude shale oil with high nitrogen content for fear of contamination of subsequent batches of conventional crude oils. Consequently, either crude shale oil upgrading must occur at the mine site, or a dedicated crude shale oil pipeline infrastructure must be created.

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 and 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.[2] 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).[3] The Canadian crude experience can help define 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, typically small amounts of nitrogen, acidity, density, etc. At the most fundamental level, the refining process involves actions in any of the following categories:

- Separation—Distillation,

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2 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.

3 To facilitate discussion of the potential effects of oil shale development, the BLM assumed a commercial production level of approximately 2 million bbl/day.

- 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. 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.

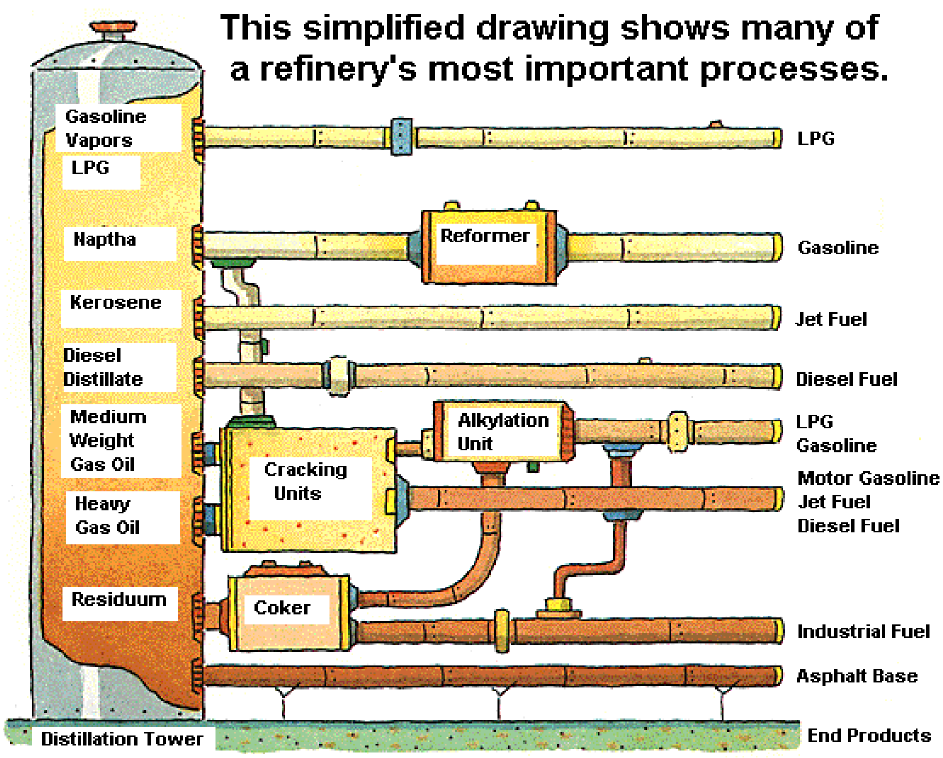

FIGURE 1 Generic Refinery Configuration (Source: EIA 2006a) (LPG stands for liquefied petroleum gas.)[a]

[a] Not all conventional crude oils are appropriate starting material for production of asphalt; however, they can instead efficiently produce heavy-weight fuel oils, such as bunker fuels used in ocean-going vessels or #6 fuel oil used in industrial boilers.

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).[4] 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. 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.

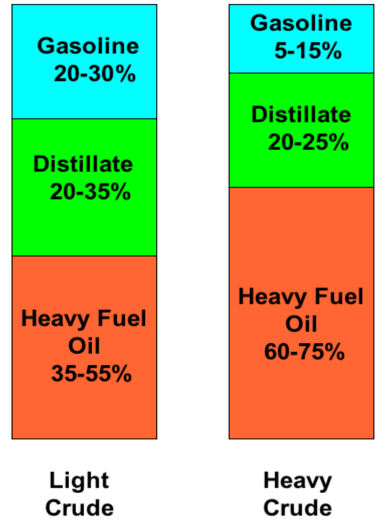

FIGURE 2 Comparison of Conversion Products Based on Crude Composition (Adapted from Day 2005)

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

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4 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.

very little experience related to commercial-scale shale oil development.[5] 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 (e.g., 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 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.

5 However, crude shale oil upgrading efforts associated with the Unocal operation at Parachute, Colorado, successfully demonstrated that crude shale oil could be converted to a syncrude whose properties, including substantially reduced concentrations of nitrogen and sulfur-bearing contaminants, made it acceptable for receipt at refineries.

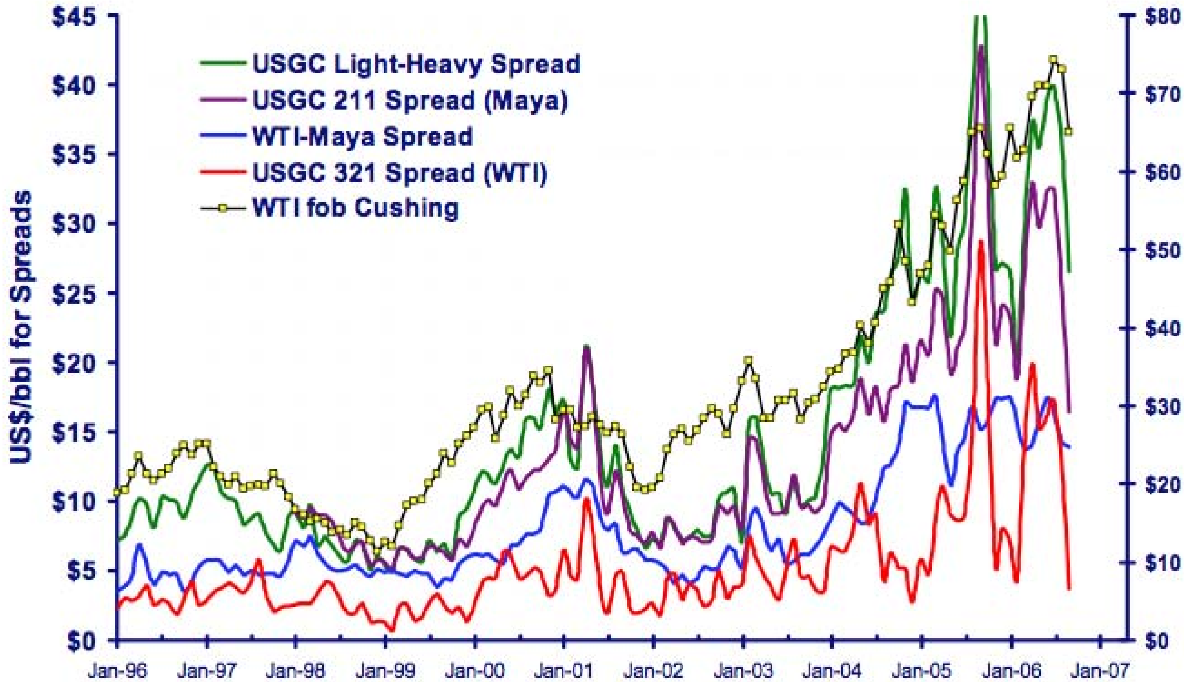

FIGURE 3 Heavy vs. Light Crude Refining Margins (Source: Arnold 2006)

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.[6]

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 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.

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6 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.

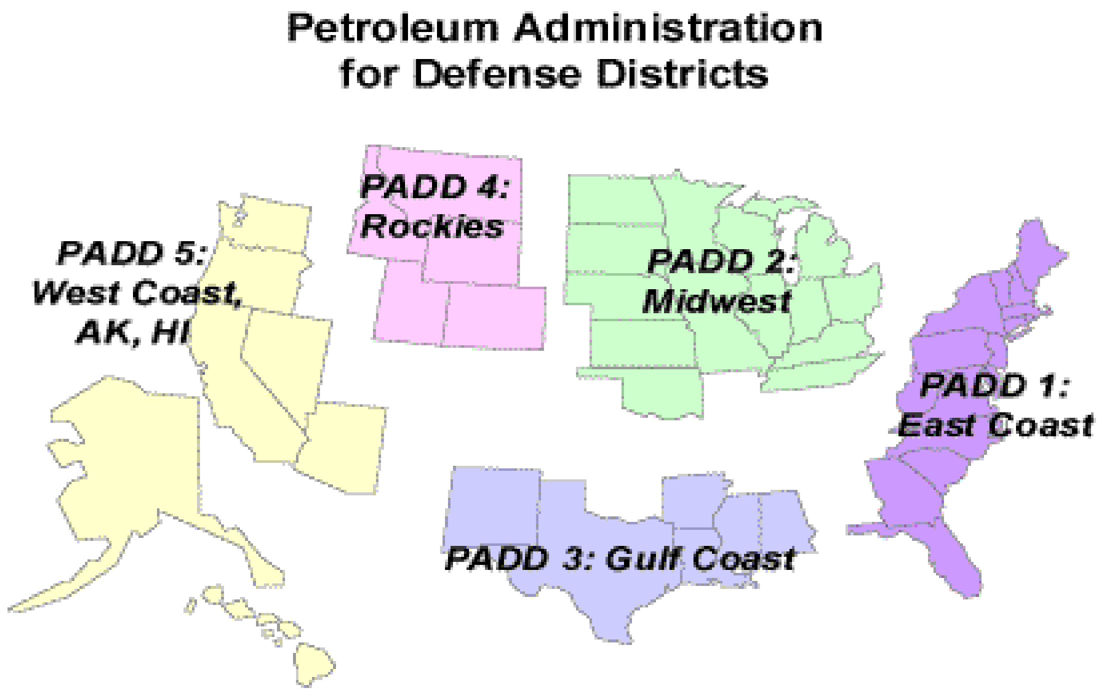

FIGURE 4 Petroleum Administration for Defense Districts Map (Source: EIA 2006b)

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 maintained 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

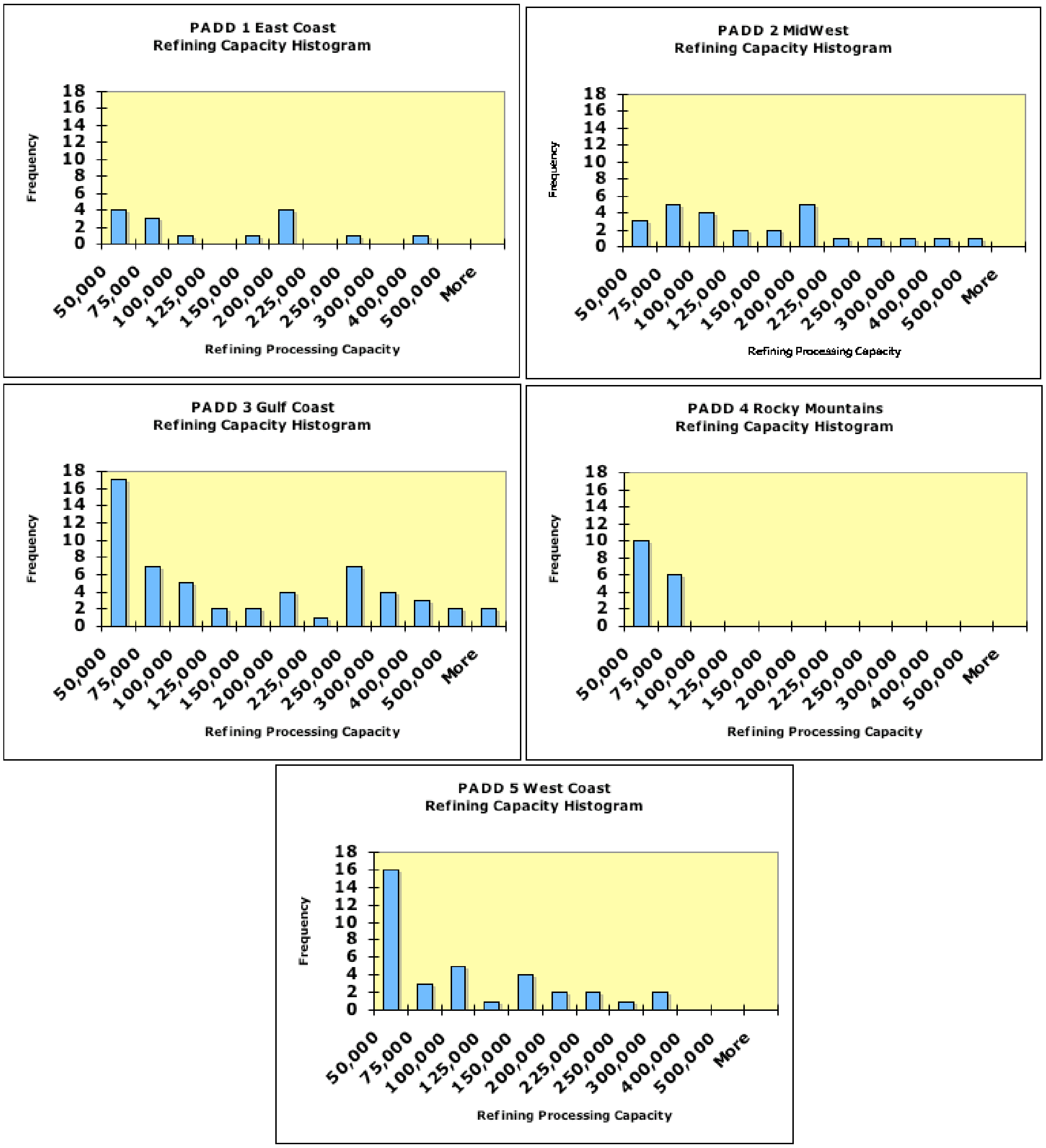

FIGURE 5 Distribution of Refining Capacities (Source: EIA 2006c)

have spent approximately $47 billion (Slaughter 2005) to reduce sulfur levels in transportation fuels and to comply with 14 new environmental regulations that come into place this decade (*Wall Street Journal* 2004). 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

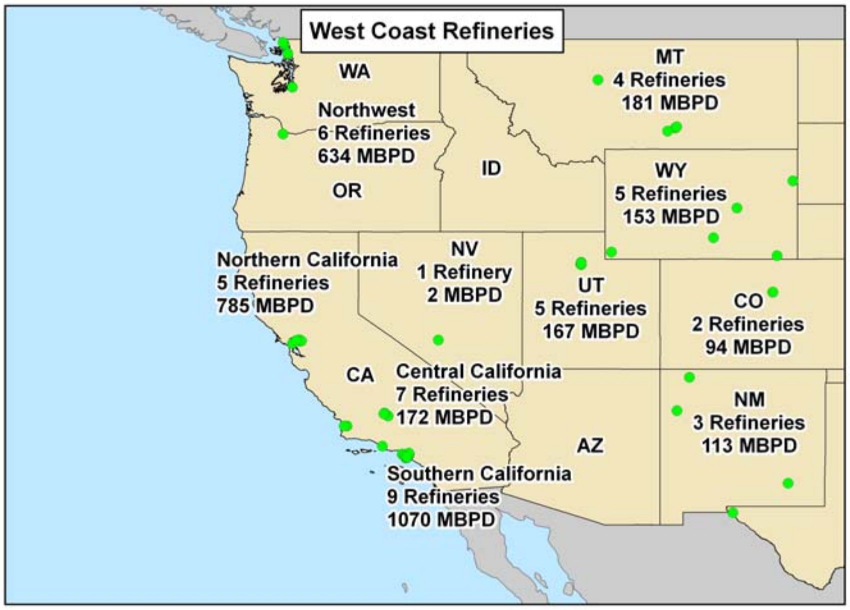

FIGURE 6 Western States Refining Capacity (Source: EIA 2006c)

are not expected to change substantially.[7] 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. 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.

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7 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.

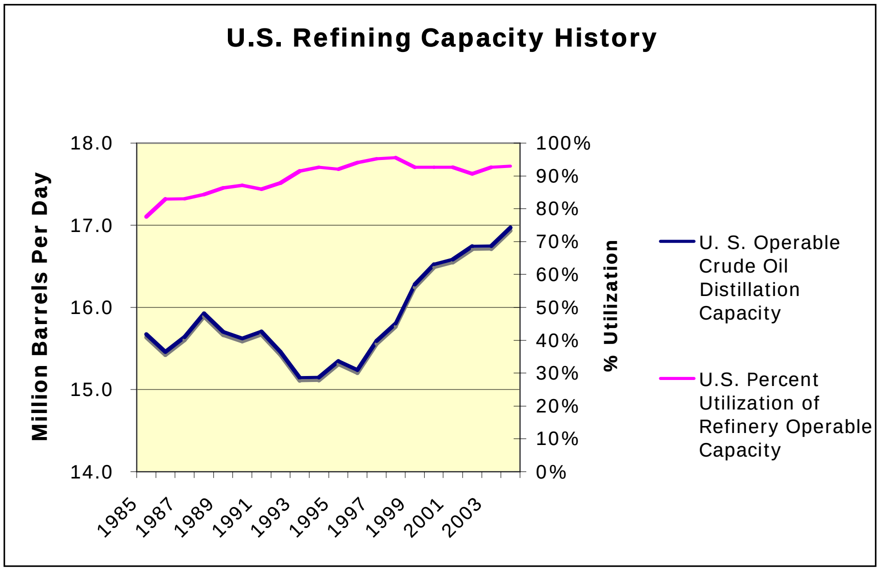

FIGURE 7 U.S. Refining Capacity (Source: EIA 2006d)

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

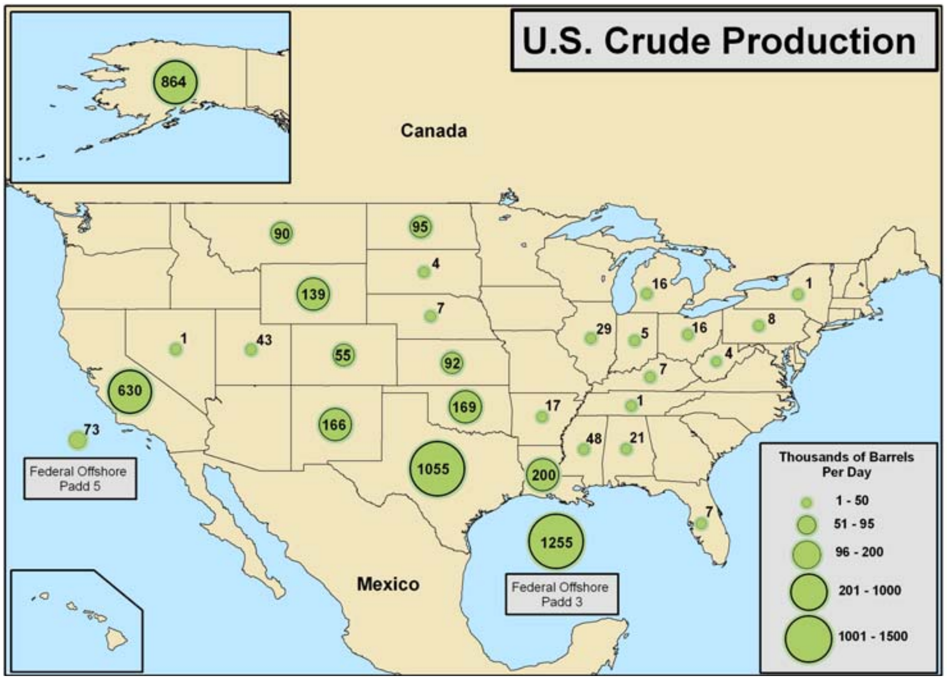

FIGURE 8 Domestic Crude Production (Source: EIA 2006e)

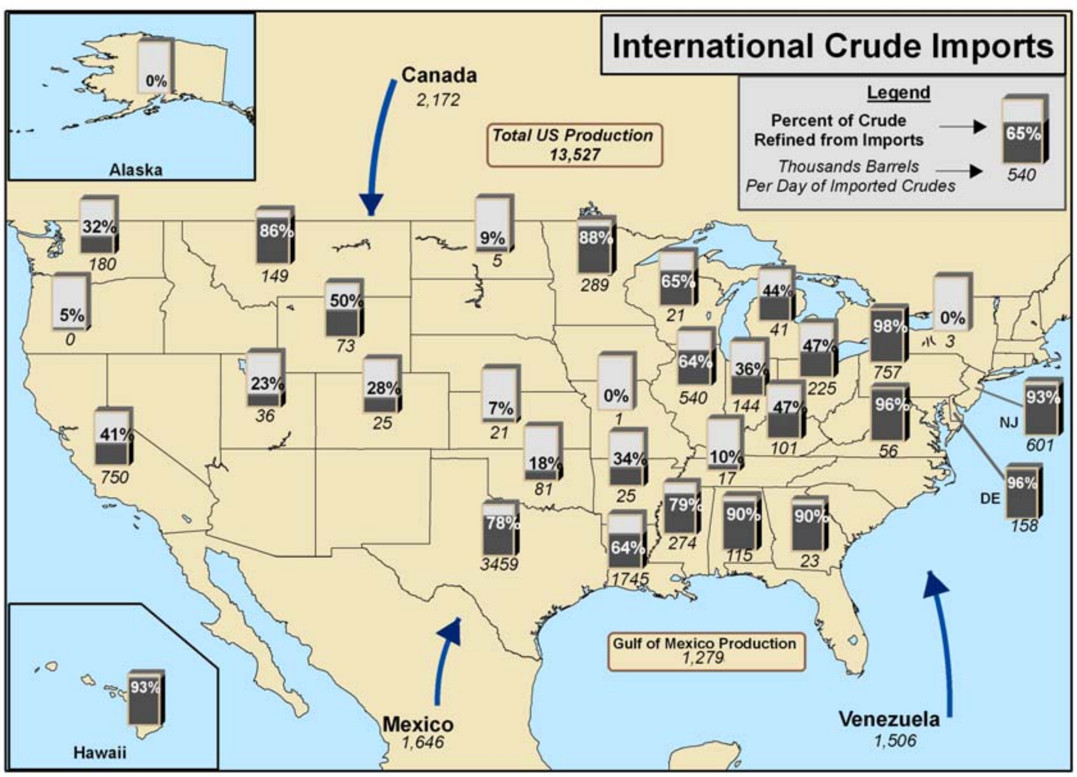

FIGURE 9 International Crude Imports (Source: EIA 2007)

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.

- 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. The refiner 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 could be made 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 increase their disadvantage. 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 it 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.[8]

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

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8 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 (2006f).

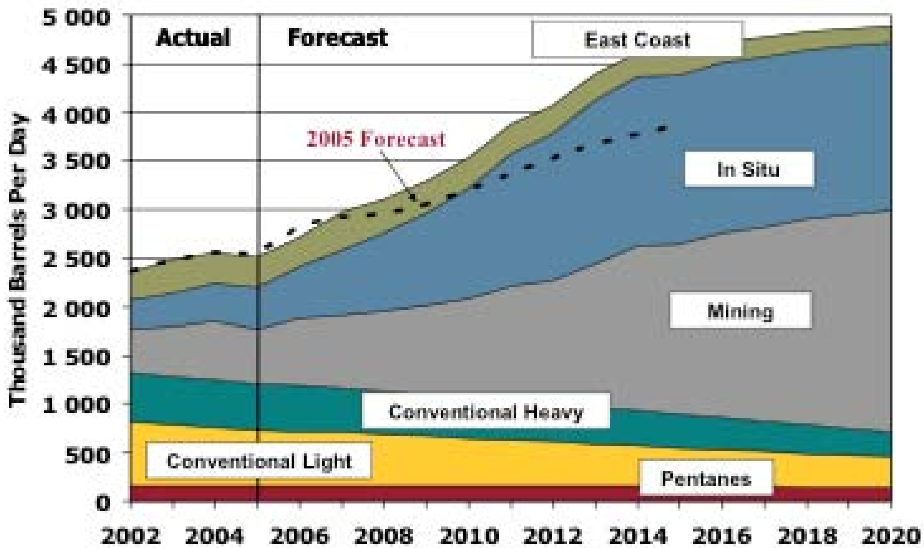

FIGURE 10 Canadian Crude Supply Forecast (Source: CAPP 2005)

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 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.

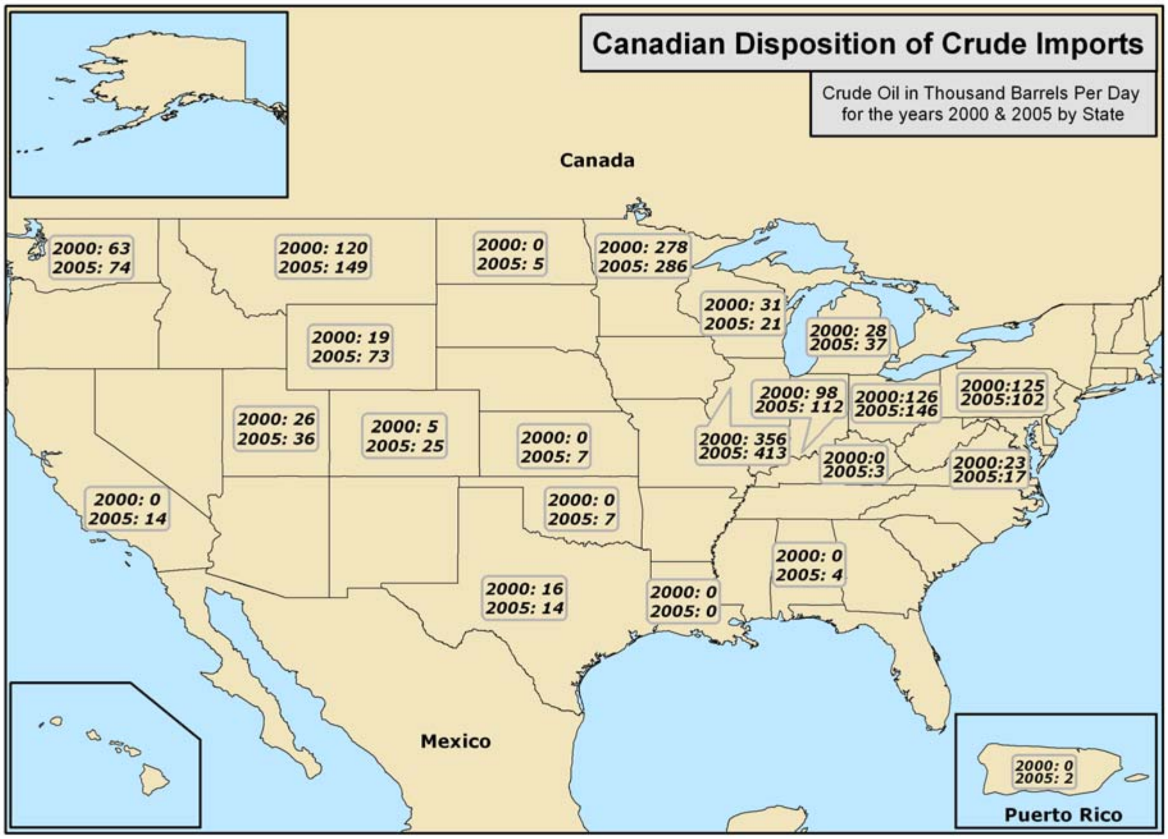

FIGURE 11 Canadian Crude Oil Disposition (Source: EIA 2007)

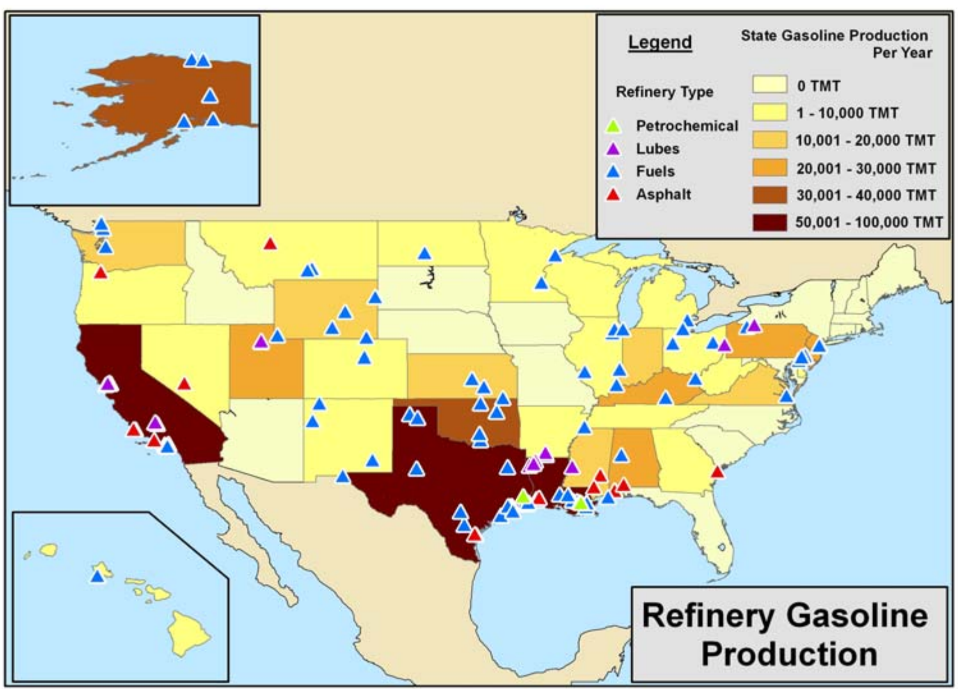

FIGURE 12 Refinery Locations and Gasoline Production (Source: EIA 2006c)

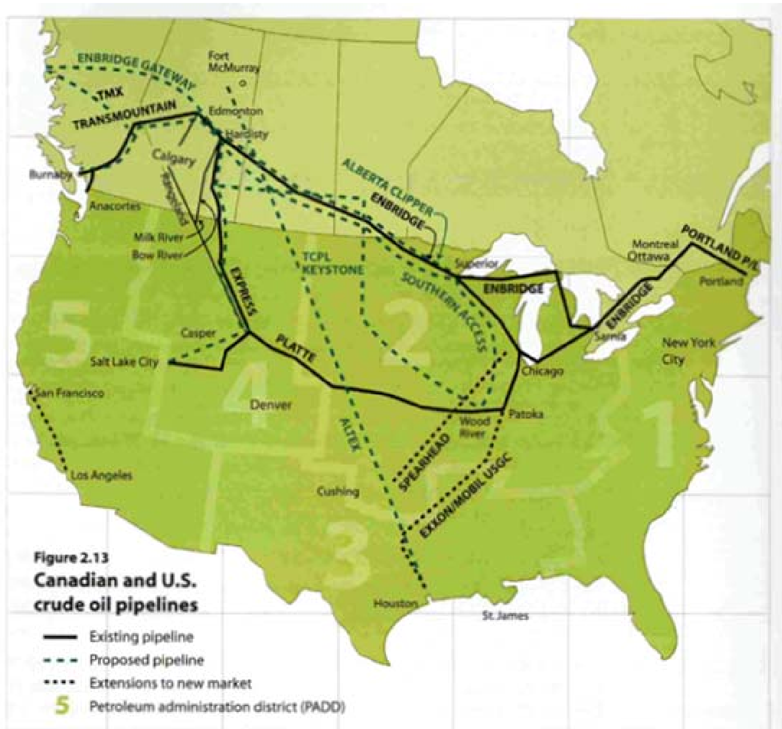

FIGURE 13 Canadian and U.S. Crude Oil Pipelines (Source: CAPP 2005)

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.

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 lightweight 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 compared to 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 over 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 over 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 for 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, for which, 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 is 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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Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

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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. Finally, Attachment B1 provides an analysis of how the refining industry may adjust to the availability of syncrude feedstocks derived from U.S. tar sands.

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 *Proposed Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Final 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).

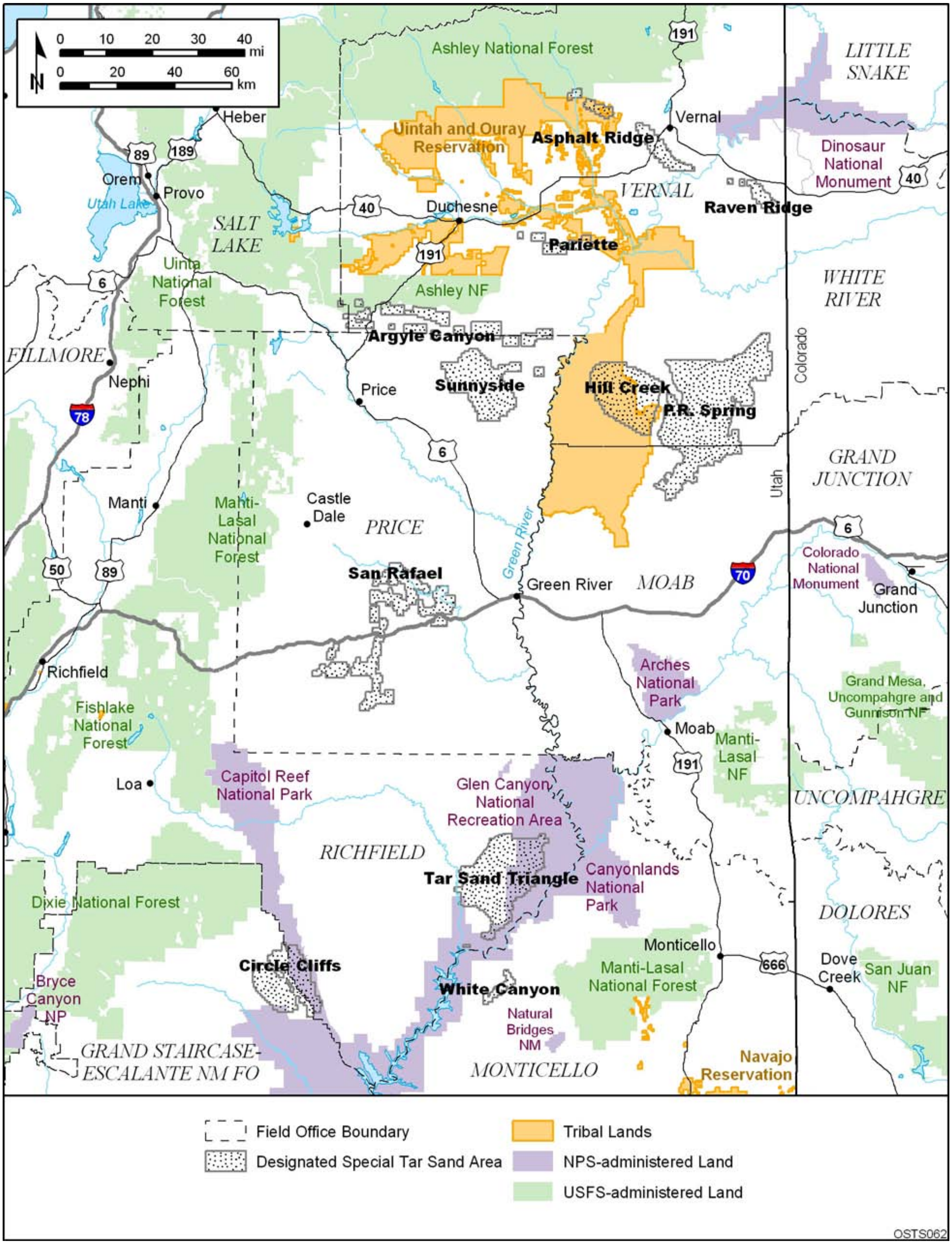

FIGURE B-1 Special Tar Sand Areas in Utah

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.

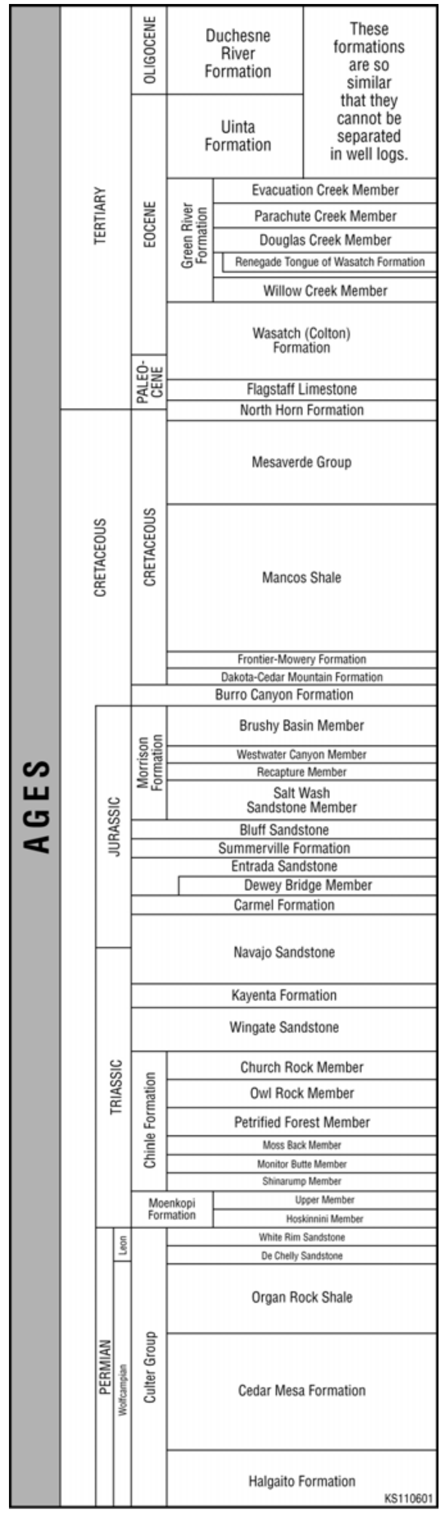

FIGURE B-2 Generalized Stratigraphy of the Areas in Utah Where the STSAs Are Present

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 oil sands deposits. Research on recovery mining from the Athabasca oil 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; Meyer 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 2006a.) By 2004, about two-thirds of the recovered oil 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 oil 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 oil 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 oil 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 from slope crests,
- The abrasive sands cause a high rate of equipment wear, and
- The large quantity of tailings from the extraction process requires 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).

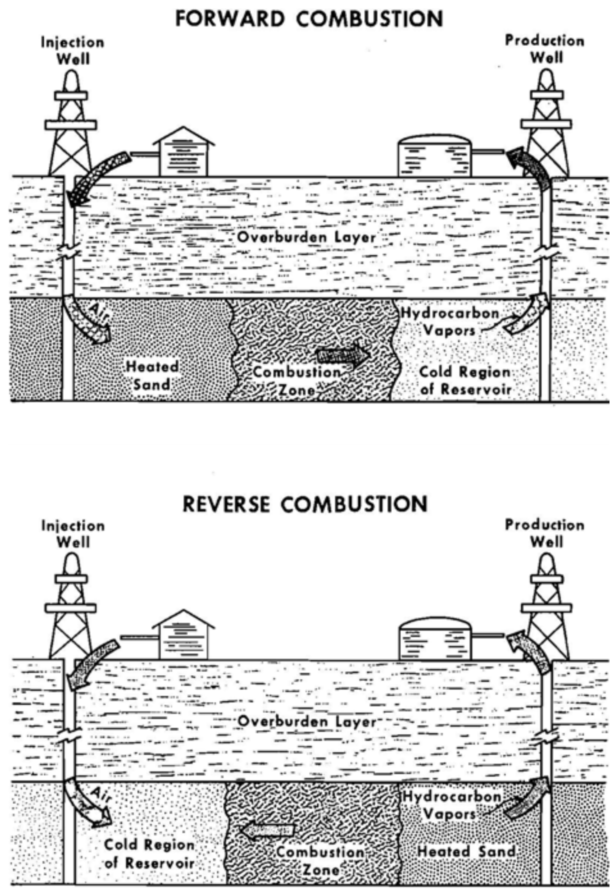

FIGURE B-3 Simplified Diagrams of Forward and Reverse Combustion Processes (Speight 1990) (Copyright 1990 from Fuel Science and Technology Handbook edited by James G. Speight. Reproduced by the permission of Routledge/Taylor & Francis Group, LLC.)

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

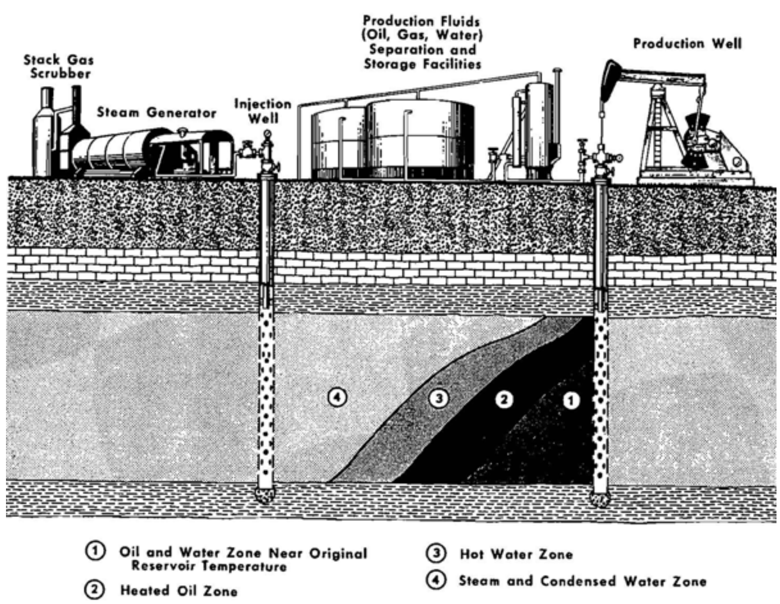

FIGURE B-4 Simplified Steam Drive Process (Speight 1990) (Copyright 1990 from *Fuel Science and Technology Handbook* edited by James G. Speight. Reproduced by the permission of Routledge/Taylor & Francis Group, LLC.)

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).

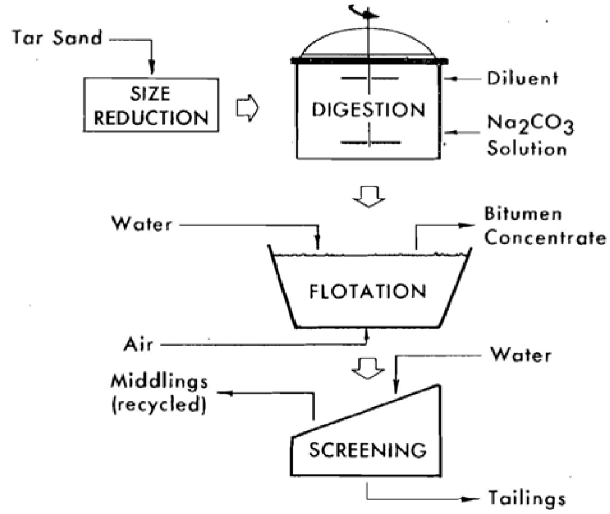

FIGURE B-5 Simplified Diagram of Hot Water Recovery Process (Marchant and Westhoff 1985)

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,d]	106,930	173,760	267,330	534,650
Noise (dBA at 500 ft)	73–88	–[e]	–	–
Air emissions (tons/yr)[e,f]				
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[g]				
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[h]				
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 not calculated.

[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).

[g] 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).

[h] 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).

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 not calculated.

[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 includes 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 2006b).

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

Impact-Producing Factor[a]	Production Capacity (bbl/day syncrude)[b,c]			
	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 2006b).

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 2006b).

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 2006b).

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 2006b).

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 2006b).

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 2006b).

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 oil 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 oil 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_r, 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. Severe limitations could be placed on resulting processing emissions, which 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 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) 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. Not only is the Canadian tar sands resource 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 United 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/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 a total of about only 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

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

Brierley, G., et al., 2006, *Changing Refinery Configuration for Heavy and Synthetic Crude Processing*, presented at the Annual Meeting of the National Petroleum Refiners Association, Salt Lake City, Utah, March 19–21.

EIA (Energy Information Administration), 2006a, “Petroleum Navigator, Number and Capacity of Petroleum Refineries.” Available at http://tonto.eia.doe.gov/dnav/pet/pet_pnp_cap1_dcu_R40_a.htm. Accessed Jan. 26, 2007.

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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, 2008])
  - Grand Junction RMP (BLM 1987)
  - White River RMP (BLM 1997a, as amended by the 2006 Roan Plateau Plan Amendment [BLM 2006a, 2007, 2008])

- 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:

- Utah
  - Book Cliffs RMP
  - Diamond Mountain RMP
  - Henry Mountain MFP (BLM 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,b]

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 on public lands (including federal split estate) 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.[c]	Same as Alternative B.
Specify that while the PEIS refers to "application for leasing for commercial oil shale development," the BLM could publish in the *Federal Register* one or more additional requests for expressions of interest in RD&D leasing within one or more of the states of Colorado, Utah, and Wyoming. Any new RD&D lease would have to be consistent with the applicable BLM land use plans. *Rationale:* In Section 369(c) of the Energy Policy Act of 2005, Congress expressly authorized the Secretary to make land available for leasing to conduct R&D activities with respect to technologies for the recovery of liquid fuels from oil shale. The impacts of new RD&D leasing are anticipated to be qualitatively similar to those of commercial oil shale leasing as analyzed in this PEIS. The RD&D impacts, however, are anticipated to be smaller in scale than those of commercial projects, at least until any RD&D lease might	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Common to All Land Use Plans (Cont.)	
be converted to a commercial oil shale lease and expanded to include preference right acreage. Therefore, the analysis in the PEIS for commercial oil shale projects also provides sufficient analysis of RD&D projects for purposes of amending land use plans. New RD&D leases would be issued, if at all, only after site-specific analysis under NEPA. Conversion to commercial leases would also require an individualized NEPA document.	
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 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 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.	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Common to All Land Use Plans (Cont.)	
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.
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. *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.

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 described in Section 2.3.3, 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 described in Section 2.3.3.2, 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 described in Section 2.3.1, 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 2.3-1).[d]	

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Colorado Cont.)	
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.	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 described in Section 2.3.3, 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 described in Section 2.3.3.2, 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 2.3.1, 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 2.3-1).[c]	

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Colorado Cont.)	
<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. Rationale: As described in Section 2.3.3, 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 (i.e., commercial and/or RD&D). 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. Rationale: As described in Section 2.3.3.2, 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 described in Section 2.3.1, 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 2.3-1).[d]	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Colorado Cont.)	
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) that 294,680 acres of land are 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 retain the existing decision regarding the 70,820-acre (which is included in total acres available for oil shale lease) Multimineral Zone (see Figure 3.1.1-3) 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
Amendments Specific to Individual Plans (Colorado Cont.)	
Utah	
Book Cliffs RMP, Vernal Field Office Designate 531,593 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 described in Section 2.3.3, 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 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 described in Section 2.3.3.2, 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 2.3-1). Applications for commercial leasing using surface mining technologies will not be accepted in any other areas. *Rationale:* As described in Section 2.3.1, 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.	Same as Alternative B.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Utah Cont.)	
Specify that the Ute Indian Tribe will be consulted regarding potential leasing for commercial oil shale development on 57,657 acres of 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.
Specify that certain decisions designating five areas totaling 48,000 acres as priority management areas for oil shale leasing will be removed from the RMP. Specifically, the decisions to be removed include those designating (1) three areas totaling 42,000 acres as available for underground mining, and (2) two areas totaling 6,000 acres as available for in-situ development. *Rationale:* The BLM has determined that it will make all lands within the most geologically prospective oil shale area available for application for leasing.	Same as Alternative B.
<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.	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.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Utah Cont.)	
Rationale: As described in Section 2.3.3, 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 described in Section 2.3.3.2, 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 described in Section 2.3.1, 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 2.3-1).[d]	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.	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.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Utah Cont.)	
Rationale: As described in Section 2.3.3, 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 described in Section 2.3.3.2, 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 described in Section 2.3.1, 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 2.3-1).[d]	
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.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Wyoming Cont.)	
Rationale: As described in Section 2.3.3, 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 described in Section 2.3.3.2, 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 described in Section 2.3.1, 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 2.3-1).[d]	
<u>Green River RMP, Rock Springs Field Office</u> 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.	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.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Wyoming Cont.)	
Rationale: As described in Section 2.3.3, 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 described in Section 2.3.3.2, 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 2.3-1). 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 2.3-1). Applications for commercial leasing using surface mining technologies will not be accepted in any other areas.
Rationale: As described in Section 2.3.1, 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.	Same as Alternative B.
<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.

TABLE C-1 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Wyoming Cont.)	
Rationale: As described in Section 2.3.3, 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 described in Section 2.3.3.2, 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 described in Section 2.3.1, 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 2.3-1).[d]	Same as Alternative B.

[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; RD&D = research, development, and demonstration; RMP = resource management plan.

[b] Commercial leasing as used herein includes both commercial and RD&D leasing.

[c] 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.

[d] 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,b]

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Common to All Land Use Plans	
Identify the most geologically prospective tar sand 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 tar sand resources in Utah as those deposits on public lands (including federal split estate) within the boundaries of the Special Tar Sand Areas.[c]	Same as Alternative B.
Specify that while the PEIS refers to "application for leasing for commercial oil shale and tars sands development," the BLM could publish in *the Federal Register* one or more additional requests for expressions of interest in RD&D leasing within the state of Utah. Any new RD&D lease would have to be consistent with the applicable BLM land use plans. *Rationale:* In Section 369(c) of the Energy Policy Act of 2005, Congress expressly authorized the Secretary to make land available for leasing to conduct R&D activities with respect to technologies for the recovery of liquid fuels from oil shale and tar sands. The impacts of new RD&D leasing are anticipated to be qualitatively similar to those of commercial tar sands leasing as analyzed in this PEIS. The RD&D impacts, however, are anticipated to be smaller in scale than those of commercial projects, at least until any RD&D lease might be converted to a commercial tar sands lease and expanded to include preference right acreage. Therefore, the analysis in the PEIS for commercial tar sands projects also provides sufficient analysis of RD&D projects for purposes of amending land use plans. New RD&D leases would be issued, if at all, only after site-specific analysis under NEPA. Conversion to commercial leases would also require an individualized NEPA document.	

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Common to All Land Use Plans (Cont.)	
Specify that commercial leasing 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 plans 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
Amendments Common to All Land Use Plans (Cont.)	
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	
<u>Book Cliffs 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: Hill Creek STSA: 56,506 acres P.R. Spring STSA: 153,003 acres[d] Raven Ridge STSA: 14,364 acres	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[d] Raven Ridge STSA: 9,950 acres

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Cont.)	
Rationale: As described in Section 2.4.3, 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 described in Section 2.4.3.2, 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.
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.	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.
Rationale: During the tribal consultation process conducted in conjunction with this PEIS, the Ute Indian Tribe requested that such consultation be conducted.	
<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:	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	Argyle Canyon STSA: 0 acres Asphalt Ridge STSA: 1,464 acres Sunnyside STSA: 1,199 acres

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Cont.)	
Rationale: As described in Section 2.4.3, 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 described in Section 2.4.3.2, 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.
<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 described in Section 2.4.3, 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 described in Section 2.4.3.2, 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

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Cont.)	
Rationale: As described in Section 2.4.3, 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 described in Section 2.4.3.2, 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.
<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 described in Section 2.4.3, 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 described in Section 2.4.3.2, 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.

TABLE C-2 (Cont.)

Proposed Change and Rationale	
Alternative B	Alternative C
Amendments Specific to Individual Plans (Cont.)	
Rationale: As described in Section 2.4.3, 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 described in Section 2.4.3.2, 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.

[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; RD&D = research, development, and demonstration; RMP = resource management plan; STSA = Special Tar Sand Area.

[b] Commercial leasing as used herein includes both commercial and RD&D leasing.

[c] 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).

[d] 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.

REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

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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	*Uintah County Utah Code (Uintah 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	
State	• Air Quality Control (CRS 25-7-101 et seq.)
County	• Garfield County: Air Quality (GCLUR 7-208) • Rio Blanco County: Air (RBCLUR 258)
Utah	
State	• Air Conservation Act (UCA 19-2-101 et seq.)
County	• 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	
State	• Air Quality (WS 35-11-201 et seq.)
County	• 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	
State	• Historical, Prehistorical, and Archeological Resources (CRS 24-80-401 et seq.) • Unmarked Human Graves (CRS 24-80-1301 et seq.)
County	• Garfield County: NA • Rio Blanco County: NA
Utah	
State	• History Development (UCA 9-8-102 et seq.) • Native American Graves Protection and Repatriation Act (UCA 9-9-102 et seq.)
County	• 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	
State	• Protection of Prehistoric Ruins (WS 36-1-114 et seq.)
County	• 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	
State	• Local Government Regulation—Location, Construction, or Improvement of Major Electrical or Natural Gas Facilities—Legislative Declaration (CRS 29-20-108)
County	• Garfield County: Fiscal Impact Mitigation Program (GCLUR Article IV, Division 5) • Rio Blanco County: NA
Utah	
State	• 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.)
County	• 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	
State	• 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)
County	• 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	
State	• Drainage of State Lands (CRS 37-30-101 et seq.) • Marsh Land (CRS 37-33-101 et seq.) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.)
County	• Garfield County: Protection of Wetlands and Waterbodies (GCLUR 7-203) • Rio Blanco County: Wetlands (RBCLUR 256)
Utah	
State	• Plan Preparation (UCA 10-9a-403) • Plan Preparation (UCA 17-27a-403)
County	• 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	
State	• Legislative Policy and Intent (WS 35-11-309 et seq.) • Application for Permit; Generally; Denial; Limitations (WS 35-11-406 (b)(v); (xv))
County	• 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	
State	• Water Right Determination and Administration (CRS-37-92-101 et seq.) • Reservoirs (CRS 37-87-101 et seq.) • Underground Water (CRS 37-90-101 et seq.) • Water Well Construction and Pump Installation Contractors (CRS 37-91-101 et seq.) • Water Quality Control (CRS 25-8-101 et seq.) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.)
County	• Garfield County: NA • Rio Blanco County: NA
Utah	
State	• 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.)
County	• 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	
State	• 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))
County	• 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	
State	• 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.) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.)
County	• Garfield County: Additional Standards Applicable to Storage Areas and Facilities (GCLUR 7-819) • Rio Blanco County: NA
Utah	
State	• Hazardous Materials—Transportation Regulations (UCA 41-6a-1639) • Hazardous Materials Emergency—Recovery of Expenses (UCA 53-2-105)
County	• 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	
State	• 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)
County	• 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	
State	• Hazardous Waste (CRS 25-15-101 et seq.) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.)
County	• Garfield County: NA • Rio Blanco County: NA
Utah	
State	• Solid and Hazardous Waste Act (UCA 19-6-101 et seq.)
County	• 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	
State	• Solid Waste Management (WS 35-11-501 et seq.)
County	• 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	
State	• 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.) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.)
County	• 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	
State	• 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) • Utah Mined Land Reclamation Act (UCA 40-8-1 et seq.)
County	• 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	
State	• 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.) • Abandoned Mine Reclamation Program (WS 35-11-1201 et seq.)
County	• 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	
State	• Noise Abatement (CRS 25-12-101 et seq.)
County	• Garfield County: Fiscal Impact Mitigation Program (GCLUR Article IV, Division 5) • Rio Blanco County: Noise (RBCLUR 260)
Utah	
State	• No specific primary statutory authority
County	• 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	
State	• No specific primary statutory authority
County	• 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	
State	• Pesticide Act (CRS 35-9-101 et seq.) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.)
County	• Garfield County: Fiscal Impact Mitigation Program (GCLUR Article IV, Division 5) • Rio Blanco County: Weeds and Invasive Species (RBCLUR 261)
Utah	
State	• Utah Pesticide Control Act (UCA 4-14-1 et seq.)
County	• 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	
State	• Weed and Pest Control (WS 11-5-101 et seq.)
County	• 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	
State	• Solid Waste Disposal Sites and Facilities (CRS 30-20-100.5 et seq.)
County	• Garfield County: Additional Standards Applicable to Solid Waste Disposal Sites (GCLUR 7-818) • Rio Blanco County: Waste Disposal (RBCLUR 257)
Utah	
State	• Solid Waste Management Act (UCA 19-6-501 et seq.)
County	• 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	
State	• 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))
County	• 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	
State	• Water Quality Control (CRS 25-8-101 et seq.)
County	• Garfield County: Protection of Water Quality from Pollutants (GCLUR 7-204) • Rio Blanco County: NA
Utah	
State	• Water Quality Act (UCA 19-5-101 et seq.)
County	• 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	
State	• 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))
County	• 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	
State	• Water Quality Control (CRS 25-8-101 et seq.) • Water and Wastewater Treatment Plant Operations (CRS 25-9-101 et seq.) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.)
County	• 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	
State	• Water Quality Act (UCA 19-5-101 et seq.)
County	• 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	
State	• Water Quality (WS 35-11-301 et seq.) • Application for Permit; Generally; Denial; Limitations (WS 35-11-406 (b)(ix))
County	• 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	
State	• 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.) • Colorado Mined Land Reclamation Act (CRS 34-32-101 et seq.)
County	• 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	
State	• Wildlife Resources Code of Utah (UCA 23-13-1 et seq.)
County	• 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 State	• 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))
County	• 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. 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

	Maximum Permissible Noise Level[a] (dBA)	
Zone	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
Plants						
Abies concolor	White fir	NL[e]	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.
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.
Astragalus calycosus var. *calycosus*	King’s milkvetch	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Pinyon-juniper woodland between 4,900 and 12,000 ft.
Astragalus coltonii var. *moabensis*	Moab milkvetch	NL	WY-SC	WY-Sweetwater, Uinta	Green River and Washakie	Pinyon-juniper and mountain brush communities between 4,400 and 6,900 ft.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
Atriplex wolfii	Wolf's orache	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Alkaline flats.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.
Chamaechaen-actis 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.

TABLE E-1 (Cont.)

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 (Cont.)						
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	UT-Uintah; WY-Sweetwater	Green River, Uinta, and Washakie; Raven Ridge STSA	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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
Gentianella tortuosa	Utah gentian	BLM	NL	CO-Rio Blanco; UT-Duchesne, Emery, Garfield, Uintah	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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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 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 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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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[c]	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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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 debilis	Parachute beardtongue	ESA-C	NL	CO-Garfield	Piceance	Oil shale outcrops on south-facing, steep white shale talus on the Mahogany Zone of the Parachute Creek Member of the Green River Formation; 2,400 to 2,800 m.
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 grahamii	Graham's beardtongue	BLM	NL	CO-Rio Blanco; UT-Duchesne, Uintah	Uinta; Hill Creek, Pariette, P.R. Spring, and Raven Ridge STSAs	Exposed raw shale knolls and slopes derived from the Parachute Creek and Evacuation Creek members of the Green River Formation at elevations from 1,430 to 2,600 m. Most populations occur on the surface of the oil shale Mahogany ledge.

TABLE E-1 (Cont.)

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 (Cont.)						
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 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.
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.
Physocarpus alternans	Dwarf ninebark	NL	WY-SC	WY-Sweetwater	Green River and Washakie	Pinyon-juniper woodland between 5,900 and 10,200 ft.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
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.

TABLE E-1 (Cont.)

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 (Cont.)						
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.
Invertebrates						
Oreohelix eurekensis	Eureka mountainsnail	BLM	UT-SC	UT-Duchesne, Grand	None	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	BLM	UT-SC	UT-San Juan	None	Terrestrial; aspen and spruce groves with open areas of grass and sandstone outcrops.

TABLE E-1 (Cont.)

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]
Invertebrates (Cont.)						
Physa utahensis	Utah physa	BLM	UT-SC	UT-Garfield	None	Vegetated springs.
Pyrgulopsis plicata	Black Canyon pyrg	BLM	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.
Fish						
Catostomus discobolus	Bluehead sucker	BLM	WY-SC	CO-Garfield, Rio Blanco; UT-Carbon, Duchesne, Emery, Garfield, Grand, San Juan, Uintah; WY-Lincoln, Sublette, Sweetwater, Uinta	Green River, Piceance, Uinta, and Washakie; all STSAs	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[c]	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	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	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	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 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[c]	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Fish (Cont.)						
Gila elegans	Bonytail	ESA-E	NL	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 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-Garfield, 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.

TABLE E-1 (Cont.)

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]
Fish (Cont.)						
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.
Ptychocheilus lucius	Colorado pikeminnow	ESA-E	CO-T	CO-Rio Blanco; 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.

TABLE E-1 (Cont.)

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]
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	BLM	UT-SC	UT-Garfield, San Juan	None	Irrigation ditches and flooded fields, as well as streams bordered by willows and cottonwoods.
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.

TABLE E-1 (Cont.)

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]
Amphibians (Cont.)						
Rana pipiens	Northern leopard frog	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; 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[c]	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Reptiles						
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.
Elaphe guttata	Corn snake	BLM	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.
Gambelia wislizenii	Longnose leopard lizard	BLM	CO-SC	CO-Garfield	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	BLM	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	BLM	UT-SC	UT-Garfield, San Juan	None	Rocky desert; lava flows, hillsides, and outcrops.
Xantusia vigilis	Desert night lizard	BLM	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[c]	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	WY-Lincoln, Uinta	Green River 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[c]	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Asio flammeus	Short-eared owl	BLM	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.
Botaurus lentiginosus	American bittern	NL	WY-SC	WY-Lincoln, Sweetwater, Uinta	Green River, Washakie	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.

TABLE E-1 (Cont.)

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]
Birds (Cont.)						
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.
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.
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[c]	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	BLM	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[c]	Oil Shale Basins and Special Tar Sand Areas in Which Species Could Occur[d]	Habitat[e]
Birds (Cont.)						
Dolichonyx oryzivorus	Bobolink	BLM	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	NL	UT-Carbon, Emery, Garfield, Grand, San Juan, Uintah, Wayne	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[c]	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[c]	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	BLM	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[c]	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	BLM	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[c]	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, Rio Blanco	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.
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.

TABLE E-1 (Cont.)

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]
Mammals (Cont.)						
Cynomys gunnisoni	Gunnison's prairie dog	ESA-C; BLM	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 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.
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[c]	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	BLM	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.
Lasiurus blossevillii	Western red bat	BLM	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.
Microtus mogollonensis	Mogollon vole	BLM	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; WY-Sublette, Sweetwater	Green River, Piceance, 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[c]	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	BLM	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.

TABLE E-1 (Cont.)

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]
Mammals (Cont.)						
Sorex preblei	Preble's shrew	NL	WY-SC	WY-Lincoln, Uinta	Green River	Arid and semiarid shrub-grass communities.
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	BLM	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; XN = experimental population, nonessential.

[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 species is listed and 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] NL = not listed.

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).

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Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

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APPENDIX F:

PROPOSED CONSERVATION MEASURES FOR OIL SHALE AND TAR SANDS LEASING AND DEVELOPMENT

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APPENDIX F:

PROPOSED CONSERVATION MEASURES FOR OIL SHALE AND TAR SANDS LEASING AND DEVELOPMENT

CONSERVATION MEASURES

The following conservation measures were developed for the oil shale and tar sands program through consultation between the U.S. Department of the Interior, Bureau of Land Management (BLM), and 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 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, mitigation 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.

IMPLAN multipliers for 2004 for oil and gas extraction, coal mining, new residential construction, power generation and supply, manufacturing and industrial buildings, and personal consumption expenditure were used to estimate the indirect impacts of OSTS and ancillary project development and temporary housing in each state ROI.

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 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

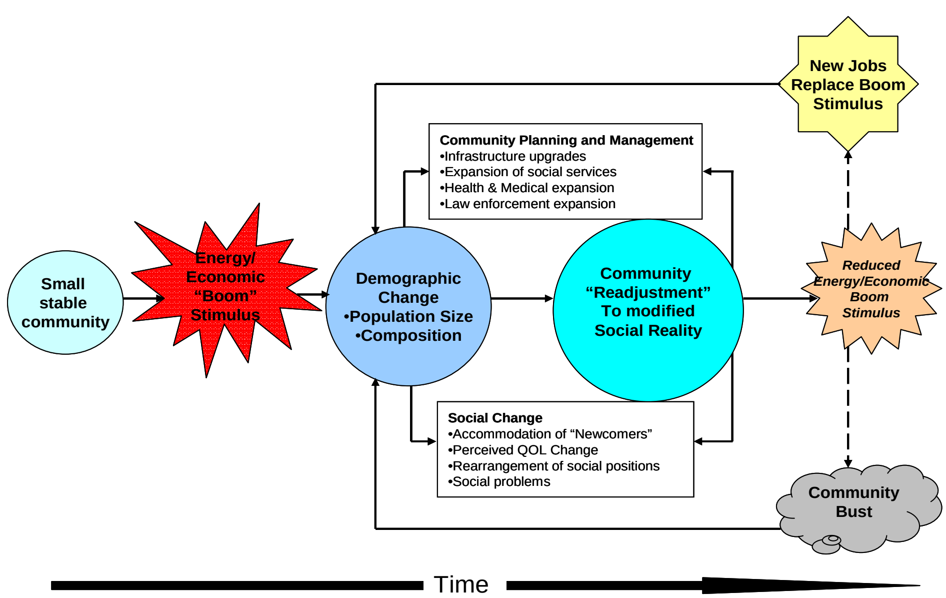

FIGURE G-1 The Cycle of Social Adjustment to “Boom” and “Bust”

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 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.

G.3 REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

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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.

APPENDIX I:

INSTREAM FLOW WATER RIGHTS IN THE PICEANCE BASIN, COLORADO

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TABLE I-1 Instream Flow Tabulation—Water Division 5, Colorado River Basin

Case Number	Stream	Watershed	County	Upper Terminus	Lower Terminus	Length (mi)	USGS Quads	Amount (cfs) (dates)	Approximate Date
5-80CW118	Abrams Creek	Eagle	Grand	Headwaters in SE SE S25 T5S R85W 6PM	Diversion in SE SW S9 T5S R84W 6PM	4.30	Eagle The Seven Hermits	0.5 (01/1 – 12/31)	3/17/1980
5-85CW644	Acorn Creek	Blue	Summit	Headwaters near lat 39 44 18N long 106 04 02W	Diversion near lat 39 45 45N long 106 06 45W	3.50	Dillon Squaw Creek Ute Peak	1 (01/1 – 12/31)	11/8/1985
5-90CW313	Cabin Creek	Colorado headwaters	Grand	Headwaters at natural lake at lat 40 00 33N long 105 42 02W	Denver Water Board diversion at lat 39 59 12N long 105 44 32W	3.50	East Portal Monarch Lake	2 (04/1 – 04/30) 4.5 (05/1 – 08/31) 2 (09/1 – 10/31) 0.75 (11/1 – 03/31)	11/27/1990
5-03CW264	Canyon Creek	Colorado Headwaters-Plateau	Garfield	Confl Johnson Creek lat 39 42 28N long 107 23 11W	Headgate Baxter Ditch #1 lat 39 37 49N long 107 26 50W	7.50	Adams Lake	13.5 (04/15 – 05/14) 24.1 (05/15 – 07/14) 13.5 (07/15 – 08/14) 9.4 (08/15 – 04/14)	1/22/2003
5-95CW289	Castle Creek	Colorado headwaters	Eagle	Confl unnamed tributary at lat 39 48 08N long 106 51 25W	Castle Creek Ditch in SW NE S29 T2S R84W 6PM	4.60	Castle Peak	1.75 (04/1 – 07/31) 1 (08/1 – 08/31) 0.5 (09/1 – 03/31)	11/6/1995
5-97CW273 (enlargement)	Cattle Creek	Roaring Fork	Garfield	Confl Coulter Creek in SW NW S8 T7S R87W 6PM	Confl Park Ditch in SW NW S7 T7S R87W 6PM	3.50	Carbondale Cattle Creek	2 (05/1 – 10/31)	9/22/1997
5-03CW267	Cottonwood Creek	Colorado Headwaters-Plateau	Eagle	Confl Slaughter Sprg Glch at lat 39 32 11N long 107 02 15W	Headgate Anderson Ditch at lat 39 34 02N long 107 02 09W	2.20	Cottonwood Pass	1.7 (05/01 – 10/31) 1.3 (11/01 – 04/30)	1/22/2003
5-03CW271	East Canyon Creek	Colorado Headwaters-Plateau	Garfield	Confl Keyser Creek at lat 39 38 11N long 107 24 21W	Keyser Creek Ditch at lat 39 37 16N long 107 25 05W	1.30	Adams Lake Storm King Mountain	12 (05/01 – 07/31) 3.8 (08/01 – 04/30)	1/22/2003
5-90CW289	Fraser River	Colorado headwaters	Grand	Headwaters in vicinity of lat 39 48 10N long 105 45 33W	Fraser River Diversion Dam at lat 39 51 43N long 105 44 57W	4.90	Berthoud Pass Empire	6 (04/15 – 09/30) 2.5 (10/1 – 04/14)	11/27/1990
5-90CW282	Hamilton Creek	Colorado headwaters	Grand	Headwaters in vicinity of lat 40 00 35N long 105 42 24W	Denver Water Board diversion at lat 39 59 50N long 105 44 40W	2.70	East Portal Monarch Lake	3 (05/15 – 08/14) 0.35 (08/15 – 05/14)	11/27/1990

TABLE I-1 (Cont.)

Case Number	Stream	Watershed	County	Upper Terminus	Lower Terminus	Length (mi)	USGS Quads	Amount (cfs) (dates)	Approximate Date
5-03CW268	Horse Creek	Colorado Headwaters-Plateau	Eagle	Outlet Horse Lake at lat 39 49 51N long 107 05 56W	Headgate Horse Cr Ditch at lat 39 45 43N long 107 01 45W	6.80	Sugarloaf Mountain	0.95 (04/01 – 08/31) 0.5 (09/01 – 03/31)	1/22/2003
5-90CW283	Iron Creek	Colorado headwaters	Grand	Headwaters at natural lake at lat 39 51 10N long 105 57 17W	Denver Water Board diversion at lat 39 51 38N long 105 54 28W	2.50	Byers Peak	2.5 (04/15 – 08/31) 1 (09/1 – 10/31) 0.5 (11/1 – 04/1)	11/27/1990
5-90CW286	Jim Creek	Colorado headwaters	Grand	Headwaters in vicinity of lat 39 50 25N long 105 42 19W	Diversion structure at lat 39 52 52N long 105 44 29W	4.20	East Portal Empire	4 (04/15 – 09/30) 1.5 (10/1 – 11/30) 1 (12/1 – 04/14)	11/27/1990
5-90CW310	Meadow Creek	Colorado headwaters	Grand	Outlet Meadow Creek Reservoir in NE NE S14 T1N R75W 6PM	Vail Irr Sys Headgate #1 in NE SE S16 T1N R75W 6PM	2.10	Strawberry Lake	3.5 (05/1 – 09/30) 1.5 (10/1 – 04/30)	11/27/1990
5-85CW637	Mesa Creek	Colorado Headwaters-Plateau	Mesa	Confl unnamed tributary in SW SE S27 T11S R96W 6PM	Headgate Mesa Creek Ditch in SW SE S16 T11S R96W 6PM	3.00	Lands End Mesa Skyway	2.5 (01/1 – 12/31)	11/8/1985
5-85CW637A	Mesa Creek	Colorado Headwaters-Plateau	Mesa	Confl Big Beaver Creek in SE SW S8 T11S R96W 6PM	Headgate Mason & Eddy in NE SE S30 T10S R96W 6PM	4.60	Lands End Mesa Skyway	2.5 (01/1 – 12/31)	11/8/1985
5-90CW288	Middle Fork Ranch Creek	Colorado headwaters	Grand	Headwaters at Deadman Lake at lat 39 55 13N long 105 41 32W	Denver Water Board diversion in NW SW S25 T1S R75W 6PM	2.60	East Portal	3.5 (05/1 – 08/14) 1.5 (08/15 – 10/31) 0.5 (11/1 – 03/31)	11/27/1990
5-98CW305	Muddy Creek	Colorado headwaters	Grand	Outlet Wolford Mtn Reserv in SW NE S25 T2N R81W 6PM	Hdgte Deberard Ditch in NE SE S7 T1N R80W 6PM	9.00	Hinman Reservoir Kremmling	70 (05/1 – 05/14) 105 (05/15 – 06/30) 70 (07/1 – 07/14) 20 (07/15 – 04/30)	7/13/1998
5-87CW276	North Fork Colorado River	Colorado headwaters	Grand	Confl with Onahu Creek in SW NE S24 T4N R76W 6PM	Hdgt Redtop Valley Ditch at lat 40 15 06N long 105 52 02W	5.30	Grand Lake	18 (05/1 – 09/30) 10 (10/1 – 04/30)	10/2/1987
5-90CW280	Pole Creek	Colorado headwaters	Grand	Headwaters in NW NW S14 T1S R77W 6PM	Gehman-Just headgate in SW SE S5 T1S R76W 6PM	2.50	Bottle Pass	1.5 (04/1 – 08/31) 0.5 (09/1 – 03/31)	11/27/1990
5-87CW273	Prince Creek	Roaring Fork	Pitkin	Headwaters in SW SW S8 T9S R87W 6PM	Headgate Mt. Sopris Ditch at lat 39 20 52N long 107 10 00W	6.20	Mount Sopris	1 (01/1 – 12/31)	10/2/1987

TABLE I-1 (Cont.)

Case Number	Stream	Watershed	County	Upper Terminus	Lower Terminus	Length (mi)	USGS Quads	Amount (cfs) (dates)	Approximate Date
5-90CW290	Ranch Creek	Colorado headwaters	Grand	Headwaters at Pumphouse Lake at lat 39 55 34N long 105 41 25W	Denver Water Board diversion in SE SW S24 T1S R75W 6PM	2.80	East Portal	4 (04/15 – 08/14) 1.5 (08/15 – 09/30) 0.5 (10/1 – 04/14)	11/27/1990
5-95CW286	Red Dirt Creek	Colorado headwaters	Eagle	Confl EF & WF Red Dirt Ck in NE NE S3 T3S R86W 6PM	Wilson and Doll Ditch in NW SE S12 T3S R86W 6PM	2.60	Burns South Sugarloaf Mountain	3 (04/1 – 07/31) 1.75 (08/1 – 10/31) 1 (11/1 – 03/31)	11/6/1995
5-03CW265	Salt Creek	Eagle	Eagle	Confl Kelly Creek at lat 39 35 07N long 106 41 37W	Headgate Hashberger Ditch at lat 39 35 06N long 106 42 02W	0.40	Fulford	0.75 (01/01 – 12/31)	1/22/2003
5-89CW185	Sheep Creek	Colorado headwaters	Eagle	Confl E & W Fks Sheep Ck in SW NW S19 T3S R86W 6PM	Hdgt Allen Ditch in SE NE S25 T3S R87W 6PM	1.00	Sugarloaf Mountain	1.5 (04/1 – 09/30) 0.75 (10/1 – 03/31)	7/11/1989
5-89CW182	South Fork Derby Creek	Colorado headwaters	Eagle	Headwaters at lat 39 55 04N long 107 10 08W	Hdgt South Derby Ditch in SE NW S8 T2S R86W 6PM	6.50	Dome Peak Trappers Lake	4.5 (04/1 – 09/30) 2 (10/1 – 03/31)	7/11/1989
5-90CW291	South Fork Ranch Creek	Colorado headwaters	Grand	Headwaters in vicinity of lat 39 52 59N long 105 42 27W	Denver Water Board diversion in SE NW S35 T1S R75W 6PM	3.40	East Portal	3.5 (05/1 – 08/14) 1 (08/15 – 10/31) 0.5 (11/1 – 03/31)	11/27/1990
5-03CW272	Spring Creek	Eagle	Eagle	Headwater springs at lat 39 35 49N long 106 53 51W	Headgate Best Ditch at lat 39 36 23N long 106 54 40W	1.00	Suicide Mountain	0.35 (01/01 – 12/31)	1/22/2003
5-90CW303	St Louis Creek	Colorado headwaters	Grand	Headwaters in vicinity of lat 39 48 27N long 105 57 20W	Denver Water Board diversion at lat 39 51 09N long 105 54 34W	4.70	Byers Peak	6 (05/15 – 09/15) 2.5 (09/16 – 05/14)	11/27/1990
5-90CW316	St Louis Creek	Colorado headwaters	Grand	Confl King Creek at lat 39 54 52N long 105 52 27W	Tyron ditch diversion in NW NE S19 T1S R75W 6PM	4.20	Fraser	6 (05/15 – 09/15) 3.5 (09/16 – 05/14)	11/27/1990
5-85CW651	Stillwater Creek	Colorado headwaters	Grand	Headwaters in the vicinity of lat 40 16 25N long 105 59 20W	Headgate Redtop Valley Ditch in SE NW S22 T3N R76W 6PM	8.20	Bowen Mountain Trail Mountain	3 (01/1 – 12/31)	11/8/1985
5-85CW648	Straight Creek	Blue	Summit	Headwaters in vicinity of lat 39 41 37N long 105 55 42W	Diversion in SW NW S4 T5S R77W 6PM	6.90	Dillon Loveland Pass	2.5 (01/1 – 12/31)	11/8/1985

TABLE I-1 (Cont.)

Case Number	Stream	Watershed	County	Upper Terminus	Lower Terminus	Length (mi)	USGS Quads	Amount (cfs) (dates)	Approximate Date
5-90CW295	Strawberry Creek	Colorado headwaters	Grand	Confl unnamed tributary in SW NE S5 T1N R75W 6PM	Vail Irr Sys Headgate #2 at lat 40 04 24N long 105 51 25W	3.60	Granby Strawberry Lake	2 (04/15 – 09/30) 1 (10/1 – 04/14)	11/27/1990
5-85CW629	Supply Creek	Colorado headwaters	Grand	Confl N & M Supply Creek at lat 40 16 25N long 105 52 46W	Hdgt Redtop Valley Ditch in SE SW S2 T3N R76W 6PM	1.80	Bowen Mountain Shadow Mountain	3 (01/1 – 12/31)	11/8/1985
5-03CW273	Thomas Creek	Roaring Fork	Pitkin	Outlet St John Reservoir at lat 39 19 00N long 107 09 46W	Headgate Lewis Ditch at lat 39 20 05N long 107 11 03W	1.80	Mount Sopris	1.5 (05/01 – 07/31) 0.5 (08/01 – 04/30)	1/22/2003
5-03CW275	Thompson Creek	Roaring Fork	Pitkin	Confl N & S Thompson Cr at lat 39 18 49N long 107 15 33W	Hdgt Northside Thompson D at lat 39 19 56N long 107 13 08W	2.80	Mount Sopris Stony Ridge	12.4 (04/01 – 07/14) 4.3 (07/15 – 03/31)	1/22/2003
5-90CW292	Vasquez Creek	Colorado headwaters	Grand	Headwaters at Vasquez Lake at lat 39 48 19N long 105 53 14W	Denver Water Board diversion at lat 39 51 56N long 105 49 12W	6.80	Berthoud Pass Byers Peak	2.5 (01/1 – 12/31)	11/27/1990
5-90CW318	Vasquez Creek	Colorado headwaters	Grand	Denver Water Board diversion at lat 39 51 56N long 105 49 12W	Grand County diversion in SW NE S5 T2S R75W 6PM	3.10	Berthoud Pass Fraser	6 (05/15 – 09/15) 3 (09/16 – 05/14)	11/27/1990

Totals for Water Division 5
Total No. of Stream Miles = 148.4
Total No. of Appropriations = 37
(Totals do not include donated/acquired water)

Source: Colorado Water Conservation Board, 2007, *Colorado's Water Supply Future, Statewide Water Supply Initiative—Phase 2*, Denver, Colo., Nov.

TABLE I-2 Instream Flow Tabulation—Water Division 6, White River Basin

Case Number	Stream	Watershed	County	Upper Terminus	Lower Terminus	Length (mi)	USGS Quads	Amount (cfs) (dates)	Approximate Date
6-81CW295	Arapaho Creek	North Platte headwaters	Jackson	Confl MF & SF Arapaho Creek at lat 40 24 55N long 106 23 22W	Headgate Eureka Ditch at lat 40 26 10N long 106 24 29W	2.00	Spicer Peak	8 (01/1 – 12/31)	12/3/1981
6-92CW075	Beaver Creek	Upper Green-Flaming Gorge Reservoir	Moffat	Utah-Colorado Stateline in SW SW S24 T11N R104W 6PM	Confl Jarvee Ditch in SW SE S12 T10N R104W	4.70	Swallow Canyon Willow Creek Butte	3.25 (04/1 – 08/31) 2 (09/1 – 03/31)	9/16/1992
6-81CW297	Colorado Creek	North Platte headwaters	Jackson	Hheadwaters in vicinity of lat 40 26 20N long 106 38 28W	Headgate Moraine Ditch at lat 40 28 14N long 106 35 47W	4.10	Mount Werner Rabbit Ears Peak	3 (01/1 – 12/31)	12/3/1981
6-92CW049	East Branch	North Platte headwaters	Jackson	Headwaters at SE SE S5 T4N R78W 6PM	Headgate School Section Ditch at lat 40 23 40N long 106 07 48W	5.20	Parkview Mountain Rand	2.5 (04/1 – 09/30) 1 (10/1 – 03/31)	5/8/1992
6-77W1285	Hinman Creek	Upper Yampa	Routt	Confl Farwell Creek at lat 40 49 53N long 106 48 48W	Headgate Sunnyside Ditch in SW SW S4 T9N R84W 6PM	5.50	Farwell Mountain	4 (01/1 – 12/31)	9/23/1977
6-92CW074	Illinois River	North Platte headwaters	Jackson	Headwaters at lat 40 22 27N long 105 56 57W	Headgate Park Ditch at lat 40 24 27N long 106 02 42W	7.00	Bowen Mountain Jack Creek Ranch Mount Richthofen	3 (04/1 – 10/31) 1.5 (11/1 – 03/31)	5/8/1992
6-92CW052	Jack Creek	North Platte headwaters	Jackson	Headwaters at lat 40 23 21N long 105 56 26W	Headgate Teller Ditch at lat 40 25 30N long 106 02 15W	8.40	Jack Creek Ranch Mount Richthofen	8.5 (05/1 – 08/15) 4 (08/16 – 10/31) 2 (11/1 – 04/30)	5/8/1992
6-81CW298	Little Grizzly Creek	North Platte headwaters	Jackson	Headwaters in vicinity of lat 40 32 54N long 106 39 10W	Headgate Jennie Ditch at lat 40 33 21N long 106 36 21W	3.10	Buffalo Pass Teal Lake	4 (01/1 – 12/31)	12/3/1981
6-81CW299	Norris Creek	North Platte headwaters	Jackson	Headwaters in vicinity of lat 40 39 34N long 106 40 30W	Headgate Roaring Ditch in NE SW S14 T8N R82W 6PM	6.30	Mount Ethel Pitchpine Mountain	7 (01/1 – 12/31)	12/3/1981
6-92CW053	Rock Creek (Little Willow Ck)	North Platte headwaters	Jackson	Headwaters at lat 40 21 33N long 106 16 34W	Headgate Darcy Ditch at lat 40 23 30N long 106 15 08W	3.10	Buffalo Peak Hyannis Peak	1 (04/1 – 10/31) 0.5 (11/1 – 03/31)	5/8/1992
6-92CW055	South Fork Canadian River	North Platte headwaters	Jackson	Jewel Lake at lat 40 36 02N long 105 56 18W	Headgate Bradfield Ditch at lat 40 35 37N long 105 59 47W	4.00	Clark Peak	2 (04/16 – 08/31) 1 (09/1 – 10/31) 0.5 (11/1 – 04/15)	5/8/1992

TABLE I-2 (Cont.)

Case Number	Stream	Watershed	County	Upper Terminus	Lower Terminus	Length (mi)	USGS Quads	Amount (cfs) (dates)	Approximate Date
6-77W1386	South Fork Little Snake River	Little Snake	Routt	National Forest boundary in S1 T10N R87W 6PM	Headgate Assman Ditch No 1 in SW SE S29 T12N R86W 6PM	6.60	Shield Mountain	4 (01/1 – 12/31)	9/23/1977
6-92CW056	South Fork Michigan River	North Platte headwaters	Jackson	Confl Silver Creek at lat 40 28 54N long 106 00 26W	Headgate Mason Ditch at lat 40 30 19N long 106 01 29W	2.10	Gould Jack Creek Ranch	18 (05/1 – 8/15) 8.5 (08/16 – 10/31) 4.5 (11/1 – 04/30)	5/8/1992
6-79CW102	Walton Creek	Upper Yampa	Routt	USGS gage at lat 40 24 28N long 106 47 12W	Headgate Walton Creek Ditch in SE NE S10 T5N R84W 6PM	0.20	Steamboat Springs	16 (01/1 – 12/31)	3/14/1979
6-92CW057	Willow Creek	North Platte headwaters	Jackson	Headwaters at lat 40 20 16N long 106 14 09W	Headgate Wycoff Ditch at lat 40 23 43N long 106 10 57W	5.90	Parkview Mountain Rand	5 (04/1 – 10/31) 2.75 (11/1 – 03/31)	5/8/1992

Totals for Water Division 6
Total No. of Stream Miles = 68.2
Total No. of Appropriations = 15
(Totals do not include donated/acquired water)

Source: Colorado Water Conservation Board, 2007, *Colorado's Water Supply Future, Statewide Water Supply Initiative—Phase 2*, Denver, Colo., Nov.