Economic Analysis
for
The Proposed Commercial Oil Shale Management Regulations

Introduction

By statute and executive order, an agency proposing a significant regulatory action is required to provide a qualitative and quantitative assessment of the anticipated costs and benefits of that action. Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of their assessment to the Office of Management and Budget (OMB) for review. A rule may be significant under Executive Order 12866 if it meets any of four criteria. A significant regulatory action is any rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities;

- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

The proposed rule does not create any serious issues with other agencies, materially alter entitlements, grants, user fees, or loan programs, or raise any novel legal or policy issues. The specific criterion that could apply to the proposed commercial oil shale management regulations is the potential annual effect on the economy of $100 million or more.

For a major rule, as defined by the Small Business Regulatory Enforcement Fairness Act (SBREFA), the agency must prepare an initial regulatory flexibility analysis when proposing a major rule. For SBREFA, a rule may be major if it meets any of three criteria. The specific SBREFA criterion that could apply to this rule is that the proposed rule may have an effect on the economy of $100 million or more in a year. SBREFA requires an agency to prepare a final analysis when issuing a final rule that will have a significant impact on a substantial number of small entities.

The economic analysis is to provide information allowing decision makers to determine that:

- There is adequate information indicating the need for and consequences of the proposed action;

- The potential benefits to society justify the potential costs, recognizing that not all benefits and costs can be described in monetary or even in quantitative terms, unless a statute requires another regulatory approach;

- The proposed action will maximize net benefits to society (including potential economic, environmental, public health and safety, and other advantages; distributional impacts; and equity), unless a statute requires another regulatory approach;

- Where a statute requires a specific regulatory approach, the proposed action will be the most cost-effective, including reliance on performance objectives to the extent feasible; and

- Agency decisions are based on the best reasonably obtainable scientific, technical, economic, and other information.

To provide this information, the economic analyses of economically significant rules will[1] contain three elements:

- A statement of the need for the proposed action;

- An examination of alternative approaches; and

- An analysis of benefits and costs.

There is no industry or even commercially adapted technology currently involved in the extraction of oil from shale. As such, obtaining verifiable inputs is problematic. For the most part, the Bureau of Land Management (BLM) has not attempted to independently forecast the critical inputs used in the analysis, but rather relied on forecasts and assumptions developed by other Federal agencies. Specifically, the production scenario and production cost assumptions are taken from the Task Force on Strategic Unconventional Fuels report on *America's Strategic Unconventional Fuels*[2]. The oil price projections are based on Department of Energy, Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007[3]. The following analysis is a simulated scenario-based analysis in both the estimation and conclusion based on these critical inputs.

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[1] Office of Management and Budget, Regulatory Analysis Circular A-4, September 17, 2003 (http://www.whitehouse.gov/omb/inforeg/circular_a4.pdf).

[2] *America's Strategic Unconventional Fuels Resources, Volume I, II and III*, Task Force on Strategic Unconventional Fuels, September 2007 (http://www.unconventionalfuels.org).

[3] Department of Energy, Energy Information Administration, Annual Energy Outlook 2007, Report #: DOE/EIA-0383(2007), February 2007 (http://www.eia.doe.gov).

Statement of Need

The Energy Policy Act of 2005 (42 U.S.C. 15927) (the Act) requires the Department of the Interior (DOI) to publish oil shale commercial leasing program regulations. The proposed regulation sets out the policies and procedures of the DOI for management of Federal oil shale resources. The regulations will establish competitive oil shale leasing procedures for implementing a long-term commercial oil shale leasing program based on multiple-use management planning that allows for orderly leasing and development of oil shale, when appropriate; minimizes any adverse social and environmental impacts of oil shale development; generates a fair economic return to the public based on market conditions; and balances National interests with state and local interests. As stated in the Act:

> *Congress 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.*

Section 369(c) of the Act requires the establishment of a research, development and demonstration program, and a commercial leasing program. The agency has already implemented a leasing effort to facilitate research and development of Federal oil shale resources. Procedures related to research and development leasing were established in the June 9, 2005 Federal Register notice (70 FR 33753).

Section (d)(1) of the Act requires that "*. . . 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.*" Section 369(d)(2) of the Act requires the Secretary of the Interior (Secretary) to issue final regulations establishing the commercial leasing program not more than six months after issuance of a programmatic environmental impact statement for a commercial oil shale leasing program on Federal lands.

Proposed Regulations

The proposed oil shale regulations are intended to establish competitive oil shale leasing procedures for implementing a long-term commercial oil shale leasing program based on principals of multiple-use management and one that allows for orderly leasing and development of publicly owned oil shale in a manner that minimizes any adverse social and environmental impacts of oil shale development; generates a fair economic return to the public based on market conditions; and balances national interests with state and local interests. The proposed regulations will provide operators with an opportunity to develop, in an environmentally sound manner, oil shale resources on Federal lands. In developing and implementing the commercial leasing program the DOI is charged with considering the interests of various stakeholders, including the affected states and local communities.

A number of aspects of the proposed oil shale management program are defined by statute. Potential lessee nominations are to be used to determine the level of interest in leasing and which tracts to offer for lease. In addition, leases are to be offered for sale. Commercial oil shale leases are to include diligent development requirements, have an annual rental rate of $2.00 per acre, and be subject to a production royalty. The royalties, fees, rentals, bonuses or other payments are to be established by the Secretary. These payments are to be set at a level that encourages development of the oil shale resources, while ensuring a fair return to the government. Beyond these specific requirements mentioned in the Act, the DOI is directed to develop the details of a leasing and management system. The proposed regulatory provisions address plan of development approval, inspection requirements, production reporting, royalty point of determination, fair market value determination, small tract leasing, and lease and reclamation bonding.

Many of the sections of the proposed rule contain requirements similar to regulatory provisions in the BLM's existing mineral leasing programs, namely, oil and gas, coal, and non-energy minerals. This includes basic components and processes common to all of the BLM's leasing programs under the Mineral Leasing Act (MLA), such as, pre-leasing, leasing, bonding, operational activities (including plan of development), post-leasing, reclamation, inspection and enforcement. The rationale for proposing specific provisions are discussed in the Preamble for the proposed rule. The following provides a brief section-by-section summary of the proposed rule.

Subpart 3900 – Oil Shale Management – Introduction

Part 3900 -- Oil Shale Management - General

This subpart would establish competitive oil shale leasing administrative procedures for implementing a long-term commercial oil shale leasing program.

The proposed rule would contain specific provisions required by Section 369 of the EP Act. Many of the sections of the proposed rule contain regulatory requirements similar to the regulations in the BLM's existing mineral programs namely, coal, non-energy leasable minerals, and oil and gas. In creating a regulatory framework for this proposed oil shale commercial leasing program, the BLM proposes to adopt certain basic components and processes common to the BLM's leasing programs. Most of the BLM's leasing programs are governed by the MLA. The regulations governing those programs and this program would include the following types of provisions: pre-lease exploration; leasing processes; bonding; operations (including plan of development); reclamation; and inspection and enforcement.

Section 3900.2 would contain the definitions and terms used in these proposed regulations. Many of the terms and definitions found in this section would be similar to terms and definitions in the regulations of other BLM mineral leasing programs. Because most of the terms and concepts in this section are well-established, this section of the preamble does not address each of the definitions, but focuses only on definitions for certain terms that directly affect the reader's understanding of the regulatory framework of the oil shale leasing program or that are unique to these regulations.

The term "commercial quantities" means production of shale oil quantities in accordance with the approved Plan of Development for the proposed project through the research, development, and demonstration activities conducted on the lease, based on and at the conclusion of which a reasonable expectation exists that the expanded operation would provide a positive return after all costs of production have been met, including the amortized costs of the capital investment.

The term "infrastructure" means all support structures necessary for the production or development of shale oil. The definition lists examples of the different types of support structures that the BLM would consider to be infrastructure. This term is defined in these proposed regulations because it is critical to the BLM's review of lease applications. Infrastructure impacts are a key component of the plan of operations that the BLM will review when undertaking various analyses such as those required by NEPA. Furthermore, the BLM believes that a detailed itemization of examples is necessary since installation of infrastructure is one of the proposed diligent development milestones.

The term "oil shale" means a fine-grained sedimentary rock containing:
(1) Organic matter which was derived chiefly from aquatic organisms or waxy spores or pollen grains, which is only slightly soluble in ordinary petroleum solvents, and of which a large proportion is distillable into synthetic petroleum; and
(2) Inorganic matter, which may contain other minerals. This term is applicable to any argillaceous, carbonate, or siliceous sedimentary rock which, through destructive distillation, will yield synthetic petroleum.

The BLM defined the term "production" to acknowledge the various technologies associated with operations for extraction of shale oil, shale gas, or shale oil by-products.

Section 3900.5 would leave a place holder for the information collection requirements in parts 3900-3930 under 44 U.S.C. 3501 et. seq. The BLM will add the OMB form number once we receive OMB's approval for information collection in the final regulations. The table in paragraph (d) of this section lists the subparts in the rule requiring the information and its title and summarizes the reasons for collecting the information and how the BLM would use the information.

Section 3900.10 would identify which lands would be subject to leasing under parts 3900 through 3930. Section 21 of the MLA authorizes the issuance of oil shale leases (30 U.S.C. 241(a)).

Section 3900.20 would address the right to appeal the BLM decisions issued under these regulations to the Interior Board of Land Appeals under 43 CFR part 4. This section would adopt standard appeals language found in the regulations of other BLM mineral programs.

Section 3900.30 would contain standard language providing that documents (i.e., applications, statements of qualification, plans of development and supporting information, etc.) required by these proposed regulations be filed in the proper BLM office with the required fees. The term "proper BLM office" is defined in the definitions section of this rule.

Section 3900.40 would address the multiple use mandate of FLPMA, by providing that the BLM's issuance of an exploration license or lease for the development or production of oil shale would not preclude the issuance of other exploration licenses or leases on the same lands for deposits of other minerals or other resource uses. This provision is similar to regulatory provisions in the BLM's other leasing programs, which also promote multiple use of the public lands.

Section 3900.50 would clarify the relationship of land use plans and NEPA to the BLM's proposed commercial oil shale leasing program. This section would provide that any lease or exploration license issued under these regulations would be issued under the decisions, terms, and conditions of a comprehensive land use plan. The land use planning process is the key tool used by the BLM to protect resources and designate uses for BLM-administered lands. Compliance with NEPA and land use planning is required prior to the BLM's issuing a lease or exploration license.

Section 3900.61 would address the procedures the BLM would follow concerning consent and consultation where the surface of public land is administered by other Federal agencies outside of the Department of the Interior and procedures for particular situations where the U.S. has conveyed title to or transferred control of the surface. Paragraphs (a) and (b) would address those procedures the BLM would follow concerning consent and consultation where the surface of public lands is administered by other agencies outside of the Department of the Interior. Paragraph (c) would provide procedures an applicant may pursue in challenging a decision issued by a particular agency outside of the Department of the Interior relating to special stipulations or refusal of consent. Paragraph (d) would not allow the BLM to issue a lease or license on National Forest Service lands without the consent of the Forest Service. Under paragraph (d), the BLM's decision whether to issue the lease or license is based on a determination as to whether the interests of the United States would best be served by issuing the lease or license. The provisions of this section closely mirror BLM regulations for oil and gas, coal, and non-energy leasable minerals. Paragraph (e) would provide that the BLM make the final decision as to whether to issue a lease or license in those cases not involving a Federal agency, where the United States has conveyed title to any state or political subdivision or agency, including a college or any other educational corporation or association, to a charitable or religious corporation or association, or to a private entity.

Section 3900.62 would address situations where the BLM may require lease or exploration license stipulations to protect lands and resources. Stipulations are site specific provisions that the BLM may add to standard lease or license terms prior to issuance for the purpose of protecting Federal resource values and mitigating impacts to other values identified in a NEPA document. Stipulations frequently restrict operations on the lease or permit by limiting surface disturbance for the purpose of protecting the environment. This includes the protection of wildlife, plants, and cultural or other resources. This provision is similar to those found in the BLM's other mineral leasing programs.

Subpart 3901 -- Land Descriptions and Acreage

Section 3901.10 would contain the BLM's requirements for land descriptions in applications or documents submitted to the BLM. This section is similar to the regulatory provisions addressing land descriptions found in other BLM leasing programs and would establish consistent standards for land descriptions in applications submitted to the BLM.

Sections 3901.20 and 3901.30 would incorporate the provisions of Section 369(j)(2) of the EP Act that 50,000 acres would be the maximum acreage of oil shale leases on public lands that any entity may hold in any one state and that the oil shale lease acreage would not count toward acreage limitations associated with oil and gas leases. Another 50,000 acres may be held on acquired lands. Since the provisions in this section relating to maximum acreage holdings are statutory, the BLM does not have the authority to revise the requirements in this section.

Subpart 3902 -- Qualification Requirements

Sections under this subpart would detail the various statutory requirements under Section 27 of the MLA relating to who can hold Federal oil shale leases and interests. These proposed regulations would mirror many of the qualification provisions of the BLM's other mineral leasing regulations, namely oil and gas (43 CFR subpart 3102), geothermal (43 CFR subpart 3202), coal (43 CFR subpart 3425), and non-energy leasable minerals (43 CFR subpart 3502).

Section 3902.10 would enumerate the requirements of the MLA relating to who is authorized to hold leases or interests in leases (30 U.S.C. 181, 352). These requirements have a longstanding statutory and regulatory history and are found in the regulations for the BLM's mineral leasing programs.

Sections 3902.21 and 3902.22 would explain the filing procedures for qualification documents, including when and where to file documents. Section 3902.21 would also require that all documentation submitted to the BLM as evidence of qualifications be current, accurate, and complete.

Sections 3902.23 through 3902.29 would detail the type of qualifications documentation that the BLM would require from:
(1) Individuals (section 3902.23);
(2) Associations, including partnerships (section 3902.24);
(3) Corporations (section 3902.25);
(4) Guardians or trustees (section 3902.26);
(5) Heirs and devisees (section 3902.27);
(6) Attorneys-in-fact (section 3902.28); and
(7) Other parties in interest (section 3902.29).

The requirements proposed in these sections are similar to the standard requirements of other BLM regulations to show evidence of qualifications to hold a lease under the MLA.

Subpart 3903 -- Fees, Rentals, and Royalties

For payments of required rental and royalties, sections 3903.20 and 3903.30 would address the acceptable forms of payment (section 3903.20) and where to submit payment for processing or filing fees, rentals, bonus payments, and royalties (section 3903.30). The acceptable forms of payment listed in section 3903.20 would mirror the forms of payment accepted in the BLM's other mineral leasing regulations.

Section 3903.40 would incorporate the requirement of Section 369(j) of the EP Act that the annual rental rate for an oil shale lease would be $2.00 per acre. Since the statute sets the rental rate, the BLM has no discretion to revise it.

Section 3903.51 would address the minimal annual production requirement that would apply to every lease. It also would discuss payments in lieu of production beginning with the 10th lease year. The BLM would determine the payment in lieu of annual production, but in no case would it be less than $4 per acre. Payments in lieu of production are not unique to this proposed rule. They are a requirement of other BLM mineral leasing regulations and the BLM believes they provide an incentive to maintain production.

Setting the payment in lieu of production at no less than $4 per acre should be an adequate payment to the Federal government to justify allowing the lessee to continue holding a lease absent production, but should not be high enough to cause the lessee to relinquish the lease. A payment in lieu of production of $4 per acre for the maximum lease size of 5, 760 acres equals a payment of $23, 040 per year.

In response to the ANPR, the BLM received comments expressing various ideas concerning minimum production amounts and requirements. The comments are summarized as follows:
(1) Minimum production should be 1,000 barrels a day;
(2) Minimum production should be based on the viability of the operation;
(3) Minimum production levels should be based on resource potential and production levels identified in the plan of development;
(4) Minimum royalties should be assessed at the end of the primary term;
(5) Minimum production should be based on a percentage of the projected resource base; and
(6) There should not be a minimum production requirement.

We agree with several of the commenter's suggestions. The suggestions to base minimum production on the approved plan of development and the specifics of the operation were incorporated into proposed sections 3930.30(c) and 3930.30 (d). The suggestions related to defining the minimum production on a percentage of the resource base were not incorporated into the proposed rule because of the difficulties associated with defining the recoverable resource, the variables associated with the different development technologies, and the differing kerogen content of the shales. We consider the suggestion that identified 1,000 barrels a day as the correct minimum production requirement too inflexible a standard because it does not allow for differences in shale quality and differences in extraction technology.

Section 3903.52 – Royalty Rates on Oil Shale Production

Section 3903.52 would establish a royalty rate for all products that are sold from or transported off of the lease area. The BLM recognizes that encouraging oil shale development presents some unique challenges compared to BLM's traditional role in managing conventional oil and gas operations. We received a wide range of comments presenting alternative royalty approaches as part of the ANPR process, and we address those comments below. However, while we have narrowed the range of options based on the ANPR comments, we have not yet settled on a single royalty rate for this proposed rule. Instead, we are presenting two royalty rate alternatives in the proposed rule (as outlined later in this section), and requesting public comment on those specific alternatives. In addition, we are considering a third alternative, a sliding scale royalty rate (also outlined in this preamble), and we are seeking public comment on the appropriate parameters for the sliding scale royalty rate should the BLM choose to adopt this alternative. We anticipate adopting one of these alternatives, or variations on one of these alternatives, at the final rule stage.

EP Act (Section 369(o)) directs the agency to establish royalties and other payments for oil shale leases that "shall-
(1) Encourage development of the oil shale and tar sands resources; and
(2) Ensure a fair return to the United States."

The market demand for oil shale resources based on the price of competing sources (e.g., crude oil) of similar end products is expected to provide the primary incentive for future oil shale development. Additional encouragement for development may be provided through the royalty terms employed for oil shale relative to conventional oil and gas royalty terms, but we recognize that such incentives must be balanced against the objective of providing a fair return to taxpayers for the sale of these resources. Through the ANPR process, the BLM initially examined a wide range of royalty options, including:

(1) 12.5 percent royalty rate on the first marketable product;
(2) 12.5 percent royalty rate on the value of the mined oil shale rock, as proposed in 1983;
(3) 8 percent royalty rate on products sold for 10 years with optional increases of 1 percent per year up to a maximum of 12.5 percent, similar to the rates established by the State of Utah in 1980;
(4) Initial 2 percent royalty to encourage production and a 5 percent maximum upon establishment of infrastructure;
(5) Sliding scale royalty rate tied to timeframes up to a maximum of 12.5 percent;
(6) Sliding scale royalty rate tied to production amounts up to a maximum of 12.5 percent;
(7) Sliding scale royalty rate with royalty rates tied to the price of crude oil;
(8) Royalty rate of 1 percent of gross profit before payout and royalty rate of 25 percent net profit after payout – (Canadian oil sands model);
(9) Royalty based on cents per ton as proposed in the 1973 oil shale prototype program; and
(10) Royalty based on British Thermal Unit (Btu) content as compared to crude oil.

In evaluating an appropriate royalty rate system for oil shale that would meet the dual EP Act objectives of encouraging development and ensuring a fair return to the government, the BLM also reviewed other Federal royalty rates for Federal minerals set by statute and under existing regulations administered by Department of the Interior bureaus, and royalty rates applied to oil shale production in other countries.

The royalty rates for other Federal energy minerals vary. Specifically, current royalty rates for Federal energy minerals under Department of the Interior leasing programs include:

(1) Onshore oil and gas (12.5 percent);
(2) Offshore oil and gas (16.67 percent), Gulf of Mexico Region (18.75 percent);
(3) Underground coal (8 percent);
(4) Surface coal (12.5 percent) and
(5) Geothermal (for new leases: 1.75 percent for the first 10 years and 3.5 percent thereafter. For leases issued prior to the EP Act, 10 percent on net proceeds after deductions).

Many of these programs allow for royalty rate relief under certain circumstances.

The BLM also looked at royalty applications for oil shale and similar unconventional fuels in other countries, including:
(1) For oil sands, Canada applies a royalty rate of 1 percent of the gross revenue before payout (before companies have recouped investment costs) with a 25 percent net profit royalty rate applied after payout;
(2) Australia has a 10 percent gross royalty on the value of the shale oil produced;
(3) Brazil applies a 3 percent gross royalty rate;
(4) Estonia does not have a royalty; and
(5) No information on a royalty rate for shale oil produced in China was available.

It should be noted that Canada produces oil from oil sands, not oil shale. The oil in the sands is the same as crude oil, but dispersed in sand. Extraction and processing is more expensive than for conventional crude oil production, but less expensive than is anticipated for oil shale. Canadian operators have never reached the payout point due to the continued capital expenditures in new equipment, so to date, Canada has received a 1 percent royalty on oil sands production.

Australian operations are using the Alberta Taciuk Process, which is the same type of technology currently used by the Oil Shale Exploration Company (OSEC) in Utah. Despite their 10 percent royalty rate, the Australian oil shale project (the Stuart Project) was heavily subsidized by the Australian government through other means (tax incentives). Even the government subsidies could not sustain oil shale operations in Australia. The last three operators went into bankruptcy after brief operations. Suncor, the founder of the Stuart Project and a successful developer of the Canadian tar sands, exited the Australian oil shale business after losing approximately one hundred million dollars[4]. For its Utah demonstration project, OSEC is also expected to test the Petrosix horizontal retort process, which is currently being used by Petrobras, Brazil, for oil shale operations.

Australia and Brazil are the only other known countries that are producing or have produced oil shale using the same technologies as in the U.S. Oil shale developmental efforts in China and Estonia are owned by their respective governments. Because no other country has yet achieved successful commercial oil shale operations and because of the wide variety of oversight and revenue structures employed in each country, the BLM's review of these systems did not identify a useful model for a royalty system to be used for oil shale development on Federal lands in the U.S.

In the ANPR, the BLM solicited public input on the royalty rate and point of royalty determination. The BLM's purpose for requesting comments was to solicit ideas on these royalty issues for a resource that has little or no history of commercial development.

There were approximately thirty-one entities that provided comments through the ANPR process that were specific to royalty rate and royalty point of determination. The comments suggested royalty rates that ranged from a royalty rate of zero to a royalty rate of 12.5 percent. Of the royalty-related comments, three suggested that the royalty be set

[4] Environmental News Service, July 22, 2005, www.ens-newswire.com.

at 12.5 percent, the same rate as in BLM's oil and gas program, while some comments described a 12.5 percent royalty rate as unreasonable. It is contemplated that the primary products produced from oil shale will compete directly with those from onshore oil and gas production, which has a 12.5 percent royalty rate. However, the BLM recognizes that the nature of potential oil shale operations differs from that of conventional oil and gas operations and that these differences may suggest the need for a royalty system other than the traditional flat rate of 12.5 percent used for conventional onshore oil and gas operations.

In determining the royalty rate for oil shale, it should be noted that there is a significant difference between oil shale mineral deposits and a conventional crude oil reservoir. As discussed in the Background section of this preamble, oil shale is a marlstone that contains no oil, but kerogen, that needs to be refined and converted to synthetic crude oil.

Currently, proposed processes to extract kerogen from an oil shale deposit are also considerably different, as well as labor and capital intensive. Oil shale is a solid rock that must be mined or treated in place to release the kerogen. Two of these processes are discussed in the Background section of this preamble.

Seven of the comments recommended that a "very low royalty rate" be established until after companies have recouped the costs of their investments (debt service and capital investment). Many among the seven recommended that a 1 percent royalty rate be the starting point, and they used the Canadian oil sands royalty scheme as an example. As discussed above, the BLM looked at royalty applications for oil shale and similar unconventional fuels in other countries. The Canadian tar sand model presents two challenges. First, because of the continual infusion of capital to acquire new equipment the payout point is never being reached. Secondly, because of the complexity of determining when payout may occur, such a royalty scheme is subject to easy manipulation and higher administrative costs. Therefore, the BLM considered the investment payout scheme as inconsistent with the premise of "a fair return" to the taxpayers as mandated in EP Act.

Three of the ANPR comments recommended that "royalties must be high enough" to support local communities and infrastructure; however, these comments did not provide specific royalty rates. Oil shale royalties are not designated for community and infrastructure support, but by statute are required to be split between the Federal Treasury and the states (30 U.S.C. 191). Presumably states could choose to direct a portion of the royalty revenues they receive to local community and infrastructure support, but that would be a state choice, and for the purposes of this rulemaking, these comments were not considered because they assume a use of royalty revenues not available under current law.

Three comments suggested that royalties should not be charged on hydrocarbons unavoidably lost or used on the lease for the benefit of the lease, but did not directly address the royalty rate issue.

One comment suggested the royalty be "based on the material as it exists naturally in the land, and as it is removed from the land." This comment seems to suggest that royalty should be based on mined raw shale. While the BLM acknowledges the inherent differences between an oil shale deposit and other deposits from which similar products can be produced, this suggestion was not considered because there is no known value for raw oil shale since there is no oil shale industry or an established market for raw oil shale. However, it should be noted that in 1983 the BLM proposed a rule to establish a royalty rate equivalent to 12.5 percent of the value of oil shale after mining or resource extraction and before processing, as determined by the BLM. The 1983 proposed rule was published on February 11, 1983 (48 FR 6510). The 1983 proposed rule provided that "the derivation methodology for this value shall be announced prior to the solicitation of bids." The proposed rule further stated that "the royalty rate shall, to the extent practicable, not be levied on any value added by the production process after the point of resource extraction." It would be unreasonable to adopt such a proposal today, due to the changes in extraction methodology (in situ versus ex situ). It would also be challenging to develop a fair and transparent process to calculate the royalty equivalent in today's economic environment, and no values were assigned to the mined or unprocessed rock and tonnage in the 1983 proposed rule. As noted, the 1983 proposed rule deferred the determination of those parameters to a later date.

In addition to ANPR comments received on royalty rates, the BLM looked at an initial 2 percent royalty to encourage production and a maximum 5 percent rate upon establishment of infrastructure. This method recognizes the high costs involved in producing shale oil. However, we dismissed this approach because of the difficulty involved in determining when necessary infrastructure is in place.

The BLM also considered the 8 percent royalty rate established by the State of Utah for state oil shale leases. It was determined that this rate represents the historic base royalty rate for solid fuel minerals on the State of Utah School and Institutional Trust Lands Administration lands--including asphaltic sands, uranium, and coal. To date, none of the state leases in Utah have been developed. Based on these facts, the BLM determined that there is not currently a sufficient basis for simply adopting the State of Utah's royalty rate for oil shale on Federal lands.

After examining the basis for setting rates, as suggested in the ANPR comments, the BLM determined that a flat 12.5 percent royalty rate for all future production may not allow oil shale to become competitive with traditional oil and gas development and therefore could be viewed as inconsistent with the requirements of EP Act. The BLM has decided to consider other alternatives in this proposed rule that may provide some additional incentive beyond that of a flat 12.5 percent royalty rate while also meeting the EP Act objective of providing a fair return to taxpayers.

Royalty Rate Alternatives Proposed for Further Consideration.

As noted previously, we are not proposing a single royalty system in the proposed rule. Based on the information the BLM has reviewed to date and considering the unique challenge of trying to set a royalty rate on oil shale production in light of the many uncertainties regarding the economics and technology of a potential future oil shale industry, we are instead presenting two different royalty rate alternatives in the proposed rule text:

1. A flat 5 percent royalty rate; and
2. A 5 percent royalty rate on a specific volume of initial production beginning within a prescribed timeframe, with a 12.5 percent rate applied thereafter.

In addition, we are seeking comment on the appropriate parameters for a third option: a two- three tiered sliding scale royalty based on the market price of competing products (e.g., crude oil and natural gas). A further explanation of each of these proposals is presented below. We are requesting the public to comment on these specific options.

Option 1. Flat 5 percent royalty.

Although mitigated somewhat by the much greater geographic concentration of oil shale resources, there is a significant difference between the energy value of oil shale and crude oil. On a per-pound basis, very high quality oil shale rock generates 4,300 Btu, coal generates an average of 10,600 Btu, while crude oil generates 19,000 Btu. Even wood has more heating capacity than oil shale rock, generating an average of 6,500 Btu. Applying the relative Btu value of oil shale to crude oil would result in a 2.6 percent royalty for oil shale. Using the same comparison to the royalty rate for underground coal would result in a 3.2 percent royalty rate for oil shale. In other words, it would require almost 5 times as much oil shale to produce the Btu value of crude oil and more than 2 times as much oil shale to produce the equivalent Btu value of coal.

The BLM looked at royalty rates on leases issued under Interior's 1973 Prototype Leasing Program. The prototype leases provided for royalties of $.12 per ton for oil shale with a quality of 30 gallons of oil per ton (30g/t) with the addition of $.01 for every increase in gallon per ton of oil shale. In 1973, the average price of a barrel of oil was $3.89. At $.24 per ton of 42g/t or one barrel/ton of oil shale, the royalty per barrel of oil would have been 5 percent. This rate is similar to the rate derived by comparing production costs to royalty rates as recommended by these proposed regulations.

The BLM also estimated what royalty rates for shale oil might be, based on comparisons of production costs for similar products. The cost of removing oil from shale rock is currently estimated to be two to three times higher than the current cost of producing conventional crude oil from onshore operations. The current estimated production cost for shale oil ranges from about $37.75-$65.21 a barrel. The production cost for conventional onshore crude is approximately $19.50 a barrel[5]. The table below compares

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[5] Energy Information Administration, Crude Oil Production, dated July 3, 2008. http://www.eia.doe.gov/neic/infosheets/crudeproduction.html and

the estimated cost of shale oil production for different technologies with the estimated cost of current onshore U.S. conventional oil production. The table also estimates what royalty rates for oil shale production might be, for the different production methods, compared to a 12.5 percent royalty rate for conventional oil production, if the higher anticipated production costs for oil shale are taken into account.

Technology	**Estimated shale oil production costs per barrel**	**Royalty calculation based on difference in production cost of a barrel of conventional oil versus shale oil**	**Adjusted royalty for shale oil**
Surface mining	$44.24	$19.50/$44.24 = 44.07% X 12.5% = 5.51 %	5.5 percent
Underground mining	$54.00	$19.50/$54 = 36.11% X 12.5% = 4.51%	4.5 percent
Fracturing and heating in place	$65.21	$19.50/$65.21 = 29.90 % X 12.5% = 3.74%	3.75 percent
Heating only in place	$37.75	$19.50/$37.75 = 51.65% X 12.5% = 6.46%	6.5 percent

Adjusting royalty rates based on higher anticipated production cost for oil from oil shale is not a new concept and is similar to the situation in the coal program where underground coal operations compete with surface coal operations, which have lower production costs. Congress addressed this disparity in production costs by allowing for different royalty rates for coal mined underground versus coal mined at the surface.

Please specifically comment on whether or not the anticipated costs of producing oil shale should be considered in establishing the royalty rate for all oil shale products and whether the BLM has chosen appropriate reference points for this production cost comparison.

Therefore, one alternative that considers the decreased energy content and increased production costs, while encouraging production and ensuring an appropriate return to the government is to set a flat royalty rate of 5%. This alternative assumes that oil shale will continue to be more expensive to produce for many years when compared to new conventional oil.

Option 2. A 5 percent royalty on initial production, with 12.5 percent thereafter.

This alternative would provide a reduced royalty rate of 5% as a temporary incentive for early production of oil shale (similar to royalty incentives offered to spur initial Outer Continental Shelf (OCS) deepwater production), but with the standard 12.5% onshore oil and gas royalty rate applying to all oil shale production after a set timeframe and a set

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http://www.eia.doe.gov/emeu/perfpro/tab_12.htm. The production cost at the time of analysis was approximately $18 per barrel.

amount of production has taken place. Like the other royalty options, this option would require oil shale lessees to pay royalties on the amount or value of all products of oil shale that are sold from or transported off of the lease. This section would explain that the standard royalty rate for the products of oil shale is 12.5 percent of the amount or value of production. However, under this option, for leases that begin production of oil shale within 12 years of the issuance of the first oil shale commercial lease, the royalty rate would be 5 percent of the amount or value of production on the first 30 million barrels of oil equivalent produced.

The advantage of this alternative over a flat 5% royalty (Option 1) is that it provides a better return to taxpayers on later production if oil prices remain high and oil shale production becomes competitive with new conventional oil projects. At $60/barrel, this would amount to roughly $1.8 billion in production allowed per lease at the lower 5% royalty rate, providing roughly a $135 million in savings per lease compared to using the standard onshore oil and gas royalty rate of 12.5%.

One potential downside to this alternative is that offering royalty incentives without regard to oil prices increases the likelihood that, if oil prices remain high, the government will sacrifice revenue without affecting actual oil shale development. For example, at $120/barrel, the savings would be worth $270 million, even though oil shale operations would be more profitable than at oil prices of $60/barrel.
Therefore, we are also requesting comment on whether, if this proposal were adopted in the final rule, the temporary 5% royalty on initial production should also be conditioned on crude oil and natural gas prices (similar to OCS deepwater royalty incentives) and if so, what oil and gas price level would trigger payment at the higher 12.5% rate if prices exceeded the threshold. We would also like comments on the 12 year timeframe for reduced royalty.

Option 3. Sliding scale royalty based on the market price of oil.
Two comments suggested a sliding scale royalty format. One comment specifically suggested a sliding scale royalty scheme based on a royalty schedule that varies with the price of conventional crude, as follows:
At $10 per barrel of conventional crude, the royalty rate should be zero;
At $15 per barrel, royalty should be 0.25 percent and should increase by 0.25 percent for every $5 per barrel increase up to $35 per barrel;
At $40 per barrel, the royalty rate should be 2 percent and should increase by 0.5 percent for every $5 per barrel increase in the price of conventional crude oil until the price of conventional crude reaches $100 per barrel; and
At $100 per barrel, royalty rate should be 8 percent and should remain at 8 percent at prices above $100 per barrel.

Another comment suggested two approaches to calculating royalty. The first part of the comment suggested that a simple way to accomplish royalty rates would be to index the value of barrels of oil equivalent to some percentage of NYMEX futures (say, 30 day average front month) prices. The commenter suggested that the index should be some fraction of the price, such as 50 to 65 percent. In the second part of the comment, the commenter suggested that, as an alternative to indexing, the BLM use a sliding royalty rate that is calculated on the difference between product price and the highest-cost production in the industry. The commenter cautioned that "there need to be provisions that deferred portions of the royalty do not reduce mineral lease payments to the States, if an escalating royalty rate is used."

The BLM, in consultation with the MMS, evaluated these variable royalty options, but decided that as presented, they would be highly complex, and therefore, cumbersome to administer. With price volatility in the crude oil market, an intricate sliding scale royalty scheme could make enforcing compliance very difficult for the MMS. In addition, there is uncertainty about the types of products that would be derived from oil shale refining. Royalties based on oil shale quality would also be difficult for the BLM to administer when attempting to verify production quantities. For instance, if oil shale is extracted in an underground heating system, it would be extremely difficult for the BLM to determine how much oil or other product came from a particular volume or area of in-place oil shale.

While the BLM and MMS are concerned about the complexity of administering some of the proposed sliding scale royalty proposals, we recognize that there is some merit to the sliding scale concept, and in a simpler form, a sliding scale royalty may prove useful in meeting the dual goals of encouraging production and ensuring a fair return to taxpayers from future oil shale development.

One of the concerns that has been expressed regarding oil shale development is that potential oil shale developers may be reluctant to make the large upfront investments required for commercial operations if they believe there is a chance that crude oil prices might drop in the future below the point at which oil shale production would be profitable (i.e., competitive with new conventional oil production). A sliding scale royalty system could allow the government to at least partially mitigate this development risk by providing for a lower royalty rate if crude oil prices fall below a certain price threshold. The basic concept is that in return for the government accepting a greater share of the price risk that an operator faces when prices are low (in the form of a lower royalty), the government would receive a greater share of the rewards (through a higher royalty) when prices are high.

The BLM has not decided on the specific parameters of a sliding scale royalty system, but is considering a simplified, two- or three-tiered system based on the current royalty rates already in effect for conventional fuel minerals and with a 5 percent royalty rate (Option 1) representing the first tier. The applicable royalty rate would be determined based on market prices of competing products (e.g., crude oil and natural gas) over a certain time period. If prices remain below a certain point during the applicable period, the royalty rate on oil shale products would be 5 percent for that period. If prices are above that range for the period, a higher royalty would be charged. In a three-tiered system, a third royalty rate would apply if prices rise above a second price threshold during the applicable period.

The BLM seeks comment on the specific parameters that could be applied to a sliding scale royalty system, should the BLM choose to adopt such a system in the final rule. More specifically, the BLM would like feedback on the following questions:

1. Should a sliding scale system include two or three tiers? Assuming a 5 percent royalty for the first tier, what would be appropriate royalty rates for the second and/or third tiers?
2. What are appropriate price thresholds to apply to each tier? Should the thresholds be fixed (in real dollar terms), or should they float relative to a published index?
3. Should the sliding scale apply to all products, or should nonfuel products pay a traditional flat rate?
4. Are there other ways to simplify a sliding scale royalty to reduce the administrative costs for BLM, MMS, and producers?

Under a sliding scale system, if prices fall below the lower range, producers would have a "safety net" in the form of the lower 5% royalty rate. Whether or not the lower royalty kicks in at some point, simply having it in place provides some added certainty for investors that would help encourage oil shale production. In return for this "safety net" that conventional oil and gas producers do not enjoy, oil shale producers would be required to pay a higher royalty rate(s) when crude oil and/or natural gas prices are high (and where oil shale is expected to be substantially more profitable).

There are a couple of advantages of this alternative. It reduces the risk for oil shale operators that oil prices might fall below the point that continued oil shale production would be economic. However, it also ensures an improved return to the government if prices remain within one of the higher expected ranges at which oil shale may be profitable. One disadvantage is that taxpayers accept a greater risk of lower returns if prices fall and remain well below the lowest threshold. However, with the lowest royalty rate step set at 5 percent, this risk is no greater than under a flat 5 percent royalty system (Option #1).

Other Royalty Issues

The BLM also received 5 comments specific to the royalty point of determination. Two of the comments suggested that royalty should be determined "at the point at which the oil product exits a process facility in a marketable state." One comment suggested that "the point of royalty determination be at the earliest point of liquid or gaseous product marketability." Another comment suggested that "the oil produced should be measured at the point at which the oil product exits a processing facility in a marketable state." The last comment did not provide a specific suggestion; rather, it stated that the BLM "must set the royalty rate and point of royalty determination with reference to the economic cost of emissions that would be created from developing, and then burning, the oil shale resource." After a careful evaluation of these comments and consultation with the MMS, under the proposed rule the royalty would be assessed on all products of oil shale that are sold from or transported off of the lease. This proposed point of royalty determination is similar to points of royalty determination for other Interior Department minerals programs.

The BLM received three ANPR comments relating to the oil shale research, development, and demonstration (R, D and D) program. One comment encouraged the BLM to "continue the existing BLM R, D and D leasing program for access to oil shale for companies wishing to test unproven technologies." Another comment suggested that the BLM "should let several 'boutique' small companies with large R, D and D budgets to develop a small number of sites," on the condition that those companies "would have to agree to allow their findings to be shared." The last comment specifically requested that the "commercial leasing regulations make clear that the BLM will not hold a commercial lease sale for Federal oil shale resources until successful technologies have been developed and demonstrated on R, D and D leases." These proposed regulations do not address the first comment. The Secretary has discretion under the EP Act to offer additional tracts for R, D and D leasing. These regulations do not decide whether additional R, D and D leasing is necessary. Although the BLM could require that proprietary information be made public as a condition of further R, D and D leasing, we believe that the industry would not be interested in leasing under such conditions. Furthermore, as previously explained, these regulations do not address any new R, D and D leases. The BLM could not incorporate the third comment, because it suggested a limitation that is inconsistent with the terms of the EP Act. Sections 369(c) and 369(e) of EP Act authorize the commercial leasing of oil shale following promulgation of regulations and consultation with interested parties without the limitations sought by the comment.

Finally, it is important to note that the proposed rule allows the Federal Government to readjust royalty rates on leases after the first 20-year term.
Currently, there is no oil shale industry and the oil shale extractive technology is still in its rudimentary stages; as such, commercial oil shale production does not exist anywhere in the world. As research and development of oil shale technology progresses, the BLM will have adequate time to reexamine and readjust royalty rates for oil shale production, either up or down. Please specifically comment on the time necessary to develop an oil shale industry.

The BLM is proposing alternatives for the royalty rate and the products on which the royalties will be collected. The BLM anticipates selecting one of these alternatives, or based on public comment and further analysis, variations on these alternatives in the final rule in order to provide predictability for the industry and ease of administration both for the United States and for payers. However, the Department is not proposing corresponding MMS valuation regulations at this time. Because the oil shale industry is still in the research and development phase, it would be speculative to predict whether the industry as it matures would predominantly sell from its leases mined solid oil shale, shale oil, synthetic petroleum, shale gas, natural gas, or products in several different forms or stages of processing. It is also difficult to predict whether or when multi-buyer/multi-seller markets would develop that would provide FMV pricing for products of oil shale. Therefore, the MMS will promulgate royalty valuation regulations before oil shale leases are required to begin paying production royalties under this rule.

To the extent possible, the MMS will ensure that any oil shale valuation regulation is consistent with other valuation regulations and will incorporate principles of simplicity, early certainty, and reduced administrative costs in the oil shale valuation regulations it promulgates. For example, the MMS could promulgate regulations similar to the current Federal oil valuation regulation to value crude oil produced from oil shale. Under this regulation, the value of oil sold at arm's-length would be based on gross proceeds less allowable costs of transporting oil to the point of sale. The value of oil not sold at arm's-length would be based on a market index price or the affiliate's arm's-length resale price. In both arm's-length and non-arm's-length situations, the regulations provide for adjustments for location, quality, and transportation allowances. Further, lessees also can petition for alternate valuation agreements that are situation specific when regulatory provisions do not apply.

Royalties would not be payable on potentially valuable minerals or inorganic matter that are not sold or transported off the lease for commercial purposes. Those materials would be considered waste, and would be subject to management and reclamation requirements as provided in the lease or in an approved plan of development.

The Department seeks comments on what future royalty valuation regulations need to contain. In particular, the Department is seeking comments on the potential types of oil shale products, the most equitable and practical point and method to determine the value on which to apply the royalty rate, and whether there are or should be opportunities to determine value by market proxy or indices. The Department also seeks comments on alternative approaches to valuation and royalty rates.

In the economic analysis for this rule, the BLM analyzed the royalty implications of a range of royalty rates. Specifically, the BLM conducted a simulation-based analysis to estimate the revenue, profit, and royalty implication of a production scenario[6] using three discount rates (7 percent, 3 percent, and 20 percent), three world crude oil price projections (EIA's 2007 reference, high, and low price projections[7]), and six different royalty rates (1 percent, 3 percent, 5 percent, 7 percent, 9 percent, and 12.5 percent). The likelihood of a company, in the face of numerous technological challenges, having the incentive to develop Federal oil shale reserves and experiencing economic success will depend on a number of factors. However, because the simulated scenario analysis is based on a given production scenario and set production costs, the analysis did not assist in determining the project(s) economic viability due to the royalty rate applied. The analysis did, however, clearly identify world oil price as a critical variable determining a project's economic viability. Under EIA's 2007 low oil price projection all operations

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[6] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, September 2007, page III-17, Table III- 4. Potential Oil Shale Development Schedule – Base Case, (http://www.unconventionalfuels.org).
[7] Department of Energy, Energy Information Administration, Annual Energy Outlook 2007, Report #: DOE/EIA-0383(2007), February 2007.

are assumed to be uneconomic based on the set production costs used in the analysis of the rule.

Section 3903.53 would require the filing of documentation of all overriding royalties associated with a lease and would require that the filing must occur within 90 days of the date of execution of the assignment. This section is similar to that of the BLM's other mineral leasing programs.

Section 3903.54 would contain the requirements for filing an application for waiver, suspension, or reduction of rental or payment in lieu of production, or a reduction in royalty, or waiver of royalty in the first 5 years of the lease. As with the BLM's other mineral leasing programs, this section is intended to encourage the maximum ultimate recovery of the mineral(s) under lease. This section is similar to the BLM's coal leasing regulations and similarly includes a case-by-case processing fee under 43 CFR 3000.11.

Section 3903.60 would provide that late payments or underpayment charges would be assessed under MMS regulations at 30 CFR 218.202.

Subpart 3904 – Bonds and Trust Funds

Sections in this subpart would address the requirements associated with bonding and trust funds, including the:

(1) Types of bonds the BLM requires and when bonds would be required (section 3904.10);
(2) When and where bonds would be filed (sections 3904.11 and 3904.12);
(3) Acceptable types collateral for personal bonds (section 3904.13);
(4) Individual lease, exploration license, and reclamation bonds (section 3904.14);
(5) Amount of bond coverage (section 3904.15);
(6) Default (section 3904.20); and
(7) Long-term water treatment trust funds (section 3904.40).

Since all of the BLM's mineral leasing programs require bonds, the requirements in subpart 3904 would be similar to the regulatory provisions in the BLM's other mineral leasing programs. The bonding requirements in this rule are consistent with the bonding requirements under the BLM's mining law program. Both programs require that bonds cover the full cost of reclamation. Both programs also allow for the use of long-term trust funds as a mechanism to address potential long-term water issues.

Bonding ensures performance at a cost up to the bond amount in the event of default by a lessee or licensee. Sections of this subpart would establish that the BLM would require two types of bonds; a lease or exploration license bond and a reclamation bond. This subpart would also explain that reclamation bonds would be required to be in an amount sufficient to cover the entire cost of reclamation of the disturbed areas as if they were to be performed by a contracted third party.

Section 3904.10 would provide that prior to lease or an exploration license issuance, the BLM would require a lease or exploration license bond for each lease or exploration license to cover all liabilities on a lease, except reclamation, and all liabilities on a license. The bond would be required to cover all record title owners, operating rights owners, operators, and any person who conducts operations on or is responsible for making payments under a lease or license. This section would also require the lessee or operator to file a reclamation bond to cover all costs the BLM estimates would be necessary to cover reclamation on a lease. This is similar to the requirement found in other BLM mineral regulations.

Section 3904.11 would require the lessee or operator to file a lease bond prior to issuance of a lease, file a reclamation bond prior to approval of a plan of development, and file an exploration bond prior to exploration license issuance. This section is similar to other BLM bonding regulations as it would require the filing of a bond before liabilities may accrue.

Section 3904.12 would require that a copy of the bond with original signatures be filed in the proper BLM office and section 3904.13 would describe the different types of bonds that the BLM would accept. These sections are similar to the bonding regulations in other BLM mineral leasing programs.

Section 3904.13 would address the types of personal and surety bonds the BLM would accept. Personal bonds would be limited to pledges of cash, cashier's check, certified check, or U.S. Treasury bond. The BLM state offices would list qualified sureties for bonds.

Section 3904.14 would provide that the BLM will establish bond amounts on a case-by-case basis. These regulations would set the minimum lease bond amount at $25,000. Although the minimum lease bond amount is greater than that required in other BLM mineral leasing programs, the BLM believes that it is justified because the potential liability may be greater and there are still some unknowns. Reclamation and exploration bond amounts would be established to cover the costs of reclamation as if it were to be performed by a contracted third party.

Past oil shale operations have required extensive reclamation, and this has demonstrated the need to have a reclamation bond that covers the full cost of reclamation. By requiring that the bond equal the estimated costs of having a third party perform the reclamation, the BLM anticipates that the cost of reclamation would be covered.

This section would provide that the BLM may enter into agreements with states to accept a state-approved reclamation bond to satisfy the BLM's reclamation requirements and protect the BLM to the extent the bond is adequate to cover all the operator's liabilities on Federal, state, and private lands. This would avoid duplicate procedures and the inconvenience and cost of filing separate bonds with both the state and the BLM. Such agreements were recommended by state representatives at the BLM listening sessions and are also addressed in regulatory provisions of other BLM mineral leasing programs.

Section 3904.15 would explain that under this proposed rule the BLM may increase or decrease the bond amount if it determines that a change in coverage is warranted to cover the costs and obligations of complying with the requirements of the lease or license and these proposed regulations. This section would also explain that the BLM would not decrease the bond amount below the minimum established in section 3904.14(a). This section would require the lessee or operator to submit a revised cost estimate of the reclamation costs to the BLM every three years after reclamation bond approval. If the current bond would not cover the revised estimate of the reclamation costs, the lessee or operator would be required to increase the reclamation bond amount to meet or exceed the revised cost estimate. This section is consistent with the bonding regulations that currently exist for other BLM minerals programs.

Section 3904.20 would describe what actions the BLM would take in the event of a default payment from a lease, exploration, or reclamation bond to cover nonpayment of any obligations that were not met. It also would require the bond to be restored to the pre-default level. This section is similar to sections in the other BLM mineral regulations regarding default.

Section 3904.21 would allow the termination of the period of liability of a bond. The BLM will not consent to the termination of the period of liability under a bond unless an acceptable replacement bond has been filed or until all of the terms and conditions of the license or lease have been fulfilled. Termination of the period of liability of a bond would end the period during which obligations continue to accrue, but would not relieve the surety of the responsibility for obligations that accrued during the period of liability.

Section 3904.40 would establish trust funds or other funding mechanisms to ensure the continuation of long-term treatment to achieve water quality standards and for other long-term, post-mining maintenance requirements. Experience in other mineral programs has shown the need for a mechanism to ensure the long-term treatment of water. This provision is similar to regulations in the BLM's mining law program under 43 CFR 3809.552 and is designed to address similar long-term water protection issues. In determining whether a trust fund will be required, the BLM will consider the following factors:

(1) The anticipated post-mining obligations (PMO) that are identified in the environmental document and/or approved plan of development;
(2) Whether there is a reasonable degree of certainty that the treatment will be required based on accepted scientific evidence and/or models;
(3) The determination that the financial responsibility for those obligations rests with the operator; and
(4) Whether it is feasible, practical, or desirable to require separate or expanded reclamation bonds for those anticipated long-term PMOs.

The determination that a trust fund is needed and the amount needed in the fund may be made during review of the proposed plan of development or later as a result of further inspections or reviews of the operations.

Subpart 3905 -- Lease Exchanges

This subpart would allow the BLM to approve oil shale lease exchanges.

Section 3905.10 would explain that the BLM would approve a lease exchange if it would facilitate the recovery of oil shale and it would consolidate mineral interests into manageable areas. It also states that oil shale lease exchanges would be governed by the regulations under 43 CFR part 2200. Section 206 of FLPMA authorizes land exchanges of interests in Federal lands for non-Federal lands (43 U.S.C. 1716).

Part 3910 -- Oil Shale Exploration Licenses

The regulations proposed under this part would address exploration licenses. An exploration license would allow a licensee to enter the Federal land covered by an exploration license and explore for minerals, but it would not authorize the licensee to extract any minerals, except for experimental or demonstration purposes. Since regulatory provisions for the issuance and approval of exploration licenses are common to the BLM mineral leasing programs, this part would contain similar regulatory provisions, particularly with respect to:
(1) Lands that are subject to exploration (section 3910.21);
(2) Lands managed by agencies other than the BLM (section 3910.22);
(3) Requirements for conducting exploration activities (section 3910.23);
(4) Application procedures (section 3910.31);
(5) Environmental analysis (section 3910.32);
(6) License requirements (section 3910.40);
(7) Issuance, modification, relinquishment, termination, and cancellation (section 3910.41);
(8) Limitations on exploration licenses (section 3910.42);
(9) Collection and submission of data (section 3910.44); and
(10) Surface use (section 3910.50).

Section 3910.21 would authorize the issuance of oil shale exploration licenses on all Federal lands subject to leasing under section 3900.10, except lands within an existing oil shale lease or in preference right lease areas under the R, D and D program. This type of limitation on which lands the BLM may issue an exploration license is consistent with that of other BLM minerals exploration regulations.

Section 3910.22 would make it clear that the consent and consultation procedures under section 3900.61 that apply to leases also apply to exploration licenses. The BLM would issue these licenses under the terms and conditions prescribed by the surface managing agency concerning the use and protection of the nonmineral interests in those lands. Section 3910.22 is similar to regulations for BLM's other mineral leasing regulations requiring consent and consultation for exploration licenses.

Section 3910.23 would require the operator to have a lease or license before conducting any exploration activities on Federal lands. This section would also allow that under an exploration license small amounts of material may be removed for testing purposes only; however, any material removed cannot be sold. This is similar to regulations in other BLM mineral programs that recognize that some removal of material is necessary for testing purposes.

Section 3910.31 would identify specific requirements for filing an application for an exploration license. Application requirements under this section would include:
(1) Submission of a nonrefundable filing fee;
(2) Description of lands covered by the application;
(3) An exploration plan;
(4) Compliance with maximum acreage limitations for an exploration license; and
(5) Submission of information to prepare a notice of invitation for other parties to participate in exploration.

Mirroring the coal regulations, this section would establish an acreage limit of 25,000 acres as the maximum size allowable for an exploration license. As is the case for other BLM leasing programs which provide for exploration licenses, there would be no required application form. The $295 filing fee for an exploration license is based on the current filing fee for a coal exploration license. The BLM anticipates that the time required to process an oil shale exploration license would be similar to that for a coal exploration license, and therefore believes the same filing fee is justified.

Section 3910.32 would require the BLM to perform the appropriate NEPA analysis before issuing an exploration license. The section also explains that the BLM would include in an exploration license terms and conditions to mitigate impacts to the environment analyzed in a NEPA document and to protect Federal resource values of the area and to ensure reclamation of the lands disturbed by exploration activities.

Section 3910.40 would provide that a licensee must comply with all applicable Federal laws and regulations and the terms and conditions of the license and approved exploration plan as well as applicable state and local laws not otherwise preempted by Federal laws, such as FLPMA.

Section 3910.41 would explain provisions relating to the administration of the exploration license, including the license term, the effective date of an exploration license, conditions for approval, and provisions relating to the modification, relinquishment, and cancellation of an exploration license. Like exploration licenses for other BLM mineral leasing programs, the term of an exploration license would be 2 years. The requirements proposed here for oil shale exploration licenses are similar to existing requirements in regulations relating to exploration licenses in other BLM minerals programs, particularly coal.

Section 3910.42 would provide that issuance of an exploration license would not preclude the issuance of a Federal oil shale lease for the same area. This section would also make it clear that if an oil shale lease is issued for an area covered by an exploration license, the BLM would cancel the exploration license effective the date of lease issuance.

Section 3910.44 would address collection and submission of data relating to an exploration license and would include provisions relating to confidentiality of data. This section is similar to provisions in other BLM minerals programs.

Section 3910.50 would address the issue of surface damage resulting from exploration operations and would require that exploration activities not unreasonably interfere with or endanger any other lawful activity on the same lands or damage any surface improvements on the lands. This is similar to other BLM minerals regulations that address surface use.

Part 3920 – Oil Shale Leasing

The foundation for the proposed oil shale leasing program would be a competitive leasing process similar to the BLM's coal leasing program. Prior to making areas available for consideration for leasing through a competitive lease sale, the BLM is proposing a 2-step process that would begin with a call for expressions of leasing interest (section 3921.30), to be followed by a call for applications (section 3921.60) if the BLM determines that there is interest in a competitive lease sale. In addition to contributing to the orderly development of the resource, this process would facilitate compliance with NEPA by focusing the analysis on areas in which there is active interest in obtaining a lease.

Subpart 3921 -- Pre-Sale Activities

The sections under this subpart would contain regulatory provisions relating to pre-leasing activities. Many of the sections would be similar to existing provisions of other BLM mineral leasing programs, particularly coal.

Section 3921.10 would explain that a BLM State Director may announce in the Federal Register a call for expressions of interest for those areas identified in the land use plan as available for oil shale leasing.

Section 3921.20 clarifies that the appropriate NEPA analysis must be prepared for the proposed leasing area under the Council on Environmental Quality's regulations at 40 CFR parts 1500 through 1508 and Department of the Interior methods and procedures developed pursuant to NEPA.

Section 3921.30 would provide that the notice announcing calls for expressions of leasing interest would be published in the Federal Register and in at least 1 newspaper of general circulation in the affected state. The notice would allow a minimum of 30 days to submit expressions of leasing interest, including a legal land description and other specified information.

Section 3921.40 would require that the BLM notify the appropriate state governor's office, local governments, and interested Indian tribes of their opportunity, after the BLM receives responses to the call for expression of leasing interest, to provide comments regarding the responses and other issues related to oil shale leasing. The BLM included this requirement in the proposed rule in response to discussion at the three listening sessions with the governors' representatives.

Section 3921.50 would explain that after analyzing expressions of leasing interest, the BLM would determine a geographic area for receiving applications to lease. This section would also explain that the BLM may add lands to those areas identified by the public in the expressions of leasing interest.

Under proposed section 3921.60, the BLM's call for applications would be published in the Federal Register and would identify the geographic area available for application under proposed subpart 3922. Under this section, the public would have at least 90 days to submit applications for lease.

Subpart 3922 -- Application Processing

The sections under this subpart would contain regulatory provisions relating to application requirements, including:
(1) A nonrefundable case-by-case processing fee (section 3922.10);
(2) Content of application (section 3922.20);
(3) Additional information (section 3922.30); and
(4) Tract delineation (section 3922.40).

These provisions are similar to existing regulations of other BLM mineral leasing programs.

Section 3922.10 would require an applicant nominating a tract for competitive leasing to pay a cost recovery or processing fee that the BLM will determine on a case-by-case basis as described in 43 CFR 3000.11 and as modified by provisions of section 3922.10. The section would provide that the applicant who nominates a tract will pay to the BLM the processing costs that the BLM incurs up to the publication of the competitive lease sale notice. That fee amount would be included in the sale notice. If the applicant is the successful bidder, the applicant would then also pay all processing costs the BLM incurs after the date of the sale notice. Payment of all cost recovery fees is required prior to lease issuance.

If the successful bidder is someone other than the original applicant, the successful bidder would be required to submit an application under section 3922.20 within 30 days after the lease sale and would be responsible for paying to the BLM the fee amount included in the sale notice. In such circumstances, the BLM will refund the fees the original applicant paid to the BLM. The successful bidder would also be responsible for any processing costs the BLM incurs after the date of the sale notice. If there is no successful bidder, the applicant would be responsible for processing costs, and there would be no refund.

With respect to costs incurred relating to the NEPA analysis to support a competitive lease sale, the BLM processing fees noted in the sale notice would include, if applicable, the BLM's costs associated with preparation of the NEPA analysis, which may include BLM costs incurred in contracting with a third party to perform the NEPA analysis. In cases where there are several applications that have been filed for the same area, it is likely that the BLM would prepare a single NEPA analysis, which would address issues related to environmental impacts identified in all applications that were filed in response to the call for applications.

In the case where the successful bidder for a tract is not the original applicant, the successful bidder would be responsible for paying the fee noted in the sale notice and any additional BLM processing costs, including any additional NEPA analysis.

For example, in the case where a successful high bidder is not the original applicant and the technology that the successful bidder proposes to use was not previously analyzed in the NEPA analysis, the successful bidder would be responsible for paying for the cost of that NEPA analysis and any additional NEPA analysis that would be necessary.

It should be noted that an applicant would not be reimbursed for moneys the applicant (and not the BLM) may pay directly to third persons to perform studies, including any required analyses under NEPA.

Under section 3922.10, the BLM is proposing adopting case-by-case processing fees for applications that would mirror case-by-case fee requirements applicable to the leasing of coal and non-energy leasable minerals offered through competitive lease sales. The BLM's minerals material sales regulations also contain case-by-case processing fees. Case-by-case fees would allow the BLM to recoup its processing costs by charging an applicant the reasonable costs the BLM incurs in processing a particular application. Cost recovery is authorized under the Independent Offices Appropriation Act of 1952, as amended, 31 U.S.C. 9701, which states that Federal agencies should be "self-sustaining to the extent possible" and authorizes agency heads to "prescribe regulations establishing the charge for a service or thing of value provided by the agency." The BLM also has specific authority to charge fees for processing applications and other documents relating to public lands, including Environmental Impact Statements (EISs), under Section 304(b) of FLPMA (43 U.S.C. 1734(b)). Cost recovery policies are explained in Office of Management and Budget Circular A-25 (Revised), entitled "User Charges." The general Federal policy stated in Circular A-25 (Revised) is that a charge will be assessed against each identifiable recipient for special benefits derived from Federal activities beyond those received by the general public.

Additionally, this section states that the BLM will not issue a lease offered by competitive sale without having first received an application from the successful bidder under section 3922.20. Under section 3922.10(b)(5) a successful bidder at a competitive lease sale who was not an applicant must file an application within 30 calendar days after the lease sale.

Section 3922.20 would identify specific information that an applicant would be required to include in a lease application to enable the BLM to have sufficient information to prepare the appropriate NEPA analysis to evaluate the impacts of proposed leasing. The amount of information requested as part of an oil shale lease application differs from other mineral leasing programs because the methodology for recovering oil shale is not as standardized as it is for more conventional fuels. The NEPA compliance documents at this stage in the leasing process are necessary because the PEIS addresses land use planning decisions and not leasing decisions and was unable to anticipate with any certainty the effects of oil shale leasing development due to the newness of the industry.

The possible oil shale development technologies are very different from conventional mining methods associated with other BLM minerals programs, as are the impacts associated with each. The technologies are yet to be proven, or commercially viable and their associated impacts are unknown. Because the BLM is presently uncertain of the mining methods (and associated impacts) that may be used for oil shale development, additional NEPA analysis will be performed during the application and leasing process. When required by applicable law, the BLM will conduct site-specific NEPA analysis, including a period of public review, to evaluate the impacts on known resource values on the lands in any application. Although no specific form is required, information the applicant would be required to provide includes, but is not limited to:
(1) Proposed extraction method (including personnel requirements, production levels, and transportation methods) and estimate of the maximum surface area to be disturbed at any one time;
(2) Sources and quantities of water to be used and treatment and disposal methods necessary to meet applicable water quality standards;
(3) Air emissions;
(4) Anticipated noise levels from proposed development;
(5) How proposed lease development would comply with all applicable statutes and regulations governing management of chemicals and disposal of waste;
(6) Reasonably foreseeable social, economic, and infrastructure impacts of the proposed development on the surrounding communities and on state and local governments;
(7) Mitigation of impacts on species and habitats; and
(8) Proposed reclamation methods.

Section 3922.30 would provide that the BLM could request additional information from the applicant, and explain that failure to provide the best available and most accurate information might result in suspension or termination of processing of the application or in a decision to reject the application. The BLM's ability to obtain additional information at this stage is essential to the NEPA analysis to support leasing. Failure to provide the needed information would have a direct impact on the adequacy of the NEPA analysis and therefore could greatly impact the BLM's decision to proceed with a lease sale.

Section 3922.40 would make it clear that the purpose of tract delineation for a competitive lease sale is to provide for the orderly development of the oil shale resource. This section would also clarify that in addition to adding or deleting lands from an area covered by an application, where lands covered by applications overlap, the BLM may delineate those lands that overlap as separate tracts. The BLM may delineate tracts in any area acceptable for further consideration for leasing, regardless of whether it received expressions of interest or applications for those areas. The need to delineate tracts for adequate development of the mineral resource is recognized in all the BLM mineral leasing programs, and provisions similar to this are contained in the other BLM mineral leasing regulations.

Subpart 3923 – Minimum Bid

Section 3923.10 would implement the policy of the United States under Section 102(a) of FLPMA (43 U.S.C. 1701(a)(9)) that the Federal government should receive a FMV for leasing its minerals. Also, Section 369(o) of the EP Act which requires that payments for leases under that section must ensure a fair return to the United States. Under section 3924.10 of the proposed rule, the BLM sales panel would determine if the high bid reflects the FMV of the tract, which we equate to fair return. We anticipate that the sales panel will analyze the bids and make a determination, taking into account, among other things, the geology, market conditions, mining methods, and industry economics.

The BLM recognizes the difficulty in determining a value for a resource (oil shale) that has tremendous potential, but has not yet been proven to be economic to develop. The risk of setting pre-sale FMVs that are too high and would discourage development of a commercial leasing program is very real. The BLM is also aware that the oil shale industry is presently in the research and development stage and comparable lease sales might be rare or unavailable when leasing first occurs under these regulations, but this will not always be the case. Competitive lease sales of Federal oil shale leases in the 1970s resulted in bids of $10,000 per acre, or higher, indicating that even though development risks are high, the potential reward is also high. Both the economic and the technological circumstances have changed since the 1970s, but the vast quantities of oil shale within the Federal acreage weigh in favor of high minimum bid amounts. For comparison purposes, the coal program has a minimum bid amount of $100 per acre and the oil and gas program has a minimum bid amount of $2 per acre. This section would set a minimum bid of $1,000 per acre, but the BLM invites comments supporting reasonable alternative minimum bid amounts.

Subpart 3924 – Lease Sale Procedures

Provisions of this subpart would identify the process by which tracts of land would be made available for competitive lease sale. The BLM proposes to lease oil shale through a competitive bidding leasing procedure that would mirror competitive lease sales procedures currently in place for other solid minerals leasing programs, particularly coal.

Section 3924.5 would detail the contents of the sale notice that the BLM would publish in the Federal Register and newspapers of general circulation in the area of the proposed lease. The purpose of the notice is to alert the public that the BLM will be holding an oil shale lease sale and to provide enough of the details about the proposed lease terms and conditions, lease area, and leasing limitations for the public to make an informed decision whether to participate in the lease sale. This section would be similar to other BLM mineral leasing regulations that require notification of the lease sale and is a necessary part of the oil shale leasing program.

Section 3924.10 would detail competitive lease sale procedures, including receipt and opening of sealed bids, submission of the one-fifth of the amount of the bonus bid, requirements for future submission of remaining installments of the bonus bid, and post-sale procedures for determining the successful bidder. This section would also address the actions of the sale panel in determining whether or not to accept the high bid, including a FMV determination. This section is similar to the BLM's competitive leasing regulations for coal and non-energy leasable minerals. The BLM is proposing to adopt this process because it has been successful in these other mineral leasing programs and because we believe this process is appropriate for oil shale leasing.

The BLM will rely on the appraisal process to estimate the fair market value (FMV) for commercial oil shale leases under the proposed regulations. An appraisal is an unbiased estimate of the value of property. The appraisal process is a systematic approach to property valuation. It consists of defining data requirements, assembling the best available data, and applying an appropriate appraisal method. The principles of property valuation are presented in the Uniform Appraisal Standards for Federal Land Acquisitions and in The Appraisal of Real Estate. The term "fair market value" is defined in the Uniform Appraisal Standards for Federal Land Acquisitions as the amount in cash, or on terms reasonably equivalent to cash, for which in all probability the property would be sold by a knowledgeable owner willing, but not obligated, to sell to a knowledgeable purchaser who desired, but is not obligated, to buy.

In ascertaining that figure, consideration should be given to all matters that might be brought forward and substantial weight given in bargaining by persons of ordinary prudence. Factors that will affect the market value of an oil shale lease include the lease terms which encompass rental and royalty obligations. The bonus bid for the lease must be equal or greater than the lease FMV.

There are three methodologies generally used in appraising real property: the comparable sales approach, income approach, and replacement cost approach. Normally, the replacement cost approach is not applied to appraisals involving property such as mineral leases.

In the comparable sales approach, the value of a property is estimated from prior sales of comparable properties. The basis for estimation is that the market would impute value to the subject property in the same manner that it determines value of comparable competitive properties. When reliable comparable sales data are available, it generally is assumed that the comparable sales approach will provide the best indication of value.

In the income approach, the value assigned to the property is derived from the present worth of future net income benefits. If sufficiently similar sales are not available, the FMV determination will generally rely on the income approach.

The FMV determination follows a pre-existing valuation standard, which utilizes the circumstances of place, time, the existence of comparable precedents, and the evaluation principles of each involved party. In determining the FMV under this rule, our determination would be based on comparison with identical or similar past, actual, or expected services and goods relating to oil shale. It is the policy of the United States, stated in Section 102(a) of FLPMA (43 U.S.C. 1701(a)(9)) and Section 369(o)(2) of the EP Act, that the United States receive FMV for the issuance of Federal mineral leases.

In the ANPR, the BLM solicited public input on the process for bid adequacy evaluation and minimum acceptable lease bonus bid. The BLM's purpose for requesting comments on the FMV it should receive for lease tracts was to solicit ideas on how FMV would be determined for a resource that has little or no history of comparable sales.

The public comments received were primarily concerned with the need to receive an appropriate value for the lease. The BLM received comments from 6 entities related to this question, specifically mentioning that: a FMV determination needs to reflect private sector valuations; competitive bidding should establish a lease's FMV; the process for establishing FMV should be modeled after the Federal coal leasing program; bonus payments are needed to stop speculation; and sealed bidding ensures the most competitive bonus bid. The comments also posed arguments for and against using a minimum acceptable bonus bid. In addition, the BLM received comments that bonus bids should be high and suggested that the 1974 bonus bid amounts pertaining to 4 oil shale leases that were offered in Colorado and Utah, with bonus bids that ranged from $74 million to $210 million, were indicative of expected bonus bid amounts.

In response to the ANPR comments and other considerations, the BLM proposes to establish oil shale lease FMV using a process similar to that used in the Federal coal leasing program. This proposed process relies on the appraisal process in an attempt to estimate the market value for those leases. As such, the proposed process relies on many of the procedures used in private sector valuations, and where available, will rely on private sector transactions to establish the market value for Federal oil shale leases. The Federal coal leasing program and this proposed rule, utilize competitive bidding, specifically sealed bidding, for determining who receives the lease.

In the rule, the BLM is proposing to establish a minimum acceptable bonus bid for Federal oil shale leases. The amount is not a reflection of FMV, but is intended to establish a floor value to limit or dissuade nuisance bids. The proposed rule requires a minimum acceptable bonus bid of $1,000 per acre. The assumption is that such an amount will not exceed FMV or be a deterrent to companies interested in bidding for the lease tracts. At the same time, the BLM has requested further comments on the value proposed.

As per comments on specific values, the proposed rule does not attempt to establish actual FMV for future Federal oil shale leases. Values received in the 1970's may not be an accurate indicator for future values.

<u>Subpart 3925 – Award of Lease</u>

Section 3925.10 would provide that the lease would ordinarily be awarded to the qualified bidder submitting the highest bid which exceeds the minimum bid amount. It also contains requirements for the submission of the necessary lease bond, the first year's rental, any unpaid cost recovery fees, including costs associated with the NEPA analysis, and the bidder's proportionate share of the cost of publication of the sale notice. The provisions in this section are similar to regulations in the BLM's competitive leasing regulations for coal and non-energy leasable minerals.

<u>Subpart 3926 – Conversion of Preference Right for Research, Demonstration, and Development Leases</u>

Section 3926.10 would provide application procedures or requirements to convert R, D and D leases and preference rights acreages to commercial leases. Under this section, a lessee of any of the R, D and D lease would be required to apply for conversion to a commercial lease no later than 90 days after the BLM determines that commencement of production in commercial quantities had occurred. As stated in Section 23 of the R, D and D leases (issued in response to the BLM's call for nominations of parcels for R, D and D leasing (70 FR 33753 and 33754, June 9, 2005) R, D and D lessees can acquire contiguous acreage of the remaining preference right lease area up to a total of 5,120 acres. In order to acquire the contiguous acreage and convert to a commercial lease, the lessee would be required to demonstrate to the BLM that the technology tested in the original lease would have the ability to produce shale oil in commercial quantities. In addition, the lessee, as required in R, D and D leases, would be required to submit to the BLM:

(1) Documentation that there have been commercial quantities of oil shale produced from the lease, including the narrative required by Section 23 of R, D and D leases;

(2) Documentation that the lessee consulted with state and local officials to develop a plan for mitigating the socioeconomic impacts of commercial development on communities and infrastructure;

(3) A bid payment no less than that specified in section 3923.10 and equal to the FMV of the lease; and

(4) Bonding as required by section 3904.14.

The BLM would approve the conversion application , in whole or in part, if it determined that:
(1) There have been commercial quantities produced from the lease;
(2) The bid payment for the lease met or exceeded FMV;
(3) The lessee consulted with state and local officials to develop a plan for mitigating the socioeconomic impacts of commercial development on communities and infrastructure;
(4) The bond provided is consistent with section 3904.14; and
(5) Commercial scale operations can be conducted, subject to mitigation measures to be specified in stipulations or regulations, without unacceptable environmental consequences.

Subpart 3927 -- Lease Terms

Sections in this subpart would address lease form, lease size, lease duration, dating of leases, diligent development, and production.

Section 3927.10 would provide that the BLM would issue oil shale leases on a standard form approved by the BLM Director. This section mirrors similar requirements in other BLM mineral leasing regulations.

Section 3927.20 would set the maximum oil shale lease size at 5,760 acres, which is the maximum size authorized under Section 369(j) of the EP Act. Several comments received in response to the BLM's ANPR included lease size recommendations varying from 500 acres to 10 square miles as the appropriate maximum lease size. Of those comments, one commenter supported a maximum lease size of 5,760 acres, which is consistent with the EP Act. One commenter stated that "Leases need to be large enough to encourage development yet not outlandishly large to allow for speculation." The maximum lease size contained in this section is not discretionary since it was established by statute (see Section 369(j) of the EP Act).

Although the EP Act does not establish a minimum lease size, in keeping with the size restrictions of the oil shale R, D and D leases, section 3927.20 would also establish 160 acres as the minimum size of an oil shale lease. The BLM received several comments relating to whether the BLM's commercial oil shale leasing regulations should include provisions for small tract leasing, all of which generally were in favor of making small lease tracts available. One comment suggested that smaller tracts would be particularly appropriate in the early years of the commercial leasing program in light of new technologies, and it recommended a minimum tract size of 1,280 acres. Recommendations relating to a minimum tract size stated in other comments ranged from over 320 acres to one square mile. Two comments suggested that there should be restrictions for small tract leasing. Of those comments, one commenter stated that small tract leasing should not be a mechanism to thwart potential development. Another commenter recommended that small tracts should only be allowed in cases where "the tracts have been orphaned, in between larger leases, basin edge or other fee-owned lands." Although section 3927.20 would not formally establish small tract leasing, the 160-acre minimum lease size set by this section would provide a lessee the opportunity to develop a relatively small-scale leasehold, identical to the lease size authorized under the BLM's oil shale R, D and D program. Thus, rather than the BLM incorporating small tract leasing as a separate component of the commercial oil shale leasing program, establishing a minimum lease size of 160 acres provides an opportunity for a lessee to utilize a preferred technology on a relatively small tract that is consistent with the size of existing R, D and D leases. For this reason, the BLM did not adopt ANPR comments that recommended a larger minimum lease size. With respect to the comment expressing concern that small tract leasing could thwart potential development and the comment recommending that small tract leasing should be allowed only in limited situations as stated above, it is the policy of the BLM, when delineating tracts to be offered through competitive lease sale, to make efforts to ensure that the configuration of any small acreage tracts would likely promote development of oil shale. The BLM believes that configuration of tracts in this manner would not impede development on any existing oil shale leases located in the vicinity of smaller tracts. As is the case in other BLM mineral leasing programs, the tract delineation process for a competitive lease sale includes the gathering of detailed information on tracts and conducting various analyses. Because the steps customarily included in the tract delineation process are designed to promote or encourage development of mineral resources, the BLM maintains that establishing a minimum lease size of 160 acres will not thwart potential development of oil shale resources. Likewise, the competitive leasing process and the required minimum bonus bids would discourage speculation.

One comment endorsing small tract leasing also recommended that a small tract lease should include a preference right for additional adjoining acreage. The BLM is not adopting this recommendation since it maintains that the concept of a preference right for the future leasing of additional acreage—a key component of the R, D and D leasing program—is not a necessary provision in a commercial leasing program in light of lease modification provisions under proposed subpart 3932. In the event that a lessee of a small tract has interest in obtaining additional acreage adjacent to its lease, under the proposed rule the lessee could apply for a lease modification to include Federal lands adjacent to the lease, but not to exceed the maximum lease size (see section 3932.10).

Two comments received in response to the ANPR contained recommendations relating to consolidation of leases into larger development units. One of the comments suggested that oil shale commercial leasing regulations should include a provision to allow for consolidation of multiple contiguous leases for individual leaseholders as long as there remains one operator. The BLM interprets these comments as a recommendation to establish a mechanism similar to a logical mining unit that exists in BLM's coal leasing program. As defined in the coal leasing regulations at 43 CFR 3480(a)(19), "Logical mining unit (LMU) means an area of land in which the recoverable coal reserves can be developed in an efficient, economical, and orderly manner as a unit with due regard to conservation of recoverable coal reserves and other resources." Due to the fact that the commercial oil shale leasing regulations proposed here today are aimed at establishing a new mineral leasing program; a program that does not have any history of oil shale development in the U.S., does not require any standardized extraction methods, and also adopts different diligence requirements than those of the coal leasing program, it is the BLM's position that establishing a mechanism similar to a LMU is not warranted at this time. After the promulgation of final regulations and after the oil shale industry is more well-established, if the BLM determines that the creation of a mechanism similar to an LMU is warranted, then the BLM would pursue rulemaking to adopt this recommendation. Please specifically comment on whether or not the final rule should include provisions for the establishment of LMUs for oil shale leases.

Section 3927.30 would provide that an oil shale lease will be for a period of 20 years and so long thereafter as the condition of annual minimum production is met. Section 21 of the MLA (30 U.S.C. 241(a)(3)) authorizes issuance of oil shale leases for "indeterminate periods." The BLM chose a 20-year period for the original lease term for ease of administration because Section 21 of the MLA (30 U.S.C. 241(a)(4)) specifies that leases should be subject to readjustment at the end of each 20-year period. Lease readjustment is common to other BLM mineral leasing programs, including coal and certain non-energy leasable minerals.

Section 3927.40 would identify the effective date of the lease and the process used to determine the effective date of the lease. This section is similar to regulations on the effective dating of leases under the BLM's coal program.

Diligent development is a component of other mineral leasing programs such as coal and oil and gas and is required under Section 369(f) of the EP Act.

Section 3927.50 would require lessees to meet diligent development milestones and annual minimum production requirements. The BLM considers continued minimum annual production a necessary part of diligent development of the lease. This requires that a company continue to produce the minimum annual requirement or make payments in lieu of production in order to hold the lease.

<u>Part 3930 – Management of Oil Shale Exploration Licenses and Leases</u>

Sections in this part would address the requirements for exploration and leases, including general performance standards, operations, diligent development milestones, plans of development and exploration plans, lease modifications and readjustments, assignments and subleases, relinquishments, cancellations and terminations, post-mining and development hazards, production and sale records, and inspection and enforcement.

Sections 3930.10 through 3930.13 would explain the performance standards for exploration, development, production, and the preparation and the handling of oil shale under Federal leases and licenses. Additional standards may be required at the time of lease issuance and as operations proceed. The BLM used the coal program as basis of many of the performance standards for these sections because of the similarity of the mining and exploration methods and the possible impacts associated with those methods. The performance standards for in situ operations were derived from aspects of the standards used for exploration and standards applicable to the BLM's oil and gas program.

Section 3930.20 would establish the various standard operating requirements associated with development of an oil shale lease, including requirements concerning the maximum economic recovery (MER) of the resource, how to report new geologic information, and compliance with Federal laws. The section would also address disposal and treatment of solid wastes. This section provides operational requirements that are common to other BLM mineral leasing programs.

The BLM received 6 comments regarding diligent development in response to the ANPR. The comments received primarily expressed the view that diligent development requirements are necessary to prevent speculation, but that they should not be so onerous as to prevent investment in oil shale development. Most of the comments concerning the diligence provisions were related to either plan of development requirements or production requirements and requiring payment of a minimum royalty in lieu of production. The comments received suggested :

(1) Making diligence a requirement of operations;
(2) Not starting the diligence requirement until after the needed infrastructure is in place;
(3) Requiring submittal of a plan of development;
(4) Staging the permitting process to essentially define diligence as accomplishing necessary sequential steps in the development process;
(5) Escalating minimum royalty;
(6) Requiring minimum production levels; and
(7) Requiring production of a percentage of the resource base.

The BLM incorporated the following commenter's suggestions into the proposed rule:

(1) Diligent development and staged development requirements (section 3930.30 (a));
(2) Requirements for a plan of development (section 3930.30(a)(1)); and
(3) Requirements for minimum production (section 3930.30(d)).

The BLM's proposed diligent development requirements are based on fulfilling tasks necessary to reach production, such as applying for permits, submitting plans of development, and installing needed infrastructure within specified timeframes. Comments related to basing diligence on production of a percentage of the reserve base were considered, but rejected based on the difficulty of administering such a scheme with varying technologies, recovery rates, and shale characteristics. The comment regarding infrastructure was incorporated into the proposed rule as a diligence development step towards production.

Section 3930.30 would list the milestones for diligent development of an oil shale lease. The requirement for establishing milestones is in Section 369(f) of the EP Act. The BLM considered many options when determining how to establish milestones that would ensure diligent development of the lease. The BLM considered requiring production based on a percentage of the resource similar to coal and requirements for minimum dollar expenditures per year similar to the BLM's geothermal program.

Because the oil shale mining technology that is being tested is new, and there is little experience to rely on, it would be difficult to base milestones on production or monetary expenditures. Ultimately, the BLM determined that the milestones should be the series of steps necessary for the development of the oil shale. Defining milestones this way is logical because the steps are necessary to begin production and the BLM believes the requirement would encourage development. This section would require a lessee to meet the following five diligent development milestones:

(1) Within 2 years of lease issuance, submit to the BLM a proposed plan of development which would meet the requirements of subpart 3931;

(2) Within 3 years of lease issuance, submit a final plan of development;

(3) Within 2 years after the BLM approves the plan of development, apply for all required permits and licenses;

(4) Before the end of the 7th lease year, begin infrastructure installation, as described by the BLM approved plan of development; and

(5) Begin production by the end of the 10th lease year.

Each of the milestones in this section would be an opportunity for the lessee or operator to fulfill the statutory requirements and would provide evidence of its commitment to diligent development of the resource.

The requirement to maintain production under an approved plan of development is also in this section. Although it is not a milestone, the BLM would require yearly production as part of the diligent development of the lease. This section also would allow payments in lieu of production to meet the requirement of yearly production. Minimum annual production is required starting the 10th year of the lease. Payment in lieu of production in year 10 of the lease satisfies the milestone requiring production by the end of the 10th year of the lease.

Section 3930.40 would identify the penalties for not achieving the required milestones. The BLM views these penalties as incentives for maintaining development of the resource and prevent speculation. Under this proposed rule, the BLM would assess a penalty of $50 per acre for each missed diligence milestone for each year until the operator or lessee complies with the diligence milestone. The BLM believes that this penalty process would provide operators incentive for diligent development of the resource, and also that the dollar amount of the penalties is high enough to be a deterrent to speculation.

Subpart 3931 – Plans of Development and Exploration Plans

Sections in this subpart would provide requirements for submission of a plan of development (section 3931.10), required contents of a plan of development (section 3931.11), reclamation of all disturbed areas (section 3931.20), suspending operations and production on a lease (section 3931.30), exploration on a lease prior to plan of development approval (section 3931.40), information to be included in the exploration plan (section 3931.41), modification of exploration or development plans (section

3931.50), maps of underground and surface mining workings and in situ surface operations (3931.60), production reporting (section 3931.70), geologic information (section 3931.80), and boundary pillars (section 3931.100).

Section 3931.10 would require submission of a plan of development that details all aspects of development of the resource and protection of the environment, including reclamation. It would also identify the need for a similar plan for exploration activities. The plan of development is a key document that would detail the specifics of all activities associated with developing or exploring the lease.

Section 3931.11 would list and describe the contents of a plan of development. Some of the contents include a general description of geologic conditions and mineral resources, maps or aerial photography, proposed methods of operation and development, public protection, well completion reports, quantity and quality of the oil shale resources, environmental aspects, reclamation plan, and the method of abandonment of operations. The information in the plan of development is necessary so that the BLM can review the plan and ensure that operations, production, and reclamation will occur consistent with Federal law and regulation and to ensure the protection of the resource and the environment.

Section 3931.20 would describe the requirements for reclamation of all disturbed areas under a lease or exploration license. This section is similar to requirements in other BLM mineral program regulations requiring prompt reclamation of disturbed areas.

Section 3931.30 would detail the requirements for suspending operations and production on a lease. Under this section, if the BLM determined it was in the interest of conservation, it may order or agree to a suspension of operations and production. If the BLM approved the suspension, the lessee or operator would be relieved of the obligation to pay rental, to meet upcoming diligent development milestones, or to meet minimum annual production, including payments in lieu of production. The term of the lease would be extended by the amount of time the lease is suspended. The need to suspend operations is well established and similar provisions are found in other BLM mineral leasing regulations.

Section 3931.40 would provide the requirements necessary for the BLM to authorize exploration on an exploration license or on a lease prior to plan of development approval. Often, exploration is necessary after lease issuance to acquire the geologic information necessary to prepare a plan of development.

Section 3931.41 would list the information required for an exploration plan. The information required is similar to that required in other BLM mineral regulations and is necessary to adequately evaluate the proposed exploration activities and the measures to protect or limit environmental impacts in accordance with applicable laws.

Section 3931.50 would explain how the operator or lessee may apply for a modification of exploration or development plans to address changing conditions and situations that might develop during the course of normal exploration activities or to correct an oversight. This section would also explain that the BLM may, on its own initiative, require modification of a plan. Finally, this section would explain that the BLM may approve a partial exploration plan or plan of development in circumstances where operations are dependent on factors that would not be known until exploration or development progresses. These modification provisions are similar to those in other BLM minerals programs.

Section 3931.60 would contain information relating to the format and certification of required maps of underground and surface mining workings and in situ surface operations. These maps are necessary for the BLM to properly assess the potential impacts associated with exploration and mining.

Section 3931.70 would explain the requirements for production reporting, the associated maps and surveys for mining operations, and maps showing the measurement systems for in situ operations. This section would require accurate maps and production reports and would explain the requirements for production reporting. These are necessary requirements for the Federal government to track lease production accurately.

Section 3931.80 would address requirements for handling geologic information resulting from exploration activities. Additional requirements related to abandonment operations, well conversions, and blow-out prevention equipment would also be addressed in this section. This section contains requirements similar to those in the BLM's oil and gas operations regulations.

Section 3931.100 would detail the standards for boundary pillars and provisions to protect adjacent lands. This section would allow for the recovery of the pillars if the operator provided evidence to the BLM that the recovery activities would not damage the Federal resource or those of the adjacent lands. These provisions are similar to those in the BLM's coal program.

Subpart 3932 – Lease Modifications and Readjustments

Sections in this subpart would provide requirements for lease size modification, (section 3932.10), availability of lands for a lease modification (section 3932.20), terms and conditions of a modified lease (section 3932.30), and the readjustment of lease terms (section 3932.40).

Section 3932.10 would provide the requirements for lease size modifications and is similar to sections in the other BLM mineral program regulations. This section would explain that the lands in the modified lease must not exceed the acreage limitation in section 3927.20. The section also would explain what items are necessary for a complete application, including the filing fee and qualifications statements.

Section 3932.20 would provide the land availability criteria for lease modifications. The language in this section is similar to language used in other BLM mineral program regulations and is necessary to facilitate effective development of the resource. This section would explain the conditions under which the BLM would grant a lease modification, and that the BLM may approve the modification (adding lands to the lease) if there is no competitive interest in the lands. This section would explain that before the BLM will approve a modification application, the applicant must pay the FMV for the interest to be conveyed. This section would also make it clear that the BLM will not approve a lease modification prior to conducting the appropriate NEPA analysis and receipt of the processing costs.

Section 3932.30 would provide that the terms and conditions of any modified lease will be adjusted so that they are consistent with law, regulations, and land use plans applicable at the time the lands are added by the modification. Under this proposed section, the royalty rate of the modified lease would be the same as that in the original lease. Bonding and lessee acceptance requirements would also be addressed in this section. This section is similar to those in other BLM minerals program regulations.

Section 3932.40 would provide that all oil shale leases are subject to readjustment of lease terms, conditions, and stipulations, except royalty rates, at the end of the first 20-year period (the primary term of the lease) and at the end of each 10-year period thereafter. Royalty rates would be subject to readjustment at the end of the primary term and every 20 years thereafter. The procedures for the readjustment of the lease would be detailed in this section. Under this section, the BLM would provide the lessee with written notification of the readjustment. This section would also allow lessees to appeal the readjustment of lease terms.

Subpart 3933 – Assignments and Subleases

Sections in this subpart would address various requirements related to assignments or subleases of record title (section 3933.31) and overriding royalty interests (section 3933.32). This subpart would also address requirements for:
(1) Assigning or subleasing leases in whole or part (section 3933.10);
(2) Filing fees (section 3933.20);
(3) Lease account status and assumption of liability (section 3933.40);
(4) Bonding (sections 3933.51);
(5) Continuing responsibility (section 3933.52);
(6) Effective date (section 3933.60); and
(7) Extensions (section 3933.70).
The sections in this subpart would be similar to the regulatory requirements of BLM's other mineral leasing programs.

Section 3933.10 would provide that all leases may be assigned or subleased in whole or in part to any person, association, or corporation as long as the qualification requirements are met. Section 30 of the MLA requires an assignee to obtain BLM approval for an assignment.

Section 3933.20 would require payment of a $60 non-refundable filing fee for processing an assignment, sublease of record title, or overriding royalty. The filing fee would be the same fee required by the coal regulations for filing an assignment. The BLM anticipates that lease assignment, sublease of record title, or overriding royalty activities associated with an oil shale lease would be similar to the same activities in the BLM's coal program, and therefore believes the same filing fee is justified.

Section 3933.31 would require that assignment applications be filed with the BLM within 90 days of the date of final execution of the assignment, and would list what must be included in the assignment application, including the filing fee. This section also explains that the assignment of all interests in a specific portion of a lease would create a separate lease.

Section 3933.32 would explain that overriding royalty interests do not have to be approved by the BLM, but would be required to be filed with the BLM. The filing of overriding royalty interests provides a more complete record of the financial transaction affecting the Federal lease. The BLM has found this information to be useful in other mineral leasing programs, especially in making rent and royalty reduction determinations.

Section 3933.40 would require that the lease account be in good standing before the BLM would process a lease assignment.

Section 3933.51 would require that assignees have sufficient bond coverage before the BLM will approve the assignment. This is a necessary component of the bonding program and is similar to requirements of other BLM solid mineral leasing programs.

Section 3933.52 would address the responsibilities, obligations, and liabilities of the assignor and assignee. In addition to stating expressly that an assignor is responsible after an assignment for accrued obligations, this section addresses joint and several liabilities of the lessee and operating rights owner. After the effective date of the sublease, the sublessor and sublessee are jointly and severally liable for the performance of all lease obligations, notwithstanding any term in the sublease to the contrary.

Section 3933.60 would explain that the effective date of an assignment and sublease would be the first day of the month following the BLM's final approval, or if the assignee requested it in advance, the first day of the month of the approval. This is the customary effective date for an assignment in other BLM leasing programs.

Consistent with other BLM mineral leasing programs, section 3933.70 would provide that the BLM's approval of an assignment or sublease does not extend the readjustment period of the lease.

Subpart 3934 – Relinquishments, Cancellations, and Terminations

Sections in this subpart would contain requirements for relinquishments (section 3934.10), termination of leases and cancellation and/or termination of exploration licenses (section 3934.30), written notice of cancellation (section 3934.21), cause and procedures for lease cancellations (section 3934.22), payments due (section 3934.40), and bona fide purchasers (section 3934.50). Sections in this subpart are similar to sections found in regulations for other BLM mineral leasing programs.

Section 3934.10 would provide that the record title holder of a lease may relinquish all or part of the lease if the requirements in this section are met. This section would also contain provisions for the relinquishment of an exploration license. Prior to relinquishment, the licensee must give any other parties participating in the exploration license an opportunity to take over operations under the exploration license.

Section 3934.21 would require the BLM to notify the lessee or licensee in writing of any default, breach, or cause of forfeiture, and the corrective actions that could be taken to avoid defaulting on the lease terms and lease cancellation.

Section 3934.22 would explain the procedure for the BLM to cancel a lease. Section 31 of the MLA requires that lease cancellation take place in the United States District court for the district in which all or part of the lands covered by the lease are located.

Section 3934.30 would provide the reasons that the BLM may cancel a license, including:
(1) The BLM issued it in violation of law or regulation;
(2) The licensee is in default of the terms and conditions of the license; and
(3) The licensee has not complied with the exploration plan.
Unlike leases, the BLM may cancel an exploration license administratively.

Section 3934.40 would provide that if a lease is canceled or relinquished for any reason, all bonus, rentals, royalties, or minimum royalties paid would be forfeited and any amounts not paid would be immediately payable to the United States.

Section 3934.50 would address the rights of bona fide purchasers and provide that the BLM would not immediately cancel a lease or an interest in a lease if, at the time of purchase, the purchaser could not reasonably have been aware of a violation of the regulations, legislation, or lease terms.

Subpart 3935 – Production and Sale Records

Section 3935.10 would address books of account. Operators and lessees must maintain accurate records. This section would explain what records must be maintained, and that the records must be made available to the BLM during normal business hours.

Subpart 3936 – Inspection and Enforcement

Like other BLM minerals inspection and enforcement (I and E) programs, the objective of BLM's oil shale I and E program would be to:
(1) Ensure the protection of the resource;

(2) Ensure that Federal oil shale resources are properly developed in a manner that would maximize recovery while minimizing waste; and
(3) Ensure the proper verification of production reported from Federal lands.

The BLM would also be responsible for lease inspections to determine compliance with applicable statutes, regulations, orders, notices to lessees, plans of development, and lease terms and conditions. These terms and conditions would include those related to drilling, production, and other requirements related to lease administration.

This subpart would address inspection of underground and surface operations and facilities (section 3936.10), issuance of notices of noncompliance and orders (section 3936.20), enforcement of notices of noncompliance and orders (section 3936.30), and appeals (section 3936.40).

Section 3936.10 would require operators or lessees to allow the BLM to inspect underground or surface mining and exploration operations at any time both to determine compliance with the plan of development and to verify oil shale production.

Section 3936.20 would advise the operator, licensee, or lessee of the procedures the BLM would follow when issuing orders and notices of noncompliance. The section would also address delivery of notices and verbal orders.

Section 3936.30 would explain the procedures the BLM would follow when enforcing notices of noncompliance. This section explains the action the BLM may take in cases of noncompliance, including orders to cease operations and the initiation of lease or license cancellation or termination procedures. An example of the type of non-compliance that might warrant the BLM issuing a cease operations order would be noncompliance with the BLM approved plan of development and refusal to comply with the notice of noncompliance.

Section 3936.40 would allow a lessee or operator to appeal BLM decisions under 43 CFR part 4. This section would also provide that the BLM decisions and orders remain in full force and effect pending appeal, unless the BLM or the Interior Board of Lands Appeals decides otherwise. Appeals language in this section mirrors regulatory provisions in other BLM minerals programs.
This part would contain regulations on the general management of the oil shale program, including discussions of the descriptions and acreage in oil shale leases, qualifications requirements, fees, rentals, royalties, bonds and trust funds, and lease exchanges.

Alternative Approaches

By statute, the Secretary must issue regulations implementing a commercial oil shale leasing program within six months of completion of the PEIS. To meet this mandate, the agency evaluated and considered the approaches currently used in the various BLM energy and mineral leasing programs, specifically focusing on the leasing and operational aspects of the oil and gas, coal, and nonenergy leasing regulations. The BLM considered numerous aspects of existing nomination approaches, competitive leasing systems, plan filing and approval processes, financial guarantee requirements, and operational standards from these and other energy and mineral programs. The rationale for incorporating specific regulatory components from these existing energy and mineral leasing programs are discussed in the preamble for the proposed rule.

Alternative royalty approaches and royalty rates were key considerations in the rulemaking. A number of factors went into the deliberation as to the appropriate approach and rate to apply to potential production of oil from shale. In the discussion of benefits and costs of the proposed rule, presented below, BLM includes an analysis of the revenue impacts of various royalty rates.

Background

Oil Shale - Oil shale is organic-rich shale that yields significant quantities of oil, when processed by conventional destructive distillation methods, such as those used by established industries. The organic-rich shale is composed of fine-textured sedimentary rock containing a high percentage of combustible organic matter.

The world's largest known oil shale deposits are located on Federal lands in the western United States. Domestic commercial-quality oil shale resources exceed 2 trillion barrels, including about 1.5 trillion barrels of oil equivalent in high quality shales concentrated in the Green River Formation in Colorado, Utah, and Wyoming[8]. For geographic reference, Figure 1 shows the location of the Green River Formation.

In a report, *Oil Shale Development in the United States – Prospects and Policy Issues*, prepared for the U.S. Department of Energy, National Energy Technology Laboratory in 2005, the RAND Corporation cites in-place resource estimates of 1.5 to 1.8 trillion barrels for the Green River Formation[9]. RAND's recoverable resource estimates for the Green River Formation ranged from 500 billion to 1.1 trillion barrels of oil. The Strategic Unconventional Fuels Task Force[10] estimated that "as much as 800 billion barrels of oil equivalent could be recoverable from oil shale resources yielding >25 gallons per ton.[11]" To put these estimates in perspective, domestic oil consumption is currently about 20 million barrels per day.

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[8] *America's Strategic Unconventional Fuels Resources, Volume I - Preparation Strategy Plan, and Recommendations*, Task Force on Strategic Unconventional Fuels, September 2007, page I-17 (http://www.unconventionalfuels.org).

[9] *Oil Shale Development in the United States – Prospects and Policy Issues*, RAND Corporation, 2005, page 6 (www.rand.org).

[10] The Task Force on Strategic Unconventional Fuels was established in 2005 as required by the Energy Policy Act to promote the development of the nation's unconventional fuel resources.

[11] *America's Strategic Unconventional Fuels Resources, Volume I - Preparation Strategy Plan, and Recommendations*, Task Force on Strategic Unconventional Fuels, September 2007, page I-17 (http://www.unconventionalfuels.org).

Recent estimates for domestic oil shale resources range from 2.1 to 26 trillion barrels (see Table 2).

Quality and Grade - Oil shale resources of the United States have been extensively characterized. Yields greater than 25 gallons per ton are generally viewed as the most economically attractive, and hence, the most favorable for initial development.

The most economically attractive deposits, containing in excess of 1.2 trillion barrels, are found in the Green River Formation of Colorado (Piceance Creek Basin), Utah (Uinta Basin), and Wyoming (Green River and Washakie Basins). More than a quarter million assays have been conducted on the Green River oil shale. In the richest zone, known as the Mahogany Zone, oil yields vary from 10 to 50 gallons per ton and, for a few feet in the Mahogany zone, up to about 65 gallons per ton[12]. An estimated 418 billion barrels of the Western resources are in deposits that will yield at least 30 gallons per ton in zones at least 100 feet thick. Additional resource estimates are for 750 billion at 25 gallons per ton in zones at least 10 feet thick.

[12] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, September 2007, page III-2 (http://www.unconventionalfuels.org).

Figure 1
Green River Formation

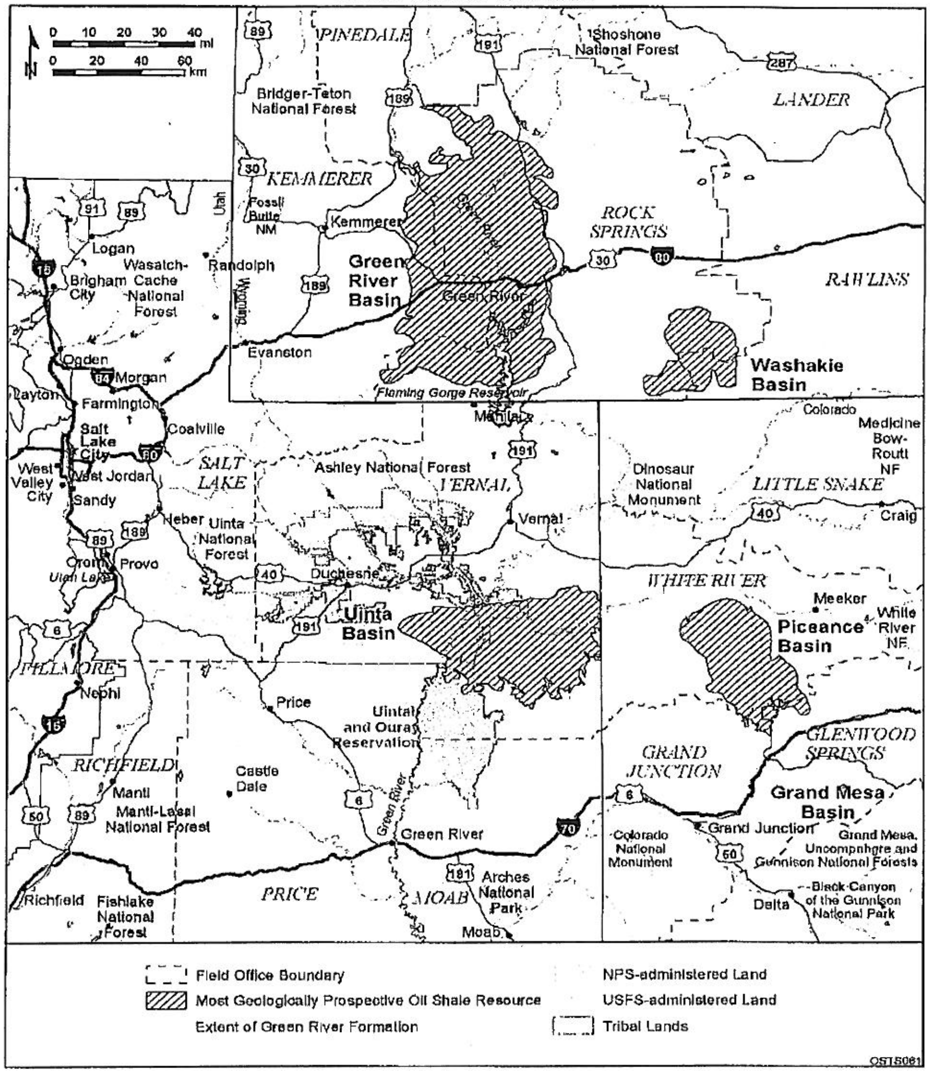

Table 2
U.S. Oil Shale Resource Estimates

Source of Estimate	Oil Shale (billion barrels)
U.S. Geological Survey[13]	2,100
American Petroleum Institute[14]	5,600
Office of Technology Assessment[15]	26,000

[13] Dyni, J.R., *Geology and Resources of Some World Oil-Shale Deposits*, U.S. Geological Survey, Investigations Report 2005–5294, June 2006 (http://pubs.usgs.gov).
[14] Porter, E.D., American Petroleum Institute, Policy Analysis and Strategic Planning Department, *Are we running out of oil?*, Discussion Paper #081, December 1995 (http://new.api.org).
[15] Congress of the United States, Office of Technology Assessment, *An Assessment of Oil Shale Technologies*, June 1980, OTA Report # OTA-M-118 (http://govinfo.library.unt.edu/ota/).

Uncertainty of the quality of recoverable oil is a function of natural geologic environment of deposition for the resources. The mineral deposits (conventional crude oil versus oil shale –kerogen) are distinctly different. Uncertainty relating to the quantity of recoverable oil is a function of technological efficiency. All oil shale technologies and projects are purely experimental, and technological efficiency would not be known until technology has been perfected.

Historic Development - The use of oil shale can be traced back to ancient times. By the 17th century, oil shale rocks were being exploited in several countries. An example of this exploitation is the Swedish alum shale, which is noted for its alum content and high concentrations of metals, including uranium and vanadium. As early as 1637, the alum shale rocks were roasted over wood fires to extract potassium aluminum sulfate, a salt used in tanning leather and for fixing colors in fabrics. Late in the 1800s, the alum shale rocks were retorted on a small scale for hydrocarbons. Production continued through World War II, but ceased in 1966, because of the availability of cheaper supplies of petroleum crude oil. In addition to hydrocarbons, some hundreds of metric tons of uranium and small amounts of vanadium were extracted from the Swedish alum shale rocks in the 1960s. The oil shale deposit at Autun, France, was commercially exploited as early as 1839. Canada produced some shale oil from deposits in New Brunswick and Ontario in the mid-1800s.

The Scottish oil shale industry began about 1859, the year that Colonel Drake drilled his pioneer well at Titusville, Pennsylvania. Mining continued during the 1800s and by 1881 oil shale production had reached 1 million metric tons per year. With the exception of the World War II years, between 1 and 4 million metric tons of oil shale were mined yearly in Scotland from 1881 to 1955 when production began to decline, then ceased in 1962.

In 1974, several oil shale leases on Federal lands in Colorado, Utah, and Wyoming, were offered for lease sale. The parcels, Wa and Wb, in Wyoming were not leased, because acceptable bids were not received. The parcels in Colorado and Utah were issued to private companies under the Prototype Oil Shale Leasing Program. Large-scale mine facilities were developed on the properties and experimental underground "modified in situ," retorting was carried out on one of the lease tracts. These projects were unsuccessful, and thee efforts failed to create a viable oil shale industry.

Most recent efforts to develop oil shale occurred in Australia. In 1999, Suncor Energy, Inc., (a Canadian-based company) set up a large oil shale demonstration project dubbed the Stuart project near Gladstone, Queensland, Australia. From June 2001 through March 2003, the Project produced 703,000 barrels of oil, 62,860 barrels of light fuel oil, and 88,040 barrels of ultra-low sulphur naphtha. In January 2003, the operation produced 79,000 barrels of oil. This effort failed due to technical, economical, and environmental difficulties.

Besides the technical and economic difficulties, the environmental challenges exerted a toll on the company. The organization Green Peace has heavily protested the Australian oil shale project. On several occasions, the Green Peace activists broke into the facilities, which resulted in several arrests. The Queensland Supreme Court issued an injunction against Green Peace. However, the protests continued, although from a distance. The operational and reputational costs mounted for Suncor Energy, Inc. On September 2000, the Chief Financial Officer of Suncor announced, "Until oil shale can be developed on a sustainable basis meeting greenhouse gas emissions, it won't happen and Suncor won't be a part of it." In June 2001, Southern Pacific Petroleum (SPP) took over as 100 percent owner and operator of the Stuart Shale Oil Project. The cost per barrel of oil was approximately $55. This figure was based on the 2003 first quarter report issued by the project operator, SPP. Today, the Stuart Project is not viable.

<u>Technological Advances</u> - There has been recent interest and activity in the development of oil shale in both Utah and Colorado. Currently, Shell Oil Company is conducting an experiment at the Mahogany Research Facility near Rangely, Colorado. This research is being conducted in the Cathedral Bluffs area on the west side of the Piceance Creek Basin, Colorado. Information released by Shell Oil shows that the company has received a number of patents as a result of this work. This experiment utilizes heater element technology designed to heat a localized area of an oil shale zone(s) underground and pump the fluid to the surface. The heater elements are installed in drill holes and the combustible fluids are recovered from nearby wells. From all indications, the technique is deemed to be promising. As a result, the company has indicated its desire to perform additional exploration in the Piceance Basin to determine prime locations for future RD&D sites to test the non-conventional oil shale recovery technology. Exxon also is initiating a field project to look at some sort of in-situ recovery of shale oil in the Piceance Creek Basin, but details of their technique are not yet available.

In Utah, at least two companies have indicated their desire to proceed with research on oil shale technology and have acquired shale from the White River Oil Shale Project for testing purposes. The State of Utah included the former Ua and Ub oil shale tracts in a recent proposed legislative exchange proposal. Congress did not pass the proposal, but the State has indicated that they are still interested in acquiring the lands.

While there has been a great deal of interest recently in the potential of oil shale resources, utilization of this material is still, for the most part, in the research and development mode. Currently, there is no commercial production of oil from shale in the United States. 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.

Oil shale development has two basic extraction technologies. The first is surface or underground mining with surface retorting. The second involves drilling holes, similar to oil and gas, and the shale is processed underground and brought to the surface through conventional oil and gas methods.

Based on the interest expressed by the prospective oil shale research, demonstration, and development lease applicants, each technology appears to have an area of focus. As an example, all interests expressed in Utah focused on mining and surface retorting, while the interests in Colorado focused on the in situ process. For Utah, there is an existing mine on Federal land, and the prospective applicants expect to reactivate the mine to extract shale as feed stock for their operations.

Mining and Surface Retorting - The richer shale zones in the Piceance basin are more than a thousand feet thick in some parts, and are continuous over an area of 1,200 square miles, according to the Office of Technology Assessment (Assessment of Oil Shale Technologies, 1980). Deposits of this nature could be amenable to surface or underground mining, depending on topographical features, accessibility, overburden thickness, presence of ground water in the mining zone, etc. Only a limited area of the Piceance basin and somewhat more of the Uinta basin and the Wyoming basins is open to surface mining, due to the thickness of the overburden.

Two principal types of mining (surface mining (open pit and strip) and underground mining) have both been widely used to develop seams and deposits of coal and other minerals. Their technical aspects are fairly well-understood for these minerals. This approach was demonstrated to be technically viable for oil shale in the 1970's and 1980's, but fell short of being commercially viable. As noted in the report prepared by the Task Force on Strategic Unconventional Fuels[16] significant technical advances have occurred since those earlier efforts. However, only the underground mining technique has been applied to the oil shale of the Green River formation in Colorado and Utah.

Surface retorting involves three retort technologies, two of which are patented in the United States, and one patented in Canada. These are: 1) Electric powered Vertical Retort; 2) Horizontal Synthetic gas powered Rotary Kiln; and 3) the Alberta Taciuk Process (ATP). Under all three technologies, shale is mined, crushed underground, and brought to the surface.

The Electric Powered Vertical Retort consists of a vertical packed-bed columns (modular construction), that are air tight, electrically heated, and assembled in no more than one acre of space. Mined shale is crushed and fed into the system from the top (gravity). The shale is heated to approximately 500 - 650 degrees Fahrenheit (F). The kerogen is vaporized and the vapor is vacuum-drawn into the product collection system where it is cooled into liquid kerogen oil, which is later converted into synthetic hydrocarbon. This process generates spent shale (left over rock or charred rock). The spent shale is analyzed for its chemical composition to determine an appropriate disposal mechanism.

An operator developing the Electric Powered Vertical Retort process estimated that the cost of electricity is approximately $7.75 per barrel of oil, with the cost of operations at $9.93 per barrel of oil. The operator estimated its process capacity at 1,000 barrels of oil

[16] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, September 2007, (http://www.unconventionalfuels.org).

per day, scalable to 20, 000 barrels of oil per day with a projected twenty-year production exceeding 2 million barrels of oil per day. However, it should be noted that the operator went out of the oil shale business nine months into their operations.

The rotary kiln method gasifies coal to generate (Chevron gasifier) heat for its operations. The crushed mined oil shale rock is fed into the rotary kiln and preheated to 300 degrees F. The hot synthetic gas (at a temperature of 900 to 1,000 degrees F) is fed into the rotary kiln to remove the hydrocarbon in vapor form (kerogen is vaporized out of the oil shale). The vapor is sent to the distillation tower where the hot vapor is condensed into liquid. The carbon dioxide generated in the process is separated from the system and could be sold or sequestered, and the synthetic gas is cleaned and processed into electricity. The hot spent shale is sent into the cool down rotary kiln to preheat new unprocessed oil shale. The spent shale is analyzed for its chemical composition to determine an appropriate disposal mechanism.

The owner of this technology estimated that the rotary kiln process would yield 5.7 barrels of oil and 2.4 megawatts hours of electricity per ton of coal. The company estimated that production cost would be $17.5 per barrel of oil. This system has the capability of processing 2,800 tons of coal per day to produce 18,000 barrels of fully-refined oil per day, 275 megawatts of electricity above operational needs, and a marketable quantity of carbon dioxide. The company estimated that their technology would use an average of 1 barrel of water per barrel of oil produced. The spent shale would be analyzed for its chemical composition to determine an appropriate disposal mechanism. It should be noted that this company has not had a full field test, and currently is out of the oil shale development business.

In the ATP (a horizontal rotary kiln), oil shale is fed into a preheated chamber where moisture is driven off and collected as steam. The dried oil shale is transferred into the retort chamber where additional heat (450 degrees to 500 degrees F) is provided by hot recycled solids, and the organic matter (kerogen) in the shale rock is converted into hydrocarbon vapor and gases. The hydrocarbon vapor is collected in the oil recovery chamber. The combusted materials are cooled in the cooling chamber and discharged from the system and processed further, as necessary. The hydrocarbon vapor collected is passed through multiple stages of condensation where the condensate is separated into kerogen oil, water, and non-condensable gaseous hydrocarbons. The kerogen oil is pumped to a storage vessel for further treatment. The combustible gases are sent to a flue gas treatment system where the gases are treated (cleaned up) and discharged in accordance with acceptable environmental practices. The associated spent shale is analyzed for its chemical composition to determine an appropriate disposal mechanism.

The company plans to ultimately develop commercial oil shale operations at 50,000 barrels of oil per-day capacity. The company is now operating in Utah under the DOI/BLM oil shale research, demonstration, and development program. Currently, they report a production cost of $54 per barrel of oil produced.

In Situ - The other main approach to developing the resource is referred to as in-situ retorting. In-situ operations entail heating the oil shale in place, recovering the liquid, and processing it on the surface. Various in-situ operations were attempted in the 1970's and 1980's with limited success. These earlier attempts primarily involved burning a portion of the shale oil underground to create the heat needed to separate the liquid from the shale.

As with the surface retorting, there have been significant technological advances in in-situ retorting approaches. The most significant new approach to in-situ retorting is the use of electric heaters, instead of burning the in-place oil shale, to separate the liquid from the shale. This new approach is currently being researched by the Shell Oil Company. Shell has reported successfully producing shale oil from a pilot in-situ operation. Preliminary information from the company indicates that the process may not only be technically feasible, but also economically viable.

The in situ process is the most innovative of all the current technologies. There are various forms of the in situ process, because the structure or form varies from company to company. However, all in situ operations depend on the introduction of heat into the body of oil shale rock underneath the ground. As an example; Chevron, ExxonMobil, and Shell are all using the in situ technology, but the methodology for the application of heat varies by company.

The Chevron oil company's in situ technology for the recovery and upgrading of oil from shale involves drilling vertical holes and applying a series of fractures to rubblize the shale rock to increase the surface area of the exposed kerogen. The exposed kerogen is then converted through a chemical process from a solid material to a liquid hydrocarbon. The converted hydrocarbon is pumped to the surface through traditional oil and gas methods. The produced hydrocarbon is then upgraded to refinery feedstock specifications.

ExxonMobil has a main technological method known as "electrofrac." This method employs horizontal wells with hydraulically-induced longitudinal vertical fractures. The fractures are filled with electrically conductive material, which form the heating element for the conversion process. This technology is designed to generate linear heat (planar heat source) to convert kerogen into hydrocarbon. The converted hydrocarbon is produced through traditional oil and gas methods, and further processed for suitability as a refinery feedstock. If successful, this technology will require fewer wells and well bores, thereby reducing the operational footprint on the environment. Research is continuing to determine the technical and economic feasibility of this technology.

Under Shell's in situ conversion process (ICP) technology, a vertical hole is drilled to a depth of 2,000 feet with a target zone of 1,000 to 2,000 feet of shale rock. Electric heaters are inserted into the drilled holes, which gradually heats the target zones at temperatures ranging from 650 to 750 degrees F. The heaters remain in the hole for 3 to 5 years during which the kerogen in the shale rock is converted into hydrocarbon. The converted hydrocarbon is pumped to the surface through traditional oil and gas methods.

The produced hydrocarbon requires further processing to produce high quality transportation fuels.

If Shell's ICP is successful, one acre of land has the potential to yield approximately one million barrels of oil equivalent. The rudimentary recovery efficiency for the ICP is estimated to be between approximately 65 percent to 70 percent of the original carbon in place with 67 percent oil and 33 percent gas. The liquid product is approximately 30 percent naphtha (precursor to gasoline), 30 percent jet fuel, and 30 percent diesel with the remaining 10 percent of heavy ends, which can be processed like the conventional crude oil. The production cost is estimated at $35 - $40 per barrel of oil equivalent. This is the primary basis for using the production cost figure of $37.75 found on Table III-3, page III-14, of the Task Force on Strategic Unconventional Fuels' report.

The bottom line is that the best existing technologies for producing U.S. oil shale have not yet been tested beyond the pilot scale. Demonstration of first-generation technologies will be required at a commercially representative scale before significant private investment will lead to commercial production. Major investments by industry and government have resulted in in-depth understanding of oil shale resources and the development and testing of a broad spectrum of surface retorting and in-situ technologies for converting oil shale to liquid fuels. The lessons learned and the technologies developed from these past efforts remain available and provide the technical basis needed to advance oil shale commercialization efforts. With the above history, it is difficult to assess or project the viability of oil shale projects if other production technologies are used.

<u>Economic Viability</u> - The last concerted effort to bring domestic shale oil into production was in the 1970s and 1980s. There was significant interest in developing the vast oil shale resources on Federal lands, specifically in Colorado. The last of these operations ceased in 1991. Numerous times throughout history, see discussion above, there have been attempts to produce oil from shale with limited reported success. The availability of relatively inexpensive alternative sources of oil has generally made shale oil production uneconomic.

Extractive technologies for oil shale have gone from roasting over wood fires to above ground indirectly and directly heated gas flow, in-situ and modified in-situ retorting, and retorting oil shale with heaters installed in drill holes and recovering combustible fluids from nearby wells. The above-ground indirectly heated gas flow, above-ground directly heated gas flow, and the underground retort using directly heated gas flow, have been extensively tested with limited commercial results.

At the time the prototype program was implemented, the DOI believed that the basic operations of development such as above-ground retorting, underground mining, and upgrading of the resource were fairly well developed. While the economics of oil shale development were not known, the general belief was that oil prices would continue to rise and eventually shale oil would be competitive with conventional sources of oil. In reality, it was found that numerous technological problems existed that still need further research to overcome. Additional research and development will be necessary to perfect a commercial oil shale recovery technology.

Oil shale technologies must be demonstrated at commercial scale before definitive capital and operating costs of oil shale projects will be known. Cost estimates vary according to the oil shale resource and the process selected. The components of capital cost for an oil shale project for mining and surface retorting include:

- Mine development: surface or underground;
- Retorting and upgrading facilities: design, manufacture, and construction of facilities; and
- Infrastructure: roads, pipelines, power, utilities, storage tanks, waste treatment and pollution control.

For in-situ (underground) processing:

- Subsurface facilities: wells or shafts to access and heat the shale, recover liquids and gases, and isolate and protect subsurface environments; and
- Surface facilities: production pumps and gathering systems, process controls, and upgrading facilities.

Oil shale production is characterized by high initial capital investments, high operating costs, and long periods of time between expenditure of capital and the realization of production revenues and return on investment. For first-generation facilities there is substantial uncertainty about the magnitude of capital and operating costs because technologies are not yet proven on a commercial scale. Revenues are uncertain because world crude oil prices are volatile and future market prices for shale oil and byproducts are unknown. These and other uncertainties pose investment risks that make oil shale investment less attractive than other potential uses of capital.

Against this historic backdrop, the RAND and Strategic Unconventional Fuels Task Force reports present fairly positive scenarios for domestic oil shale development and development economics. In the 2005 report, RAND estimated that a 50,000 barrel per day mine and surface retort operation could incur capital costs at least in the $5 billion to $7 billion range and possibly higher[17]. For such an operation, RAND assumed maintenance and operating costs of $17 to $23 per barrel. Given these capital and operation costs, West Texas Intermediate crude would need to be in the $70 to $95 per barrel range (2005 dollars) for a first generation mine and surface retort operation to be profitable. RAND also projected that over a 12-year production period the costs could

[17] *Oil Shale Development in the United States – Prospects and Policy Issues*, RAND Corporation, 2005, page 15 (www.rand.org). These capital cost estimates are based on the reported capital costs for Exxon's Colony Project that was eventually cancelled in 1982. The capital costs for that project were reported to be about $10 billion in 2005 dollars.

drop into the $35 to $48 per barrel range as further economic and technological improvements are realized.

As noted in the RAND report, these projections come with significant uncertainties. A number of factors could make actual costs diverge from these cost estimates. One example the RAND report mentioned is that the designs for commercial plants proposed in the 1980s, which is the source period for many of the cost estimates, are based on compliance with environmental regulations and standards which may not be adequate today.

Oil shale technologies must be demonstrated at commercial scale before definitive capital and operating costs of oil shale projects will be known. Cost estimates will vary according to the oil shale resource and the extraction process selected. The Strategic Unconventional Fuels Task Force identified in their report that first-of-a-kind mining and surface retorting plants may be economic, providing a minimum 15 percent rate of return, at sustained average world oil prices of between $44 and $54 per barrel[18]. In-situ processes may be economic at sustained average world oil prices above $30 per barrel. Table 3 presents the Task Force's cost estimates for the various extraction technologies.

Table 3
Estimated Costs and Minimum Economic Prices for Oil Shale Processes[19]

Technology	Average Minimum Economic Price (Dollars per Barrel)	Capital Cost ($1000 per SDB[20])	Operating Costs (Dollars per Barrel)
Surface Mining	$44.24	$40 - $41	$12 - $13
Underground Mining	$54.00	$41 - $42	$16 - $17
Modified In-Situ[21]	$65.21	$27 - $40	$18 - $26
True In-Situ[22]	$37.75[23]	$36 - $56	$19 - $20

Source: *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, February 2007, page III-14, Table III-3. Estimated Costs and Minimum Economic Prices for Oil Shale Processes, (http://www.unconventionalfuels.org).

[18] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, September 2007, page III-14 (http://www.unconventionalfuels.org).
[19] Capital and operating costs are reported in constant 2005 dollars.
[20] Daily stream barrels (SDB) is a measure of an operations productive or installed capacity. Capital costs are the sum of investments needed per barrel of installed capacity. These costs include investments in mining, retorting, solid waste disposal, refining and upgrading, plant utilities, and other facilities.
[21] MIS involves mining below the target shale before heating. Once the shale is mined, the virgin shale is rubblized by explosions to create a void space of 20 to 25 percent. Combustion is started on the top of the rubblized shale and moves down the column. In advance of the combustion front, oil shale is raised to retorting temperature that converts the kerogen to shale oil and to gases. Both products are captured and returned to the surface.
[22] A true in-situ process involves no mining. The shale is fractured, air is injected, the shale is ignited to heat the formation, and shale oil moves through fractures to production wells.
[23] Shell Oil Company has estimated the average minimum economic per barrel price for a true in situ operation to between $35 and $40 per barrel.

Capital and operating costs can be expected to decrease over time with operating experience, improved understanding, design enhancements, and improved operating efficiencies.

Benefits and Costs

The Act requires the DOI to prepare regulations to allow for the leasing and commercial development of oil shale resources on Federal lands. The proposed commercial oil shale leasing and management regulations are the agency's response to the Act and proposed approach to provide companies the opportunity to lease and ultimately develop this strategically important domestic resource. The proposed regulations have the potential to generate net economic benefits to the Nation by allowing for the development of our vast domestic oil shale resources, though there is substantial uncertainty about the magnitude and timing of these benefits. The most significant direct benefit to this regulatory action is to provide a vehicle for the leasing and development of Federal oil shale resources. Operators will have the opportunity to obtain leases with the right to develop the oil shale and ultimately produce shale oil in an environmentally sound manner.

Any assessment of future costs and benefits, including the value of any shale oil that may ultimately be produced, must recognize the significant uncertainties and unknowns. Currently there is no domestic oil shale industry or even a definitive technology for extracting oil from the shale. Estimates of production, capital and production costs, and environmental and socioeconomic consequences of oil shale development are speculative at best.

Discounted Present Value - In addition, it must be recognized that there is a time dimension to the analysis. The potential events described, if they occur at all, may be in the distant future. As such, future costs and benefits must be discounted. The further in the future the benefits and costs are expected to occur, the smaller the present value associated with the stream of costs and benefits. Generally a "discount factor" will be calculated for a given discount rate[24]. The discount factor is then used to convert the stream of costs and benefits into "discounted present values" or simply "present values." When the estimated benefits and costs have been discounted, they can be added to determine the overall value of net benefits[25].

The OMB's basic guidance on the appropriate discount rate to use is provided in OMB Circular A-94[26]. The OMB's Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The OMB considers the 7 percent rate as an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business

[24] The formula is $1/(1+\text{the discount rate})^t$ where "t" measures the number of years in the future that the benefits or costs are expected to occur.
[25] Executive Office of the President, Office of Management and Budget, *Circular A-4*, September 17, 2003 (http://www.whitehouse.gov/omb/inforeg/circular_a4.pdf).
[26] Executive Office of the President, Office of Management and Budget, *Circular A-94*, October 29, 1992 (http://www.whitehouse.gov/omb/circulars/index.html).

capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.

Inherent in any discounting is the opportunity costs, but there is also a risk consideration. There are significant risks and uncertainties associated with every aspect of the leasing and development of oil shale, especially since there is no domestic commercial oil shale industry. With these higher risks, a higher discount may be appropriate. In addition to analyzing the potential future costs and benefits using a 7 percent discount rate, the BLM also used a discount rate of 20 percent to reflect these substantial risks and associated uncertainties in the opportunity costs that would not be reflected in the historic industry average of 7 percent[27]. We also analyzed the future costs and benefits using a 3 percent discount rate.

<u>Shale Oil</u> - The particular section in the Act dealing with oil shale development (Section 369 - *Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005*[28]) makes it clear that sustainable, environmentally sound oil shale development is viewed by Congress as a benefit to the United States. Specifically the potential increase in the domestic oil supply and thus reducing the growing dependence of the United States on politically and economically unstable sources of foreign oil imports must be viewed as a direct benefit of this legislation.

The proposed rule will provide companies the opportunity to benefit from the leasing, development and ultimately production of shale oil from this vast resource. The lack of a domestic oil shale industry makes it speculative to project the demand for oil shale leases, the technical capability to develop the resource and the economics of producing shale oil. Projections that have been prepared vary significantly in not only the potential volume of shale oil that could be produced, but also the assumptions used to generate those projections. For example, the 2005 RAND report concluded shale oil production of 1 million barrels per day, under certain conditions, could be possible within 20 years, and that figure could rise to 3 million barrels per day within 30 years.

The recent report prepared by the Task Force on Strategic Unconventional Fuels provided shale oil production projections under three scenarios[29]. There three scenarios were:

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[27] The 20 percent discount rate is not based on any analysis that the selected rate accurately reflects the greater risks and opportunity costs associated with future oil shale development. We note that discount rates for oil and gas properties are often reported in the high teens and low twenties. The Texas Comptroller of Public Accounts Property, Tax Division, (*2006 Property Value Study - Discount Rate Range for Oil and Gas Properties*, http://www.window.state.tx.us/taxinfo/proptax/drs06/drs06.pdf) reported a discount rate range of 16.80 to 22.27 percent.

[28] Energy Policy Act of 2005 (42 U.S.C. 15927).

[29] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, September 2007, page III-17, Table III- 4. Potential Oil Shale Development Schedule – Base Case, Table III- 5. Potential Oil Shale Development Schedule – Measured Case, and Table III- 6. Potential Oil Shale Development Schedule – Accelerated Case (http://www.unconventionalfuels.org).

- Base Case assumes a price floor of about $40 per barrel;

- Measured Case assumes a $40 per barrel price floor plus a $5 per barrel production tax credit; and

- Accelerated Case assumes a $40 per barrel price floor, a production tax credit, and cost-shared demonstration projects undertaken to reduce the technical risks associated with the development of a new industry.

Under the base case, production is estimated at 0.5 million barrels per day from 2020 through 2035, all from true in-situ projects. The measured case production is estimated at 0.53 million barrels per day by 2020 and peak production is estimated at 1.5 million barrels per day by 2028. For the accelerated case, production is estimated to reach 1.08 million barrels per day by 2020 and peak production is estimated at 2.38 million barrels per day by 2034. The projections presented in the Strategic Unconventional Fuels Task Force report were based on a number of assumptions, including[30]:

- Those current technologies are successfully demonstrated to be viable at commercial scale over the next five to ten years. To the extent that this is not achieved, the development of the resource will be impeded.

- That the environmental permitting process for the projects could be completed within three to five years. To the extent that the permitting process is not streamlined, and additional time is required, the timing of the production will be impacted.

- The analysis is based on the Department of Energy, Energy Information Administration's Annual Energy Outlook (AEO) 2006 oil price projection over the next 25 years. To the extent that the prevailing oil prices over this period are different from the AEO projections, the estimated benefits will be impacted.

- The economics are based on the use of average costing algorithms. Although developed from the best available data and explicitly adjusted for variations in energy costs, they do not reflect site-specific cost variations applicable to specific operators. To the extent that the average costs understate or overstate the true project costs, the actual results will be impacted accordingly.

- The estimates of potential contribution to gross domestic product, values of imports avoided, and employment do not take into account potential impacts to other sectors of the U.S. economy from altering trade patterns. It is possible that reduction in petroleum imports, depending on where the petroleum was coming from, could reduce the quantity being exported of some other good. It is likely, however, that such effects would be small.

[30] Ibid, page III-26.

- Those operators have access to capital to start and sustain the projects. The unconventional fuels projects are typically characterized as "capital intensive" and have longer payback period relative to oil and gas development projects. To the extent that capital constraints exist, then the potential benefit estimated in this report is overestimated.

For our simulation based analysis, we focused on the Strategic Unconventional Fuels Task Forces' base case as a plausible scenario. This scenario presents a future without any subsidies in the form of tax credits or cost-sharing. All production in the base case is assumed to come from three true in-situ operations[31].

The base case production of 0.5 million barrels per day is approximately 182.50 million barrels per year. The Task Force estimates that resulting production could reduce the cost of oil imports by $0.41 billion per year in 2015 to $4.21 billion per year in 2035[32]. This estimate is based on EIA's 2006 oil price projection. In their report, the Task Force also provides estimates of oil shale development's contribution to GDP. In the base case, annual direct contributions to GDP for the oil shale industry activity rises from $0.65 billion per year in the early years, to $5.72 billion per year in 2035.

We estimated the revenue, profit, and royalty implication of such a production scenario using three discount rates (7 percent, 3 percent, and 20 percent), three world crude oil price projections (EIA's 2007 reference, high, and low price projections[33]) and six different royalty rates (1 percent, 3 percent, 5 percent, 7 percent, 9 percent, and 12.5 percent). The full calculations and results are reported in Appendix A. Tables 4, 5 and 6 present summaries of our findings with 5 percent and 12.5 percent royalty.

We estimate the value of the forecasted production, using EIA's 2007 reference case assumptions, could be approximately $9.5 billion[34] for 2020, up to $11 billion by 2035[35]. The gross present value, using a 7 percent discount rate, of all shale oil produced for the period of analysis (2007 to 2035) is estimated at about $50 billion. The gross present value of production for the year 2020 is estimated at about $3.9 billion and for 2035 we estimate $1.7 billion with a 7 percent discount rate.

Using a 3 percent discount rate, as required by the Circular A-4, the gross present value of all shale oil produced from 2007 to 2035, under EIA's reference case, is estimated at

[31] In-situ production of shale oil includes wells or shafts to access and heat the shale, recover liquids and gases, and isolate and protect subsurface environments (subsurface facilities), and production pumps and gathering systems, process controls, and upgrading facilities (surface facilities).

[32] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, September 2007, page III-21 (http://www.unconventionalfuels.org).

[33] Department of Energy, Energy Information Administration, Annual Energy Outlook 2007, Report #: DOE/EIA-0383(2007), February 2007.

[34] Unless noted otherwise all revenue, cost, profit and royalty figures are reported in constant 2005 dollars.

[35] Oil price projects provided in AEO 2007 only went out to 2030. We extended these projections to the year 2035 by inflating their price projection by the average increase over the final 5 years (2025-2030) of the forecast: 0.7 percent per year for the reference case, 1.0 percent for the high price case, and 0.5 percent for the low price case.

$182 billion. For 2020 the gross present value of the oil produced would be approximately than $9.5 billion, and the gross present value of the production in 2035, using a 3 percent discount rate, is estimated at about $11.3 billion.

Because of opportunity costs associated with the high risk in the natural resource extraction industries, specifically the energy sector, we also ran the same analysis using a 20 percent discount rate[36]. The gross present value of all shale oil produced from 2007 to 2035 is estimated at $7.3 billion. For 2020 the gross present value of the oil produced would be less than $0.9 billion, and the gross present value of the production in 2035, using a 20 percent discount rate, is estimated at about $70 million.

[36] This rate is not the result of any conclusive study on appropriate rates for oil shale development. However, 20 percent does fall within the range of discount rates often applied to oil and gas properties.

Table 4
Simulated Scenario Summary with 5 Percent Royalty Rate[37]

Year	2020[38]	2035	Total[39]
Shale Oil Production (millions of barrels per year)	182.50	182.50	3194
Discounted Revenue (millions of dollars per year)[40]			
Low Price/7% Discount	2582	1004	31283
Low Price/3% Discount	4238	2918	63326
Low Price/20% Discount	582	40	4647
Reference/7% Discount	3941	1680	49920
Reference/3% Discount	6457	4883	101743
Reference/20% Discount	888	68	7271
High Price/7% Discount	6749	2883	84334
High Price/3% Discount	11075	8379	172031
High Price/20% Discount	1520	116	12254
Discounted Profit @ 5% Royalty (millions of dollars per year)[41]			
Low Price/7% Discount	-405	-82	-4102
Low Price/3% Discount	-665	-239	-8004
Low Price/20% Discount	-91	-3	-665
Reference/7% Discount	885	560	13603
Reference/3% Discount	1453	1628	28493
Reference/20% Discount	199	23	1828
High Price/7% Discount	3553	1703	46296
High Price/3% Discount	5830	4949	95266
High Price/20% Discount	800	69	6562
Discounted Royalties @ 5% Royalty (millions of dollars per year)[42]			
Low Price/7% Discount	129	50	1564
Low Price/3% Discount	212	146	3166
Low Price/20% Discount	29	2	232
Reference/7% Discount	197	84	2496
Reference/3% Discount	323	244	5087
Reference/20% Discount	44	3	364
High Price/7% Discount	337	144	4217
High Price/3% Discount	554	419	8602
High Price/20% Discount	76	6	613

[37] Detailed calculations are presented in Appendix A-1 through A-9.
[38] In the Task Forces' base case scenario, the year 2020 reflects the highest annual discounted production value. The year 2035 is the final year of the period of analysis.
[39] Total production, revenue, profit and royalty figures are for the period of analysis (2015-2035).
[40] All revenue, profit, and royalty figures are million dollars (constant 2005 dollars) per year.
[41] Profits and royalties are calculated on the defined production scenario even where operations are calculated to be operating at a loss.
[42] Royalty calculations are based on a fixed production scenario regardless of oil price and operator revenue losses.

Table 5
Simulated Scenario Summary with 12.5 Percent Royalty Rate[43]

Year	2020[44]	2035	Total[45]
Shale Oil Production (millions of barrels per year)	182.50	182.50	3194
Discounted Revenue (millions of dollars per year)[46]			
Low Price/7% Discount	2582	1004	31283
Low Price/3% Discount	4238	2918	63326
Low Price/20% Discount	582	40	4647
Reference/7% Discount	3941	1680	49920
Reference/3% Discount	6457	4883	101743
Reference/20% Discount	888	68	7271
High Price/7% Discount	6749	2883	84334
High Price/3% Discount	11075	8379	172031
High Price/20% Discount	1520	116	12254
Discounted Profit @ 12.5% Royalty (millions of dollars per year)[47]			
Low Price/7% Discount	-599	-158	-6448
Low Price/3% Discount	-983	-458	-12753
Low Price/20% Discount	-135	-6	-1013
Reference/7% Discount	590	434	9659
Reference/3% Discount	968	1262	20862
Reference/20% Discount	133	18	1283
High Price/7% Discount	3047	1487	39971
High Price/3% Discount	5000	4320	82364
High Price/20% Discount	686	60	5643
Discounted Royalties @ 12.5% Royalty (millions of dollars per year)[48]			
Low Price/7% Discount	323	126	3910
Low Price/3% Discount	530	365	7916
Low Price/20% Discount	73	5	581
Reference/7% Discount	493	210	6240
Reference/3% Discount	808	610	12718
Reference/20% Discount	111	8	909
High Price/7% Discount	844	360	10542
High Price/3% Discount	1384	1047	21504
High Price/20% Discount	190	15	1532

Production Costs – Oil shale development is characterized by high capital investment and long periods of time between expenditure of capital and the realization of production revenues and return on investment. Revenues are uncertain because future market prices for shale oil and byproducts, as well as crude oil, are unknown. Therefore, a key

[43] Detailed calculations are presented in Appendix A-1 through A-9.
[44] In the Task Forces' base case scenario, the year 2020 reflects the highest annual discounted production value. The year 2035 is the final year of the period of analysis.
[45] Total production, revenue, profit and royalty figures are for the period of analysis (2015-2035).
[46] All revenue, profit, and royalty figures are million dollars (constant 2005 dollars) per year.
[47] Profits and royalties are calculated on the defined production scenario even where operations are calculated to be operating at a loss.
[48] Royalty calculations are based on a fixed production scenario regardless of oil price and operator revenue losses.

economic barrier to private development is the inability to predict when profitable operations will begin. The economic risk associated with this uncertain outcome is magnified by the unusually large capital exposure, measured in billions of dollars per project, required for development.

Once commercial operation is successfully demonstrated, capital and operating costs will fall as the industry matures and learns how best to economically develop the resource. If oil prices remain at levels that justify further investments, second and third generation technology may improve profitability, and the relative economics of oil shale development will become more attractive.

The Task Force on Strategic Unconventional Fuels' base case production projection assumes all produced shale oil will come from three true in-situ operations. The Task Force also estimated the breakeven price for true in-situ operations at $37.75 per barrel (Table 3).

Using the base case production projection, the cost to produce 182.50 million barrels annually would be almost $6.9 billion (Appendix A-1 through A-9). The present value of the production costs for 2020 would be about $2.9 billion using a 7 percent discount rate, $644 million using a 20 per cent discount rate, and $6.9 billion using a 3 percent discount rate. For production occurring in 2035, the present value of those production costs would be about $1 billion with a 7 percent discount rate, $42 million using a 20 percent discount rate, and $3 billion with a 3 percent discount rate. For the period of analysis (2007 to 2035), the present value of all production costs is estimated at about $34 billion using a 7 percent discount rate, $5 billion using a 20 percent discount rate, and $68 billion using a 3 percent discount rate.

Profits - With the opportunity to lease and ultimately develop Federal oil shale resources, companies would be expected to generate profits from their commercial activities. Using the revenue and cost projections presented above including EIA's reference oil price and a 5 percent royalty rate, by the year 2020 lessees/operators could see profits from oil shale development of over $2.1 billion per year, with a net present value of $885 million with a 7 percent discount rate, $199 million using a 20 percent discount rate and $1.5 billion using a 3 percent discount rate (Table 4). For 2035, we estimate the present value of the potential profit could be approximately $560 million using a 7 percent discount rate, $23 million using a 20 percent discount rate and $1.6 billion using a 3 percent discount rate. The net present value of shale oil produced in the period of analysis (2007 to 2035) is estimated at approximately $13.6 billion using a 7 percent discount rate, $1.8 billion using a 20 percent discount rate and $28.5 billion using a 3 percent discount rate.

Using the same scenario except with a 12.5 percent royalty (Table 5), the net present value of shale oil produced in the period of analysis (2007 to 2035) is estimated at approximately $9.7 billion using a 7 percent discount rate, $1.3 billion using a 20 percent discount rate and $20.9 billion using a 3 percent discount rate.

Using EIA's high crude oil price scenario, calculated profits were substantially high. Total undiscounted profits for the period of analysis with a 5 percent royalty rate were $171.2 billion, with a present value of $46.3 billion (7 percent discount rate), $6.5 billion (20 percent discount rate) and $95.3 billion (3 percent discount rate). At the higher price scenario and applying a 12.5 percent royalty rate, the net present value of shale oil produced in the period of analysis is estimated at approximately $40 billion using a 7 percent discount rate, $5.6 billion using a 20 percent discount rate and $82.4 billion using a 3 percent discount rate. For EIA's low oil price projection all operations are uneconomic regardless of the discount rate and/or royalty rate applied.

Environmental and Socioeconomic Impacts - Most of the following discussion of the potential environmental and socioeconomic impacts is taken from the PEIS and the Task Force on Strategic Unconventional Fuels' report. By necessity, most of the discussion of potential impacts is qualitative. The Task Force's base case scenario is used to provide some quantification, however, without a better understanding of the technology, timing, and location of any potential development quantifying potential impacts is problematic.

Future oil shale development could entail significant environmental and socioeconomic consequences. A wide range of resources and resource uses could be affected including groundwater quality and quantity, air quality, cultural resources, wildlife habitat, competing land uses, and local employment and infrastructure.

Should full scale commercial oil shale development occur, it is anticipated to involve large parcels of Federal land. In addition to the disturbance directly associated with extraction and retorting processes, power generation, transmission lines, pipelines, housing, and other surface uses could occupy many thousands of acres of land. These lands, both private and public, currently host a wide range of uses. Current uses of the Federal lands include various types of recreational activity, grazing, wildlife habitat, and mineral development. Even with proper mitigation, remediation and reclamation to address long-term conflicts, while operations are active, oil shale development, even in situ operations, may not be compatible with some of the existing land uses in areas of active development. These potentially displaced uses represent an opportunity cost to society of allowing oil shale leasing and development to occur on Federal lands.

Grazing activities, recreational uses, and other mineral uses could be precluded from areas where commercial oil shale development activities are occurring, depending on the type of extraction technology employed. In addition, there are a number of "use values" such as the benefit of being in close proximity to a wilderness or clean water, or being able to see wildlife that could be potentially impacted by oil shale development. While these other land uses and use values could be possible in undeveloped or restored portions of the lease area, the amount of land that would be available would vary from project-to-project. The change in the overall character of the undeveloped BLM-administered lands to a more industrialized, developed area would displace people seeking more primitive surroundings in which to hunt, camp, ride off-highway vehicles, etc. Impacts on vegetation, development of roads, and displacement of big game could degrade the recreational experiences and hunting opportunities near commercial oil shale projects.

Grazing - Impacts on livestock grazing activities are generally the result of activities that affect forage levels, of the ability to construct range improvements, and of human disturbance/harassment of livestock within grazing allotments. In the draft EIS for the Little Snake Resource Management Plan[49], the analysis assumes the average forage production in the study area to be 0.33 animal unit months (AUMs) per acre. Using the Task Force's base case scenario of three in-situ operations, with total maximum lease acreage of 17,280, there could be a loss of approximately 5,700 AUMs. This simple example assumes total incompatibility between oil shale development and grazing, and does not recognize the significant variation in AUMs for different plant communities[50]. Prior to authorization of development, subsequent NEPA documentation will address oil shale development and grazing conflicts.

Recreation Uses - Recreational use of BLM-administered lands within the three-state study area (Colorado, Utah, and Wyoming) is varied and dispersed. Specific recreational sites and use areas have been designated by the BLM throughout the region. Generally, the BLM provides recreational opportunities where they are compatible with other authorized land uses, while minimizing risks to public health and safety and maintaining the health and diversity of the land. The Recreation Opportunity Spectrum (ROS) is one of the means that the BLM uses to inventory, plan, and manage recreational use. Seven elements provide the basis for inventorying and delineating recreational settings: access, remoteness, naturalness, facility and site management, visitor management, social encounters, and visitor impacts. The PEIS[51] provides a partial listing of the many recreational areas and other areas that may provide recreation opportunities located within a 50-mile radius of the oil shale resources. The extent of the list demonstrates the overall importance of recreational land use and the large variety of recreation areas in the region.

Impacts on recreation would be considered significant if potential oil shale development results in long-term elimination or reduction of recreation opportunities, activities, or experience, or they compromise public health and safety. As such, the significant of potential impacts from oil shale development could have on recreational opportunities will depend on the location of potential development. Recreation conflicts will be discussed in future environmental analyses.

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[49] Little Snake Resource Management Plan, Draft Environmental Impact Statement, U.S. Department of the Interior, Bureau of Land Management, Little Snake Field Office, Colorado, January 2007 (http://www.blm.gov/co/st/en/fo/lsfo/plans/rmp_revision/rmp_docs.html#DEIS).

[50] Although the area covered by the Little Snake RMP is in western Colorado the resource values, land uses, plant communities, etc. do not necessarily reflect the uses and values for all areas that may potentially experience oil shale development.

[51] Oil Shale and Tar Sands Draft Programmatic Environmental Impact Statement, U.S. Department of the Interior, Bureau of Land Management, 3.1.2 Recreational Land Use in the Three-State Study Area, December 2007 (http://ostseis.anl.gov/documents/dpeis/vol1/OSTS_DPEIS_Vol1_Ch3.pdf).

Energy and Mineral Resources - In addition to oil shale, the study area contains a wide range of energy and mineral resources[52]. Mineral development, specifically oil and gas, is a major contributor to the local economies.

The Piceance Basin contains the sodium minerals halite, dawsonite, and nahcolite, which are intermingled with the oil shale. Nahcolite is sodium bicarbonate and may be used as soda ash, to remove sulfur from industrial air emissions, and as cattle feed supplement. Dawsonite is dihydroxy sodium aluminum carbonate and is found in the lower portion of the northern province of the Piceance Basin. Inter-bedded halite and oil shale are found in a sequence in the northern province of the Piceance Basin. In a surrounding area set aside for sodium leasing, sodium mineral extraction is not allowed to damage oil shale units.

Oil, natural gas, and coal are also present in the Piceance Basin. The most productive zone is at the base of the Green River Formation. Other productive sandstones are up to 6,000 feet deeper than the Green River Formation. Extensive natural gas drilling is occurring in the southern portion of the northern Piceance province. Coal underlies essentially the entire basin. Oil and gas have been produced from the lower part of the Green River Formation, the Wasatch Formation, and deeper Mesozoic-age rocks.

According to the DOI, sodium minerals have not been discovered in the Washakie Basin. The central Green River Basin, however, has economic deposits of trona and halite in the Wilkins Peak Member of the Green River Formation. Oil and natural gas are present in the Wasatch, Fort Union, and Mesaverde Formations and have been produced in commercial quantities at locations surrounding the Washakie Basin. These formations underlie the basin at depths several thousand feet below the lowermost Green River Formation oil shale. Coal is also present below the oil shale in the Green River and Washakie Basins.

Mineral resource development conflicts may occur with oil shale development. The issuance of oil shale exploration licenses and leases does not preclude BLM from issuing licenses and leases for other minerals. However, BLM generally attempts to avoid issuing conflicting authorizations on the same lands.

Non-Market Uses and Values - Many multiple use outputs from BLM land are not traded in markets and might not have measurable onsite expenditures associated with them. Without expenditures, or prices, it becomes problematic to include these uses in a regional economic analysis. However, the absence of market price does not mean an absence of value to society. For a resource to have economic value, it must provide some individuals with enjoyment or satisfaction and be scarce. These criteria are met for a variety of multiple use outputs, such as clean water, wild horses, wilderness, nongame wildlife, etc. These non-market uses and values would need to be considered in any

[52] Oil Shale and Tar Sands Draft Programmatic Environmental Impact Statement, U.S. Department of the Interior, Bureau of Land Management, 3.2 Geological Resources and Seismic Setting, December 2007 (http://ostseis.anl.gov/documents/dpeis/vol1/OSTS_DPEIS_Vol1_Ch3.pdf).

subsequent environmental analysis required for leasing decisions and also development plan approval.

Water Resources – In addition to land use conflicts, water consumption is a major concern in the arid intermountain region. Certain types of oil shale development are anticipated to consume significant quantities of water. Increasing the demand for water resources in the arid West must be considered a major opportunity cost to society associated with oil shale development and fully analyzed before commercial development is allowed to proceed.

The oil shale is present in the White River hydrologic basin in Colorado, the Uinta Basin in Utah, and the Green River Basin in Wyoming. Water use in the Colorado River Basin is highly regulated.

The use of the Colorado River Basin water is shared by many states and Mexico. On the basis of the Colorado River Compact of 1922, the Colorado River Basin is divided into the Upper Colorado River Basin and Lower Colorado River Basin at Lee's Ferry (just below the confluence of the Paria River and the Colorado River near the Utah-Arizona boundary). The upper basin and the lower basin were each apportioned a consumptive use of 7.5 million acre-feet (ac-ft) of water annually, based on an assumption of 15 million ac-ft of totally available water for the Colorado River. The assumption was demonstrated to be an overestimate and reduced to 12 million ac-ft in a hydrologic study by the U. S. Bureau of Reclamation. In the Upper Colorado River Basin Compact of 1948, the water of the Upper Colorado River Basin was further allocated among the states of Arizona, Colorado, New Mexico, Utah, and Wyoming. Arizona has a fixed allocation of 50,000 ac-ft annually. The remainder is shared by Colorado (51.75 percent), New Mexico (11.25 percent), Utah (23 percent), and Wyoming (14 percent). A detailed discussion of the current water demand and the water consumption in Colorado, Utah, and Wyoming in the Upper Colorado River Basin can be found in the PEIS[53].

Generally, water demand in the Upper Colorado River Basin cannot be totally met because the availability of water is limited by physical streamflow conditions, water rights (physically and legally available water, respectively), and lack of storage facilities. In addition, infrastructure for storage (reservoirs) and delivery systems is required to send physically and legally available water to end users. In many agricultural areas, the lack of financial resources often limits the construction of infrastructure, thereby reducing potential agricultural water use. These result in a disparity between high water demand and relatively lower consumptive water use. The infrastructure also dictates water supply availability.

Environmental and recreation water use to maintain in stream flows are not considered consumptive water use. Oil shale basins are situated in much smaller areas. Hydrologic basins enriched with surplus water resources are not necessarily coincident with the oil

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[53] Oil Shale and Tar Sands Draft Programmatic Environmental Impact Statement, U.S. Department of the Interior, Bureau of Land Management, 3.4 Water Resources, December 2007 (http://ostseis.anl.gov/documents/dpeis/vol1/OSTS_DPEIS_Vol1_Ch3.pdf).

shale basins. Storage infrastructures and delivery systems have to be built to capture water for use. Also, water rights and water storage rights (for reservoirs) have to be transferred or purchased before the water can be used for development, as most of the water and storage rights have been claimed in the Upper Colorado River Basin. Finally, water use for oil shale development must meet different state and Federal regulations, including requirements to protect in stream flows for endangered Colorado River fishes in the basin. All in all, whether enough water is available for oil shale development depends on the results of intensive negotiations between various parties, including water right owners, state and Federal agencies, and municipal water providers, as well as the developers.

Demand for reliable, long-term water supplies to support oil shale development could lead to the conversion of water rights from current uses. While it is not presently known how much surface water will be needed to support future development of an oil shale industry, or the role that groundwater would play in future development, it is likely that additional agricultural water rights could be acquired. Depending on the locations and magnitude of such acquisitions, there could be a noticeable reduction in local agricultural production and use. Water use, availability and the extent of impact would be evaluated in subsequent environmental analyses.

The base case scenario envisioned by the Task Force on Strategic Unconventional Fuels[54] assumes true in-situ development of the shale oil. True in-situ recovers oil *without* first creating void spaces. Many of the issues associated with surface and underground mining, and spent shale disposal do not apply to in-situ processes. However, other subsurface impacts, including ground water contamination, are possible and must be controlled.

During project construction, soil can be affected as a result of removal or compaction (e.g., during site clearing and grading, foundation excavation and preparation, and pipeline trenching), and by erosion during project construction and operation (e.g., erosion of exposed soils in construction areas or of topsoil stockpiles). Erosion of exposed soils can also lead to increased sedimentation of nearby water bodies and to the generation of fugitive dust, which can affect local air quality.

The potential impacts to water resources can include degradation of surface water quality caused by increased sediment load or contaminated runoff from project sites, alteration of natural drainages by both diverting and concentrating natural runoff, and surface disturbances that might become a source of sediment and dissolved salts, metals, and hydrocarbons. Additional water may be required for in situ projects including water for hydro-fracturing, steam generation, water flooding, quenching of kerogen products at production holes, cooling of productive zones in the subsurface, cooling of equipment,

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[54] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, September 2007, page III-17, Table III- 4. Potential Oil Shale Development Schedule – Base Case, Table III- 5. Potential Oil Shale Development Schedule – Measured Case, and Table III- 6. Potential Oil Shale Development Schedule – Accelerated Case (http://www.unconventionalfuels.org).

and rinsing of oil shale after the extraction cycle. Depending on the quality of the shale oil produced directly from in-situ processes, water may be required for additional processing of the product at the surface. In general, the potential impacts on water resources are closely related to the technologies used to mine, extract, process, and upgrade the shale oil from the source rocks. Impacts can be reduced tremendously starting from the planning stage. Local hydrologic conditions, including those of surface water and groundwater and the interactive relationship between them, can be characterized and considered in selecting development sites, access roads, pipelines, transmission lines, and/or reservoirs. Sensitive areas can be avoided or receive special attention during the planning of oil shale development activities.

In conjunction with its in-situ conversion process (ICP) currently being tested in Colorado, Shell Oil Company developed an environmental barrier system called a "freeze wall" to isolate the in-situ process from local groundwater. The freeze wall would be created by freezing ground water occurring in natural fractures in the rock into a ring wall surrounding the area to be heated. This barrier protects groundwater from contamination with products liberated from the kerogen while at the same time keeping water out of the area being heated. Once extraction is completed, the remaining rock within the freeze wall would be flushed with water and steam to remove any remaining hydrocarbons and to recover heat from the spent reservoir. Once the area has been sufficiently cleaned, the freeze wall would be allowed to melt and groundwater can flow through this area once more.

Air Resources - The PEIS presents annual emission inventory data for criteria pollutants and volatile organic compounds (VOC) for counties within the study area in Colorado, Utah, and Wyoming. The emission inventory is based on six categories: area, biogenic, fire, nonroad, onroad, and point air pollutant emission sources, including existing transportation, mining, manufacturing, and oil and gas emission sources. In Colorado, fire, including wildfire, prescribed fire, and agricultural burning, was a major contributor to total emissions of carbon monoxide and particulate matter. Stationary point sources accounted for about 72 percent of the sulfur oxides emissions and 41 percent of the nitrogen oxides emissions. Biogenic sources (e.g., naturally occurring emissions from vegetation, including trees, plants, and crops) accounted for most of the VOC emissions. Onroad sources and area sources were secondary contributors to nitrogen oxides and carbon monoxide emissions and particulate matter, respectively. Nonroad sources were minor contributors to all pollutants in Colorado. For Utah, major and secondary contributors were similar to those in Colorado, although the levels of emissions were different. In Wyoming, stationary point sources were a major contributor to total emissions of sulfur oxides, nitrogen oxides, particulate matter, while onroad emissions accounted for about half of the carbon monoxide emissions. Biogenic sources composed the predominant source for VOC emissions. Area sources were secondary contributors to particulate matter, while nonroad and fire were minor contributors in Wyoming.

The PEIS also presents the National Ambient Air Quality Standards (NAAQS) and the State Ambient Air Quality Standards (SAAQS) for Colorado, Utah, and Wyoming for six criteria pollutants—sulfur dioxide, nitrogen dioxide, carbon monoxide, ozone, particulate matter, and lead. In Utah, the standards are equivalent to the NAAQS for each pollutant. Colorado has more stringent standards than the NAAQS for sulfur oxides and lead. In addition, the State of Wyoming has adopted standards for hydrogen sulfide, suspended sulfates, fluorides, and odors, as well as more stringent standards for sulfur oxides.

The existing air quality of the study area is in attainment with all ambient air quality standards. No major population centers or industrial complexes occur within the study area. Accordingly, all counties containing oil shale resources are currently in attainment for all criteria pollutants. One exception is Utah County, in which a small portion of resources are located, which is currently designated as a nonattainment area for particulate matter. A request for redesignation of Utah County to an attainment area is pending U. S. Environmental Protection Agency (EPA) approval, since significant emission reductions from one steel plant have resulted in improved air quality.

The Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21), which are designed to limit the growth of air pollution in "clean" areas, apply to all new sources within attainment and unclassified areas. The PSD regulations limit the amount of additional air pollution above legally established baseline levels of sulfur oxides, nitrogen oxides, and particulate matter. Incremental increases in PSD Class I areas are strictly limited, while those in Class II areas allow for moderate emission growth. Most of the oil shale resource areas are classified as PSD Class II, except for the oil shale area immediately upwind of the Flat Tops Wilderness Area in Colorado.

Most U. S. western oil shale source rock is a carbonate-based kerogen-bearing marlstone. Retorting involves heating the source rock, embedded with kerogen, to temperatures of approximately 500 degrees centigrade. Heating carbonate rock to these temperatures generates not only shale oil, but also a mixture of gases, some of which can be beneficially captured and re-used in plant operations or sold for conventional energy use. The off-gases and stack gases of oil shale processes principally contain: oxides of sulfur and nitrogen, carbon dioxide, particulate matter, water vapor, and hydrocarbons. Also, a potential exists for the release of other hazardous trace materials into the atmosphere. Commercially available stack gas cleanup technology could be used to limit emissions to within permitted quantities. Regulated gases, such as sulfur oxides, would need to be captured and processed, or otherwise treated.

The plant design requirements would need to be responsive both to the prevailing regulatory environment, and to possible future requirements for carbon dioxide capture and sequestration. With significant conventional oil production in close proximity to the oil shale regions of Utah, Colorado, and Wyoming, potential beneficial use for significant quantities of carbon dioxide for improved oil recovery may exist. Opportunities may also exist to sequester carbon dioxide from oil shale operations in depleted oil and gas reservoirs, and in the coal deposits in the region. Sequestering in coal beds could lead to significant natural gas coal bed methane production.

Other produced gases, nitrogen oxides and sulfur oxides, could most likely be controlled using commercially-proven technologies developed for petroleum refining and coal-fired power generation. Prospective oil shale developers would need to employ appropriate control technologies to reduce potential air emissions which otherwise could result from construction and operation of surface facilities.

In addition to the emissions associated with the operations themselves, extraction of oil from shale could consume immense quantities of electricity. This would necessitate the building of new power plants, more than likely coal-fired, which could further contribute air emissions.

Impacts on air quality would be limited by applicable local, state, Tribal, and Federal regulations, standards, and implementation plans established under the Clean Air Act (CAA) and administered by the applicable air quality regulatory agency, with EPA oversight. These agencies include, but are not limited to, the Colorado Department of Public Health and Environment–Air Pollution Control Division (CDPHE-APCD), the Utah Department of Environmental Quality–Division of Air Quality (UTDEQ-DAQ), and the Wyoming Department of Environmental Quality–Division of Air Quality (WYDEQ-DAQ). Air quality regulations require that proposed new or modified existing air pollutant emission sources undergo a permitting review before their construction can begin. Therefore, these state agencies 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.

The U.S. Congress (through CAA Section 116) authorized local, state, and Tribal air quality regulatory agencies to establish air pollution control requirements more (but not less) stringent than Federal requirements. In addition, under the CAA and FLPMA, Federal agencies 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.

Before oil shale development could occur, additional project-specific NEPA analyses would be performed, subject to public and agency review and comment. The applicable air quality regulatory agencies (including the states and EPA) would also review site-specific preconstruction permit applications to examine potential project-wide air quality impacts. As part of these permits (depending on source size), the air quality regulatory agencies could require additional air quality impact analyses or mitigation measures. Those evaluations would take into consideration the specific project features being proposed (e.g., specific air pollutant emissions and control technologies) and the locations of project facilities (including terrain, meteorology, and spatial relationships to sensitive receptors.) Project-specific NEPA assessments would predict site-specific impacts, and these detailed assessments (along with BLM consultations) would result in the required actions by the applicant to avoid or mitigate significant impacts.

Under no circumstances can the BLM conduct or authorize activities that would not comply with all applicable local, state, Tribal, or Federal air quality laws, regulations, standards, or implementation plans. All air quality issues would be evaluated in greater detail in subsequent environmental analyses.

Solid Waste - Using the assumption of 3 in-situ projects, solid waste generated would be the drill cuttings and those would be handled as they are for oil and gas, which is to bury them on-site, in compliance with the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act and the Hazardous Solid Waste Amendments of 1984 (42 U.S.C. 6901 et seq.). Solid wastes generated during operations by coal-fired power plants would consist of fly ash and bottom ash. It is assumed that newly constructed units would be required to conform to new source production standards (BLM does not regulate coal-fired power plants). In addition to the Solid Waste Disposal Act, all three states and several of the counties within the three states have 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 on public lands in Colorado, Utah, and Wyoming.

Aquatic Resources - Aquatic habitats include perennial and intermittent streams, springs, and flatwater (lakes and reservoirs) that support fish or other aquatic organisms through at least a portion of the year. The oil shale study areas fall within the Upper Colorado River Basin hydrographic area. Aquatic habitats of the Upper Colorado River Basin in Colorado, Utah, and Wyoming include more than 300,000 acres of natural lakes and impoundments and more than 10,000 miles of perennial streams: Of these, approximately 36,000 acres of reservoir habitat (Flaming Gorge Reservoir) and about 650 miles of perennial stream habitat occur within the geologically prospective portions of the oil shale study area.

Historically, only 12 species of fish were native to the Upper Colorado River Basin, including 5 minnow species, 4 sucker species, 2 salmonids, and the mottled sculpin. Four of these native species (humpback chub, bonytail, Colorado pikeminnow, and razorback sucker) are now federally-listed as endangered and critical habitat for these species has been designated within the Upper Colorado River Basin. In addition to native fish species, more than 25 non-native fish species are present in the basin, often as a result of intentional introductions (e.g., for establishment of sport fisheries). While most of the trout species found within the Upper Colorado River Basin are introduced non-natives (e.g., rainbow, brown, and some strains of cutthroat trout), mountain whitefish and Colorado River cutthroat trout are native to the basin. Although it was once common within the upper Green River and upper Colorado River watersheds, the Colorado River cutthroat trout is now found only in isolated subdrainages in Colorado, Utah, and Wyoming.

Plant Communities and Habitats – The PEIS discusses the various ecoregions encompassed by the oil shale study area (i.e., counties within which commercial-scale development may occur) that include a diversity of plant communities and species which, in turn, provide a wide range of habitats that support diverse assemblages of terrestrial wildlife.

Wildlife - The wildlife species that may be associated with any particular project would depend on the specific location of the project and on the plant communities and habitats present at the site.

Wildlife management programs are largely aimed at habitat protection and improvement. The general objectives of wildlife management are to: (1) maintain, improve, or enhance wildlife species diversity while ensuring healthy ecosystems; and (2) restore disturbed or altered habitat with the objective of obtaining desired native plant communities, while providing for wildlife needs and soil stability. The BLM has active wildlife and wild horse management programs within each of its field offices.

Amphibians and Reptiles - The counties within the three states in which oil shale development may occur on BLM-administered land support a wide variety of amphibian (frogs, toads, and salamanders) and reptile (turtles, lizards, and snakes) species. The number of amphibian species reported from the oil shale study areas within these states ranges from 6 in Wyoming to 18 in Colorado, while the number of reptile species ranges from 10 in Wyoming to 49 in Colorado.

Birds - Several hundred species of birds have been reported from the three states where oil shale development may occur: 290 for Colorado, 264 for Utah, and 318 for Wyoming. The number of species listed for each state does not imply that all species could be found in a potential oil shale development area. Many of the bird species identified from the three states are also seasonal residents within individual states and exhibit seasonal migrations. These birds include waterfowl, shorebirds, raptors, and neotropical songbirds. The area where commercial-scale oil shale and development may occur on BLM-administered lands falls primarily within the Central Flyway. Birds migrating north from wintering areas to breeding areas use this flyway in the spring, and birds migrating southward to wintering areas use it in the fall. The flyway encompasses a broad geographic area and includes a number of specific routes that would be an important parameter for identifying site-specific concerns related to migratory birds.

Mammals - More than 75 species of mammals have been reported in the PEIS from each of the three states where oil shale development may occur on BLM-administered lands (82 from Colorado, 76 from Utah, and 96 from Wyoming). Within the area big game and small mammal species: (1) have key habitats within or near the study area that could be developed for oil shale; (2) are important to humans (e.g., big game species); and/or (3) are representative of other species that share important habitats.

Big Game - Big game species within the study area include elk (*Cervus elaphus*), mule deer (*Odocoileus hemionus*), pronghorn (*Antilocarpra americana*), bighorn sheep (*Ovis canadensis*), moose (*Alces americanus*), American black bear (*Ursus americanus*), and mountain lion (*Felis concolor*). The elk and mule deer are generally the most abundant, widely distributed, intensely managed, and sought-after big game in the region. A number of the big game species make migrations when seasonal changes reduce food availability, when movement becomes difficult (e.g., due to snowpack), or where local conditions are not suitable for calving or fawning.

Threatened and Endangered Species - A total of 210 plant and animal species are either federally (U. S. Fish and Wildlife Service (USFWS) and BLM) or state-listed (Colorado, Utah, and, Wyoming) and occurs or could occur in counties within oil shale basins. These species and their habitats are presented in the PEIS. In the study areas, 32 species are listed or candidates for listing by the USFWS under the Endangered Species Act (ESA); 78 species are listed as sensitive by the BLM; 24 are listed by the State of Colorado; 33 are listed by the State of Utah; and 121 are listed by the State of Wyoming. Species listed by the USFWS under the ESA have the potential to occur in all oil shale basins. The likelihood of occurrence in study areas cannot be fully determined at this time because actual project locations and footprints will not be determined until some later date. A complete evaluation of listed species in the study areas will be made at that time, before project activities begin. Listed species that could occur in the study areas (based on state and Federal records) are discussed in the PEIS.

The PEIS discusses the potential impacts of oil shale development on Threatened and Endangered Species. The evaluation in the PEIS presents the potential for impacts on federally or state-listed threatened or endangered species, BLM-designated sensitive species, or species that are proposed or candidates for listing if development occurs. Project-specific NEPA assessments, ESA consultations, and coordination with state natural resource agencies will address project specific impacts more thoroughly. These assessments and consultations will result in required actions to avoid or mitigate impacts on protected species.

The potential for impacts on threatened, endangered, and sensitive species of commercial oil shale development, including ancillary facilities such as access roads, power plants, and transmission systems, is directly related to the amount of land disturbance, the duration and timing of construction and operation periods, and the habitats affected by development (i.e., the location of the project). Indirect effects such as impacts resulting from the erosion of disturbed land surfaces and disturbance and harassment of animal species are also considered, but their magnitude also is considered proportional to the amount of land disturbance.

Impacts on threatened and endangered species are fundamentally similar to or the same as those described for impacts on aquatic resources; plant communities and habitats; and wildlife. The most important difference from these impacts is the potential consequence of the impacts. Because of low population sizes, threatened and endangered species are far more vulnerable to impacts than more common and widespread species. Low population size makes them more vulnerable to the effects of habitat fragmentation, habitat alteration, habitat degradation, human disturbance and harassment, mortality of individuals, and the loss of genetic diversity. Specific impacts associated with development would depend on the locations of projects relative to species populations and the details of project development.

The potential magnitude of the impacts that could result from oil shale development is presented for different species in the PEIS[55]. Unlike some projects where there are discrete construction and operation phases with different associated impacts, oil shale development projects include facility construction and extraction activities that would have similar types of impacts throughout the life of the project. Project construction and extraction activities would occur over a period of several decades. Reclamation that would occur after extraction activities are complete would serve to reduce or eliminate ongoing impacts by recreating habitats and ecological conditions that could be suitable for threatened, endangered, and sensitive species. The effectiveness of any reclamation activities would depend on the specific actions taken, but the best results would occur if site topography, hydrology, soils, and vegetation patterns were reestablished.

Post-lease land clearing and construction activities could remove potentially suitable habitat for threatened, endangered, and sensitive plant and animal species. Any plants present within the project areas would be destroyed, and plants adjacent to project areas could be affected by runoff from the site either through erosion or sedimentation and burial of individual plants or habitats. In addition, fugitive dust from site activities could accumulate in adjacent areas occupied by listed plants. Dust that accumulates on leaf surfaces can reduce photosynthesis and subsequently affect plant vigor. Disturbed areas could be colonized by non-native invasive plant species.

Larger, more mobile animals such as birds and medium-sized or large mammals would be most likely to leave the project area during site preparation, construction, and other project activities. Development of the site would represent a loss of habitat for these species and potentially a reduction in carrying capacity in the area. Smaller animals, such as small mammals, lizards, snakes, and amphibians, are more likely to be killed during clearing and construction activities. If land clearing and construction activities occurred during the spring and summer, bird nests and nestlings in the project area could be destroyed.

Operations could affect protected plants and animals as well. Animals in and adjacent to project areas would be disturbed by human activities and would tend to avoid the area while activities were occurring. Site lighting and operational noise from equipment would affect animals on and off the site, resulting in avoidance or reduction in use of an area larger than the project footprint. Runoff from the site during site operations could result in erosion and sedimentation of adjacent habitats. Fugitive dust during operations could affect adjacent plant populations.

For all potential impacts, the use of mitigation measures, possibly including pre-disturbance surveys to locate protected plant and animal populations in the area, erosion control practices, dust suppression techniques, establishment of buffer areas around protected populations, and reclamation of disturbed areas using native species upon project completion, would greatly reduce or eliminate the potential for effects on

[55] Oil Shale and Tar Sands Draft Programmatic Environmental Impact Statement, U.S. Department of the Interior, Bureau of Land Management, 3.7 Ecological Resources, and 4.8 Ecological Resources, Table 4.8.1-2, December 2007 (http://ostseis.anl.gov/documents/dpeis/vol1/OSTS_DPEIS_Vol1_Ch3.pdf).

protected species. The specifics of these practices should be established in project-specific consultations with the appropriate Federal and state agencies. The ESA Section 7 consultations between the BLM and the USFWS would be required for all projects that have the potential to affect listed species before leased areas could be developed. Those consultations would identify conservation measures, allowable levels of incidental take, and other requirements to protect listed species. Potential conservation measures for oil shale development have been developed jointly by the BLM and USFWS to avoid and minimize impacts of commercial oil shale development on federally-listed threatened and endangered species and could be applied, if deemed appropriate, and in consultation with the USFWS, at the lease or development stage of potential future projects.

There is a potential for commercial oil shale development projects to adversely affect most of the threatened, endangered, and sensitive species that occur in the counties where development could occur. This potential for adverse effects results from a lack of specificity on the locations of lease areas and the often incomplete information on species distributions.

Federally listed plant species that could occur in project areas and that could be affected by project activities include clay reed-mustard, Dudley Bluffs bladderpod, Dudley Bluffs twinpod, shrubby reed-mustard, Uinta Basin hookless cactus, and Ute ladies'-tresses. All but the Ute ladies'-tresses are upland species that could be affected by a variety of impacting factors, including vegetation clearing, habitat fragmentation, dispersal blockage, alteration of topography, changes in drainage patterns, erosion, sedimentation from runoff, oil and contaminant spills, fugitive dust, injury or mortality of individuals, human collection, increased human access, spread of invasive plant species, and air pollution. Clay-reed mustard, Dudley Bluffs bladderpod, Dudley Bluffs twinpod, and shrubby reed-mustard are all found on shale-derived soils and are therefore more likely to occur in potential development areas. Three Areas of Critical Environmental Concern (ACEC) 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. This action reduces the potential for impact on these species, but does not necessarily eliminate it, as individuals could occur outside of the ACECs in suitable habitat.

The Ute ladies'-tresses could occur in Utah project areas in wetland habitats and along the Green River or White River. This species is dependent on a high water table and, in addition to the factors affecting upland plants, could be adversely affected by any water depletions from the Green River or White River basins associated with oil shale development in Utah.

Impacts on the endangered Colorado River fishes (bonytail, Colorado pikeminnow, humpback chub, and razorback sucker) could result from oil shale developments in the Green River and White River basins. On the basis of proximity of populations and critical habitat to potential lease areas, the greatest potential for impacts on these species is related to development in Utah, where the Green River and White River flow through oil shale areas, although areas immediately adjacent to these rivers are not available for leasing because they are either designated as ACECs (Lower Green River) or have been proposed as ACECs (Four Mile Wash and White River). In Colorado, the White River is outside potential lease areas (the closest distance is about 5 kilometers (km) [3 mi]), but tributaries to the White River (e.g., Yellow Creek and Piceance Creek) flow through potential lease areas. Potential factors associated with oil shale development that could affect these species include alteration of topography, changes in drainage patterns, erosion, sedimentation from runoff, and oil and contaminant spills. Any water depletions from the upper Colorado River Basin are considered an adverse effect on endangered Colorado River fishes. Commercial oil shale development could affect these species if they resulted in water depletions in the basin.

Listed bird species that could be affected by commercial oil shale development include the Mexican spotted owl and southwestern willow flycatcher. The Mexican spotted owl could occur year-round in steep forested canyons in Utah and could be affected if these types of habitats are disturbed during oil shale development. Impacts on individual owls could result from injury or mortality (e.g., collisions with transmission lines), human disturbance or harassment, increased human access to occupied areas, increases in predation rates, and noise from facilities.

The southwestern willow flycatcher is most commonly found in riparian areas, especially along large rivers (e.g., Green River, White River). Direct impacts on these habitats are not anticipated because they occur within designated ACECs or potential ACECs. However, these riparian habitats could be affected indirectly by activities in their watersheds that resulted in alteration of topography, changes in drainage patterns, erosion, sedimentation from runoff, and oil and contaminant spills. In addition, impacts on riparian habitats that support these species could result if the habitats were crossed by project transmission lines or roads. Impacts on individual birds could result from injury or mortality (e.g., collisions with transmission lines), human disturbance or harassment, increased human access to occupied areas, increases in predation rates, and noise from facilities.

Listed mammals that could be affected by oil shale development include the black-footed ferret and Canada lynx. The black-footed ferret occurs in grassland and shrublands that support active prairie dog towns and potentially occurs in both Utah and Colorado project areas. The Canada lynx occurs in coniferous forests and potentially occurs in project areas in all three states. Impacts on these species could result from impacts on habitat (including vegetation clearing, habitat fragmentation, and movement-dispersal blockage) and individuals (injury or mortality [e.g., collisions with vehicles], human disturbance or harassment, increased human access to occupied areas, increases in predation rates, and noise from facilities).

BLM-Designated Sensitive Species and State-Listed Species - The BLM and the states of Colorado, Utah, and Wyoming maintain lists of sensitive plant and animal species. Many of these species have restricted distributions within the states, limited population sizes, and specialized habitat requirements that make them particularly vulnerable to human or natural perturbations. Special status provides a measure of protection through consideration in planning processes and is intended, at least in part, to avoid the need for Federal listing under the ESA. The BLM manages BLM-listed sensitive species and state-listed species as if they were candidates for Federal listing under the ESA. The species and their habitats that could occur in potential development areas are presented in the PEIS. There are 78 BLM-listed sensitive species that occur in counties of potential development areas. Of these, 48 potentially occur in the Green River, 38 in the Washakie, 39 in the Piceance, and 29 in the Uinta Basins. Of these BLM-listed species, 42 are plants, 1 is an invertebrate, 6 are fish, 5 are amphibians, 2 are reptiles, 12 are birds, and 10 are mammals. Forty-seven of the BLM-listed sensitive species are also listed by at least one of the states as species of special concern. Within study area counties, 156 species are listed by 1 or more states. Many of these (115) are also federally-listed under the ESA or are considered sensitive by the BLM. State-listed species not listed by either the USFWS or the BLM include 4 by Colorado, 21 by Utah, and 79 by Wyoming.

Other Species of Concern - There are four species that potentially occur in oil shale areas and for which the USFWS has developed conservation measures. These species are the bald eagle, Colorado River cutthroat trout, Graham beardtongue, and the sage-grouse. These species have either been recently removed from the list of threatened and endangered species list (bald eagle) or have recently undergone a formal status review by the USFWS, but listing was determined to be not warranted at this time (Colorado River cutthroat trout, Graham beardtongue, and the sage-grouse).

Oil shale development would potentially impact the biology and ecology of the area. Impacts on wildlife from commercial oil shale development could occur as result of: habitat loss, alteration, or fragmentation; disturbance and displacement; mortality; and increase in human access. These could result in changes in species distribution and abundance; habitat use; changes in behavior; collisions with structures or vehicles; changes in predator populations; and chronic or acute toxicity from hydrocarbons, herbicides, or other contaminants.

Wildlife may also be affected by human activities that are not directly associated with the oil shale project or its workforce, but that are instead associated with the potentially increased access to BLM-administered lands that had previously received little use. The construction of new access roads or improvements to old access roads may lead to increased human access into the area. The extent of impact would be evaluated in subsequent environmental analysis and appropriate actions taken to mitigate the impact.

Before any activity begins, investigations need to be conducted to determine existing field conditions. The primary objective would be to provide adequate baseline information prior to mineral development activities that could cause destruction of habitat.

Plant and animal surveys provide information about the flora and fauna existing in the area that may be disturbed by subsequent program activities. The terrestrial ecosystems must be thoroughly evaluated, including vegetation, fauna, and flora climatology. A wildlife management plan for the area should be developed with Federal and state wildlife authorities to monitor and track wildlife dislocations. The primary concern would be to maintain the habitat quality and keep population levels in balance.

Aquatic ecosystems would be characterized to aid in the development of mitigation measures to minimize damage to aquatic habitats. Seasonal variations of aquatic species and correlations between present water quality and existing aquatic species would be determined. Studies could also determine whether any rare or endangered species of fish exist in the streams.

Environmental control technologies were developed for oil shale development through the early 1990's. Future development would be build on that technology base and on advances that continue to be made and applied in similar mineral extraction (coal mining and reclamation) and processing (oil refining) industries. Overall, various mitigation measures would be required to reduce the impact of oil shale development on ecological resources during construction, operations, and reclamation. This includes application of existing guidance, recommendations, and requirements related to management practices. Impact mitigation plans would need to be implemented based on detailed site-specific data and analyses of the data collected.

In particular, federally-listed and state-listed threatened and endangered species and BLM sensitive species will be protected through siting and development decisions to avoid impacts. Pre-disturbance surveys in all areas proposed for development will be conducted following accepted protocols and in consultation with the USFWS and/or state agencies. If any federally-listed species are found, and it is determined that the proposed development "may affect" the listed species or their critical habitat, the USFWS will be consulted as required by Section 7 of the ESA and an appropriate course of action developed to avoid (if possible) or mitigate impacts and address any potential incidental take from the activity. If any state-listed or BLM sensitive species are found, plans to avoid or mitigate impacts will be developed prior to construction consistent with guidance provided in BLM Handbook 6840.

Infrastructure - Oil shale development, initially in the western states of Colorado, Wyoming, and Utah, requires infrastructure to support industry development and operation, to supply process inputs, and to upgrade and transport manufactured fuels and other products to defense and civilian markets.

Products produced from oil shale differ from conventional petroleum. In general, upgraded shale oil will be free of distillation residue and will contain low concentrations of nitrogen and sulfur. Both characteristics add market value to the product. However, current refineries, particularly Gulf Coast refineries, are highly integrated, complex refineries designed to accept higher concentrations of distillation residue and sulfur. In fact such refineries count on purchasing such crude oils at a lower price to optimally utilize the unit capacities built into those refineries. In the Rocky Mountain West, where sweet (low sulfur) crudes have been the historic norm, and where increasing amounts of oil sand synthetic crude oil from Canada are being run, refineries are simpler in design and matching unit capacities with shale oil will be easier.

Western refining capacity (Utah, Colorado, Wyoming, and New Mexico) is about 527 thousand barrels per day (Bbl/d) [56]. Increases in the demand for oil have been met by Canadian imports that, in 2004, averaged 252 MBbl/d. About one-half of the oil demand is supplied locally and the other half is imported from Canada. Shale oil will need to compete with Canadian syncrude on a price and quality basis. Utah and Wyoming refineries can probably absorb first shale oil production, up to about 50 MBbl/d. However, growth of the oil shale industry will soon outstrip existing regional pipeline and refining capacity. For distribution to broader markets, both to the east and to the west, additional infrastructure will be required.

Pipeline corridors connect oil shale country south to New Mexico, west to Salt Lake City, and northeast to the mid-continent area. Construction of a new pipeline in a potential corridor along I- 70 to the Kern River gas pipeline corridor is possible in order to serve the California markets. A key issue will be permitting of pipeline additions and expansions.

In addition to pipelines, a wide range of other infrastructure requirements are needed to support a growing oil shale industry, including natural gas and electricity. Natural gas may be required for process heat and for upgrading shale oil to pipeline quality. Natural gas is indigenous to the region and produced in ample quantity. Some technologies may require additional electric power generation capacity. Natural gas or coal burning facilities may need to be constructed and/or existing facilities expanded.

Socioeconomic Environment - The socioeconomic environment potentially affected by the development of oil shale resources includes a region of influence (ROI) in each state (Colorado, Utah, and Wyoming), consisting of the counties and communities most likely impacted by development of oil shale resources. Construction and operation of oil shale facilities could have a major affect on the local communities, impacting the economy and the social and demographic make-up of the affected communities.

The Task Force on Strategic Unconventional Fuels provides employment projections for their production scenarios, including their base case. Direct employment could range from 120 to 9,700 personnel in the base case. The total number of petroleum sector jobs (including indirect employment), estimated by the Task Force, ranges from 2,930 employees in 2015 to 20,830 in 2035 for their base case[57]. For 2004, the PEIS reported total employment within the ROIs at approximately 185,000. It is important to note that these estimates do not represent estimates for new jobs created nationwide.

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[56] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, September 2007, page III-36 (http://www.unconventionalfuels.org).

[57] *America's Strategic Unconventional Fuels Resources, Volume III Resource and Technology Profiles*, Task Force on Strategic Unconventional Fuels, February 2007, page III-23 (http://www.unconventionalfuels.org).

Impact Significance - The potential effects of developing the oil shale resources are likely to be quite significant; however, at this point, with the significant unknowns as to what may be developed and how it may be developed, plus where and when development may occur, there is no practical way to quantify the potential environmental and socioeconomic consequences, much less put a monetary value on them.

We recognize that because these potential effects are not adequately accounted for, the estimated net benefits of the rule may be significantly different that this analysis would indicate. These impacts will, however, be the subject of subsequent and more specific NEPA documentation.

<u>Federal and State Revenues</u> - The Act requires the Secretary to establish royalties, fees, rentals, bonus, or other payments for oil shale leases that encourage development of the resource, but also ensuring a fair return to the government. As proposed, the three key payments associated with Federal oil shale leases are the bonus bid, rental, and production royalty. As a result of any leasing and development, the Federal and State governments[58] will collect the revenue generated through the bonuses, rents, and eventually royalties. The monetary payments, such as rents, royalties and bonus bids, from the lessee to the government do not affect total resources available to society and in the context of a benefit-cost analysis are considered transfer payments.

Bonuses - The bonus is the amount paid by the successful high bidder when a parcel is offered for lease. By statute the parcel must be leased for fair market value. The minimum bonus the government could receive can be defined by the minimum bid. The proposed regulations call for a minimum bid of $1,000 per acre plus a fair market value conversion fee for the RD&D leases. The actual bonus bids and conversion fees may be significantly higher than the proposed minimum bid. For the four oil shale leases the BLM leased in 1974, the winning bonus bids were almost $450 million. This would suggest potential bonus bids could be significantly higher than the minimum bid; however, at this juncture there is no practical way to generate a meaningful estimate of the potential bonus bids or fair market values for potential lease parcels.

Rents - Until the operation starts paying a production royalty, the lessee is required to pay the government a rental. The proposed regulations include a rental rate of $2 per acre. Maximum lease acreage is 5,760 acres for a maximum annual rental payment per lease of $11,520 (constant-dollars) per year until an operation commences shale oil production. Based on the Task Force's base case of three in-situ operations, with total maximum lease acres of 17,280 acres, those three leases could generate a rental income of $34,560 per year.

Royalties - Producing leases will be required to pay a production royalty. Using the production projections and other assumptions discussed above, including a 5 percent royalty rate, royalty payments for the period of analysis (2007 to 2035) could be almost

[58] Bonus and royalty payments paid to the Federal government for Federal mineral leases are split 50/50 with the state in which the lease is located.

$9.1 billion, with a net present value of $2.5 billion (7 percent discount rate), $364 million (20 percent discount rate) and $5.1 billion (3 percent discount rate), see Table 4. The projected royalty in year 2020 has a present value of about $197 million using a 7 percent discount rate, $44 million using a 20 percent discount rate and $323 million using a 3 percent discount rate.

Using EIA's high oil price scenario, the undiscounted royalty for the period of analysis could be $15.4 billion, with a present value of $4.2 billion (7 percent discount rate), $613 million (20 percent discount rate) and $8.6 billion (3 percent discount rate). The present value of royalty payments in 2020, under EIA's high oil price scenario, could peak at $337 million using a 7 percent discount rate, $76 million using a 20 percent discount rate and $554 million using a 3 percent discount rate.

Using EIA's low oil price scenario, present value of the royalty for the period of analysis could be $1.6 billion (7 percent discount rate), $232 million (20 percent discount rate) and $3.2 billion (3 percent discount rate). The present value of royalty payments in 2020, under EIA's low oil price scenario, could peak at $129 million using a 7 percent discount rate, $29 million using a 20 percent discount rate and $212 million using a 3 percent discount rate. Note, these estimates are based on a constant production scenario regardless of oil price and operator profits. Under EIA's low price scenario all operations regardless of royalty rate are projected to be operating at a loss. Over an extended period operations would generally discontinue in such a situation.

Using EIA's reference oil price and a 12.5 percent royalty rate, the net present value of the royalty payments is estimated at $4.2 billion (7 percent discount rate), $613 million (20 percent discount rate) and $8.6 billion (3 percent discount rate), see Table 5. Twelve and a half percent is the current royalty rate applied to Federal onshore oil and gas leases. As such, this rate helps define the upper boundary for the royalty revenues generated from shale oil production using the Task Force's base case scenario.

We also analyzed the Federal revenue implications of other royalty rates (see Appendix A) given constant production and production cost assumptions. The present value of the royalty for the period of analysis ranged from a low of $45 million using EIA's low oil price, 20 percent discount rate and a 1 percent royalty rate to a high of $21.5 billion using EIA's high oil price, 3 percent discount rate and a 12.5 percent royalty rate. Note the significant limitations on these calculations as production and production costs inputs are fixed.

Public comments suggested the use of variable or sliding scale royalty schemes. One approach is to have the royalty rate change based on the prevailing world price of crude oil. For example, if the price of crude oil is above $50 per barrel, the royalty rate might be 5 percent. Should the world price of crude oil reach $90 per barrel then the applicable royalty rate would be raised 9 percent. A 5 percent royalty on the lower priced oil would generate discounted (7 percent) royalty payments of $197 million in the year 2020 (Appendix A-4). For the same year and discount rate, but higher price and royalty rate, the discounted royalty payment would be $607 million.

Payment in lieu of Production - Beginning in the 10th lease year, for leases that have not commenced production, the lessee is subject to a payment in lieu of production of no less than $4 per acre. Payments will be credited to production royalties for years when shale oil is produced from the lease. For an operation with 5,760 acres under lease and no production by the end of the eleventh lease year, the minimum royalty payment would be $23,040 (constant-dollars) per year. Based on the Task Force's base case of three in-situ operations, with total maximum lease acres of 17,280 acres, should operations on those three leases not commence production the payment in lieu of production could generate payments to the Federal government of $69,120 per year.

Bonding - The proposed regulations require license and lease bonds for exploration licenses and oil shale leases. These bonds are intended to guarantee payments (rents, royalties, and deferred bonuses) the lessee may owe the government. The bond amount will be determined on a case-by-case basis. The BLM will determine reclamation bond and exploration license bond amounts on a case-by-case basis when it approves a plan of development or exploration plan. The reclamation or exploration license bond must be sufficient to cover the estimated cost of site reclamation. The minimum lease bond is proposed at $25,000.

The operator is also obligated to provide the BLM with a reclamation bond. The amount of these bonds will be based on the estimated cost for the government to contract with a third party to reclaim the operation should the operator be unable or unwilling to fulfill their reclamation obligations. The amounts of these reclamation bonds are likely to be quite significant; however, at this point there is no practical way to estimate the amount of these reclamation bonds.

License, lease, and reclamation bonds are provided to the government to ensure lessees and/or operators meet their obligations. Once the obligation has been met, the lessee/operator does not need to maintain the bond. As such, the actual cost to the lessee/operator of providing the government a financial guarantee is substantially less than the actual bond amount. However, there are still costs to the lessee/operator associated with posting these bonds, such as annual premiums charged by the surety company. For example, a typical reclamation bond from a surety company might involve a 2 percent annual premium, or about $500 per year on a $25,000 bond.

Administrative Costs - There will be increases in BLM administrative costs associated with the issuance of leases and licenses and review and approval of operational plans. Most of these costs will be subject to cost recovery that will be paid for by the benefiting party. Table 7 provides processing steps that will be subject to cost recovery and the estimated costs for each action. In addition, there will be some BLM actions that will not be subject to cost recovery, including increased costs associated with ongoing inspection and enforcement responsibilities.

Table 7
Estimated Cost Recovery

Processing Step	Estimated Unit

	Cost
Exploration Licenses	$295
Application Processing	$172,323
Lease Size Modification	$250
Assignments and Subleases	$60

Conclusion

Executive Order 12866 and SBREFA require agencies to assess, where practical, the anticipated costs and benefits of proposed regulatory actions to determine if the regulation is significant. Presented above are projections and assumption concerning what the future might hold for the leasing and development of oil shale resources on Federal lands. As has been noted, there is no domestic oil shale industry to help substantiate or form the basis for the projections. In addition, the assumption is that any significant production of shale oil is not likely to occur for a number of years. As such, the projected cost and revenue figures must be discounted to account for this time dimension.

This rule would provide interested parties an opportunity to lease and develop oil shale resources on Federal lands. Companies' willingness to take advantage of the leasing and development opportunities provided by this rule would determine the level of production of shale oil, exploration, development and production costs incurred, and conceivably the profits (or losses) to be enjoyed.

Using the shale oil production projections for the period of analysis (2007 to 2035), EIA's reference oil price, and other assumptions discussed above, we estimate the present value of the shale oil produced would be about $50 billion using a 7 percent discount rate, $7.3 billion using a 20 percent discount rate, and $102 billion using a 3 percent discount rate. Using a 7 percent discount rate and a 5 percent royalty rate, the present value production costs for the period of analysis are estimated at $34 billion and profits of $13.6 billion. The present value of production costs would be $5 billion and profits $1.8 billion for the period of analysis with a 20 percent discount rate. Using a 3 percent discount rate the present value of the production costs for the period of analysis are estimated at $68.1 billion, with profits of $28.5 billion. With a 12.5 percent royalty rate, profit figures are estimated at $9.7 billion (7 percent discount rate), $1.3 billion (20 percent discount rate), and $20.9 billion (3 percent discount rate). Appendix A-1 through A-9 presents a range of revenue, profit, and royalty scenarios using three discount rates (7 percent, 3 percent and 20 percent), three world crude oil price projections (EIA's 2007 reference, high and low price projections), and six different royalty rates (1 percent, 3 percent, 5 percent, 7 percent, 9 percent, and 12.5 percent).

In addition, there could be significant environmental and socioeconomic effects. These potential effects could affect a wide range of resources and resource values, including groundwater quality and quantity, air quality, cultural resources, wildlife habitat, competing land uses, and local employment and infrastructure. Discussed above is a brief qualitative discussion of these impacts. These impacts will be discussed in detail in subsequent NEPA documentation.

Of the proposed regulatory requirements, bonus and royalty payments are the primary provisions that could conceivably have a direct annual economic effect of $100 million or more.

The amount of the bonus the potential lessee is willing to bid is based on the value of the potential development rights to the prospective lessee. Results from oil shale lease sales that took place in the 1970s indicate there could be significant demand for oil shale leases offered for lease under these rules, which may result in bonuses in excess of $100 million. However, bonuses are not annual costs, but rather one-time transfer payments from the lessee to the government for the rights to develop the resource.

Royalty payments are recurring income to the government and costs to the operator/lessee. They are monetary payments (transfer payments) that do not affect total resources available to society. The royalty income is dependent on how much shale oil may be produced and the market price of the commodity. Using the projections, including EIA's reference oil price, and assumptions discussed above, we estimate potential royalty income of about $9.1 billion (constant 2005 dollars) for the period of analysis (2007 through 2035) with a 5 percent royalty. For the period of analysis, the present value of all royalty income is estimated at about $2.5 billion using a 7 percent discount rate, $364 million using a 20 percent discount rate, and $5.1 billion using a 3 percent discount rate. For the year 2020, the future royalty income could have a present value of approximately $197 million using a 7 percent discount rate, $44 million using a 20 percent discount rate, and $323 million using a 3 percent discount rate.

Using a 12.5 percent royalty rate, the present value for the period of analysis is estimated at $6.2 billion (7 percent discount rate), $909 million (20 percent discount rate), and $12.7 billion (3 percent discount rate).

There would also be increases to the BLM's administrative costs, specifically in the issuing of leases and licenses, and in the authorizing of proposed operations. Most of these additional costs are relatively minor (Table 7) and would be subject to cost recovery. The agency would also incur some increased costs not covered by cost recovery, such as inspection and enforcement activities.

This conclusion includes one significant caveat. The magnitude of socioeconomic and environmental effects associated with oil shale development remains unknown. As has been noted above, we have no reasonable way to generate meaningful projects to quantify the potential impacts for an industry that does not exist or technologies that have not been deployed.

Appendix A-1

EIA Low Price Case/7% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Shale Oil Production[60]	18.25	18.25	18.25	109.50	109.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA Low Oil Price[61]	33.99	33.81	33.90	33.99	34.05	34.10	34.26	34.42	34.57	34.72	34.89	35.04	35.20	35.37	35.52	35.68	35.86	36.04	36.22	36.40	36.58	
Revenue[62]	620	617	619	3722	3728	6223	6252	6282	6309	6336	6367	6395	6424	6455	6482	6512	6544	6577	6610	6643	6676	112395
Discounted Revenue	361	336	315	1768	1655	2582	2425	2277	2137	2006	1884	1768	1660	1559	1463	1374	1290	1212	1138	1069	1004	31283
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[63]	6	6	6	37	37	62	63	63	63	63	64	64	64	65	65	65	65	66	66	66	67	1124
Royalty Cost - 3%	19	19	19	112	112	187	188	188	189	190	191	192	193	194	194	195	196	197	198	199	200	3372
Royalty Cost - 5%	31	31	31	186	186	311	313	314	315	317	318	320	321	323	324	326	327	329	331	332	334	5620
Royalty Cost - 7%	43	43	43	261	261	436	438	440	442	444	446	448	450	452	454	456	458	460	463	465	467	7868
Royalty Cost - 9%	56	56	56	335	336	560	563	565	568	570	573	576	578	581	583	586	589	592	595	598	601	10116
Royalty Cost - 12.5%	78	77	77	465	466	778	782	785	789	792	796	799	803	807	810	814	818	822	826	830	834	14049
Total Cost - 1%	695	695	695	4171	4171	6951	6952	6952	6952	6952	6953	6953	6953	6954	6954	6954	6954	6955	6955	6955	6956	121683
Total Cost - 3%	708	708	708	4246	4246	7076	7077	7077	7078	7079	7080	7081	7082	7083	7083	7084	7085	7086	7087	7088	7089	123931
Total Cost - 5%	720	720	720	4320	4320	7200	7202	7203	7204	7206	7207	7209	7210	7212	7213	7215	7216	7218	7220	7221	7223	126179
Total Cost - 7%	732	732	732	4395	4395	7325	7327	7329	7331	7333	7335	7337	7339	7341	7343	7345	7347	7349	7352	7354	7356	128427
Total Cost - 9%	745	745	745	4469	4470	7449	7452	7454	7457	7459	7462	7465	7467	7470	7472	7475	7478	7481	7484	7487	7490	130675
Total Cost - 12.5%	767	766	766	4599	4600	7667	7671	7674	7678	7681	7685	7688	7692	7696	7699	7703	7707	7711	7715	7719	7723	134608
Discounted Production Cost	401	375	350	1964	1836	2859	2672	2497	2334	2181	2038	1905	1780	1664	1555	1453	1358	1269	1186	1109	1036	33821
Discounted Total Cost - 1%	405	378	353	1982	1852	2885	2696	2520	2355	2201	2057	1923	1797	1679	1570	1467	1371	1281	1198	1119	1046	34134
Discounted Total Cost - 3%	412	385	360	2017	1885	2936	2744	2565	2398	2241	2095	1958	1830	1711	1599	1494	1397	1306	1220	1141	1066	34759
Discounted Total Cost - 5%	419	392	366	2052	1918	2988	2793	2611	2440	2281	2132	1993	1863	1742	1628	1522	1423	1330	1243	1162	1086	35385
Discounted Total Cost - 7%	426	398	372	2088	1951	3039	2841	2656	2483	2321	2170	2029	1896	1773	1657	1549	1448	1354	1266	1183	1106	36011
Discounted Total Cost - 9%	433	405	379	2123	1985	3091	2890	2702	2526	2361	2208	2064	1930	1804	1687	1577	1474	1378	1289	1205	1126	36636
Discounted Total Cost - 12.5%	446	417	390	2165	2042	3181	2975	2781	2601	2432	2274	2126	1988	1859	1738	1625	1519	1421	1329	1242	1162	37731
Profit	-69	-72	-70	-412	-406	-666	-637	-607	-580	-553	-522	-494	-465	-434	-407	-377	-345	-312	-279	-246	-213	-8164
Profit - 1%	-75	-78	-77	-449	-443	-728	-699	-670	-643	-616	-585	-558	-529	-499	-471	-443	-410	-377	-345	-312	-280	-9288
Profit - 3%	-87	-90	-89	-524	-517	-852	-824	-798	-769	-743	-713	-686	-658	-628	-601	-573	-541	-509	-477	-445	-413	-11536
Profit - 5%	-100	-103	-101	-598	-592	-977	-949	-921	-895	-869	-840	-814	-786	-757	-731	-703	-672	-641	-609	-578	-547	-13784
Profit - 7%	-112	-115	-114	-673	-667	-1101	-1074	-1047	-1022	-996	-967	-942	-915	-886	-860	-833	-803	-772	-742	-711	-680	-16031
Profit - 9%	-125	-128	-126	-747	-741	-1226	-1199	-1173	-1148	-1123	-1095	-1070	-1043	-1015	-990	-963	-934	-904	-874	-844	-814	-18279
Profit - 12.5%	-148	-149	-148	-877	-872	-1444	-1418	-1393	-1369	-1345	-1318	-1294	-1268	-1241	-1217	-1191	-1163	-1134	-1105	-1076	-1048	-22213
Discounted Profit	-40	-39	-36	-196	-180	-276	-247	-220	-196	-175	-154	-137	-120	-105	-92	-80	-68	-57	-48	-40	-32	-2538
Discounted Profit - 1%	-44	-43	-39	-213	-197	-302	-271	-243	-218	-195	-173	-154	-137	-120	-106	-93	-81	-70	-59	-50	-42	-2851
Discounted Profit - 3%	-51	-49	-45	-249	-230	-354	-320	-288	-261	-235	-211	-190	-170	-152	-136	-121	-107	-94	-82	-72	-62	-3476
Discounted Profit - 5%	-58	-56	-51	-284	-263	-405	-368	-334	-303	-275	-249	-225	-203	-183	-165	-148	-132	-118	-105	-93	-82	-4102
Discounted Profit - 7%	-65	-63	-58	-320	-296	-457	-417	-380	-346	-315	-286	-260	-236	-214	-194	-176	-158	-142	-128	-114	-102	-4728
Discounted Profit - 9%	-72	-69	-64	-355	-329	-509	-465	-425	-389	-355	-324	-296	-270	-245	-223	-203	-184	-166	-150	-136	-122	-5353
Discounted Profit - 12.5%	-85	-81	-75	-417	-387	-599	-550	-505	-464	-426	-390	-358	-328	-300	-275	-251	-229	-209	-190	-173	-158	-6448
Discounted Royalty - 1%	4	3	3	18	17	26	24	23	21	20	19	18	17	16	15	14	13	12	11	11	10	313
Discounted Royalty - 3%	11	10	9	53	50	77	73	68	64	60	57	53	50	47	44	41	39	36	34	32	30	938
Discounted Royalty - 5%	18	17	16	88	83	129	121	114	107	100	94	88	83	78	73	69	65	61	57	53	50	1564
Discounted Royalty - 7%	25	23	22	124	116	181	170	159	150	140	132	124	116	109	102	96	90	85	80	75	70	2190
Discounted Royalty - 9%	32	30	28	159	149	232	218	205	192	181	170	159	149	140	132	124	116	109	102	96	90	2815
Discounted Royalty - 12.5%	45	42	39	221	207	323	303	285	267	251	235	221	208	195	183	172	161	151	142	134	126	3910

[59] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).

[60] Production figures are in millions of barrels per year.

[61] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (0.5 percent increase for the low price scenario) for the years 2025 through 2030.

[62] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.

[63] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5% royalty rate.

Appendix A-2
EIA Low Price Case/3% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total[64]
Shale Oil Production[65]	18.25	18.25	18.25	109.50	109.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA Low Oil Price[66]	33.99	33.81	33.90	33.99	34.05	34.10	34.26	34.42	34.57	34.72	34.89	35.04	35.20	35.37	35.52	35.68	35.86	36.04	36.22	36.40	36.58	
Revenue[67]	620	617	619	3722	3728	6223	6252	6282	6309	6336	6367	6395	6424	6455	6482	6512	6544	6577	6610	6643	6676	112395
Discounted Revenue	490	473	460	2689	2615	4238	4134	4032	3932	3834	3740	3647	3557	3470	3383	3299	3219	3141	3065	2991	2918	63326
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[68]	6	6	6	37	37	62	63	63	63	63	64	64	64	65	65	65	65	66	68	66	67	1124
Royalty Cost - 3%	19	19	19	112	112	187	188	188	189	190	191	192	193	194	194	195	196	197	198	199	200	3372
Royalty Cost - 5%	31	31	31	186	186	311	313	314	315	317	318	320	321	323	324	326	327	329	331	332	334	5620
Royalty Cost - 7%	43	43	43	261	261	436	438	440	442	444	446	448	450	452	454	456	458	460	463	465	467	7868
Royalty Cost - 9%	56	56	58	335	336	560	563	565	568	570	573	576	578	581	583	586	589	592	595	598	601	10116
Royalty Cost - 12.5%	78	77	77	465	466	778	782	785	789	792	796	799	803	807	810	814	818	822	826	830	834	14049
Total Cost - 1%	695	695	695	4171	4171	6951	6952	6952	6952	6952	6953	6953	6953	6954	6954	6954	6954	6955	6955	6955	6956	121683
Total Cost - 3%	708	708	708	4246	4246	7076	7077	7077	7078	7079	7080	7081	7082	7083	7083	7084	7085	7086	7087	7088	7089	123931
Total Cost - 5%	720	720	720	4320	4320	7200	7202	7203	7204	7206	7207	7209	7210	7212	7213	7215	7216	7218	7220	7221	7223	126179
Total Cost - 7%	732	732	732	4395	4395	7325	7327	7329	7331	7333	7335	7337	7339	7341	7343	7345	7347	7349	7352	7354	7356	128427
Total Cost - 9%	745	745	745	4469	4470	7449	7452	7454	7457	7459	7462	7465	7467	7470	7472	7475	7478	7481	7484	7487	7490	130675
Total Cost - 12.5%	757	766	766	4599	4600	7667	7671	7674	7678	7681	7685	7688	7692	7696	7699	7703	7707	7711	7715	7719	7723	134608
Discounted Production Cost	544	528	513	2986	2900	4691	4554	4422	4293	4168	4047	3929	3814	3703	3595	3491	3389	3290	3194	3101	3011	68163
Discounted Total Cost - 1%	549	533	517	3013	2926	4733	4596	4462	4332	4206	4084	3965	3850	3738	3629	3524	3421	3322	3225	3131	3040	68797
Discounted Total Cost - 3%	559	542	526	3067	2978	4818	4678	4543	4411	4283	4159	4038	3921	3807	3697	3590	3486	3384	3286	3191	3099	70063
Discounted Total Cost - 5%	568	552	536	3121	3030	4903	4761	4623	4490	4360	4234	4111	3992	3877	3764	3656	3550	3447	3348	3251	3157	71330
Discounted Total Cost - 7%	578	561	545	3175	3083	4968	4844	4704	4568	4436	4308	4184	4063	3946	3832	3722	3614	3510	3409	3311	3215	72596
Discounted Total Cost - 9%	588	571	554	3228	3135	5072	4926	4785	4647	4513	4383	4257	4134	4015	3900	3788	3679	3573	3470	3371	3274	73853
Discounted Total Cost - 12.5%	605	587	570	3323	3226	5221	5071	4926	4784	4647	4514	4385	4259	4137	4018	3903	3791	3683	3578	3475	3376	76079
Profit	-69	-72	-70	-412	-406	-665	-637	-607	-580	-553	-522	-494	-465	-434	-407	-377	-345	-312	-279	-246	-213	-8164
Profit - 1%	-75	-78	-77	-449	-443	-728	-699	-670	-643	-616	-585	-558	-529	-499	-471	-443	-410	-377	-345	-312	-280	-9288
Profit - 3%	-87	-90	-89	-524	-517	-852	-824	-798	-769	-743	-713	-686	-658	-628	-601	-573	-541	-509	-477	-445	-413	-11536
Profit - 5%	-100	-103	-101	-598	-592	-977	-949	-921	-895	-869	-840	-814	-786	-757	-731	-703	-672	-641	-609	-578	-547	-13784
Profit - 7%	-112	-115	-114	-673	-667	-1101	-1074	-1047	-1022	-996	-967	-942	-915	-886	-860	-833	-803	-772	-742	-711	-680	-16031
Profit - 9%	-125	-128	-126	-747	-741	-1226	-1199	-1173	-1148	-1123	-1095	-1070	-1043	-1015	-990	-963	-934	-904	-874	-844	-814	-18279
Profit - 12.5%	-146	-149	-148	-877	-872	-1444	-1418	-1393	-1369	-1345	-1318	-1294	-1268	-1241	-1217	-1191	-1163	-1134	-1105	-1076	-1048	-22213
Discounted Profit	-54	-55	-52	-298	-284	-453	-421	-390	-361	-334	-306	-282	-257	-233	-212	-191	-169	-149	-129	-111	-93	-4838
Discounted Profit - 1%	-59	-60	-57	-325	-311	-496	-462	-430	-401	-373	-344	-318	-293	-268	-246	-224	-202	-180	-160	-141	-122	-5471
Discounted Profit - 3%	-69	-69	-66	-378	-363	-580	-545	-511	-479	-449	-419	-391	-364	-337	-314	-290	-266	-243	-221	-200	-181	-6737
Discounted Profit - 5%	-79	-79	-75	-432	-415	-665	-628	-591	-558	-526	-493	-464	-435	-407	-381	-356	-330	-306	-283	-260	-239	-8004
Discounted Profit - 7%	-88	-88	-85	-486	-467	-750	-710	-672	-637	-603	-568	-537	-506	-476	-449	-422	-395	-369	-344	-320	-297	-9270
Discounted Profit - 9%	-98	-98	-94	-540	-520	-835	-793	-753	-715	-679	-643	-610	-578	-546	-517	-488	-459	-432	-405	-380	-356	-10537
Discounted Profit - 12.5%	-115	-114	-110	-634	-611	-983	-938	-894	-853	-814	-774	-738	-702	-667	-635	-604	-572	-542	-512	-485	-458	-12753
Discounted Royalty - 1%	5	5	5	27	26	42	41	40	39	38	37	36	36	35	34	33	32	31	31	30	29	633
Discounted Royalty - 3%	15	14	14	81	78	127	124	121	118	115	112	109	107	104	101	99	97	94	92	90	88	1900
Discounted Royalty - 5%	24	24	23	134	131	212	207	202	197	192	187	182	178	173	169	165	161	157	153	150	146	3166
Discounted Royalty - 7%	34	33	32	188	183	297	289	282	275	268	262	255	249	243	237	231	225	220	215	209	204	4433
Discounted Royalty - 9%	44	43	41	242	235	331	372	363	354	345	337	328	320	312	304	297	290	283	276	269	263	5699
Discounted Royalty - 12.5%	61	59	58	336	327	530	517	504	491	479	468	456	445	434	423	412	402	393	383	374	365	7916

[64] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).
[65] Production figures are in millions of barrels per year.
[66] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (0.5 percent increase for the low price scenario) for the years 2025 through 2030.
[67] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.
[68] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5 royalty rate.

Appendix A-3
EIA Low Price Case/20% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Shale Oil Production[70]	18.25	18.25	18.25	109.50	109.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA Low Oil Price[71]	33.99	33.81	33.90	33.99	34.05	34.10	34.26	34.42	34.57	34.72	34.89	35.04	35.20	35.37	35.52	35.68	35.86	36.04	36.22	36.40	36.58	
Revenue[72]	620	617	619	3722	3728	6223	6252	6282	6309	6336	6367	6395	6424	6455	6482	6512	6544	6577	6610	6643	6676	112395
Discounted Revenue	144	120	100	501	418	582	487	408	341	286	239	200	168	140	117	98	82	69	58	48	40	4547
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[73]	6	6	6	37	37	62	63	63	63	63	64	64	64	65	65	65	65	66	66	66	67	1124
Royalty Cost - 3%	19	19	19	112	112	187	188	188	189	190	191	192	193	194	194	195	196	197	198	199	200	3372
Royalty Cost - 5%	31	31	31	186	186	311	313	314	315	317	318	320	321	323	324	326	327	329	331	332	334	5620
Royalty Cost - 7%	43	43	43	261	261	438	438	440	442	444	446	448	450	452	454	456	458	460	463	465	467	7868
Royalty Cost - 9%	56	56	56	335	336	560	563	565	568	570	573	576	578	581	583	586	589	592	595	598	601	10116
Royalty Cost - 12.5%	78	77	77	465	466	778	782	785	789	792	796	799	803	807	810	814	818	822	826	830	834	14049
Total Cost - 1%	695	695	695	4171	4171	6951	6952	6952	6952	6952	6953	6953	6953	6954	6954	6954	6954	6955	6955	6955	6956	121683
Total Cost - 3%	708	708	708	4246	4246	7076	7077	7077	7078	7079	7080	7081	7082	7083	7083	7084	7085	7086	7087	7088	7089	123931
Total Cost - 5%	720	720	720	4320	4320	7200	7202	7203	7204	7206	7207	7209	7210	7212	7213	7215	7216	7218	7220	7221	7223	126179
Total Cost - 7%	732	732	732	4395	4395	7325	7327	7329	7331	7333	7335	7337	7339	7341	7343	7345	7347	7349	7352	7354	7356	128427
Total Cost - 9%	745	745	745	4469	4470	7449	7452	7454	7457	7459	7462	7465	7467	7470	7472	7475	7478	7481	7484	7487	7490	130675
Total Cost - 12.5%	767	766	766	4599	4600	7667	7671	7674	7678	7681	7685	7688	7692	7696	7699	7703	7707	7711	7715	7719	7723	134608
Discounted Production Cost	160	134	111	556	464	644	537	447	373	311	259	216	180	150	125	104	87	72	60	50	42	5079
Discounted Total Cost - 1%	162	135	112	561	468	650	541	451	376	313	261	218	181	151	126	105	87	73	61	51	42	5126
Discounted Total Cost - 3%	165	137	114	571	476	661	551	459	383	319	266	222	185	154	128	107	89	74	62	52	43	5219
Discounted Total Cost - 5%	167	140	116	581	485	673	561	468	390	325	271	226	188	157	131	109	91	76	63	53	44	5312
Discounted Total Cost - 7%	170	142	118	591	493	685	571	476	396	331	275	230	191	160	133	111	92	77	64	54	45	5405
Discounted Total Cost - 9%	173	144	120	601	501	696	580	484	403	336	280	234	195	162	135	113	94	78	65	55	45	5498
Discounted Total Cost - 12.5%	178	148	124	619	516	717	597	498	415	346	289	241	201	167	139	116	97	81	67	56	47	5660
Profit	-69	-72	-70	-412	-406	-666	-637	-607	-580	-553	-522	-494	-465	-434	-407	-377	-345	-312	-279	-248	-213	-8164
Profit - 1%	-75	-78	-77	-449	-443	-728	-699	-670	-643	-616	-585	-558	-529	-499	-471	-443	-410	-377	-345	-312	-280	-9288
Profit - 3%	-87	-90	-89	-524	-517	-852	-824	-796	-769	-743	-713	-686	-658	-628	-601	-573	-541	-509	-477	-445	-413	-11536
Profit - 5%	-100	-103	-101	-598	-592	-977	-949	-921	-895	-869	-840	-814	-786	-757	-731	-703	-672	-641	-609	-578	-547	-13784
Profit - 7%	-112	-115	-114	-673	-667	-1101	-1074	-1047	-1022	-996	-967	-942	-915	-886	-860	-833	-803	-772	-742	-711	-680	-16031
Profit - 9%	-125	-128	-126	-747	-741	-1226	-1199	-1173	-1148	-1123	-1095	-1070	-1043	-1015	-990	-963	-934	-904	-874	-844	-814	-18279
Profit - 12.5%	-146	-149	-148	-877	-872	-1444	-1418	-1393	-1369	-1345	-1318	-1294	-1268	-1241	-1217	-1191	-1163	-1134	-1105	-1076	-1048	-22213
Discounted Profit	-16	-14	-11	-55	-45	-62	-50	-39	-31	-25	-20	-15	-12	-9	-7	-6	-4	-3	-2	-2	-1	-433
Discounted Profit - 1%	-17	-15	-12	-60	-50	-68	-54	-43	-35	-28	-22	-17	-14	-11	-9	-7	-5	-4	-3	-2	-2	-479
Discounted Profit - 3%	-20	-18	-14	-70	-58	-80	-64	-52	-42	-33	-27	-21	-17	-14	-11	-9	-7	-5	-4	-3	-3	-572
Discounted Profit - 5%	-23	-20	-16	-81	-66	-91	-74	-60	-48	-39	-32	-25	-21	-16	-13	-11	-8	-7	-5	-4	-3	-665
Discounted Profit - 7%	-26	-22	-18	-91	-75	-103	-84	-68	-55	-45	-36	-29	-24	-19	-16	-13	-10	-8	-6	-5	-4	-758
Discounted Profit - 9%	-29	-25	-20	-101	-83	-115	-93	-76	-62	-51	-41	-33	-27	-22	-18	-15	-12	-9	-8	-6	-5	-851
Discounted Profit - 12.5%	-34	-29	-24	-118	-98	-135	-110	-90	-74	-61	-49	-40	-33	-27	-22	-18	-15	-12	-10	-8	-6	-1013
Discounted Royalty - 1%	1	1	1	5	4	6	5	4	3	3	2	2	2	1	1	1	1	1	1	0	0	46
Discounted Royalty - 3%	4	4	3	15	13	17	15	12	10	9	7	6	5	4	4	3	2	2	2	1	1	139
Discounted Royalty - 5%	7	6	5	25	21	29	24	20	17	14	12	10	8	7	6	5	4	3	3	2	2	232
Discounted Royalty - 7%	10	8	7	35	29	41	34	29	24	20	17	14	12	10	8	7	6	5	4	3	3	325
Discounted Royalty - 9%	13	11	9	45	38	52	44	37	31	26	22	18	15	13	11	9	7	6	5	4	4	418
Discounted Royalty - 12.5%	16	15	12	63	52	73	61	51	43	36	30	25	21	18	15	12	10	9	7	6	5	581

[69] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).
[70] Production figures are in millions of barrels per year.
[71] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (0.5 percent increase for the low price scenario) for the years 2025 through 2030.
[72] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.
[73] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5% and royalty rate.

Appendix A-4
EIA Reference Case/7% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Shale Oil Production[75]	18.25	18.25	18.25	109.50	109.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA Reference Oil Price[76]	49.87	49.75	50.80	51.28	51.95	52.04	52.73	53.43	54.90	55.64	56.37	57.11	57.63	58.12	58.61	59.12	59.53	59.95	60.37	60.79	61.22	
Revenue[77]	910	908	927	5615	5889	9497	9623	9751	10019	10154	10288	10423	10517	10607	10696	10789	10864	10941	11018	11094	11173	181504
Discounted Revenue	530	494	471	2668	2526	3941	3732	3534	3394	3215	3044	2882	2718	2562	2414	2276	2142	2016	1897	1785	1680	49920
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[78]	9	9	9	56	57	95	96	98	100	102	103	104	105	106	107	108	109	109	110	111	112	1815
Royalty Cost - 3%	27	27	28	168	171	285	289	293	301	305	309	313	316	318	321	324	326	328	331	333	335	5445
Royalty Cost - 5%	46	45	46	281	284	475	481	488	501	508	514	521	526	530	535	539	543	547	551	555	559	9075
Royalty Cost - 7%	64	64	65	393	398	665	674	683	701	711	720	730	736	742	749	755	760	766	771	777	782	12705
Royalty Cost - 9%	82	82	83	505	512	855	868	878	902	914	926	938	947	955	963	971	978	985	992	998	1006	16335
Royalty Cost - 12.5%	114	113	116	702	711	1187	1203	1219	1252	1269	1286	1303	1315	1326	1337	1349	1358	1368	1377	1387	1397	22688
Total Cost - 1%	698	698	698	4190	4191	6984	6985	6987	6989	6991	6992	6993	6994	6995	6996	6997	6998	6998	6999	7000	7001	122374
Total Cost - 3%	716	716	717	4302	4305	7174	7178	7182	7190	7194	7198	7202	7205	7207	7210	7213	7215	7217	7220	7222	7224	126004
Total Cost - 5%	735	734	735	4415	4418	7364	7370	7377	7390	7397	7403	7410	7415	7419	7424	7428	7432	7436	7440	7444	7448	129634
Total Cost - 7%	753	753	754	4527	4532	7554	7563	7572	7590	7600	7609	7619	7625	7631	7638	7644	7649	7655	7660	7666	7671	133264
Total Cost - 9%	771	771	772	4639	4646	7744	7755	7767	7791	7803	7815	7827	7836	7844	7852	7860	7867	7874	7881	7887	7895	136894
Total Cost - 12.5%	803	802	805	4836	4845	8076	8092	8108	8141	8158	8175	8192	8204	8215	8226	8238	8247	8257	8266	8276	8286	143247
Discounted Production Cost	401	375	350	1984	1838	2859	2672	2497	2334	2181	2038	1905	1780	1664	1555	1453	1358	1269	1186	1109	1036	33821
Discounted Total Cost - 1%	406	380	355	1991	1861	2898	2709	2532	2367	2213	2069	1934	1807	1689	1579	1476	1380	1289	1205	1127	1053	34320
Discounted Total Cost - 3%	417	390	364	2044	1911	2977	2784	2603	2435	2277	2130	1991	1862	1741	1627	1521	1422	1330	1243	1162	1087	35319
Discounted Total Cost - 5%	427	399	374	2097	1962	3056	2858	2674	2503	2342	2190	2049	1916	1792	1676	1567	1465	1370	1281	1198	1120	36317
Discounted Total Cost - 7%	438	409	383	2151	2012	3135	2933	2744	2571	2406	2251	2107	1971	1843	1724	1613	1508	1410	1319	1234	1154	37315
Discounted Total Cost - 9%	449	419	393	2204	2063	3213	3008	2815	2639	2470	2312	2164	2025	1894	1772	1658	1551	1451	1357	1269	1187	38314
Discounted Total Cost - 12.5%	467	437	409	2297	2151	3351	3138	2939	2758	2583	2419	2265	2120	1984	1857	1738	1626	1521	1423	1332	1248	40061
Profit	221	219	238	1481	1555	2608	2734	2862	3130	3265	3399	3534	3628	3718	3807	3900	3975	4052	4129	4205	4284	60945
Profit - 1%	212	210	229	1425	1498	2513	2638	2764	3030	3164	3296	3429	3523	3612	3700	3793	3867	3942	4018	4094	4172	59130
Profit - 3%	194	192	210	1313	1384	2323	2446	2569	2830	2951	3090	3221	3313	3400	3486	3577	3649	3724	3798	3872	3948	55499
Profit - 5%	176	174	192	1200	1270	2133	2253	2374	2629	2758	2884	3012	3103	3188	3273	3361	3432	3505	3578	3650	3725	51869
Profit - 7%	157	155	173	1088	1156	1943	2061	2179	2429	2554	2678	2804	2892	2975	3059	3145	3215	3286	3357	3429	3502	48239
Profit - 9%	139	137	155	976	1043	1754	1868	1984	2229	2351	2473	2596	2682	2763	2845	2929	2997	3067	3137	3207	3278	44609
Profit - 12.5%	107	105	122	779	843	1421	1531	1643	1878	1996	2113	2231	2314	2392	2470	2552	2617	2684	2751	2818	2887	38257
Discounted Profit	128	119	121	704	690	1082	1060	1037	1060	1034	1006	977	938	898	859	823	784	747	711	677	644	16099
Discounted Profit - 1%	123	114	116	677	665	1043	1023	1002	1026	1002	975	948	910	872	835	800	762	726	692	659	627	15600
Discounted Profit - 3%	113	104	107	624	614	964	948	931	959	937	914	891	856	821	787	754	719	686	654	623	594	14602
Discounted Profit - 5%	102	94	97	570	564	885	874	861	891	873	853	833	802	770	739	709	677	646	616	587	560	13603
Discounted Profit - 7%	92	85	88	517	513	806	799	780	823	809	792	775	747	719	690	663	634	605	578	552	527	12605
Discounted Profit - 9%	81	75	79	464	463	728	724	719	755	744	732	718	693	667	642	618	591	565	540	516	493	11606
Discounted Profit - 12.5%	62	57	62	370	375	590	594	596	636	632	625	617	598	578	558	538	516	495	474	454	434	9859
Discounted Royalty - 1%	5	5	5	27	25	39	37	35	34	32	30	29	27	26	24	23	21	20	19	18	17	499
Discounted Royalty - 3%	16	15	14	80	76	118	112	106	102	96	91	86	82	77	72	68	64	60	57	54	50	1498
Discounted Royalty - 5%	26	25	24	133	126	197	187	177	170	161	152	144	138	128	121	114	107	101	95	89	84	2496
Discounted Royalty - 7%	37	35	33	187	177	278	261	247	238	225	213	202	190	179	169	159	150	141	133	125	118	3494
Discounted Royalty - 9%	48	44	42	240	227	355	336	318	305	289	274	259	245	231	217	205	193	181	171	161	151	4493
Discounted Royalty - 12.5%	66	62	59	333	316	493	467	442	424	402	380	360	340	320	302	284	268	252	237	223	210	6240

[74] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).
[75] Production figures are in millions of barrels per year.
[76] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (0.7 percent increase for the reference price scenario) for the years 2025 through 2030.
[77] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.
[78] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5% royalty rate.

Appendix A-5

EIA Reference Case/3% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Shale Oil Production[80]	18.25	18.25	18.25	109.50	109.50	182.50	182.60	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA Reference Oil Price[81]	49.87	49.75	50.80	51.28	51.95	52.04	52.73	53.43	54.90	55.64	56.37	57.11	57.63	58.12	58.61	59.12	59.53	59.95	60.37	60.79	61.22	
Revenue[82]	910	908	927	5615	5689	9497	9623	9751	10019	10154	10288	10423	10517	10607	10696	10789	10884	10941	11018	11094	11173	181504
Discounted Revenue	718	696	690	4057	3990	6467	6362	6259	6244	6144	6043	5944	5823	5702	5582	5467	5344	5225	5109	4994	4883	101743
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[83]	9	9	9	56	57	95	96	98	100	102	103	104	105	106	107	108	109	109	110	111	112	1815
Royalty Cost - 3%	27	27	28	168	171	285	289	293	301	305	309	313	316	318	321	324	326	328	331	333	335	5445
Royalty Cost - 5%	46	45	46	281	284	475	481	488	501	508	514	521	526	530	535	539	543	547	551	555	559	9075
Royalty Cost - 7%	64	64	65	393	398	665	674	683	701	711	720	730	736	742	749	755	760	766	771	777	782	12705
Royalty Cost - 9%	82	82	83	505	512	855	866	878	902	914	926	938	947	955	963	971	978	985	992	998	1006	16335
Royalty Cost - 12.5%	114	113	116	702	711	1187	1203	1219	1252	1269	1286	1303	1315	1326	1337	1349	1358	1368	1377	1387	1397	22688
Total Cost - 1%	698	698	698	4190	4191	6984	6985	6987	6989	6991	6992	6993	6994	6995	6996	6997	6998	6998	6999	7000	7001	122374
Total Cost - 3%	716	716	717	4302	4305	7174	7178	7182	7190	7194	7198	7202	7205	7207	7210	7213	7215	7217	7220	7222	7224	126004
Total Cost - 5%	735	734	735	4415	4418	7364	7370	7377	7390	7397	7403	7410	7415	7419	7424	7428	7432	7436	7440	7444	7448	129634
Total Cost - 7%	753	753	754	4527	4532	7554	7563	7572	7590	7600	7609	7619	7625	7631	7638	7644	7649	7655	7660	7666	7671	133264
Total Cost - 9%	771	771	772	4639	4646	7744	7755	7767	7791	7803	7815	7827	7836	7844	7852	7860	7867	7874	7881	7887	7895	136894
Total Cost - 12.5%	803	802	805	4836	4845	8076	8092	8108	8141	8158	8175	8192	8204	8215	8226	8238	8247	8257	8266	8276	8286	143247
Discounted Production Cost	544	528	513	2986	2900	4691	4554	4422	4293	4168	4047	3929	3814	3703	3595	3491	3389	3290	3194	3101	3011	68163
Discounted Total Cost - 1%	551	535	520	3027	2939	4756	4618	4484	4355	4229	4107	3988	3873	3760	3651	3545	3442	3342	3245	3151	3060	69181
Discounted Total Cost - 3%	565	549	533	3108	3019	4885	4745	4610	4480	4352	4228	4107	3989	3874	3763	3655	3549	3447	3348	3251	3158	71216
Discounted Total Cost - 5%	580	563	547	3189	3099	5014	4873	4735	4605	4475	4349	4226	4105	3988	3874	3764	3656	3551	3450	3351	3255	73251
Discounted Total Cost - 7%	594	577	561	3270	3179	5144	5000	4860	4730	4598	4470	4345	4222	4102	3986	3873	3763	3656	3552	3451	3353	75285
Discounted Total Cost - 9%	609	591	575	3352	3259	5273	5127	4985	4855	4721	4590	4464	4338	4216	4098	3983	3870	3761	3654	3551	3451	77320
Discounted Total Cost - 12.5%	634	615	599	3494	3398	5499	5350	5204	5073	4938	4802	4672	4542	4416	4293	4174	4057	3943	3833	3726	3621	80881
Profit	221	219	238	1481	1555	2608	2734	2862	3130	3265	3399	3534	3828	3718	3807	3900	3975	4052	4129	4205	4284	60945
Profit - 1%	212	210	229	1425	1498	2513	2638	2764	3030	3164	3296	3429	3523	3612	3700	3793	3867	3942	4018	4094	4172	59130
Profit - 3%	194	192	210	1313	1384	2323	2446	2569	2830	2961	3090	3221	3313	3400	3488	3577	3649	3724	3798	3872	3948	55499
Profit - 5%	176	174	192	1200	1270	2133	2253	2374	2629	2758	2884	3012	3103	3188	3273	3361	3432	3505	3578	3650	3725	51869
Profit - 7%	157	155	173	1088	1156	1943	2061	2179	2429	2554	2678	2804	2892	2975	3059	3145	3215	3286	3357	3429	3502	48239
Profit - 9%	139	137	155	976	1043	1754	1868	1984	2229	2351	2473	2596	2682	2763	2845	2929	2997	3067	3137	3207	3278	44609
Profit - 12.5%	107	105	122	779	843	1421	1531	1643	1878	1996	2113	2231	2314	2392	2470	2552	2617	2684	2751	2818	2887	38257
Discounted Profit	175	168	177	1070	1090	1776	1808	1837	1951	1976	1996	2015	2009	1999	1987	1976	1956	1935	1914	1893	1872	33580
Discounted Profit - 1%	167	161	170	1029	1050	1711	1744	1774	1888	1914	1936	1956	1951	1942	1931	1922	1902	1883	1863	1843	1823	32562
Discounted Profit - 3%	153	147	156	948	971	1582	1617	1649	1763	1791	1815	1837	1834	1828	1820	1812	1795	1778	1761	1743	1726	30527
Discounted Profit - 5%	139	133	143	867	891	1453	1490	1524	1638	1668	1694	1718	1718	1713	1708	1703	1688	1674	1659	1643	1628	28493
Discounted Profit - 7%	124	119	129	786	811	1323	1362	1399	1514	1546	1573	1599	1601	1599	1596	1594	1581	1569	1557	1544	1530	26458
Discounted Profit - 9%	110	105	115	705	731	1194	1235	1274	1389	1423	1452	1480	1485	1485	1485	1484	1475	1465	1455	1444	1433	24423
Discounted Profit - 12.5%	85	81	91	563	592	968	1012	1055	1170	1208	1241	1272	1281	1286	1289	1293	1287	1282	1276	1269	1262	20852
Discounted Royalty - 1%	7	7	7	41	40	65	64	63	62	61	60	59	58	57	56	55	53	52	51	50	49	1017
Discounted Royalty - 3%	22	21	21	122	120	194	191	188	187	184	181	178	175	171	167	164	160	157	153	150	146	3052
Discounted Royalty - 5%	36	35	34	203	199	323	318	313	312	307	302	297	291	285	279	273	267	261	255	250	244	5087
Discounted Royalty - 7%	50	49	48	284	279	453	445	438	437	430	423	416	408	399	391	383	374	366	358	350	342	7122
Discounted Royalty - 9%	65	63	62	365	359	582	573	563	562	553	544	535	524	513	502	492	481	470	460	450	439	9157
Discounted Royalty - 12.5%	90	87	88	507	499	808	795	782	780	768	755	743	728	713	698	683	668	653	639	624	610	12718

[79] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).
[80] Production figures are in millions of barrels per year.
[81] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (0.7 percent increase for the reference price scenario) for the years 2025 through 2030.
[82] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.
[83] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5% royalty rate.

Appendix A-6

EIA Reference Case/20% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Shale Oil Production[85]	18.25	18.25	18.25	109.50	109.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA Reference Oil Price[86]	49.87	48.75	50.80	51.28	51.95	52.04	52.73	53.43	54.90	55.64	56.37	57.11	57.63	58.12	58.61	59.12	59.53	59.95	60.37	60.79	61.22	
Revenue[87]	910	908	927	5615	5689	9497	9623	9751	10019	10154	10288	10423	10517	10607	10696	10789	10864	10941	11018	11094	11173	181504
Discounted Revenue	212	176	150	756	638	888	750	633	542	458	386	326	274	231	194	163	137	115	96	81	68	7271
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[88]	9	9	9	56	57	95	96	98	100	102	103	104	105	106	107	108	109	109	110	111	112	1815
Royalty Cost - 3%	27	27	28	168	171	285	289	293	301	305	309	313	316	318	321	324	326	328	331	333	335	5445
Royalty Cost - 5%	46	45	46	281	284	475	481	488	501	508	514	521	526	530	535	539	543	547	551	555	559	9075
Royalty Cost - 7%	64	64	65	393	398	665	674	683	701	711	720	730	736	742	749	755	760	766	771	777	782	12705
Royalty Cost - 9%	82	82	83	505	512	855	866	878	902	914	926	938	947	955	963	971	978	985	992	998	1006	16335
Royalty Cost - 12.5%	114	113	116	702	711	1187	1203	1219	1252	1269	1286	1303	1315	1326	1337	1349	1358	1368	1377	1387	1397	22688
Total Cost - 1%	698	698	698	4190	4191	6984	6985	6987	6989	6991	6992	6993	6994	6995	6996	6997	6998	6998	6999	7000	7001	122374
Total Cost - 3%	716	716	717	4302	4305	7174	7178	7182	7190	7194	7198	7202	7205	7207	7210	7213	7215	7217	7220	7222	7224	126004
Total Cost - 5%	735	734	735	4415	4418	7364	7370	7377	7390	7397	7403	7410	7415	7419	7424	7428	7432	7436	7440	7444	7448	129634
Total Cost - 7%	753	753	754	4527	4532	7554	7563	7572	7590	7600	7609	7619	7625	7631	7638	7644	7649	7655	7660	7666	7671	133264
Total Cost - 9%	771	771	772	4639	4646	7744	7755	7767	7791	7803	7815	7827	7836	7844	7852	7860	7867	7874	7881	7887	7895	136894
Total Cost - 12.5%	803	802	805	4836	4845	8078	8092	8108	8141	8158	8175	8192	8204	8215	8226	8238	8247	8257	8266	8276	8286	143247
Discounted Production Cost	160	134	111	556	464	644	537	447	373	311	259	216	180	150	125	104	87	72	60	50	42	5079
Discounted Total Cost - 1%	162	135	113	564	470	653	544	453	378	315	263	219	182	152	127	106	88	73	61	51	42	5152
Discounted Total Cost - 3%	167	139	116	579	483	671	559	466	389	324	270	225	188	157	131	109	91	76	63	53	44	5298
Discounted Total Cost - 5%	171	142	119	594	496	688	574	479	400	333	278	232	193	161	134	112	93	78	65	54	45	5443
Discounted Total Cost - 7%	175	146	122	609	508	706	589	491	411	343	286	238	199	166	138	115	96	80	67	56	47	5588
Discounted Total Cost - 9%	179	149	125	624	521	724	604	504	421	352	294	245	204	170	142	119	99	83	69	57	48	5734
Discounted Total Cost - 12.5%	187	156	130	651	543	755	630	526	440	368	307	256	214	179	149	124	104	87	72	60	50	5988
Profit	221	219	238	1481	1555	2608	2734	2862	3130	3265	3399	3534	3626	3718	3807	3900	3975	4052	4129	4205	4284	60945
Profit - 1%	212	210	229	1425	1498	2513	2638	2764	3030	3164	3296	3429	3523	3612	3700	3793	3867	3942	4018	4094	4172	59130
Profit - 3%	194	192	210	1313	1384	2323	2446	2569	2830	2961	3090	3221	3313	3400	3486	3577	3649	3724	3798	3872	3948	55499
Profit - 5%	176	174	192	1200	1270	2133	2253	2374	2629	2758	2884	3012	3103	3188	3273	3361	3432	3505	3578	3650	3725	51869
Profit - 7%	157	155	173	1088	1156	1943	2061	2179	2429	2554	2678	2804	2892	2975	3059	3145	3215	3288	3357	3429	3502	48239
Profit - 9%	139	137	155	976	1043	1754	1868	1984	2229	2351	2473	2598	2682	2763	2845	2929	2997	3067	3137	3207	3278	44609
Profit - 12.5%	107	105	122	779	843	1421	1531	1643	1878	1996	2113	2231	2314	2392	2470	2552	2617	2684	2751	2818	2887	38257
Discounted Profit	51	42	38	199	174	244	213	186	169	147	128	111	95	81	69	59	50	42	36	31	26	2192
Discounted Profit - 1%	49	41	37	192	168	235	205	179	164	143	124	107	92	79	67	57	49	41	35	30	25	2119
Discounted Profit - 3%	45	37	34	177	155	217	190	167	153	133	116	101	86	74	63	54	46	39	33	28	24	1974
Discounted Profit - 5%	41	34	31	162	142	199	175	154	142	124	108	94	81	69	59	51	43	37	31	27	23	1828
Discounted Profit - 7%	37	30	28	146	130	182	160	141	131	115	101	88	75	65	55	47	40	34	29	25	21	1683
Discounted Profit - 9%	32	27	25	131	117	164	146	129	121	106	93	81	70	60	52	44	38	32	27	23	20	1537
Discounted Profit - 12.5%	25	20	20	105	95	133	119	107	102	90	79	70	60	52	45	39	33	28	24	21	18	1283
Discounted Royalty - 1%	2	2	1	8	6	9	7	6	5	5	4	3	3	2	2	2	1	1	1	1	1	73
Discounted Royalty - 3%	6	5	4	23	19	27	22	19	16	14	12	10	8	7	6	5	4	3	3	2	2	218
Discounted Royalty - 5%	11	9	7	38	32	44	37	32	27	23	19	16	14	12	10	8	7	6	5	4	3	364
Discounted Royalty - 7%	15	12	10	53	45	62	52	44	38	32	27	23	19	16	14	11	10	8	7	6	5	509
Discounted Royalty - 9%	19	16	13	68	57	80	67	57	49	41	35	29	25	21	17	15	12	10	9	7	6	654
Discounted Royalty - 12.5%	26	22	19	94	80	111	94	79	68	57	48	41	34	29	24	20	17	14	12	10	8	909

[84] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).

[85] Production figures are in millions of barrels per year.

[86] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (0.7 percent increase for the reference price scenario) for the years 2025 through 2030.

[87] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.

[88] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5% royalty rate.

Appendix A-7
EIA High Price Case/7% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total[89]
Shale Oil Production[90]	18.25	18.25	18.25	109.50	109.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA High Oil Price[91]	79.57	81.91	83.71	85.45	87.32	89.12	90.26	90.98	92.12	93.25	94.40	95.55	96.69	97.84	98.98	100.14	101.10	102.07	103.05	104.04	105.04	
Revenue[92]	1452	1495	1528	9357	9562	16264	16472	16604	16812	17018	17228	17438	17646	17856	18064	18276	18451	18628	18807	18987	19170	307113
Discounted Revenue	845	813	777	4445	4245	6749	6388	6018	5695	5388	5097	4822	4560	4312	4077	3855	3638	3432	3238	3056	2883	84334
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[93]	15	15	15	94	96	163	165	166	168	170	172	174	176	179	181	183	185	186	188	190	192	3071
Royalty Cost - 3%	44	45	46	281	287	488	494	498	504	511	517	523	529	536	542	548	554	559	564	570	575	9213
Royalty Cost - 5%	73	75	76	468	478	813	824	830	841	851	861	872	882	893	903	914	923	931	940	949	958	15356
Royalty Cost - 7%	102	105	107	655	669	1139	1153	1162	1177	1191	1206	1221	1235	1250	1264	1279	1292	1304	1316	1329	1342	21498
Royalty Cost - 9%	131	135	137	842	861	1464	1483	1494	1513	1532	1551	1569	1588	1607	1626	1645	1661	1676	1693	1709	1725	27640
Royalty Cost - 12.5%	182	187	191	1170	1195	2033	2059	2075	2101	2127	2154	2180	2206	2232	2258	2284	2306	2328	2351	2373	2396	38389
Total Cost - 1%	704	704	704	4228	4230	7052	7054	7055	7057	7059	7061	7063	7065	7068	7070	7072	7074	7075	7077	7079	7081	123630
Total Cost - 3%	733	734	735	4415	4421	7377	7383	7387	7393	7400	7406	7412	7418	7425	7431	7437	7443	7448	7453	7459	7464	129772
Total Cost - 5%	762	764	765	4602	4612	7702	7713	7719	7730	7740	7750	7761	7771	7782	7792	7803	7812	7820	7829	7838	7847	135915
Total Cost - 7%	791	794	796	4789	4803	8028	8042	8051	8066	8080	8095	8110	8124	8139	8153	8168	8181	8193	8205	8218	8231	142057
Total Cost - 9%	820	824	826	4976	4995	8353	8372	8383	8402	8421	8440	8458	8477	8496	8515	8534	8550	8565	8582	8598	8614	148199
Total Cost - 12.5%	871	876	880	5304	5329	8922	8946	8964	8990	9016	9043	9069	9095	9121	9147	9173	9195	9217	9240	9262	9285	158948
Discounted Production Cost	401	375	350	1964	1836	2859	2672	2497	2334	2181	2038	1905	1780	1664	1555	1453	1358	1269	1186	1109	1036	33821
Discounted Total Cost - 1%	409	383	358	2008	1878	2926	2736	2557	2390	2235	2089	1953	1826	1707	1596	1492	1395	1304	1219	1139	1065	34664
Discounted Total Cost - 3%	426	399	374	2097	1963	3061	2863	2677	2504	2343	2191	2050	1917	1793	1677	1569	1467	1372	1283	1200	1123	36351
Discounted Total Cost - 5%	443	415	389	2186	2048	3196	2991	2798	2618	2450	2293	2146	2008	1879	1759	1646	1540	1441	1348	1261	1180	38038
Discounted Total Cost - 7%	460	432	405	2275	2133	3331	3119	2918	2732	2558	2395	2242	2099	1966	1840	1723	1613	1510	1413	1323	1238	39724
Discounted Total Cost - 9%	477	448	420	2364	2218	3466	3247	3039	2846	2666	2497	2339	2191	2052	1922	1800	1686	1578	1478	1384	1296	41411
Discounted Total Cost - 12.5%	507	476	447	2520	2366	3702	3470	3249	3045	2854	2675	2508	2350	2203	2065	1935	1813	1698	1591	1491	1397	44363
Profit	763	806	839	5223	5428	9375	9583	9715	9923	10129	10339	10549	10757	10967	11175	11387	11562	11739	11918	12098	12281	186554
Profit - 1%	749	791	823	5129	5332	9213	9419	9549	9755	9959	10167	10374	10580	10788	10994	11204	11377	11552	11730	11908	12089	183483
Profit - 3%	720	761	793	4942	5141	8887	9089	9217	9419	9619	9822	10026	10228	10431	10633	10838	11008	11180	11353	11529	11706	177341
Profit - 5%	691	731	762	4755	4949	8562	8760	8885	9082	9278	9478	9677	9875	10074	10272	10473	10639	10807	10977	11149	11322	171198
Profit - 7%	662	701	732	4568	4758	8237	8430	8553	8746	8938	9133	9328	9522	9717	9910	10107	10270	10435	10601	10769	10939	165058
Profit - 9%	632	671	701	4381	4567	7912	8101	8221	8410	8597	8788	8979	9169	9360	9549	9742	9901	10062	10225	10389	10556	158914
Profit - 12.5%	582	619	648	4053	4232	7342	7524	7639	7821	8002	8186	8369	8551	8735	8917	9102	9255	9410	9567	9725	9885	148165
Discounted Profit	444	438	426	2481	2410	3890	3717	3521	3361	3207	3059	2917	2780	2649	2522	2402	2279	2163	2052	1947	1847	50513
Discounted Profit - 1%	436	430	419	2437	2367	3823	3653	3461	3304	3153	3008	2869	2734	2606	2482	2363	2243	2129	2020	1916	1818	49670
Discounted Profit - 3%	419	414	403	2348	2283	3688	3525	3341	3190	3045	2906	2772	2643	2519	2400	2286	2170	2060	1955	1855	1761	47983
Discounted Profit - 5%	402	398	388	2259	2198	3553	3397	3220	3076	2937	2804	2676	2552	2433	2318	2209	2097	1991	1890	1794	1703	46296
Discounted Profit - 7%	385	381	372	2170	2113	3418	3269	3100	2963	2829	2702	2579	2461	2347	2237	2132	2025	1923	1825	1733	1645	44610
Discounted Profit - 9%	368	365	356	2081	2028	3283	3142	2979	2849	2722	2600	2483	2369	2261	2155	2055	1952	1854	1761	1672	1588	42923
Discounted Profit - 12.5%	339	337	329	1926	1879	3047	2918	2769	2649	2533	2422	2314	2210	2110	2013	1920	1825	1734	1647	1565	1487	39971
Discounted Royalty - 1%	8	8	8	44	42	67	64	60	57	54	51	48	46	43	41	39	36	34	32	31	29	843
Discounted Royalty - 3%	25	24	23	133	127	202	192	181	171	162	153	145	137	129	122	116	109	103	97	92	86	2530
Discounted Royalty - 5%	42	41	39	222	212	337	319	301	285	269	255	241	228	216	204	193	182	172	162	153	144	4217
Discounted Royalty - 7%	59	57	54	311	297	472	447	421	399	377	357	338	319	302	285	270	255	240	227	214	202	5903
Discounted Royalty - 9%	76	73	70	400	382	607	575	542	513	485	459	434	410	388	367	347	327	309	291	275	259	7590
Discounted Royalty - 12.5%	106	102	97	556	531	844	799	752	712	673	637	603	570	539	510	482	455	429	405	382	360	10542

[89] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).
[90] Production figures are in millions of barrels per year.
[91] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (1 percent increase for the high price scenario) for the years 2025 through 2030.
[92] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.
[93] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5% royalty rate.

Appendix A-8
EIA High Price Case/3% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total[94]
Shale Oil Production[95]	18.25	18.25	18.25	109.50	109.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA High Oil Price[96]	79.57	81.91	83.71	85.45	87.32	89.12	90.28	90.98	92.12	93.25	94.40	95.55	96.69	97.84	98.98	100.14	101.10	102.07	103.05	104.04	105.04	
Revenue[97]	1452	1495	1528	9357	9562	16264	16472	16604	16812	17018	17228	17438	17646	17856	18064	18276	18451	18628	18807	18987	19170	307113
Discounted Revenue	1146	1146	1137	6760	6706	11075	10890	10657	10477	10296	10120	9945	9770	9598	9427	9260	9077	8897	8721	8548	8379	172031
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[98]	15	15	15	94	96	163	165	166	168	170	172	174	176	179	181	183	185	186	188	190	192	3071
Royalty Cost - 3%	44	45	46	281	287	488	494	498	504	511	517	523	529	536	542	548	554	559	564	570	575	9213
Royalty Cost - 5%	73	75	76	468	478	813	824	830	841	851	861	872	882	893	903	914	923	931	940	949	958	15356
Royalty Cost - 7%	102	105	107	655	669	1139	1153	1162	1177	1191	1206	1221	1235	1250	1264	1279	1292	1304	1316	1329	1342	21498
Royalty Cost - 9%	131	135	137	842	861	1464	1483	1494	1513	1532	1551	1569	1588	1607	1626	1645	1661	1676	1693	1709	1725	27640
Royalty Cost - 12.5%	182	187	191	1170	1195	2033	2059	2075	2101	2127	2154	2180	2206	2232	2258	2284	2306	2328	2351	2373	2396	38389
Total Cost - 1%	704	704	704	4228	4230	7052	7054	7055	7057	7059	7061	7063	7065	7068	7070	7072	7074	7075	7077	7079	7081	123630
Total Cost - 3%	733	734	735	4415	4421	7377	7383	7387	7393	7400	7406	7412	7418	7425	7431	7437	7443	7448	7453	7459	7464	129772
Total Cost - 5%	762	764	765	4602	4612	7702	7713	7719	7730	7740	7750	7761	7771	7782	7792	7803	7812	7820	7829	7838	7847	135915
Total Cost - 7%	791	794	796	4789	4803	8028	8042	8051	8066	8080	8095	8110	8124	8139	8153	8168	8181	8193	8205	8218	8231	142057
Total Cost - 9%	820	824	826	4976	4995	8353	8372	8383	8402	8421	8440	8458	8477	8496	8515	8534	8550	8565	8582	8598	8614	148199
Total Cost - 12.5%	871	876	880	5304	5329	8922	8948	8984	8990	9016	9043	9069	9095	9121	9147	9173	9195	9217	9240	9262	9285	158948
Discounted Production Cost	544	528	513	2986	2900	4691	4554	4422	4293	4168	4047	3929	3814	3703	3595	3491	3389	3290	3194	3101	3011	68163
Discounted Total Cost - 1%	555	540	524	3054	2967	4802	4663	4528	4398	4271	4148	4028	3912	3799	3690	3583	3480	3379	3282	3187	3095	69884
Discounted Total Cost - 3%	578	562	547	3189	3101	5023	4881	4742	4607	4477	4350	4227	4107	3991	3878	3768	3661	3557	3456	3358	3262	73324
Discounted Total Cost - 5%	601	585	570	3324	3235	5245	5099	4955	4817	4683	4553	4426	4303	4183	4067	3954	3843	3735	3630	3529	3430	76765
Discounted Total Cost - 7%	624	608	592	3460	3369	5466	5317	5168	5026	4889	4755	4625	4498	4375	4255	4139	4024	3913	3805	3700	3598	80206
Discounted Total Cost - 9%	647	631	615	3595	3503	5688	5535	5381	5236	5095	4957	4824	4694	4567	4444	4324	4206	4091	3979	3871	3765	83646
Discounted Total Cost - 12.5%	687	671	655	3831	3738	6075	5916	5754	5603	5455	5312	5172	5036	4903	4774	4648	4523	4402	4284	4170	4058	89667
Profit	763	806	839	5223	5428	9375	9583	9715	9923	10129	10339	10549	10757	10967	11175	11387	11562	11739	11918	12098	12281	188554
Profit - 1%	749	791	823	5129	5332	9213	9419	9549	9755	9959	10167	10374	10580	10788	10994	11204	11377	11552	11730	11908	12089	183483
Profit - 3%	720	761	793	4942	5141	8887	9089	9217	9419	9619	9822	10026	10228	10431	10633	10838	11008	11180	11353	11529	11706	177341
Profit - 5%	691	731	762	4755	4949	8562	8760	8885	9082	9278	9478	9677	9875	10074	10272	10473	10639	10807	10977	11149	11322	171198
Profit - 7%	662	701	732	4568	4758	8237	8430	8553	8746	8938	9133	9328	9522	9717	9910	10107	10270	10435	10601	10769	10939	165056
Profit - 9%	632	671	701	4381	4567	7912	8101	8221	8410	8597	8788	8979	9169	9360	9549	9742	9901	10062	10225	10389	10556	158914
Profit - 12.5%	582	619	648	4053	4232	7342	7524	7639	7821	8002	8186	8369	8551	8735	8917	9102	9255	9410	9567	9725	9885	148165
Discounted Profit	602	618	624	3773	3807	6384	6336	6236	6184	6128	6073	6016	5956	5895	5832	5769	5688	5607	5526	5447	5368	103867
Discounted Profit - 1%	591	606	613	3705	3740	6273	6227	6129	6079	6025	5972	5916	5858	5799	5738	5677	5597	5518	5439	5361	5284	102147
Discounted Profit - 3%	568	583	590	3570	3606	6052	6009	5916	5869	5819	5769	5718	5663	5607	5549	5492	5415	5340	5265	5190	5116	98706
Discounted Profit - 5%	545	560	567	3435	3471	5830	5791	5703	5660	5613	5567	5519	5467	5415	5361	5306	5234	5162	5090	5019	4949	95266
Discounted Profit - 7%	522	537	545	3300	3337	5609	5573	5490	5450	5408	5365	5320	5272	5223	5172	5121	5052	4984	4918	4848	4781	91825
Discounted Profit - 9%	499	515	522	3165	3203	5387	5356	5276	5241	5202	5162	5121	5077	5031	4984	4936	4871	4806	4741	4677	4614	88385
Discounted Profit - 12.5%	459	474	482	2928	2968	5000	4875	4903	4874	4841	4808	4773	4735	4695	4654	4612	4553	4494	4436	4378	4320	82364
Discounted Royalty - 1%	11	11	11	68	67	111	109	107	105	103	101	99	98	96	94	93	91	89	87	85	84	1720
Discounted Royalty - 3%	34	34	34	203	201	332	327	320	314	309	304	298	293	288	283	278	272	267	262	256	251	5161
Discounted Royalty - 5%	57	57	57	338	335	554	545	533	524	515	506	497	489	480	471	463	454	445	436	427	419	8602
Discounted Royalty - 7%	80	80	80	473	469	775	762	746	733	721	708	696	684	672	660	648	635	623	610	598	587	12042
Discounted Royalty - 9%	103	103	102	608	604	997	980	959	943	927	911	895	879	864	848	833	817	801	785	769	754	15483
Discounted Royalty - 12.5%	143	143	142	845	838	1384	1361	1332	1310	1287	1265	1243	1221	1200	1178	1158	1135	1112	1090	1068	1047	21504

[94] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).
[95] Production figures are in millions of barrels per year.
[96] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (1 percent increase for the high price scenario) for the years 2025 through 2030.
[97] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.
[98] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5% royalty rate.

Appendix A-9
EIA High Price Case/20% Discount Rate

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total[99]
Shale Oil Production[100]	18.25	18.25	18.25	109.50	109.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	182.50	3194
EIA High Oil Price[101]	79.57	81.91	83.71	85.45	87.32	89.12	90.26	90.98	92.12	93.25	94.40	95.55	96.69	97.84	98.98	100.14	101.10	102.07	103.05	104.04	105.04	
Revenue[102]	1452	1495	1528	9357	9562	16264	16472	16604	16812	17018	17228	17438	17646	17856	18064	18276	18451	18628	18807	18987	19170	307113
Discounted Revenue	338	290	247	1259	1072	1520	1283	1078	909	767	647	546	460	388	327	276	232	195	164	138	116	12254
Production Cost	689	689	689	4134	4134	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	6889	120559
Royalty Cost - 1%[103]	15	15	15	94	95	163	165	166	168	170	172	174	176	179	181	183	185	186	188	190	192	3071
Royalty Cost - 3%	44	45	46	281	287	488	494	498	504	511	517	523	529	536	542	548	554	559	564	570	575	9213
Royalty Cost - 5%	73	75	76	468	478	813	824	830	841	851	861	872	882	893	903	914	923	931	940	949	958	15356
Royalty Cost - 7%	102	105	107	655	669	1139	1153	1162	1177	1191	1206	1221	1235	1250	1264	1279	1292	1304	1316	1329	1342	21498
Royalty Cost - 9%	131	135	137	842	861	1464	1483	1494	1513	1532	1551	1569	1588	1607	1626	1645	1661	1676	1693	1709	1725	27640
Royalty Cost - 12.5%	182	187	191	1170	1195	2033	2059	2075	2101	2127	2154	2180	2206	2232	2258	2284	2306	2328	2351	2373	2396	38389
Total Cost - 1%	704	704	704	4228	4230	7052	7054	7055	7057	7059	7061	7063	7065	7068	7070	7072	7074	7075	7077	7079	7081	123630
Total Cost - 3%	733	734	735	4415	4421	7377	7383	7387	7393	7400	7406	7412	7418	7425	7431	7437	7443	7448	7453	7459	7464	129772
Total Cost - 5%	762	764	765	4602	4612	7702	7713	7719	7730	7740	7750	7761	7771	7782	7792	7803	7812	7820	7829	7838	7847	135915
Total Cost - 7%	791	794	796	4789	4803	8028	8042	8051	8066	8080	8095	8110	8124	8139	8153	8168	8181	8193	8205	8218	8231	142057
Total Cost - 9%	820	824	826	4976	4995	8353	8372	8383	8402	8421	8440	8458	8477	8496	8515	8534	8550	8565	8582	8598	8614	148199
Total Cost - 12.5%	871	876	880	5304	5329	8922	8948	8964	8990	9016	9043	9069	9095	9121	9147	9173	9195	9217	9240	9262	9285	158948
Discounted Production Cost	160	134	111	556	464	644	537	447	373	311	259	216	180	150	125	104	87	72	60	50	42	5079
Discounted Total Cost - 1%	164	136	114	569	474	659	549	458	382	318	265	221	184	154	128	107	89	74	62	52	43	5202
Discounted Total Cost - 3%	170	142	119	594	496	689	575	479	400	334	278	232	194	161	135	112	94	78	65	54	45	5447
Discounted Total Cost - 5%	177	148	124	619	517	720	601	501	418	349	291	243	203	169	141	118	98	82	68	57	48	5692
Discounted Total Cost - 7%	184	154	129	645	539	750	626	523	436	364	304	254	212	177	148	123	103	86	72	60	50	5937
Discounted Total Cost - 9%	191	160	133	670	560	781	652	544	454	380	317	265	221	185	154	129	108	90	75	63	52	6182
Discounted Total Cost - 12.5%	202	170	142	714	598	834	697	582	486	406	340	284	237	198	166	138	116	97	81	67	56	6511
Profit	763	806	839	5223	5428	9375	9583	9715	9923	10129	10339	10549	10757	10967	11175	11387	11562	11739	11918	12098	12281	186554
Profit - 1%	749	791	823	5129	5332	9213	9419	9549	9755	9959	10167	10374	10580	10788	10994	11204	11377	11552	11730	11908	12089	183483
Profit - 3%	720	761	793	4942	5141	8887	9089	9217	9419	9619	9822	10026	10228	10431	10633	10838	11008	11180	11353	11529	11706	177341
Profit - 5%	691	731	762	4755	4949	8562	8760	8885	9082	9278	9478	9677	9875	10074	10272	10473	10639	10807	10977	11149	11322	171198
Profit - 7%	662	701	732	4568	4758	8237	8430	8553	8746	8938	9133	9328	9522	9717	9910	10107	10270	10435	10601	10769	10939	165056
Profit - 9%	632	671	701	4381	4567	7912	8101	8221	8410	8597	8788	8979	9169	9360	9549	9742	9901	10062	10225	10389	10556	158914
Profit - 12.5%	582	619	648	4053	4232	7342	7524	7639	7821	8002	8186	8369	8551	8735	8917	9102	9255	9410	9567	9725	9885	148165
Discounted Profit	177	156	135	703	609	876	746	631	537	457	388	330	281	238	202	172	145	123	104	88	74	7174
Discounted Profit - 1%	174	153	133	690	598	861	734	620	528	449	382	325	276	235	199	169	143	121	102	87	73	7052
Discounted Profit - 3%	167	147	128	665	577	831	708	598	509	434	369	314	267	227	193	164	138	117	99	84	71	6807
Discounted Profit - 5%	161	142	123	640	555	800	682	577	491	418	356	303	258	219	186	158	134	113	96	81	69	6562
Discounted Profit - 7%	154	136	118	616	534	770	657	555	473	403	343	292	248	211	180	153	129	109	93	78	66	6316
Discounted Profit - 9%	147	130	113	590	512	739	631	534	455	388	330	281	239	203	173	147	125	105	89	76	64	6071
Discounted Profit - 12.5%	135	120	105	546	475	688	586	496	423	361	307	262	223	190	162	137	116	99	84	71	60	5643
Discounted Royalty - 1%	3	3	2	13	11	15	13	11	9	8	6	5	5	4	3	3	2	2	2	1	1	123
Discounted Royalty - 3%	10	9	7	38	32	46	38	32	27	23	19	16	14	12	10	8	7	6	5	4	3	368
Discounted Royalty - 5%	17	14	12	63	54	76	64	54	45	38	32	27	23	19	16	14	12	10	8	7	6	613
Discounted Royalty - 7%	24	20	17	88	75	106	90	75	64	54	45	38	32	27	23	19	16	14	11	10	8	858
Discounted Royalty - 9%	30	26	22	113	97	137	115	97	82	69	58	49	41	35	29	25	21	18	15	12	10	1103
Discounted Royalty - 12.5%	42	36	31	157	134	190	160	135	114	96	81	68	58	49	41	34	29	24	21	17	15	1532

[99] Total production, revenue, cost, profit, and royalty figures are for the period of analysis (2015-2035).
[100] Production figures are in millions of barrels per year.
[101] EIA price projections are reported for 2015 through 2030. BLM's price projections for 2031 through 2035 are based on the EIA's average annual price change (1 percent increase for the high price scenario) for the years 2025 through 2030.
[102] All revenue, production cost, royalty, and profit figures are million dollars (constant 2005 dollars) per year.
[103] Each scenario is run using a 1%, 3%, 5%, 7%, 9%, and 12.5% royalty rate.

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