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Revenues and Disbursements from Oil and Natural Gas Production on Federal Lands

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Revenues and Disbursements from Oil and Natural Gas Production on Federal Lands

SUMMARY

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Federal revenues arising from oil and natural gas leases on federal lands support a range of federal and state policies and programs. The 116th Congress is considering proposed changes to policies affecting the collection and disbursement of revenues from onshore federal lands. Some of the proposed changes would affect royalty collections, allocation of revenue, the leasing process, and exemptions from royalty assessment.

Total domestic production (or withdrawal) of crude oil and natural gas in 2019 was the highest in the history of the United States for each commodity; a subset of this total, crude oil produced on federal lands was also a record value in 2019. Oil and natural gas production from onshore federal lands contributed 9% to each total in 2019. Revenues from oil and natural gas leases on onshore federal lands totaled $4.202 billion in FY2019, representing 86% of total federal revenues from energy and mineral leases on onshore federal lands. These revenues are composed of royalties, $2.931 billion; bonuses, $1.181 billion; other revenue (including settlement agreements, interest payments, Application for Permit to Drill fees), $67 million; and rents, $22 million. Disbursements of these revenues include $2.002 billion to states; $1.539 billion to the Reclamation Fund; $39 million to the Permit Processing Improvement Fund; $172 million to other accounts; and $444 million to the Treasury General Fund.

The decision to drill a given well represents the outcome of many factors facing an operator, including geologic considerations, regulations, costs associated with initial capital investments, access to infrastructure, and labor, among others. Differences within and among geologic formations suitable for oil and natural gas extraction can influence the decision by an operator considering well location, including whether to drill on federal lands. Of the 242 million acres associated with U.S. shale plays (a shale play is a geologic formation with active or expected oil and/or natural gas production; production from shale employs directional drilling and hydraulic fracturing), approximately 24 million acres, or 9.9% of the total, are in the federal mineral estate; 90.1% is on nonfederal lands.

Numerous provisions in law affect revenue collection and disbursements from oil and natural gas leases. The Federal Land Policy Management Act establishes statutory authority for the Bureau of Land Management to manage the federal mineral estate. Onshore oil and natural gas are defined as leasable minerals, governed by the Mineral Leasing Act of 1920 (MLA). In FY2019, approximately 93% of revenues from oil and natural gas developments on federal lands were disbursed according to provisions in the MLA. Some key provisions in the MLA include a 12.5% minimum royalty rate; 40% of revenues arising from oil and gas leasing on federal lands in states other than Alaska are deposited into the Reclamation Fund; and that states other than Alaska receive 50% of revenues from extraction operations in those states (Alaska receives 90%). Disbursements to states are assessed a 2% administration fee, which is deposited in the Treasury. Leases are sold to the highest bidder (at or above the required minimum bid) during competitive auctions, or are obtained non-competitively.

Bills introduced in the 116th Congress would alter the minimum royalty rate assessed on new oil and natural gas leases on federal lands. Given the high percentage of revenue from royalties, changes to the minimum royalty rate represent the most direct means of altering revenues and disbursements from oil and natural gas leases, under normal market conditions. Some bills would require royalties to be collected for natural gas lost or used in production that is currently exempt from royalty assessment.

Some bills would alter the current revenue allocation scheme, allowing states to obtain the 2% administrative fee currently deposited in the Treasury. Other bills would amend minimum required bids, rental rates, and aspects of the current leasing process, including the elimination of non-competitive leasing.

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Introduction

Mineral extraction, including that of oil and natural gas, from onshore federal lands is a topic often debated. Some argue in favor of increased development, with the intent of increasing domestic energy supply, employment opportunities in the sector, and revenues from these activities. Others argue in favor of decreased development, with the intent of reducing pollution (e.g., greenhouse gas emissions) and preserving access to federal lands for other uses.

Federal revenues from oil and natural gas leases provide income streams that support a range of federal and state policies and programs. Revenues from oil and natural gas leases on onshore federal lands totaled $4.202 billion in FY2019.[1] Those revenues are 86% of total federal revenues from leasable minerals and geothermal resources on onshore federal lands.[2] The sources of these funds include bonus bids for leases, lease rental payments, production royalties, and other payments. These funds are disbursed to states, federal programs, and the U.S. Department of the Treasury (Treasury). Production of oil and natural gas on federal lands is subject to various federal regulations, including those related to air pollution, water pollution, and land use considerations, among others.

This report provides background information related to onshore oil and natural gas production on federal lands and related statutory authorities. Federal revenues and disbursements from oil and natural gas production are presented and discussed, with a focus on factors that can impact these values. A discussion of legislative proposals follows.

Oil and Natural Gas Production on Federal Lands

Background and Production History

Onshore federal lands include all federal surface lands and 710 million acres of the federal subsurface mineral estate.[3] The Bureau of Land Management (BLM), an agency within the Department of the Interior (DOI), manages energy production and mineral development from these subsurface lands, including for lands whose surface is managed by other agencies or for split estate lands.[4] Oil and natural gas developments are considered mineral developments. Some federal lands, including most National Park Service units, designated wilderness areas, military bases, and others, have been withdrawn from mineral exploration and development. BLM and the Forest Service (FS), an agency within the Department of Agriculture (USDA), also have the

[1] Not including revenue from Native American lands. Oil and natural gas resources are commonly coproduced on federal lands. The total for oil and natural gas leases includes all revenues from the commodity categories Oil, Gas, Oil & Gas, and NGL (natural gas liquids). These data are from the Office of Natural Resources Revenue (ONRR), available at https://revenuedata.doi.gov. Total includes fees from Application for Permit to Drill, received and disbursed by the Bureau of Land Management (CRS calculations using Bureau of Land Management data).

[2] Coal leases contributed 12% to the total; all other mineral leases combined contributed the remaining 2%.

[3] Native American lands are excluded from the federal mineral estate acreage (Bureau of Land Management, *Public Land Statistics 2019*, 2020, Table 1-3, pp. 7-8).

[4] Electricity produced from geothermal resources on federal lands is an example of energy production from the federal mineral estate. If surface lands over the federal mineral estate are not federally owned (i.e., split estate), BLM works with private surface owners to manage the federal mineral estate.

authority to use their surface lands for energy production, typically from renewable sources, including wind and solar.[5]

Offshore federal lands refers to the approximately 1.7 billion offshore acres in federal waters on the U.S. outer continental shelf (OCS), where energy and mineral leasing is managed by DOI's Bureau of Ocean Energy Management (BOEM). The OCS encompasses the Gulf of Mexico, Pacific, Atlantic, and Alaska regions, with offshore energy and mineral development predominantly occurring in the Gulf of Mexico. This report may in some places include data from offshore oil and natural gas production for comparison to onshore data, but it generally does not address the topic of offshore oil and natural gas production.[6]

In 2019, total U.S. crude oil production (on federal and nonfederal lands) was 4.471 billion barrels (12,248,000 barrels per day),[7] and the United States imported 2.48 billion barrels (6,795,000 barrels per day) of crude oil during the same period.[8] Prior to the COVID-19 pandemic, the U.S. Energy Information Administration (EIA) forecasted that the United States would be a net exporter of oil in 2020.[9]

EIA estimates that the United States produced 40,704 billion cubic feet (Bcf) of natural gas in 2019, and estimates of net exports were 1,914 Bcf; the United States has been a net exporter of natural gas since 2017.[10] Crude oil production and natural gas production in 2019 were the highest in the country's history.[11]

U.S. crude oil production has increased over the last 10 years. **Figure 1** shows total domestic oil production and the contributions from sources on federal (onshore and offshore) and nonfederal lands from 2010 through 2019. Oil production on nonfederal lands has increased 163%, from 1,288 million barrels in 2010 to 3,386 million barrels in 2019.[12] In 2019, oil production on nonfederal lands had increased to 76% of the total, compared to 64% of total production in 2010. Onshore oil production on federal lands[13] has increased 207%, from 124 million barrels in 2010 to 381 million barrels in 2019.[14] In 2019, onshore oil production on federal lands was 9% of the total, compared to 6% of total production in 2010.

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[5] These types of renewable energy developments on federal land are developed under Title V of the Federal Land Policy Management Act (43 U.S.C. §§1761 et seq.).

[6] For more information on the legal framework of oil and gas development on offshore lands, see CRS Report RL33404, *Offshore Oil and Gas Development: Legal Framework*, by Adam Vann. For more information on offshore oil and natural gas leasing, see CRS Report R44504, *Five-Year Program for Offshore Oil and Gas Leasing: History and Program for 2017-2022*, by Laura B. Comay, Marc Humphries, and Adam Vann; and CRS Report R44692, *Five-Year Offshore Oil and Gas Leasing Program for 2019-2024: Status and Issues in Brief*, by Laura B. Comay.

[7] Includes lease condensate and excludes natural gas liquids (Energy Information Administration (EIA), "Petroleum and Other Liquids, Crude Oil Production," https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm).

[8] EIA, "Petroleum and Other Liquids, Imports by Area of Entry," https://www.eia.gov/dnav/pet/pet_move_imp_dc_NUS-Z00_mbbl_a.htm.

[9] EIA, *Annual Energy Outlook 2020*, January 2020, p. 39.

[10] Gross withdrawals, excluding lease condensate; data for 2019 are estimates (EIA, *Monthly Energy Review July 2020*, Table 4.1, p. 101).

[11] For additional information on the history of oil and natural gas production in the United States, see CRS In Focus IF11036, *U.S. Oil and Natural Gas Transformation and Effects*, by Michael Ratner et al.; CRS Report R45493, *The World Oil Market and U.S. Policy: Background and Select Issues for Congress*, by Heather L. Greenley; and CRS Report R45988, *U.S. Natural Gas: Becoming Dominant*, by Michael Ratner.

[12] CRS calculations, based on EIA and ONRR data.

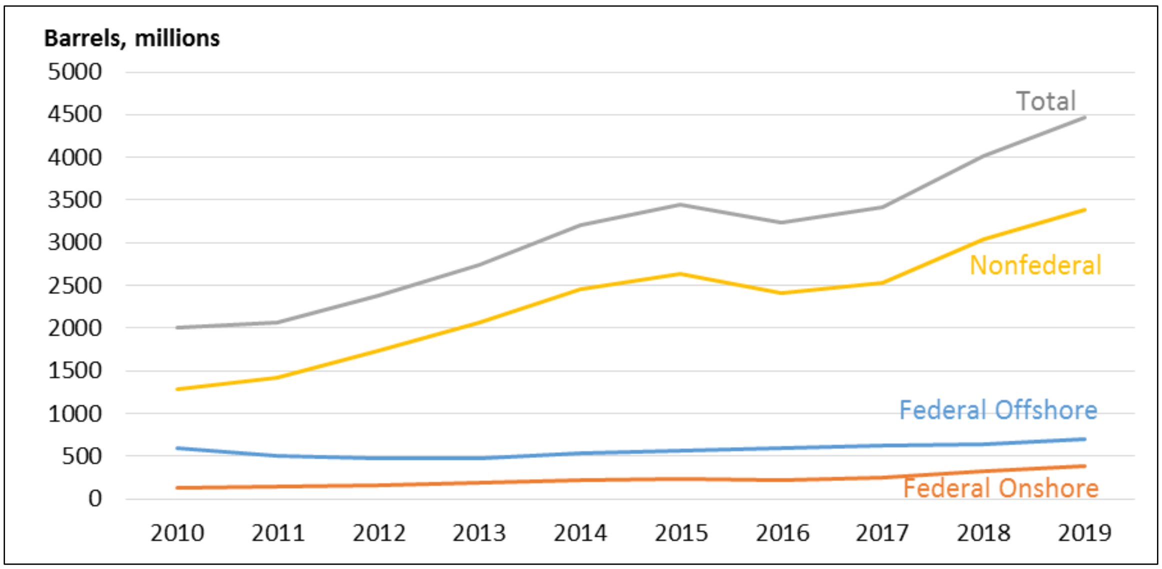
[13] Includes production from Native American lands.

[14] ONRR, https://revenuedata.doi.gov/.

U.S. natural gas production has seen a similar increase to that of crude oil production. **Figure 2** shows total domestic natural gas production and the contributions from federal (onshore and offshore) and nonfederal sources from 2010 through 2019. Natural gas production on nonfederal lands, which was 76% of total production in 2010, has increased 77%, from 20,290 Bcf in 2010 to 35,913 Bcf in 2019.[15] In 2019, natural gas production on nonfederal lands was 88% of the total. Onshore natural gas production on federal lands,[16] which was 16% of total production in 2010, has decreased 11%, from 4,205 Bcf in 2010 to 3,730 Bcf in 2019.[17] In 2019, onshore natural gas on federal lands production was 9% of the total.

In FY2010, BLM administered 22,676 oil and natural gas leases in producing status, covering 12.2 million acres.[18] In FY2019, BLM administered 24,127 oil and natural gas leases in producing status, covering 12.4 million acres.[19] Between FY2010 and FY2019, the number of producing leases increased 6.4%, and the area covered by producing leases increased 1.6%.

Figure 1. U.S. Crude Oil Production



Source: Total from EIA, https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm; Federal Offshore and Federal Onshore from ONRR, https://revenuedata.doi.gov/.

Notes: Nonfederal values are calculated by CRS as the difference between the total and the combined federal onshore and offshore values.

[15] CRS calculations, based on EIA and ONRR data.

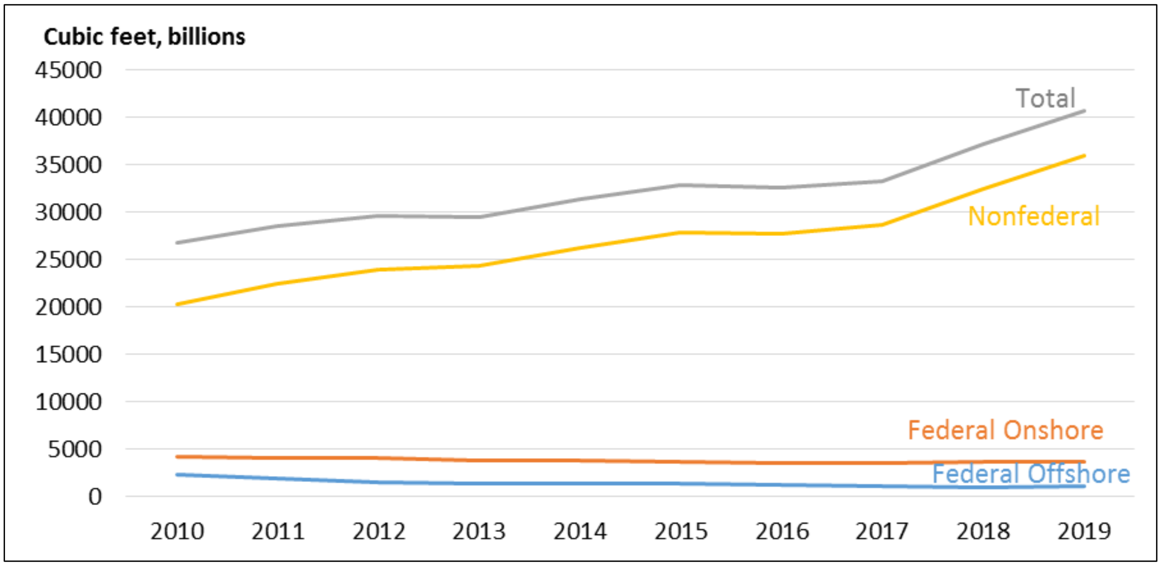
[16] Includes production from Native American lands.

[17] ONRR, https://revenuedata.doi.gov/.

[18] BLM, *Public Land Statistics 2010*, 2011, Table 3-17, p. 126.

[19] BLM, *Public Land Statistics 2019*, 2020, Table 3-17, p. 108.

Figure 2. U.S. Natural Gas Production

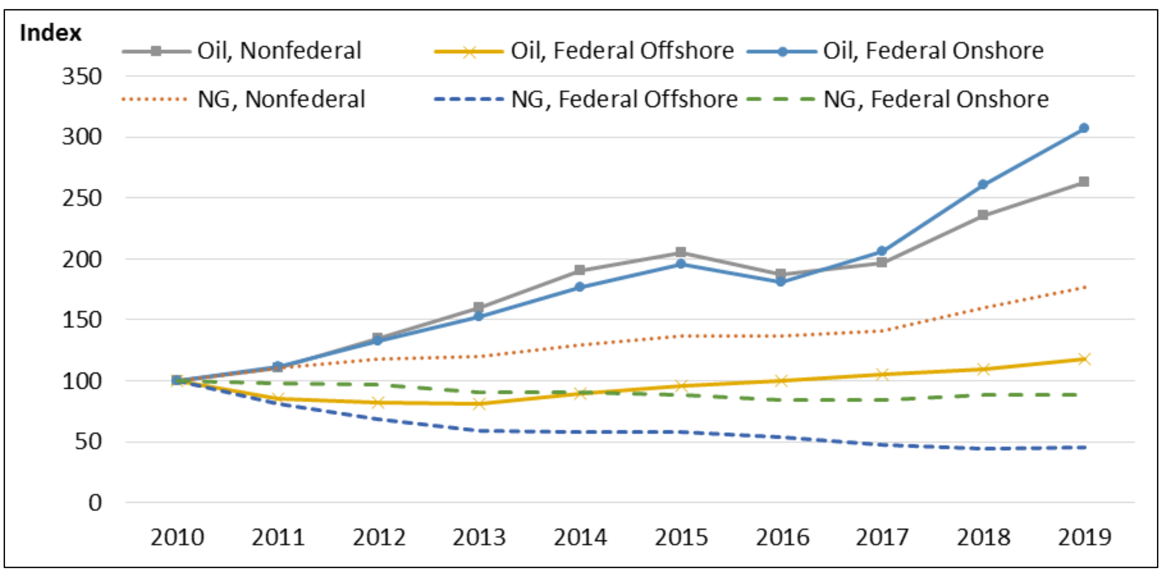


Source: Total from EIA, https://www.eia.gov/dnav/ng/ng_prod_sum_a_epg0_fgw_mmcf_a.htm; Federal Offshore and Federal Onshore from ONRR, https://revenuedata.doi.gov/.

Notes: Nonfederal values are calculated by CRS as the difference between the total and the combined federal onshore and offshore values.

Figure 3 presents the oil and natural gas data from nonfederal, federal offshore, and federal onshore regions as an index. The base year of the index is 2010; the index values are equivalent to percentage values. This presentation of the data highlights relative changes in each series. For example, onshore oil production on federal lands increased as a percentage more than oil production on nonfederal lands over the period 2010 to 2019.

Figure 3. Relative Changes in Crude Oil and Natural Gas Production



Source: CRS calculations using data from EIA, https://www.eia.gov/dnav/ng/ng_prod_sum_a_epg0_fgw_mmcf_a.htm and ONRR, https://revenuedata.doi.gov/.

Notes: 2010 is the base year for the index; values are equivalent to percentages.

The observed differences between oil and natural gas production on federal and nonfederal lands can raise questions about the source of the differences in production. The next section discusses factors that could affect production decisions, which then affect the resulting production data.

Factors Affecting Production Decisions

The decision to drill a given well represents the outcome of many factors facing an operator;[20] geology is arguably the predominant factor, as it influences the decision to drill in many ways. Loosely defined, an operator's expected profit is the difference between the expected revenue and expected costs. The expected revenue represents the operator's assessment of future revenues received for the commodity (or commodities, if more than one commodity is produced), sold at market prices, as it is produced over time. The expected costs associated with a given well, in addition to initial capital costs, can vary according to access to infrastructure (e.g., roads, water), characteristics of the given well (e.g., drilling depth, drilling costs), labor costs, resource costs (e.g., land purchase, land lease), and financial costs (e.g., taxes, debt financing, royalties), among others. An operator commonly incurs much of the costs associated with drilling a new well before drilling begins. These expenditures commonly result in financial pressures on the operator to bring the well into production as quickly as possible.

Onshore oil and natural gas production levels from federal lands are low compared to production from nonfederal lands. Some of the factors driving the difference can be grouped and discussed in three categories: geology, production inputs, and regulations.

Geology

Geologic factors are a major consideration facing an operator planning to drill a new well. Due to the limited presence of suitable geologic formations on federal lands, only in some cases can the operator choose between otherwise equal options of drilling on federal lands or on nonfederal lands.

Geologic formations likely to contain oil and natural gas resources are called basins. If exploration of a basin indicates economically recoverable quantities of oil and/or natural gas, and if the rock formation is shale, the area is called a shale play; one basin can contain multiple plays. Differences within and among shale plays influence operators' decisions about well location, as some costs depend upon geologic characteristics. For example, some shale plays are deeper than others, which can result in a higher drilling cost per well.[21] Some formations result in wells that produce only oil or natural gas; the majority of wells in the United States produce both oil and natural gas.[22]

While the federal mineral estate is over 700 million acres (mostly in the western half of the United States), the location of geologic formations in the United States containing oil and natural gas deposits suitable for extraction using current technology fall predominantly outside the federal mineral estate. **Figure 4** shows the shale plays currently suitable for oil and natural gas

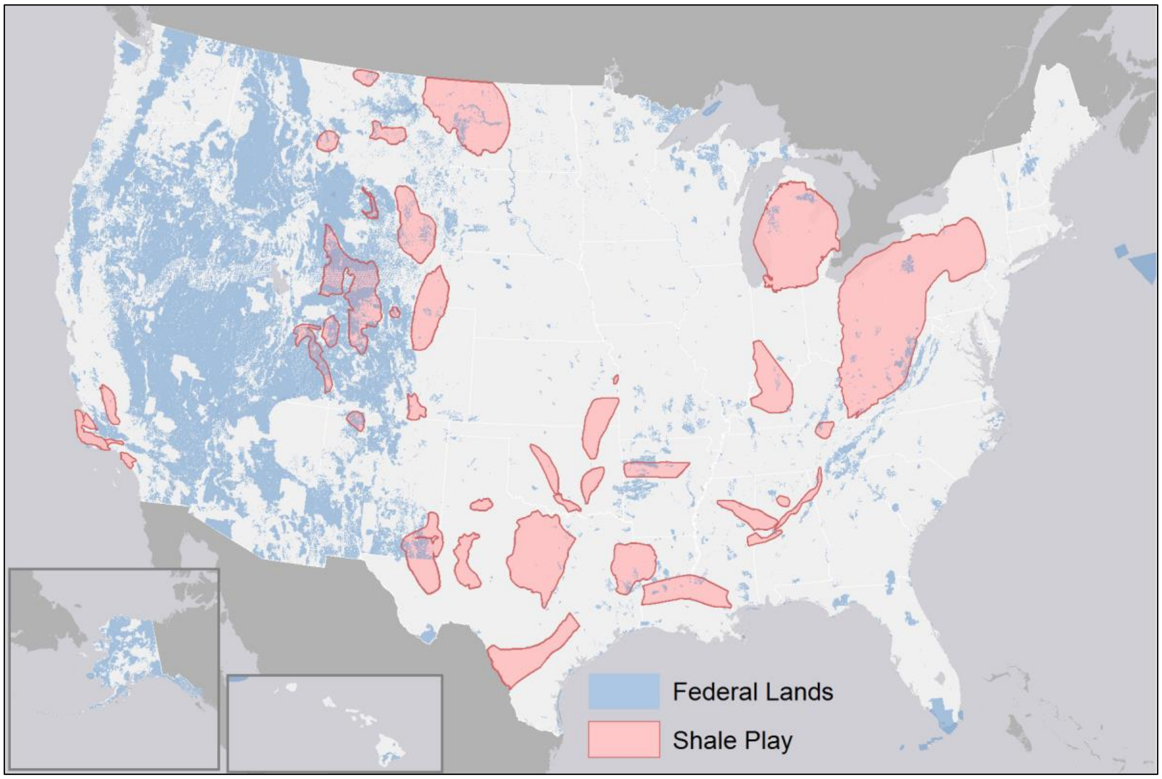
[20] One definition of *operator* is "any person or entity, including, but not limited to, the lessee or operating rights owner, who has stated in writing to the authorized officer that it is responsible under the terms and conditions of the lease for the operations conducted on the leased lands or a portion thereof" (43 C.F.R. §3100.0-5(a)).

[21] For more information on drilling oil and natural gas wells in shale plays, see CRS Report R45988, *U.S. Natural Gas: Becoming Dominant*, by Michael Ratner.

[22] For information on domestic oil and natural gas well production, see EIA, *The Distribution of U.S. Oil and Gas Wells by Production Rate*, December 2019, available at https://www.eia.gov/petroleum/wells/.

production within the United States, overlaid on a map showing federal lands. Of the 242 million acres associated with the indicated shale plays, approximately 24 million acres, or 9.9% of the total, are in the federal mineral estate.[23]

Figure 4. Federal Lands and Shale Plays



Source: Created by CRS using Tight Oil and Shale Gas Plays data from EIA, available at https://www.eia.gov/maps/layer_info-m.php, and the Protected Area Database of the U.S. (PADUS) from the U.S. Geological Survey, available at https://data.fs.usda.gov/geodata/edw/edw_resources/meta/S_USA.PADUS_Fee.xml.

Notes: Shale plays on the borders of the United States may continue beyond national boundaries.

Production Inputs

Production inputs (i.e., costs) required to bring an oil or natural gas well into production can include land or legal inputs (e.g., obtain land or mineral rights), capital inputs (e.g., drilling equipment or services), labor inputs (e.g., equipment operators, geologists), and material inputs (e.g., water, concrete, fuel), among others. As operators attempt to maximize profits, they attempt to minimize the cost of inputs; such cost-minimizing behavior can explain some of the reasons for uneven development of oil and natural gas wells, including differences in production between federal and nonfederal lands.

Production of oil and natural gas does not occur evenly across all basins: some basins contain many producing oil and natural gas wells, while other basins with known resources are not producing at the same rate. To some degree, this observation stems from operators selecting the sites expected to result in the highest profit first, proceeding to the next highest site, and so on. Some basins have been under development for years, which can represent lower costs for some

[23] Calculated by CRS using data from USA Contiguous Albers Equal Area Conic USGS version.

production inputs, for example, due to the availability of labor, equipment, and services. Moving to a new basin can result in higher costs, due to mobilizing or acquiring inputs in the new location. Additionally, drilling costs can vary between basins due to geologic differences.

Within a given basin, wells are typically found in clusters. New wells are commonly drilled on the frontiers of the clusters, rather than occurring uniformly or randomly across the basin. This observation also stems from cost-minimizing behavior of the operators: it is typically more cost-effective to drill a new well close to the most recently drilled well than to drill a well at a more distant location.

Regulations

Oil and natural gas basins often span multiple states. While applicable federal laws remain consistent across such basins (e.g., labor laws, environmental laws, federal tax law[24]), operators may face different regulations in different states (e.g., state taxes on oil and natural gas production).

One factor that affects the regulatory environment for a given well is whether it is drilled on federal land or on nonfederal land. Oil and natural gas leases on federal lands are regulated, in part, by federal authorities that may be different from leases on nonfederal lands. For example, the federal leasing process (described in "Description of the Leasing Process") can affect the time before production begins when compared to production options on nonfederal lands; it may also affect the costs of bringing a well into production. In addition to the laws discussed in the next section, when an operator plans to drill on a federal lease, BLM must comply with the National Environmental Policy Act (NEPA), the Endangered Species Act (ESA), and the National Historic Preservation Act (NHPA), among others;[25] these laws are not discussed further in this report.[26]

Statutory Authorities

This section presents a summary of the major statutory authorities that impact revenues and disbursements from oil and natural gas developments on federal lands. A discussion of key provisions follows these summaries.

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[24] A note on federal taxes on petroleum: A 9 cents per barrel excise tax is collected on domestic crude oil and imported petroleum products (26 U.S.C. §§4611 et seq.). Generally, the tax is levied on crude oil received at a refinery or petroleum products entering the U.S. for consumption or use. The tax applies whether the oil was extracted on federal lands or otherwise. Excise tax revenues are not included in the data in this report. Revenues from the tax finance the Oil Spill Liability Trust Fund (OSLTF), which is used to pay for damages resulting from oil spills or threats of oil spills. For background, see CRS In Focus IF11160, *The Oil Spill Liability Trust Fund Tax: Background and Reauthorization Issues in the 116th Congress*, by Jonathan L. Ramseur. The tax is scheduled to expire on December 31, 2020. See CRS Report R46451, *Energy Tax Provisions Expiring in 2020, 2021, 2022, and 2023 ("Tax Extenders")*, by Molly F. Sherlock, Margot L. Crandall-Hollick, and Donald J. Marples.

[25] BLM, "Operations and Production," https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production.

[26] For background information on NEPA, see CRS Report RL33152, *The National Environmental Policy Act (NEPA): Background and Implementation*, by Linda Luther; for background information on ESA, see CRS Report RL31654, *The Endangered Species Act: A Primer*, by Pervaze A. Sheikh; and for background information on NHPA, see CRS Report R45800, *The Federal Role in Historic Preservation: An Overview*, by Mark K. DeSantis.

Federal Land Policy Management Act of 1976

The Federal Land Policy Management Act (FLPMA)[27] establishes statutory authority for DOI and BLM management of federal lands, including the federal mineral estate. FLPMA directs the BLM to manage federal lands according to the principles of *multiple use* and *sustained yield*.[28] FLPMA codifies the policy that public lands remain in federal ownership, unless DOI determines disposal of public lands is in the national interest, and that *fair market value* is to be obtained for use of federal lands. Under FLPMA, the BLM prepares *resource management plans* (or *land use plans*) through a defined process that incorporates public input, including environmental, historical, and societal values, from a variety of stakeholders.[29] Where BLM is not the surface management agency of lands on which a mining operation is proposed, FLPMA directs BLM to coordinate with the surface management agency. FLPMA provides authority to DOI to withdraw lands from mineral entry (i.e., prohibit new mining).

Mineral Leasing Act of 1920

Multiple statutory authorities govern mineral development (i.e., mineral extraction) on onshore federal lands. The different authorities create different revenue and disbursement streams from mineral developments. Statutory authorities create three general categories of mineral development from onshore federal lands: locatable (or hardrock) minerals, mineral materials, and leasable minerals.[30]

Oil and natural gas are defined as leasable minerals, whose exploration and extraction are governed by the Mineral Leasing Act of 1920 (MLA).[31] The MLA authorizes DOI, and subsequently BLM, to promulgate regulations for oil and natural gas leasing on federal lands. Mineral development of Native American lands are covered by other statutory authorities, which are not discussed in this report.[32]

Authorities Related to Acquired Lands

The MLA applies only to *public domain lands*; the Mineral Leasing Act for Acquired Lands (MLAAL)[33] generally extends the MLA to *acquired lands*.[34] Public domain lands are those ceded by the original states or obtained from a foreign sovereign (via purchase, treaty, or other means). Acquired lands are those obtained from a state or individual by exchange, purchase, or gift. Lands

[27] P.L. 94-579. FLPMA is codified at 43 U.S.C. §§1701 et seq. For a background on FLPMA, see BLM, *The Federal Land Policy and Management Act of 1976, as amended*, September 2016, available at https://www.blm.gov/sites/blm.gov/files/AboutUs_LawsandRegs_FLPMA.pdf.

[28] Ibid., pp. 2-3.

[29] Ibid., p. 5. For more information on the BLM's planning process, see https://www.blm.gov/programs/planning-and-nepa/what-informs-our-plans.

[30] For more information on locatable minerals and mineral materials, see CRS Report R46278, *Policy Topics and Background Related to Mining on Federal Lands*, by Brandon S. Tracy.

[31] P.L. 66-146, codified at 30 U.S.C. §§181 et seq. Leasable minerals also include coal and some non-energy minerals, such as sodium, potassium, phosphate, gilsonite, and sulfur.

[32] Statutory authorities regarding mineral developments on Native American lands are generally contained in 25 U.S.C. Chapter 12 and 25 U.S.C. Chapter 23.

[33] P.L. 80-382, codified at 30 U.S.C. §§351 et seq.

[34] About 90% of all federal lands are public domain lands, while the other 10% are acquired lands. For more information on federal lands, see CRS Report R42346, *Federal Land Ownership: Overview and Data*, by Carol Hardy Vincent and Laura A. Hanson.

may have been or may be acquired through acts of Congress and under the authority of DOI, among other methods. When lands are acquired by legislation, provisions in the legislation may indicate treatment of mineral resources that differs from otherwise applicable law. If lands are acquired by purchase or exchange, existing mineral developments and leases may include terms that would be inconsistent with otherwise applicable laws.[35]

The MLAAL specifies that "all receipts derived from leases issued under the authority of this chapter shall be paid into the same funds or accounts in the Treasury and shall be distributed in the same manner as prescribed for other receipts from the lands affected by the lease."[36] This provision can allow for disbursements of revenues from oil and natural gas developments on acquired lands that do not follow the revenue allocations authorized by the MLA.

A number of other statutory authorities impact the collection and disbursement of revenues from oil and natural gas developments on federal land. For example, revenues from mineral developments on acquired lands managed by FS are allocated between FS and the state in which the mineral revenues originated, with 75% disbursed to FS and 25% disbursed to the state.[37] Revenues from mineral developments on lands that were acquired for flood control purposes are allocated between Treasury and the state in which the mineral revenues originated, with 75% disbursed to the state and 25% remaining in the Treasury.[38] Revenues from mineral developments on acquired lands managed by the Fish and Wildlife Service (FWS) are allocated (100%) to FWS.[39]

Key Statutory Provisions

In FY2019, approximately 93% of revenues from oil and natural gas development on federal lands were disbursed according to provisions in the MLA.[40] Some provisions within FLPMA, MLA, MLAAL, and other authorities more directly affect federal revenue collection and allocation from oil and natural gas leases than others; a presentation of some of these provisions, primarily within the MLA, follows.

Royalties

The MLA defines the minimum royalty rate on oil and natural gas produced on federal lands to be 12.5%.[41] Royalties (i.e., revenue from the application of the royalty rate to production) reflect the product of the royalty rate and the market value of the commodity produced.[42] Royalty rates are defined in the terms of each lease and are not expected to change during the term of the lease.[43]

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[35] Phone call with Congressional Liaison, BLM, March 16, 2020.

[36] 30 U.S.C. §355(a).

[37] 16 U.S.C. §§499-500.

[38] 33 U.S.C. §701c-3.

[39] 16 U.S.C. §715s.

[40] CRS calculations using ONRR and BLM data and the MLA provision that the Reclamation Fund receives 40% of bonuses, royalties, and other revenues; and the MLA provisions for Alaska.

[41] 30 U.S.C. §226(b)(1)(A).

[42] For example, if an operator produces and sells $1,000 of oil on a federal lease during a given month, application of the minimum royalty rate of 12.5% would result in $125 royalties owed to the federal government for that month's production.

[43] Additional provisions apply to reinstatement of a lease after failure to comply with the terms of the lease, including higher rental and royalty rates (30 U.S.C. §187(c-e)).

DOI has the authority to suspend, waive, or reduce royalties collected from oil and natural gas leases to ensure maximum production or to conserve natural resources.[44]

Revenue Allocation

The MLA indicates that for oil and natural gas leases on federal lands,[45] in states other than Alaska, 50% of bonuses, production royalties, and other revenues (e.g., settlements, interest) are to be disbursed to the state in which the lease is located,[46] and 40% are to be deposited in the Reclamation Fund.[47] After these disbursements, any of these funds remaining are to be credited to the General Fund (i.e., miscellaneous receipts) of the Treasury.[48] For rental revenues from oil and natural gas leases, 50% of the rental revenue is to be disbursed to the state in which the revenue occurred and the remaining 50% is to be deposited in the BLM Permit Processing Improvement Fund (PPIF).[49] For leases in Alaska, 90% of revenues, including rental revenues, are to be disbursed to the state, with the remainder credited to the Treasury as miscellaneous receipts. All disbursements to states resulting from oil and natural gas leases are to be reduced by the applicable sequestration rate for the given fiscal year.[50] For all states, 2% of funds disbursed to states are withheld as an administrative fee and deposited as miscellaneous receipts in the Treasury.[51] New onshore oil and natural gas leases on federal lands also are subject to a permit processing fee, to be submitted with the application for a permit to drill, required for each well.[52] These revenues are deposited in the PPIF, with 75% of the revenue being returned to the state BLM office that collected the fees.

Entry and Exit Requirements

The MLA defines the maximum lease acreage permitted to be held by any one entity in any one state to be 246,080 acres, in all states other than Alaska (600,000 acres are allowed in Alaska).[53] The maximum area for each oil and natural gas lease is 2,560 acres in any state other than Alaska (5,760 acres are allowed per lease in Alaska).[54] The minimum bid per acre of federal land included in an oil and natural gas lease is $2.[55] Rent is to be paid on the leased land during the period before oil and natural gas production begins; the minimum rental rates are $1.50 per acre

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[44] This provision also applies to rents (30 U.S.C. §209).

[45] These statutory allocations apply to all leasable minerals, including oil and natural gas.

[46] In using the disbursements, states other than Alaska are to give "priority to those subdivisions of the State socially or economically impacted by development of minerals leased under this chapter, for (i) planning, (ii) construction and maintenance of public facilities, and (iii) provision of public service" (30 U.S.C. §191(a)). No provisions on prioritization are given for Alaska.

[47] The Reclamation Fund was established in 1902 to develop and maintain irrigation systems in a number of western states (43 U.S.C. §391); see CRS Report R41844, *The Reclamation Fund: A Primer*, by Charles V. Stern.

[48] 30 U.S.C. §191(a).

[49] The BLM Permit Processing Improvement Fund is to be used "for the coordination and processing of oil and gas use authorizations on onshore Federal and Indian trust mineral estate land"; see 30 U.S.C. §191(c).

[50] For discussion of sequestration of mandatory spending, including mineral leasing revenues, see CRS Report R45941, *The Annual Sequester of Mandatory Spending through FY2029*, by Charles S. Konigsberg.

[51] 30 U.S.C. §191(b).

[52] 30 U.S.C. §191(d). See BLM Instruction Memorandum IM 2019-044 for the current fiscal year fee, available at https://www.blm.gov/policy/im-2019-044. The fee, indexed to inflation, is $10,230 for FY2020.

[53] 30 U.S.C. §184(d)(1).

[54] 30 U.S.C. §226(b).

[55] 30 U.S.C. §226(b)(1)(B).

during the first five years and $2 per acre thereafter.[56] Competitive bidding is to occur at least once per quarter, if parcels are available.[57] Individual leases may include lease-specific stipulations.[58] An operator must post a reclamation bond before surface-disturbing activities can begin on a given lease, among other requirements.[59] If all owed rentals and royalties have been paid, mineral lease owners can relinquish a lease at any time, subject to the termination obligations of the lease (e.g., perform site reclamation before the lease bond is released).[60]

Description of the Leasing Process

FLPMA requires that BLM obtain fair market value for the use of public lands and disposition of its resources. Under the MLA, BLM employs a competitive leasing process to issue leases to extract oil and natural gas from federal lands. BLM also has authority to issue non-competitive leases.

The competitive leasing process begins with the identification of federal lands to be included in a lease sale.[61] Federal land parcels can be nominated for inclusion in a lease sale by the public, or BLM can select the parcels to include in a lease sale. These lands must be deemed suitable for oil and natural gas development, as determined by the BLM land use planning process mandated by FLPMA, and subject to requirements under the National Environmental Policy Act (NEPA), the Endangered Species Act (ESA), and the National Historic Preservation Act (NHPA). Federal lease sales are required to occur quarterly if parcels are available, and leases are issued for an initial term of 10 years.

After notifying the public of an upcoming lease sale, BLM may issue a List of Lands Available for Competitive Nominations, and qualified bidders[62] may nominate available parcels. Submitting a nomination requires payment of the minimum acceptable bid of $2 per acre, the first year's rent, and required fees; a nomination is binding and the funds will be returned if the lease is awarded to another bidder.[63] If the bidder is successful, these payments are retained and applied to the costs of the lease.

Alternatively, anyone can submit an expression of interest, which is an informal nomination of a parcel to be included in a future lease sale. An expression of interest is non-binding and requires no deposit or fee. After reviewing an expression of interest for conformity to the land use planning process, BLM may include such parcels in a future lease sale.

A Notice of Competitive Lease Sale is posted for at least 45 days before the lease sale is held. A competitive lease sale is conducted by oral or internet auction. The lease is awarded to the qualified bid offering the highest bonus payment.[64] If a parcel was nominated by two or more

[56] 30 U.S.C. §226(d).

[57] 30 U.S.C. §226(b). Federal leases not awarded through the competitive leasing process are made available for non-competitive leasing for a period of two years (30 U.S.C. §226(c)). Non-competitive leases are awarded to the first received qualified applicant; no bonus payment is required. Non-competitive leasing regulations are found at 43 C.F.R. §§3110 et seq.

[58] 43 C.F.R. §3101.1-3.

[59] 30 U.S.C. §226(g).

[60] 30 U.S.C. §187(b).

[61] 43 C.F.R. Subpart 3120.

[62] 43 C.F.R. Subpart 3102.

[63] 43 C.F.R. §3120.3-2.

[64] 43 C.F.R. §§3120.4-3120.5.

bidders, but no bids were received above the required minimum, the parcel can be offered competitively in the future. If no qualified bid is offered during a lease sale for a parcel included by BLM, including through an expression of interest, BLM offers that parcel for non-competitive leasing.[65] Non-competitive leasing allows such parcels to be offered for lease for a period of two years to the first qualified applicant; no minimum bid payment is required.

After the lease has been awarded and the lessee has agreed to the terms and stipulations of the lease, the lessee must pay the bonus bid (if obtained through competitive leasing), first year's rent on the lease, and other filing fees (for nominated parcels, some of these fees were submitted with the nomination application). Minimum rents on leases are $1.50 per acre for the first five years, and $2.00 per acre thereafter.[66] The lessee must post a bond in an amount determined by BLM, to be released after production activities on the lease have stopped and the surface has been reclaimed to the satisfaction of BLM.[67]

Before drilling can begin, the operator must submit a completed Application for Permit to Drill (APD),[68] including an application fee, for each well.[69] Before production can begin, the operator must submit an acceptable plan of operations and receive approval from BLM.[70]

Federal Revenues and Disbursements

DOI's Office of Natural Resources Revenue (ONRR) collects and disburses most of the federal revenue from onshore and offshore energy and mineral development. ONRR maintains data on energy and mineral production, revenues, and disbursements originating from leases on federal lands and waters. Some fees related to oil and natural gas leases on federal lands are paid to the responsible agency (e.g., BLM, FS), rather than to ONRR.

The next two sections describe and discuss the revenue and disbursements from oil and natural gas developments on onshore federal lands.

Federal Revenues

As maintained by ONRR, data on revenues collected from oil and natural gas development are categorized as Bonus, Rents, Royalties, and Other Revenues.[71] Bonus, Rents, and Royalties indicate revenues from different stages of a given lease. The Bonus is the payment associated with the winning bid in a competitive lease sale, equal to or exceeding the required minimum of $2 per acre. Rents are collected from the lessee during the period between award of the lease and the start of production on the lease. Royalties are collected during production on the lease, at a minimum rate of 12.5% of the value of production. The category Other Revenues, as reported by ONRR, captures other revenues, including those from settlement agreements and interest payments.[72] Companies have seven years to adjust their production data and amounts owed,

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[65] 43 C.F.R. Subpart 3110.

[66] 43 C.F.R. Subpart 3103.

[67] 43 C.F.R. Subpart 3104.

[68] 43 C.F.R. Subpart 3162.

[69] BLM, "Instruction Memorandum IM 2019-044," https://www.blm.gov/policy/im-2019-044. This value is $10,230 for FY2020 and is indexed to inflation (30 U.S.C. §191(d)(2)).

[70] 43 C.F.R. Subpart 3170.

[71] ONRR, "Revenue by Month," https://revenuedata.doi.gov/downloads/revenue-by-month/.

[72] CRS adds fees collected by BLM for APD to this category. The data for APD do not indicate if the lease is on public

which can result in negative values in some cases.[73] Revenue data do not indicate whether the lease is on public domain land or acquired land.

In FY2019, leasable minerals and geothermal resources resulted in total collections of $4.882 billion from onshore federal lands.[74] Of these collections, $4.202 billion were from oil and natural gas resources, which are commonly coproduced on federal lands.[75] Total oil and natural gas collections represent the sum of royalties (the majority of collections), $2.931 billion; bonuses, $1.181 billion;[76] other revenue, $67 million; and rents, $22 million.

Approximately 86% of federal onshore energy and mineral revenues come from oil and gas leasing. As royalties represent the largest share of revenues, changes in oil prices have been among the major factors in revenue fluctuations from year to year; some other factors affecting revenues include changes in production and bonuses paid for leases. Royalty rates are set by statute, regulation, or for specific leases, but the rates are rarely altered once a lease has been issued.

Figure 5 shows the revenues collected from oil and natural gas developments on federal lands by revenue category, from 2010 through 2019. As royalties are partially determined by commodity prices, the reduction in royalties starting in 2015 partially reflects a 52% fall in the price of crude oil from 2014 to 2015.[77] The Bonuses series reflects an unusually large monthly collection of $976 million for October 2018, resulting from a lease sale in New Mexico.[78] **Figure 6** shows revenues from oil and natural gas developments on Native American lands by revenue category, from 2010 through 2019. This figure is included to allow comparisons between revenues from oil and natural gas developments on federal lands and Native American lands.

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domain land or other land type; values exclude APD on Indian lands, and are available at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics.

[73] For example, ONRR would indicate a negative royalty value for a given month if an operator had previously overpaid royalties and files an adjustment that results in an amount owed to the operator greater than the royalties due during that month.

[74] Not including revenues from production on Native American lands. For more information on the treatment of revenues from Native American lands, see ONRR, "Revenue from Natural Resources on Native American Land," at https://revenuedata.doi.gov/how-it-works/native-american-revenue/. Includes $32 million in fees collected by BLM for processing Applications for Permit to Drill (CRS calculations using BLM data).

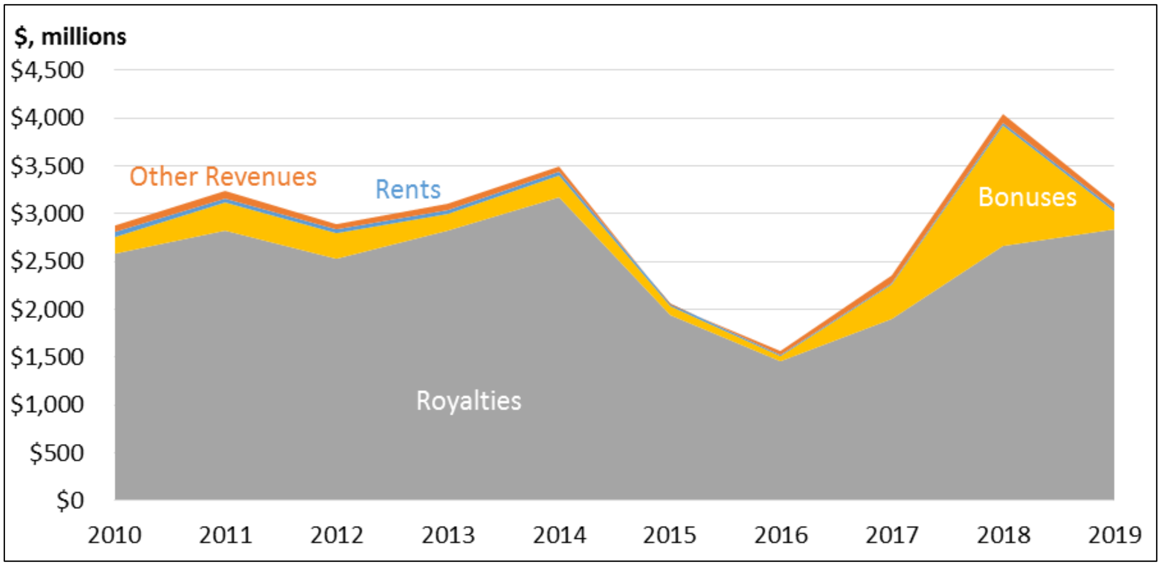
[75] Values include the ONRR categories of "Oil," "Gas," "Oil & Gas," and "Natural Gas Liquids," and APD fees collected by BLM.

[76] The Bonuses series reflects an unusually large monthly collection of $976 million for October 2018. This value falls in calendar year 2018 and fiscal year 2019 (ONRR, "Revenue by Month," https://revenuedata.doi.gov/downloads/revenue-by-month/).

[77] Calculated by CRS using annual data for WTI-Cushing, Oklahoma (EIA, "Petroleum and Other Liquids, Spot Prices," https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm).

[78] ONRR, "Revenue by Month," https://revenuedata.doi.gov/downloads/revenue-by-month/, and BLM, "Table 15 Competitive Oil and Gas Lease Sales by BLM State Offices," https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics.

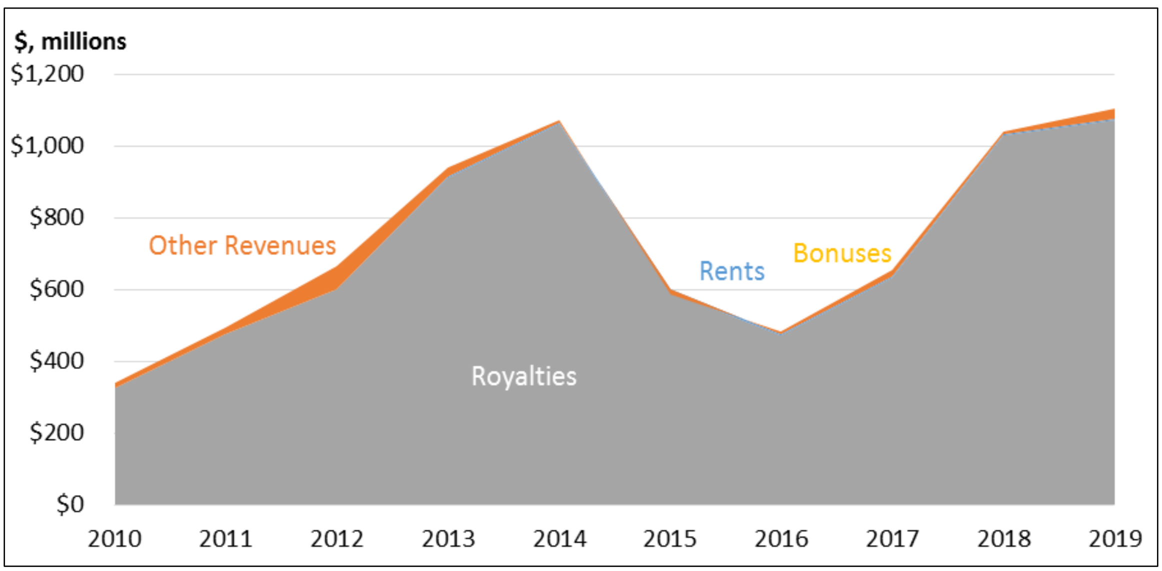
Figure 5. Federal Oil and Natural Gas Revenues from Onshore Federal Lands



Source: ONRR, "Revenue by Year," https://revenuedata.doi.gov/downloads/revenue/, and CRS calculations using BLM data for APD.

Notes: All APD fees are added to the ONRR category "Other Revenues." Excludes revenue from Native American lands.

Figure 6. Federal Oil and Natural Gas Revenues from Native American Lands



Source: ONRR, "Revenue by Year," https://revenuedata.doi.gov/downloads/revenue/.

Notes: Excludes revenue from non-Native American lands and APD fees. Rents and Bonuses are generally not visible on this graph.

Disbursements

In FY2019, leasable minerals and geothermal resources from onshore federal lands resulted in total disbursements of $4.777 billion.[79] Of these disbursements, $4.196 billion were from oil and natural gas leases, which included payments of $2.002 billion to states; $1.539 billion to the Reclamation Fund; $39 million to the PPIF; $172 million to other accounts; and $444 million to the Treasury General Fund.[80] While not reflected in these values, all disbursements to states from leasable minerals are reduced by the applicable sequestration rate for the given fiscal year.[81]

Differences between collections and disbursements for any given period can be a result of timing differences, as a disbursement generally occurs in the month following its receipt, or it may be delayed for other reasons, including disputed values, challenged amounts, or adjustments.[82] Disbursements are allocated according to the applicable statute (MLA, MLAAL, or other).

ONRR provides access to disbursement data by fiscal year, starting in 2003, and by month, starting in October 2018. The fiscal year data is relatively aggregated, indicating payments to individual states, major programs, and Treasury; payment by commodity type is not included. The monthly data indicate payments to individual states, programs (more disaggregated than the fiscal year dataset), and Treasury, by commodity type and disbursement category, where applicable.

Using provisions in the MLA and publicly available revenue data from ONRR, disbursements can be estimated. The **Appendix** provides details regarding the creation of estimated disbursements. **Figure 7** shows the estimated disbursements by major account for FY2010 through FY2019. As royalties represent the largest source of funds disbursed to states and the Reclamation Fund, the estimated disbursements to these accounts fluctuate primarily according to royalty revenues. Disbursements to states also reflect revenues from bonuses and rents; disbursements to the Reclamation Fund also reflect revenues from bonuses. Disbursements to PPIF reflect revenues from rents paid on leases in states other than Alaska and APD fees collected by BLM in all states.

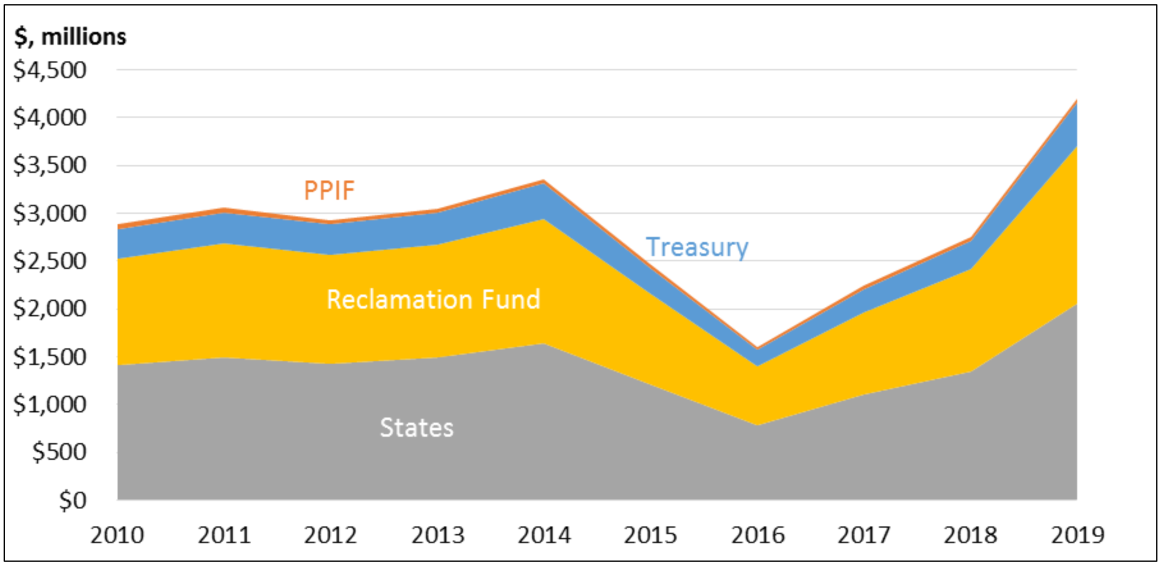
[79] Not including disbursements to Native American tribes or accounts. This value is before sequestration of mandatory spending, as sequestration amounts (which vary by year) are not attributable to a given commodity in the ONRR data. All APD fees are included as disbursements. Disbursements to states are after deduction of the 2% administration fee; Treasury values include the administrative fee.

[80] CRS calculations using disbursement data from ONRR, "Downloads / Disbursements by Month," at https://revenuedata.doi.gov/downloads/disbursements-by-month/, and CRS calculations of APD fees using BLM data.

[81] For discussion of sequestration of mandatory spending, including mineral leasing revenues, see CRS Report R45941, *The Annual Sequester of Mandatory Spending through FY2029*, by Charles S. Konigsberg.

[82] Leasable minerals and geothermal resource disbursements are required to be made before the end of the month occurring 10 days after the revenues were received by the Treasury, see 30 U.S.C. §191(a).

Figure 7. Estimated Disbursements of Oil and Natural Gas Revenues from Federal Lands



Source: CRS calculations using ONRR data, provisions from the MLA (30 U.S.C. §191), and BLM data.

Notes: The estimation applies the MLA to all revenues, as available data do not identify revenues from acquired lands. This methodology allocates all revenues from leases according to provisions in the MLA; see the Appendix for details. Years are fiscal years. PPIF is the Permit Processing Improvement Fund.

Policy Topics and Legislative Activity

Numerous bills have been introduced in the 116th Congress that could impact revenues and disbursements from oil and natural gas developments on federal lands. This section discusses selected bills and policy options related to these revenues and disbursements. The section focuses on bills that would have direct impact on revenues and disbursements. It does not consider bills that would indirectly impact revenues and disbursements through broader changes to the oil and natural gas sector (e.g., bills related to greenhouse gas emissions that could reduce demand for domestic oil and natural gas).

Royalties

Royalties constitute the largest source of federal government revenue collected from oil and natural gas leases, and consequently, they form the largest source of funds to be disbursed. Royalty collections averaged 87% of total oil and natural gas revenues from leases on federal lands between 2010 and 2019.[83] In the absence of major changes in the oil and natural gas markets, changing the royalty rate is the most direct means of changing the amount of revenue collected from oil and natural gas leases. In the absence of changes to revenue allocation, changing the royalty rate would also be the most direct means of changing the amount of disbursements.

Oil and natural gas market conditions can affect royalty revenues, as higher (or lower) market prices result in higher (or lower) royalties paid for a given quantity of production. If market prices attain or are expected to attain certain levels, high or low, some operators may choose to alter

[83] CRS calculations using ONRR revenue data and BLM data for APD fees.

their production. For example, if oil prices fall below a certain level, an operator may choose to terminate production at a given well, resulting in zero royalties collected from the well.

Some bills have been introduced in the 116th Congress that would alter the minimum royalty rate assessed on new oil and natural gas leases.[84] The current royalty rate, 12.5%, was established in 1920.[85] Changing the royalty rate for new leases would not be expected to affect an operator's production from producing wells, but it could influence interest in future leases and impact bonus payments received during lease sales.

Expected changes to the leasing process and future revenues resulting from a change in the minimum royalty rate can be hard to predict. Some studies find that increases to the royalty rate would not have significant impacts on oil and natural gas production on federal lands.[86] As an increase in the royalty rate can be viewed as an increase in costs to the operator, operations that would be marginally profitable under the current royalty rate may no longer be profitable under a higher royalty rate. This could reduce the number of new leases, but the increase in the royalty rate would be expected to result in greater collections for the affected leases once production begins. In a similar manner, a reduction in the royalty rate for new leases could increase the number of new leases, with each lease paying a lower rate on production.

Prior to changing the minimum royalty rate or in conjunction with such a change, Congress could require updated studies to inform the decision or ongoing studies to analyze the change over time. Such studies could attempt to identify the underlying causes driving changes in collections, taking into account changes in the oil and natural gas markets. The results of such studies could allow Congress to understand better the impacts of a change to the minimum royalty rate on the outcome of the leasing process and future royalty collection.

Some bills have been introduced in the 116th Congress that would change authorities related to royalties, including provisions addressing royalty relief and provisions changing how natural gas losses are treated. DOI has the authority to suspend, waive, or reduce royalty rates on federal onshore oil and natural gas leases "for the purpose of encouraging the greatest ultimate recovery ... whenever [the Secretary of the Interior judges] it is necessary to do so in order to promote development, or whenever in his judgment the leases cannot be successfully operated under the terms provided therein."[87] The existing authority may be useful for leases facing specific issues that risk the economic viability of the well. Some bills would repeal this authority.[88]

Some bills would require that all produced natural gas be assessed royalties, even if flared or vented. Existing provisions and regulations allow natural gas to be vented and flared without being assessed royalties. While closely related to the topic of royalties, this topic is discussed separately in "Natural Gas Losses."

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84 Example bills include H.R. 3225, H.R. 4364, H.R. 5435, and S. 3330.

85 41 Stat. 437.

86 The Government Accountability Office (GAO) published a report highlighting the findings from two studies that analyzed the impacts of possible changes to oil and natural gas royalty rates (GAO, *Oil, Gas, and Coal Royalties*, GAO-17-540, 2017). The report highlights many of the factors affecting the impacts of a change to the royalty rate, including royalty rates assessed by states, oil and natural gas prices, and other market conditions. The report also notes that the impacts are assumed to occur over a 25-year period, as new leases can require nearly 10 years before reaching production.

87 30 U.S.C. §209.

88 Example bills include H.R. 6289, H.R. 6707, and S. 3488.

Revenue Allocation

The revenues from oil and natural gas leases collected under the current statutory framework are allocated to the Treasury, federal programs, and states; state disbursements are assessed an administrative fee and are subject to sequestration. Congress could choose to alter the current allocation scheme to reflect different priorities.

Some examples of different allocation schemes for energy and mineral revenues include

- In 1976, Congress amended the allocation of funds to states and the Reclamation fund, allocating an additional 12.5% to states while reducing the Reclamation fund by an equal amount.[89]
- The PPIF was created in 2005, receiving all of its funding from rents.[90] In 2014, a fee was established and allocated to the PPIF.[91] A minimum of 75% of these fees are to be returned to the BLM office that received the fee.
- The Geothermal Steam Act of 1970, which competitively leases geothermal resources on federal lands, allocates 25% of revenues to the county in which the resource is located and does not allocate any funds to the Reclamation Fund.[92]

The MLA provision that assesses an administrative fee on disbursements to states has been amended multiple times.[93] Some bills introduced in the 116th Congress would eliminate the 2% administrative fee assessed on disbursements to states.[94] In addition to eliminating this fee, these bills contain provisions that would give the authorized state a greater role in managing oil and natural gas leases on federal lands. Two of these bills would allow the authorized state to issue Applications for Permit to Drill (APD) on federal lands, eliminating the associated revenue collected by BLM when an APD is submitted (authorized states would be allowed to charge an equivalent or lower fee). Allowing states to authorize drilling on federal lands could reduce the time between APD submission and production, resulting in earlier collections of royalties. It is not clear if and how an authorized state would conduct oversight of production and reclamation, ensuring adherence to applicable provisions of federal law.

A recently enacted law, the Great American Outdoors Act, is an example of amending the current allocation scheme.[95] Provisions in this law allocate, for FY2021-FY2025, 50% of miscellaneous receipts from all energy development revenues to the National Parks and Public Land Legacy Restoration Fund, created by the act, up to a maximum of $1.9 billion per fiscal year. Aside from reducing the revenues remaining in the General Fund, this act does not alter other aspects of the current allocation scheme.

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[89] P.L. 94-377.

[90] P.L. 109-58.

[91] P.L. 113-291, §3021(b).

[92] 30 U.S.C. §§1001 et seq.

[93] See “Amendments,” 30 U.S.C. §191.

[94] Examples of bills include H.R. 998, H.R. 4294, S. 218, and S. 2418.

[95] P.L. 116-152.

The Leasing Process and Fair Market Value

FLPMA requires that BLM obtain fair market value for the use of public lands and disposition of its resources. Congress has debated whether the current leasing process (competitive and non-competitive) results in receipt of fair market value for federal oil and natural gas resources.

Pursuant to the MLA, BLM generally employs a competitive bidding process to issue leases to extract oil and natural gas from federal lands.[96] BLM's competitive bidding process can be described as an oral auction for common-value goods. A common-value good is a good that offers the same value to all bidders in the auction, but that value is not fully known to the bidders. Each parcel contained in a lease sale represents a common-value good, as geologic variations within a basin prevent the actual value of the oil and natural gas from being known before it is extracted.

Economic theory posits that the outcome of a competitive exchange is one manner of achieving economic efficiency.[97] If the results of a lease sale are competitive economically, they could be deemed to represent the fair market value of the assets. However, market failures, including incomplete information, asymmetric information, and market power, can lead to outcomes that would not be equal to fair market value. A repeated auction for similar goods, where similar goods are available outside the auction, can result in strategic behavior by the bidders. Strategic behavior reduces the economic efficiency of the auction outcome.

Strategic behavior, which could be based on observed results of previous auctions, could result in BLM collecting less than fair market value for oil and natural gas leases. A given lease sale represents the momentary intersection of supply and demand for oil and natural gas leases. If the supply of leases exceeds the demand for leases, the price received (i.e., the winning bid, equal to or above the required minimum) is expected to be lower than if the supply of leases had been fewer. If the supply of leases were limited (therefore increasing demand for each lease), bidders would be expected to make offers only up to the point where they would expect to be able to profitably develop the lease; they would not bid above their expected value of the lease.

In FY2018, 24% of new onshore oil and natural gas leases were issued through non-competitive offers; for FY2019, 10% of such leases were issued through non-competitive offers.[98] Using BLM data for competitive lease sales in FY2018 (the record-breaking year for bonus bids and the only year of data provided), the average bonus paid per acre was about $849.[99] This average bonus is heavily skewed by the October lease sale in New Mexico: excluding that lease sale, the average bonus paid was about $135 per acre. Of the 28 lease sales held in FY2018, one sale did not receive any bids, and 18 sales received average bonuses of less than $40 per acre.[100] The highest average bonus per acre for an individual lease sale was over $19,000. Of the 3,073 parcels

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[96] Approximately 90% of oil and natural gas leases were issued by competitive bidding in FY2019 (BLM, *Public Land Statistics 2019*, 2020, Tables 3-13 and 3-14, pp. 91-99).

[97] Economic efficiency and fair market value can be considered equivalent. One definition of fair market value, given for coal, is "that amount in cash, or on terms reasonably equivalent to cash, for which in all probability the coal deposit would be sold or leased by a knowledgeable owner willing but not obligated to sell or lease to a knowledgeable purchaser who desires but is not obligated to buy or lease" (43 C.F.R. §3400.0-5).

[98] BLM, *Public Land Statistics 2018*, 2019, Tables 3-13 and 3-14, pp. 96-104 and BLM, *Public Land Statistics 2019*, 2020, Tables 3-13 and 3-14, pp. 91-99.

[99] CRS calculations using data from BLM, "Table 15 Competitive Oil and Gas Lease Sales by BLM State Offices," https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics.

[100] A report by the GAO states "According to Interior officials, most competitive bids for oil and gas are higher than the required minimum. For example, in fiscal year 2015, the average bonus bid per acre for all the acres leased (both competitive and noncompetitive leases) was $139, and for fiscal year 2016, the average bonus bid per acre was $213" (GAO, *Oil, Gas, and Coal Royalties*, GAO-17-540, 2017, p. 5).

available for bids in FY2018, 1,336 parcels were leased (the 1,737 parcels not receiving bids will be offered for non-competitive leasing).

Economic and auction theory cannot definitively determine if the outcome of a given lease sale obtains fair market value. Each parcel in a lease sale is unique, and each bidder has private information affecting bidding behavior. Some may view the outcomes of the FY2018 lease auctions as obtaining fair market value. The variation in bids could be taken as an indication that the market for leases was efficient, with some parcels being more desirable than others. Others might argue that if some parcels can result in average bids of $19,000 per acre while other parcels receive no bids, the supply of leases is too high and fair market value is not obtained.

Aspects of the current leasing system could be changed to address the expected receipt of fair market value; some of these aspects include:

- Leases Offered. The number of leases offered during any given lease sale could be reduced, with the expectation of receiving higher bids for each lease; reduction beyond a certain level could curtail oil and natural gas production on federal land. The number of leases offered could be increased, with the expectation that buyers will purchase all desirable leases, resulting in increased revenue.
- Lease Sale Frequency. Assuming the number of parcels available during a lease sale is constant, reducing the frequency of lease sales would reduce the supply of leases, and could increase the value of each lease. Holding lease sales more frequently could allow interested bidders to obtain leases more quickly.
- Minimum Bid. The current minimum bid of $2 per acre, amended to this value in 1987,[101] could be increased, guaranteeing a higher minimum bid. An increase in the cost to obtain the lease may deter some or all bidders from bidding, potentially reducing the number of leases sold.
- Rental Payments. Increasing the rental rate, currently $1.50 per acre for the first five years, could deter bidders from holding leases for extended periods of time before developing the lease. Such behavior can be considered a form of speculation, as expected returns from the lease can change over time; additionally, such behavior can prevent others from developing the lease. Reducing rental payments could reduce financial burdens on operators facing high costs to develop a lease.

Some bills introduced in the 116th Congress would modify aspects of the current leasing process.

Provisions in S. 3330 would increase the minimum bid to $10 per acre, increase rental rates to $3 per acre for the first five years and $5 per acre thereafter, and require the payment of $15 per acre for lands included in the submission of an expression of interest. Provisions in S. 3202 would reduce the supply of parcels in a lease sale by requiring included parcels be rated above "low," as indicated by a BLM assessment of the potential for oil and natural gas development. Provisions in S. 4223 would eliminate the option for non-competitive leasing; leases not sold competitively could be reoffered competitively at a later time.

Provisions in two bills would temporarily suspend lease sales for oil and natural gas. H.R. 5435 would suspend lease sales until USGS concludes that public lands have achieved a greenhouse gas emissions target set in the bill for the previous year. H.R. 6707 would suspend lease sales during the COVID-19 national emergency declaration. Provisions in H.R. 5435 would implement

[101] P.L. 100-203, §5102(a).

an additional fee on new leases during the period before production begins and an additional fee on new leases during production.

Natural Gas Losses

Most oil and natural gas wells in the United States, including wells on federal lands, produce some amount of natural gas. The production of natural gas requires specific safety and environmental precautions, as releases, or losses, of natural gas can pose safety and environmental hazards. These losses may contain pollutants, including, most prominently, methane (i.e., the principal component of natural gas), volatile organic compounds, and various forms of hazardous air pollutants, among others. To assist in managing these losses, the production of natural gas requires specific safety and environmental precautions, as releases of natural gas can pose safety and environmental hazards.[102]

According to the Environmental Protection Agency (EPA), natural gas emissions

> occur through intentional venting and unintentional leaks. Venting can occur through equipment design or operational practices, such as the continuous bleed of gas from pneumatic devices (that control gas flows, levels, temperatures, and pressures in the equipment), or venting from well completions during production. In addition to vented emissions, methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment. Methane emissions can also occur from the oil industry as result of ... venting of associated gas from oil wells and storage tanks [and] production-related equipment.[103]

Natural gas production may result in momentary, periodic, or continual releases of natural gas; flaring is one process that can mitigate some risks of these releases. Flaring converts waste gas and the pollutants it may contain into comparatively less polluting products, typically carbon dioxide, nitrogen oxides, less volatile hydrocarbons, and water vapor.[104]

Current provisions and regulations allow some quantities of natural gas to be vented, flared, and consumed during production; royalties are not assessed on these quantities.[105] Royalties, which are not assessed on production losses that are deemed acceptable or necessary, are to be assessed on production losses due to negligence.[106] Any production losses represent forgone revenue for the operator and reduced federal collections.

Congress has debated changes to current authorities and provisions regarding natural gas emissions. Congress could direct BLM to change the accepted uses, resulting in corresponding changes to operating costs and royalty collection. For example, BLM currently may allow oil well operators to flare up to 10 million cubic feet of associated nature gas per well per month without

[102] For background and discussion of environmental impacts of natural gas emissions, see CRS Report R42986, *Methane and Other Air Pollution Issues in Natural Gas Systems*, by Richard K. Lattanzio.

[103] EPA, "Primary Sources of Methane Emissions," available at https://www.epa.gov/natural-gas-star-program/primary-sources-methane-emissions.

[104] John L. Sorrels, *Section 3.2—VOC Destruction Controls, Chapter 1 Flares*, EPA, Air Pollution Control Cost Manual, August 2019, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[105] For authorized venting and flaring for natural gas wells, see 43 C.F.R. §§3179.101-3179.104. For authorized venting and flaring for oil wells, see 43 C.F.R. §3179.201. For acceptable uses of natural gas for production activities, see 43 C.F.R. §3178.4.

[106] 30 U.S.C. §1756.

assessing royalties on this natural gas.[107] Congress could require operators to reduce production losses, which could increase revenues and royalty collection. Reducing production losses typically represents upfront costs (or retrofit costs) to operators.[108] Given the high initial capital costs of developing a well, an operator may choose to avoid these costs, even if additional capital costs could lead to greater revenue over time.

Some bills introduced in the 116th Congress would require that some or all of currently flared or vented natural gas be assessed royalties.[109] This could be achieved by measuring the quantity of natural gas consumed in venting or flaring, and assessing royalties accordingly. An operator choosing not to capture such natural gas would pay the assessed royalty without receiving the associated revenue. H.R. 2711 would encourage capture and sale of natural gas that would otherwise be vented or flared by prohibiting venting and flaring, with civil penalties charged to violators.

[107] 43 C.F.R. §3179.201.

[108] EPA, "Recommended Technologies to Reduce Methane Emissions," https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions.

[109] Examples of bills include H.R. 2711, H.R. 4364, and S. 2818.

Appendix. Methodology to Create the Estimated Disbursements Dataset

Prior to FY2019, ONRR does not provide access to disbursement data by fiscal year that indicates payments to individual states, all federal programs, and Treasury, by commodity type and disbursement category, where applicable. ONRR provides access to disbursement data at this level of detail by month, starting in October 2018. As trends in detailed disbursement data may be of interest to some readers, a methodology to estimate disbursement data is defined and employed. The resulting estimates are subject to unknown deviations from actual disbursements.

In order to create a dataset of disbursements for FY2010 through FY2019 by major recipient or fund, the disbursement provisions of the MLA can be applied to publicly available data for revenues collected from onshore oil and natural gas developments on federal lands. However, this approach results in a dataset that only estimates disbursements. The resulting dataset includes estimated disbursements to states, the Reclamation Fund, the PPIF, and the amount remaining in Treasury. The application of the MLA to all revenue precludes the application of provisions from the MLAAL and revenue allocations from leases not subject to the MLA. The resulting estimations will differ from actual estimations by the unknown amounts that were not disbursed according to the MLA.

Data allow the accuracy of such estimates to be assessed for FY2019. The accuracy can be assessed by comparing the FY2019 disbursements from the monthly dataset to the estimates produced by application of the MLA to the same fiscal year dataset. Using the monthly dataset, in FY2019, approximately 93% of oil and natural gas revenues from federal lands were disbursed according to the MLA.[110] This allocation resulted in 48% of total revenues being disbursed to states, 37% disbursed to the Reclamation Fund, 0.9% disbursed to PPIF, 11% remained in Treasury, and 4% disbursed to other accounts (e.g., FS, FWS). Using the approximation that all revenues are disbursed according to the MLA, the resulting disbursements would be 49% to states, 40% to the Reclamation Fund, 1% to PPIF, and 11% remained in Treasury; this approximation does not allocate funds to other accounts.[111] This assessment of accuracy can only be conducted for FY2019; the accuracy of other years may not be the same. This approximation is used to create an estimated disbursements dataset from FY2010 through FY2019.

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[110] CRS calculations using ONRR data, BLM data, the MLA provision that the Reclamation Fund receives 40% of bonuses, royalties, and other revenues, and the MLA provisions for Alaska.

[111] These percentages sum to more than 100% due to rounding.

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