THE DEPARTMENT OF THE INTERIOR

WASHINGTON

Memorandum

To: Ryan Zinke
Secretary of the Interior

From: Vincent DeVito
Chair Royalty Policy Committee

Subject: Royalty Policy Committee Recommendations

Recently, the Royalty Policy Committee (Committee) met in Houston. This was the second in-person, full Committee meeting.

During the meeting, members of the Committee's three subcommittees presented and debated 16 final recommendations. The recommendations were unanimously approved by the Committee for your consideration and are the result of a thorough, cooperative, and collaborative process.

The full Committee will meet next on June 6, 2018, in Albuquerque, NM. In the meantime, working groups are continuing to meet to discuss potential incentives for your consideration that may increase coal production and optimize federal revenue from off-shore wind investments.

The Committee also heard public comments which will be made part of the official record. The minutes from the meeting will be posted to the Committee website at www.doi.gov/rpc.

Attachment:
Summary of Proceedings including recommendations

ROYALTY POLICY COMMITTEE
FEBRUARY 28, 2018 MEETING

SUMMARY OF PROCEEDINGS

U.S. DEPARTMENT OF THE INTERIOR
PREPARED: MARCH 2018

I. Introduction

The U.S. Department of the Interior (DOI), hosted by Secretary of the Interior Ryan Zinke and by Chair of the Royalty Policy Committee Vincent DeVito, and with James Schindler presiding as Designated Federal Official (DFO) and Executive Director, convened the second meeting of the Royalty Policy Committee (RPC) on February 28, 2018, in Houston, TX. Key agenda items during the meeting included:

- Report out and recommendations from Tribal Affairs Subcommittee
- Report out and recommendations from Fair Return and Value Subcommittee
- Report out and recommendations from Planning, Analysis, and Competitiveness Subcommittee
- Receive public comments
- Full committee discussion and votes on subcommittee recommendations
- Timeline review

Please note that, throughout this meeting summary, comments are provided without attribution unless made by presenters or by non-Committee members.

This meeting summary was prepared by the Department of the Interior. Interested parties are invited to contact the RPC at rpc@ios.doi.gov with any questions, comments, or concerns regarding the content of this meeting summary.

The following items are included in this meeting summary:

II. Recommendations and Action Items

A. Recommendations

The RPC approved the following recommendations for submission to the Secretary of the Interior *(see the* Committee Vote *section, page 22)*:

- Create "evergreen" Payor Handbook which can be updated regularly and link to recent rules and decisions.
- Pursue rulemaking to define simplified index price rules for Federal gas.
- Exclusively with regard to federal lands, Department of the Interior resolve an ambiguity in its current regulations by publishing a proposed rule to amend the

regulation at 30 C.F.R. 1202.151(b) to reexamine language specific to the boosting of residue gas.

- Reinforce the principle that arm's length transactions are the best indication of market value by amending the regulation at 30 CFR 1206.257(c)(2)(i) to read: "The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition by other than an arm's-length contract), provided that those gross proceeds are the equivalent to the gross proceeds derived from, or paid under comparable arms-length contracts for sale, purchases, or other dispositions of like-quality coal in the area."
- Consider a Secretarial Order / Dear Payor Letter indicating that a company's own arm's length sales are preferential under coal benchmark 4.
- Updated Solids Handbook indicating the same.
- Reduce timelines for project approval, including APDs, ROWs, sundries, lease nominations and unit agreements.
- Limit the federal nexus of wells without a majority federal interest.
- Improve land use planning and NEPA approvals.
- Revise and simplify Onshore Orders, 3, 4, and 5 to ensure more equitable and timely implementation.
- Set future OCS lease sales through 2024 at 12.5% royalty rate.
- Revise, clarify and simplify process for granting varying royalty rate for declining or particularly costly fields.
- Increase offshore acreage available for oil and natural gas leasing.
- Interior should conduct a lease sale in the 1002 area of the Arctic National Wildlife Refuge (ANWR) ahead of statutory deadlines.
- The Department of the Interior should contract for a study to compare the U.S GOM, Guyana and Mexico royalty rates, total revenue, block sizes and recent lease sales (last 3 years).
- The Department of the Interior should contract to update the IHS-CERA 2011 study, for both onshore and offshore data.

The RPC approved the following decision internal to the committee *(see the* Committee Vote *section, page 22)*:

- Change Subcommittee name from Tribal Affairs Subcommittee to Tribal Energy Subcommittee.

B. Action Items

Royalty Policy Committee

- Explore how the committee can better incorporate the broader public interest in the membership of the committee, subcommittees, and working groups and in the committee's deliberations and decision-making. *(see the* Committee Vote *section, page 22)*
- Add to and modify membership of subcommittees and working groups as requested. *(see the* Wrap up / Closing *section, page 28)*

Tribal Energy Subcommittee

- Provide to the whole RPC an overview of the different pieces of legislation that affect minerals development in Indian Country. *(see page 6)*
- Consider the proposal to add language exempting Indian tribes in all perpetuity from the boosting rule to the recommendation from the Marketable Condition Working Group of the Fair Return and Value Subcommittee. *(see page 8)*

Fair Return and Value Subcommittee

- Explore how allowances are being configured and how standardizing allowances would impact revenues. *(see page 9)*

III. Presentations and Key Discussions

James Schindler, presiding as Designated Federal Official (DFO) and Executive Director, opened the meeting and welcomed participants.

Vincent DeVito, Counselor to the Secretary for Energy Policy, US Department of the Interior, shared Secretary of the Interior Ryan Zinke's appreciation for the RPC's hard work, including numerous subcommittee and working group meetings since the previous RPC meeting in October 2017. He explained that one of the Trump Administration's goals is "energy dominance" in which the United States is a global leading energy supplier. The RPC is convened to further this goal of energy dominance by serving as a better partner to energy companies in order to increase investment in American energy resources. Mr. DeVito also noted that each of the RPC's three subcommittees would be reporting back to the RPC and providing recommendations on which the RPC would vote.

All individuals in attendance introduced themselves. A full attendance list can be found in Section VII – Meeting Participants, page 27.

A. Tribal Affairs Subcommittee

President Russell Begaye, Navajo Nation, introduced the work of the Tribal Affairs Subcommittee and noted that the subcommittee would primarily be sharing updates at this February meeting of the RPC, with recommendations to come at subsequent RPC meetings. He also emphasized the centrality of tribal sovereignty in the subcommittee's work and explained that subcommittee members would be sharing updates concerning four areas in which energy production on tribal lands could be expedited:

- TERA: Bidtah Becker, Navajo Nation Office of Natural Resources
- Model Congressional Statute: Prof. Monte Mills, University of Montana
- 1938 Act: Chairman Everett Waller, Osage Minerals Council
- Taxation: Jackson Brossy, Navajo Nation Washington Office

1. TERA

Bidtah Becker, Navajo Nation Office of Natural Resources, presented findings and preliminary recommendations concerning Tribal Energy Resource Agreements (TERAs). She described what TERAs are, the hurdles faced in entering into TERAs, and outlined the subcommittee's preliminary recommendation, which involves DOI providing additional guidance on the activities that would be considered "inherently federal functions" so that tribes can utilize TERAs. Additional information can be found in the meeting materials in Appendix A.

In response to Ms. Becker's comments, RPC members asked the following questions. *Responses from Ms. Becker and other subcommittee members are indicated in italics.*

- What would the "low-hanging fruit" be for tribal energy development? *For the Navajo Nation, renewable energy would be low-hanging fruit because they do not require subsurface work as fossil fuel development would. The Hart Act grants tribes jurisdiction over surface lands but tribes need to seek federal permission for subsurface activity on tribal lands.*
- What guidance have tribes already received from DOI and what hurdles have tribes been facing? *The Southern Ute Tribe sought to execute a TERA and, despite repeated requests to the highest levels of the DOI in the past, the Department has never clarified what constitutes "inherent federal functions."*

2. Model Congressional Statute

Monte Mills, University of Montana School of Law, presented about what a model Congressional statute might look like and how it would improve upon current statutes. He explained that the subcommittee believes that a model Congressional statute regarding tribal energy/mineral development must balance the complications of federal involvement in the development process with the potential consequences of limiting federal involvement. Mr. Mills added that the working group is exploring what such a statute might look like and how it would complement existing statutory structures rather than replace them. He also noted that, while the model statute effort is ultimately aimed at a legislative remedy rather than an administrative one, the RPC brings together the parties needed to push forward such an effort. Additional information can be found in the meeting materials in Appendix A.

In response to Mr. Mills' comments, RPC members asked the following questions and made the following comments. *Responses from Mr. Mills and other subcommittee members are indicated in italics.*

- What would the relationship be between this model statute and the 1938 Act? *This model statute effort is not directed at amending the 1938 Act. Rather, it is designed to consider how energy development on tribal lands should be governed and regulated and how that would complement the 1938 Act.*
- There is significant frustration in Indian Country about the hurdles and restrictions that tribes face to developing their energy resources and the purpose of this model congressional statute effort is to initiate a conversation about a better path forward.

3. 1938 Act

Chairman Everett Waller, Osage Minerals Council, introduced the subcommittee's work on the 1938 Act, in which a working group is considering what Congressional changes to the 1938 Act are necessary so that tribes can take control over mineral leasing. He emphasized the importance of the RPC's work in this area in order to create a more secure future for Native American children. Additional information can be found in the meeting materials in Appendix A.

In response to Chairman Waller's comments, RPC members asked the following questions and made the following comments. *Responses from Chairman Waller and other subcommittee members are indicated in italics.*

- Given that there are a number of statutes that affect minerals development in Indian Country, what is the reasoning behind focusing on the 1938 Act and what information is available about all of these different statutes? *The 1938 Act is the main legislation that governs energy development on tribal lands. Amending the 1938 Act would allow self-governing tribes to handle their own leasing without the involvement of the federal government. The subcommittee can provide an overview of the different pieces of legislation that affect minerals development in Indian Country.*

4. Taxation

Jackson Brossy, Navajo Nation Washington Office, explained that the taxation working group's efforts are looking at four key economic barriers to energy development in Indian Country: dual taxation, natural gas flaring, the property tax transportation allowance, and restrictions on tribal tax exempt bonds. The working group is also analyzing updates to the Indian Trader Regulations to that would reduce economic barriers to energy development on tribal lands. Additional information can be found in the meeting materials in Appendix A.

In response to Mr. Brossy's comments, RPC members asked the following questions and made the following comments. *Responses from Mr. Brossy and other subcommittee members are indicated in italics.*

- Given the RPC's role in making recommendations to the Secretary of the Interior about changes that the administration can make to rules and regulations, it may be better for the working group to focus on regulatory issues and recommendations rather than taxation, which would require a legislative remedy.
- While solving issues of dual taxation are beyond the purview of the RPC, currently tribal lands are uncompetitive as compared to federal, state, and fee lands due to issues like dual taxation and it is critical that we discuss that.
- One issue that the Secretary of the Interior can take action on would be to mandate that any leasing that touches tribal lands be brought to consideration before the tribe.

- Will the 1938 Act and Taxation working groups have recommendations for the subcommittee to vote on at the June 2018 RPC meeting? *The subcommittee and these specific working groups will be pushing forward work by June, but additional discussion may be required before recommendations are ready.*

5. Recommendation

Chairman Begaye put forward an internal RPC recommendation to change the name of the Tribal Affairs Subcommittee to the Tribal Energy Subcommittee as the subcommittee is specifically focused on exploring topics that relate to tribal energy development.

B. Fair Return and Value Subcommittee

Councilman Adam Red, Southern Ute Tribe, and Matthew Adams, Cloud Peak Energy, introduced the work of the Fair Return and Value Subcommittee and noted that the subcommittee has held more than 25 working group and subcommittee meetings to date, leading to the subcommittee's recommendations presented at the present February 2018 RPC meeting with additional recommendations to come at future RPC meetings. Subcommittee members shared updates and provided recommendations to the RPC in the following areas:

- Oil and Gas Payor Handbook: Gabrielle Gerholt, Concho Resources
- Index Pricing: Patrick Noah, ConocoPhillips Company
- Marketable Condition: Stella Alvarado, Anadarko Petroleum
- Coal Benchmarks: Matthew Adams, Cloud Peak Energy
- Audit: Greg Morby, Chevron

In addition, Shawna Schimke, Office of Natural Resource Revenue (ONRR), delivered a presentation about ONRR compliance process improvements.

1. Oil and Gas Payor Handbook

Gabrielle Gerholt, Concho Resources, reported to the RPC about the process and recommendations of the working group focusing on the Oil and Gas Payor Handbook created by ONRR. She noted that ONRR had started updating the Payor Handbook prior to the formation of the RPC, provided an update the current status of the update process, and summarized the working group's recommendation to create an "evergreen" handbook that can be updated regularly and link to recent rules and decisions. Additional information can be found in the meeting materials in Appendix A.

There were no questions or comments from RPC members following Ms. Gerholt's presentation.

2. Index Pricing

Patrick Noah, ConocoPhillips, recounted that the Index Pricing Working Group is charged with exploring the potential to make recommendations for an index price that addresses the issues associated with the index pricing provision in the repealed Valuation Rule and more effectively achieves a simple, certain, clear and concise index price solution. He provided background on the index pricing provision, described the working group's process, and outlined the working group's recommendation that DOI pursue rulemaking to define simplified index price rules for Federal gas.

Additional information can be found in the meeting materials in Appendix A.

In response to Mr. Noah's comments, RPC members asked the following questions and made the following comments. *Responses from Mr. Noah and other subcommittee members are indicated in italics.*

- A process point to make clear is that all recommendations generated by the RPC are recommendations to the Secretary of the Interior. Any regulatory changes would only be adopted after a formal rulemaking process including notice and public comment.
- Was revenue neutrality for the federal government a driver in creating this recommendation? *The working group did not consider revenue neutrality.*

3. Marketable Condition

Stella Alvarado, Anadarko Petroleum, and Mike Foster, ConocoPhillips, provided an overview of the Marketable Condition Working Group's process and recommendations. They reviewed the regulations governing and the process that lessees go through to put gas into marketable condition, according to ONRR regulations. They also outlined three disputes that exist between industry and ONRR about the regulations and how they are interpreted and enforced. Finally, they explained the working group's recommendation that the Department of the Interior resolve an ambiguity in its current regulations by publishing a proposed rule to amend the regulation at 30 C.F.R. 1202.151(b) to reexamine language specific to the boosting of residue gas. Additional information can be found in the meeting materials in Appendix A.

In response to Ms. Alvarado's and Mr. Foster's comments, RPC members asked the following questions and made the following comments. *Responses from Ms. Alvarado and Mr. Foster and other subcommittee members are indicated in italics.*

- What would be the cost implications of this recommendation? *The working group did not analyze the cost implications for the government of the proposal.*
- ONRR believes it has been applying the regulation correctly. There will be implications in terms of royalties collected in changing the regulation and so any proposed changes would have to go through an extensive process of public comment, economic analysis, and consultation with tribal nations.
- Language should be added to the proposed regulation that would exempt tribes in all perpetuity from the boosting rule.

RPC members and staff members engaged in discussion to clarify which version of the recommendation the RPC would be voting on, as the working group revised its recommendation the day prior to the RPC meeting and a question was raised about whether language would be added to the recommendation exempting Indian tribes from the boosting rule. It was determined that the RPC would vote on the version of the recommendation presented during the meeting and that the proposed language concerning Indian tribes would be considered separately by the Tribal Affairs Subcommittee.

4. Coal Benchmarks

Matthew Adams, Cloud Peak Energy, presented on behalf of the Coal Benchmarks Working Group. He provided background and historical context about coal valuation benchmarks, and outlined a challenge facing coal companies that restrict them from valuing non-arm's length sales using the most reliable methodology. Mr. Adams also put forward three recommendations on behalf of the working group to address this challenge, involving amending the regulation at 30 C.F.R. 1206.257(c)(2)(i); publication of an associated Secretarial Order, Dear Payor Letter, and/or a Policy Memorandum; and making an associated update to the Solids Minerals Reporting Handbook. Additional information can be found in the meeting materials in Appendix A.

In response to Mr. Adams' presentation, RPC members asked the following questions and made the following comments. *Responses from Mr. Adams and other subcommittee members are indicated in italics.*

- The State of Wyoming reviewed the changes that ONRR had worked on and the changes proposed to the benchmark system by the working group would be very beneficial.
- Why have gross proceeds from the same mine not been incorporated? *Response from Bonnie Robson, ONRR: You have to look at comparable sales. Arm's length transactions sold into the domestic market may not have the same dynamics as non-arm's length sales in foreign markets.*
- ONRR worked with the states in the most recent round of regulatory revisions and did away with the benchmarks. ONRR has been working in the direction of the recommendations presented by the working group and DOI would very closely consider a recommendation to this effect.
- The Navajo Nation owns and operates one coal mine and leases out another mine to Peabody Energy. The Navajo would like to see allowances examined to see how they are being configured and also want to explore standardizing allowances to see how they would impact revenues. *It would be helpful to discuss those issues in advance of the June RPC meeting.*

5. Audit

Greg Morby, Chevron, introduced the work of the Audit Working Group, explaining that the working group has discussed challenges facing the oil and gas and coal mining industries, particularly around audit coordination and timing, audit conduct and resource allocation, and audit closure. He proceeded to explain that discussions with ONRR representatives have indicated that the agency is in the process of making improvements in various areas of industry concern. As a result, the Audit Working Group will monitor the improvements being undertaken by ONRR and did not provide any recommendations at the February RPC meeting. Additional information can be found in the meeting materials in Appendix A.

There were no questions or comments from RPC members following Mr. Morby's presentation.

6. ONRR Compliance Process Improvements

Shawna Schimke, ONRR, delivered a presentation about ONRR compliance process improvements to the RPC. She provided an overview of the agency's process improvement initiative, including the development of its Operations Management Tool (OMT). Ms. Schimke reviewed the goals of the process improvement initiative, explained the intended benefits of the Operations Management Tool, and highlighted the steps that ONRR is taking to address the concerns raised by the Audit Working Group. Additional information can be found in the meeting materials in Appendix A.

In response to Ms. Schimke's presentation, RPC members asked the following questions and made the following comments. *Responses from Ms. Schimke and other subcommittee members are indicated in italics.*

- It is great that ONRR is undertaking this process improvement effort. Will the metrics that ONRR is collecting be made public? *Yes, ONRR will make those metrics publicly available.*
- Moving towards a system where there is certainty on payments is very admirable and we appreciate the effort.

C. Planning, Analysis, and Competitiveness Subcommittee

Colin McKee, State of Wyoming, introduced the work of the Planning, Analysis, and Competitiveness Subcommittee and introduced the working groups that would be providing updates and recommendations:

- Onshore Oil & Gas: Kathleen Sgamma, Western Energy Alliance
- Offshore Oil & Gas: Patrick Noah, ConocoPhillips Company
- Alaska: John Crowther, State of Alaska
- Coal: Matthew Adams, Cloud Peak Energy
- Non-Fossil and Renewables: Colin McKee, State of Wyoming
- Studies: Emily Kennedy Hague, American Petroleum Institute

1. Onshore Oil & Gas

Kathleen Sgamma, Western Energy Alliance, provided a detailed description of the Onshore Oil & Gas Working Group's proposals to the RPC. Those recommendations are in the areas of reducing timelines for project approvals; limiting the federal nexus of wells without a majority federal interest; improving land use planning and the process for NEPA approvals; and revising Onshore Orders, 3, 4, and 5. Additional information can be found in the meeting materials in Appendix A.

In response to Ms. Sgamma's presentation, RPC members asked the following questions and made the following comments. *Responses from Ms. Sgamma and other subcommittee members are indicated in italics.*

- Independent producers in New Mexico have indicated that they are avoiding development on federal lands because it is too complicated and expensive.
- The federal regulatory process can be very extensive. Authorization by the Secretary of the Interior for tribes to process permitting on tribal lands would allow for much more competitive development on tribal lands.
- Recommendations from the subcommittee for areas that would not require a rulemaking process would be welcome.
- Has the working group conducted an economic analysis underpinning its suggestion that the Secretary rescind Secretarial Order 3310 on Protecting Wilderness Characteristics on Lands Managed by the Bureau of Land Management? *No, the working group did not perform an economic analysis.*
- BLM would welcome direction from the Secretary for improving the NEPA process. Court processes and legal precedents limit how quickly the agency can proceed with NEPA review. Streamlining some of those elements would require legislative action.
- Approval to drill on Southern Ute lands can take 3 years whereas on neighboring private lands approvals can be secured in less than a year.

RPC members and staff members engaged in discussion to clarify whether the RPC would be voting only on the succinct high-level recommendations from this working group (and from all working groups and subcommittees) or on the high-level recommendations and the accompanying rationale and suggestions provided by the working group. It was determined that the RPC would vote only on the succinct high-level recommendations.

2. Offshore Oil & Gas

Patrick Noah, ConocoPhillips, walked through the Offshore Oil & Gas Working Group's proposals to the RPC. These involve setting a 12.5% royalty rate for all OCS lease sales through 2024, simplifying the process for granting varying royalty rate for declining or particularly costly fields, and increasing offshore acreage available for oil and natural gas leasing. Additional information can be found in the meeting materials in Appendix A.

In response to Mr. Noah's presentation, RPC members asked the following questions and made the following comments. *Responses from Mr. Noah and other subcommittee members are indicated in italics.*

- A 12.5% royalty rate would increase production and would increase royalty collections due to higher production.
- An IHS CERA study confirmed that high government take and a regressive fiscal system is likely to result in a loss of competitive edge for the U.S. Gulf of Mexico when commodity prices drop.

- There has been a significant downturn in lease sales in recent years and a lower royalty rate would help drive additional leasing and production. *Lease terms and conditions are decided on a sale-by-sale basis taking into consideration overall market conditions.*

3. Alaska

John Crowther, State of Alaska, presented the working group's recommendation that DOI conduct a lease sale in the 1002 area of ANWR ahead of statutory deadlines. He also explained that the Alaska Working Group will continue evaluating implementation of executive and secretarial orders regarding the NEPA process in Alaska as well as revising ONRR regulations and policies regarding transportation costs for Alaska offshore and remote developments. Additional information can be found in the meeting materials in Appendix A.

In response to Mr. Crowther's presentation, RPC members asked the following questions. *Responses from Mr. Crowther and other subcommittee members are indicated in italics.*

- Has the working group looked at what action should be taken for the National Petroleum Reserve in Alaska (NPRA)? *The working group is looking into that and will provide recommendations in the future.*

4. Coal

Matthew Adams, Cloud Peak Energy, stated that the Coal Working Group did not have recommendations to provide at the present February RPC meeting but would explore recommendations concerning determination of fair market value for third party transactions and for the bonus bid payment schedule. Additional information can be found in the meeting materials in Appendix A.

There were no questions asked or statements made following Mr. Adams' comments.

5. Non-Fossil and Renewables

Colin McKee, State of Wyoming, presented preliminary proposals that the Non-Fossil and Renewables Working Group is still exploring to support offshore wind development, including setting a goal for development of twenty gigawatts of offshore wind energy and to revise the operating fee for offshore wind. Additional information can be found in the meeting materials in Appendix A.

There were no questions asked or statements made following Mr. McKee's comments.

6. Studies

Emily Hague, American Petroleum Institute, presented two recommendations from the Studies Working Group, one for short-term study and one for a longer-term study. These recommendations are for DOI to contract for a study to compare the U.S GOM, Guyana and Mexico royalty rates, total revenue, block sizes and recent lease sales (for the last 3 years) and for DOI to contract to update the IHS-CERA 2011 study, for both onshore and offshore data. Additional information can be found in the meeting materials in Appendix A.

There were no questions asked or statements made following Ms. Hague's comments.

IV. Public Comments

Various members of the public took the opportunity to provide public comment during the RPC meeting.

Lem Smith, Gulf Energy Alliance

I want to commend the Administration on its actions last fall in reducing the royalty rate for shallow water to 12.5%. This was an encouraging signal to our markets and our members. I would like to encourage the Committee to consider using existing tools in the toolbox with regards to special case royalty and end-of-life royalty relief. The shelf today is 93% developed by independents. We are all experiencing difficult economics in the shelf and in deepwater, including higher operating costs and more restrictive regulations. We would encourage the Department to consider these existing tools to reinvigorate production for the country.

David Romig

I have been in this industry almost 37 years. Under the marketable condition rule, we have seen the situation change where the lessee sometimes has to bear the charge twice. I would encourage a change such that any lessee only has to bear that cost once.

Pam Eaton, Senior Advisor for Energy and Climate at The Wilderness Society

TWS has more than one million members and supporters, and its mission is to protect wilderness and inspire Americans to care for our wild places. We support solutions that balance extractive uses like energy development with conservation through open, sustainable and science-based land management practices to maintain the long-term integrity of our landscape.

Our nation's public lands provide tremendous value to the American people—awe-inspiring wild places like the Arctic National Wildlife Refuge with its caribou herds and polar bears and Wyoming's Red Desert with its antelope and sage grouse; sacred landscapes like the Greater Chaco Canyon Region in New Mexico with its ancient ruins and roadways and the Bears Ears Region with its rock art and cliff dwellings and fossil finds. Communities depend on public lands for clean water and expect them to provide clean air and opportunities to experiences the joys of the outdoors and nature.

Protecting these incredible values is not a burden on industry, it is a duty that Congress entrusted to the Department of the Interior on behalf of the American people.

I have come to Houston to urge that as you work to meet the charge set out in your charter—"to ensure the public receives the full value of the natural resources produced from Federal lands"—that you consider the public interest—taxpayers, public land owners, and the environment—as part of value Americans receive from public lands.

Editor's note: Additional detail is provided in Appendix B, which contains Ms. Eaton's full public comment.

Dan R. Bucks Former Director, Montana Department of Revenue and Former Executive Director, Multistate Tax Commission

In managing public resources, we should recall our moral obligation to pass on to our children and grandchildren a clean and healthful environment with federal lands conserved for their continuing enjoyment. That obligation is linked to Interior's legal duty to ensure the American people receive fair value for the minerals they own. Fair value is the sum of the market value of energy plus the cost to society of environmental, health and other damages energy producers fail to mitigate. When producers fail to pay full market value plus the cost of damages to society, Interior breaches its duty under federal law and its obligation to future generations.

We know from Tom Sanzillo's research along with Inspector General and GAO reports that Interior has fallen short of achieving fair value. Sanzillo documents that for Powder River coal alone, producers underpaid leases and royalties by tens of billions over a 30-year period.

In December 2007, the previous Royalty Policy Committee found Interior's methods of valuing natural gas and coal for non-arm's length sales so inadequate that they called for new rules to be proposed within nine months. It took Interior nine years to adopt those new rules—and the current Administration repealed them within a few months, returning to decades-old rules judged a failure in 2007.

So, the American people are left with royalty rules known to fail. What then does your Fair Return Subcommittee propose? It proposes to make matters worse and have Interior further breach its legal duty to the public and its obligation to the future.

Current rules give too much influence to energy companies over mineral values, resulting in underpaid royalties. Yet, the subcommittee proposes to turn industry's undue influence into nearly full control of valuations. One proposal would give the natural gas industry veto power over any index to value gas. Whoever controls the index, controls the values. Another would give coal producers power to choose their own preferred arm's length sales as the basis for valuing coal. Despite the "arm's length" label, companies can manipulate their chosen prices to produce results well below fair value. These proposals improperly delegate to private corporations Interior's legal authority to value minerals.

The proposed royalty exemption for residue gas used in a necessary step to achieve marketable condition is not justified. The industry's rationale is faulty. This gas is of economic value and the public is entitled to a royalty on that value.

The Planning, Analysis and Competitiveness recommendations do even more harm to attaining fair return and providing for future generations. They propose to weaken environmental reviews, curtail land use planning and reduce protections for sensitive lands. They claim the BLM requires too much, but courts often find the BLM fails to adequately evaluate environmental impacts or plan for alternative land uses. The proposals read like industry commands for BLM to stick to a narrow path of specific rules and handbooks and to ignore court rulings requiring it to comply with a larger body of environmental and resource law. All this risks environmental harm and invites litigation.

Capping royalty rates below those set under President Bush would subsidize offshore leasing in areas where production is difficult. Why subsidize risky production when we can produce energy in safer and better ways? Expanded leasing is proposed without proven demand for those leases. Interior is already flooding the market with excessive lease sales, finding few takers and then often at minimum prices that short-change the American people.

Worse yet is the concept of tying U.S. royalty practices to those of other nations—a terrible idea that would potentially dictate U.S. policy based on concessions companies persuade other nations to give them. A race to the bottom is contrary to U.S. law requiring a fair return. The U.S. should not—and cannot under any proper reading of the law—compete with Guyana or Mexico on how little we will collect from fossil fuels.

Defining competitiveness in terms of nations competing on how much they subsidize fossil fuels is not a legitimate issue. The real question is this: Why should we expand unjustified benefits for fossil fuels with unacceptable risks to the natural world, when we can achieve a fair and sustainable return from our federal lands and protect our children's future by pursuing clean and affordable renewable energy as rapidly as possible? Subsidizing the energy past only delays the inevitable transition to a better future.

You are allowing a short public comment period on over a hundred pages of material posted a few days before this meeting. There are citizens who have good ideas on better policies they would like to share with you. Please defer the recommendations before you, open up your subcommittee meetings, and welcome a true public dialogue on these issues of great significance to our world and its future.

Ryan Alexander, Taxpayers for Common Sense
Good afternoon. Thank you for the opportunity to offer comments today. My name is Ryan Alexander and I am president of Taxpayers for Common Sense (TCS), a non-

partisan budget watchdog organization based in Washington D.C. My organization's mission is to achieve a government that spends taxpayer dollars responsibly and operates within its means.

For more than two decades, TCS has worked to ensure that taxpayers receive a fair return on the natural resources extracted from federally owned lands and waters. Royalties and fees collected from resource development are a valuable source of income for the federal government and should be collected, managed, and accounted for in a fair and accurate manner. As the resource owners, taxpayers have the right to fair market compensation for the assets extracted from our lands and waters, as would any private landowner.

For decades, royalty and leasing policies have cost taxpayers billions of dollars in lost revenue. Poorly managed federal energy and mineral programs at the Department of the Interior have led to years of reduced and royalty-free disposition of oil and gas, and undervalued coal. The RPC has the opportunity to recommend important reforms to the revenue collection and resource valuation processes.

But the recently released subcommittee meeting notes and recommendations have raised several areas of concern. In general, it is apparent that some of the subcommittees' materials exclusively reflect the perspective of industry stakeholders, rather than a consensus from the wide range of interests affected by natural resource policy. For example, several pages in the Fair Return and Value Subcommittee's materials exactly mirror a single company's comments to ONRR's 2016 Valuation rulemaking. Proposals from the subcommittee's other working groups regarding index pricing, allowable deductions for transportation costs, and coal valuation methodology also seem to largely represent a single perspective. Of course industry can and should advocate for their own interests and the interests of their shareholders. But the RPC and the DOI have a fiduciary duty to taxpayers and must make efforts to include broader perspectives in its recommendations and policy changes.

Editor’s note: Additional detail is provided in Appendix B, which contains Ms. Alexander’s full public comment.

John Northington

First, I appreciate the opportunity to speak today and want to commend the members of the Royalty Policy Committee for giving of your time and talent by agreeing to serve as a member of this advisory committee. I also want to recognize all of the career employees at Interior for your contributions in helping to inform and educate this committee as to the statutory responsibilities of your respective bureaus.

My name is John Northington. I am a fifth generation Texan and I am the fourth generation of my family to be engaged in the oil and gas business. In the small world category, I met Texas State Representative Drew Darby of San Angelo during the lunch break. Representative Darby asked if I was related to K.V. Northington and I told him that K.V. was my uncle. Representative Darby told me that he used to do some legal work for my uncle back in the day. My uncle was a geologist and co-owned a drilling company based out of San Angelo. My father was a landman and I also did land work after I graduated from college.

I also served as a federal regulator over the oil and gas industry at Interior in the late 1990's. Today, I advise oil and gas companies that own federal oil and gas leases on how to navigate and resolve environmental, cultural, and habitat conflicts that invariably arise between the government, the environmental community and the industry.

I want to briefly address three points that I would like to make based on my past experiences. First, since 2002 I have been a member of The National Petroleum Council (NPC), an advisory board to the Secretary of Energy. Back in the early nineties, the Secretary of Energy and the NPC began to select environmental NGO's to become members of the NPC. The diversity of opinion and expertise that the NGO's bring to the energy policy discussions have positively contributed to the many studies that the NPC has undertaken over the years. Based on my experience as a member of the NPC, I would encourage the senior leadership at Interior to seriously consider broadening and diversifying the RPC membership to better reflect the various constituencies that care about our public lands.

Secondly, my bread and butter in the private sector has been to advise companies that are involved in large project level EIS's that are legally required by the National Environmental Policy Act (NEPA). I agree with Kathleen Sgamma that these EIS's take way too long. I was involved with an EIS in the Uinta Basin regarding an infill drilling program located within an active oil field that has been in production for over 50 years. That EIS took nearly eight years to complete and involved two different administrations.

Why did it take so long? Well, all the blame can't be put on BLM. When I was at BLM my boss was BLM Director Tom Fry. Tom is also a Texan. When industry would come in and meet with us about particular projects that were taking too long, Tom would always remind those in the meeting that BLM is also regulated. The bureau can't just act unilaterally because the US Fish and Wildlife Service, the National Park Service and the EPA to name just a few federal partners also have statutory rights and responsibilities. Then there are also the states, tribes, and localities that legally also are a part of the process.

Can BLM improve upon its performance concerning the permitting and NEPA process? Sure, it can, but what I would recommend that would be particularly helpful is obtaining better and more current information about our public lands. For instance, where are the recoverable oil and gas resources located, where are the known habitats of species of concern located, and where are all of the culturally sensitive areas located.

Such a study of recoverable oil and gas resources sensitive surface areas could build on the Energy Policy Act of 2005 inventory of our public lands' energy resources and conservation values. The initial study was concluded, I believe, in 2007 and was a very useful tool. The enabling legislation required that there be periodic inventory assessments conducted. We only have the initial inventory. I believe that another inventory of both economically and technically recoverable oil and gas resources would be helpful in providing current information for planning, permitting and NEPA analyses.

By also modeling economically recoverable resources, policy makers and stakeholders can really focus on those areas first as they are the most likely to be developed first. I know Mike Nedd, who is here, is very knowledgeable about the original EPCA inventory modeling and its benefits.

Finally, I want to address the RPC's recommendation of lowering the offshore royalty rate for all water depths, including the deep water, for future lease sales to 12.5%. That seems low to me, but, granted, I didn't have all of the economic analysis available to the committee. Perhaps the lower rate is justified, but the optics of lowering the rate are not great.

Since we are in Texas and not too far from the Gulf of Mexico, I want to point out that the Texas General Land Office will be having an oil and gas lease sale for state waters that benefit Texas public schools on April 3, 2018. My understanding is that the lease terms for this lease sale will be for a five- year term and a stated royalty rate of 25%, with an opportunity for a lower rate of 20-22.5% if production is brought on line in the early years of the lease. Since I'm sure that Secretary Zinke doesn't like surprises, I would suggest that in its final recommendations to the Secretary a compilation of the various rates and terms for state's oil and gas leasing terms and royalty rates be appended to your recommendation.

In sum, I recommend this committee consider the following before voting on recommendations before it today:

- Consider expanding the membership of the RPC to include NGO representatives
- Consider updating the EPCA inventory model to include information about technically and economically recoverable oil and gas resources of our public lands to better evaluate energy potential and the surface environmental values across our public lands
- Provide analysis and modeling results of the predicted impact of royalty rate reductions for the offshore on both federal revenues and recoverable reserves.

Thank you for your time today and again thank you for your efforts.

Stephanie Thomas, Public Citizen

Arctic temperatures are soaring and sea ice is plunging to record lows, but in Houston you don’t have to go outside Beltway 8 to see the effects of climate change. Hurricane Harvey devastated my community, killed 88 people and caused $125 billion in damages. Scientists have shown that Harvey’s strength was fueled by climate change.

Climate change cost Americans $306 billion in 2017 alone. The time to transition from fossil fuels to renewable energy is now, but the Interior’s policies are preventing serious action on climate change. Zinke’s proposal to gut the U.S. Bureau of Land Management’s (BLM) methane waste rule would lead to climate damage equivalent to 8.3 million cars driven for 10 years.

Controlling methane waste from oil and gas operations on federal land is one of the best ways to address climate change. Reducing waste would improve public health by reducing dangerous toxins like benzene and smog-forming pollutants that can trigger asthma and other respiratory conditions. Furthermore, cutting methane emissions would benefit taxpayers by reducing wasted releases of natural gas that would otherwise be subject to royalty payments. Gutting the BLM methane waste rule harms families and taxpayers.

Zinke’s five-year drilling plan opens up offshore acreage to oil and gas drilling in the Arctic, which would impact sensitive marine ecosystems, tourism and commercial fishing. In Texas, the rule could impact tourism, recreation, fishing, shrimping and the protection of Flower Garden Banks National Marine Sanctuary. Zinke’s DOI is also considering a rollback of several post-Deepwater Horizon safety protections, despite concerns about the safety of blowout preventers. In fact, Zinke stopped a National Academy of Sciences study to enhance drilling safety on offshore platforms. This decision puts oilfield workers and the environment at risk.

Zinke is taking the value of America’s natural resources from the American people and giving it to the oil and gas industry instead. Zinke has proposed to slash the federal royalty rate that oil companies pay to taxpayers for deepwater drilling operations from 18.75 percent to 12.5 percent. That recommendation from a Royalty Policy Committee subcommittee follows the Trump administration's move to allow offshore drilling off U.S. coastal waters. Oil companies are happy to pay less to extract fossil fuels from federal lands, but the American people will pay dearly.

Sandra Peters
I’m one of many, many public citizens who are concerned about opening up public lands to drilling, about fracking and water pollution, about causing climate change, about ruining the natural places that we love. It’s critical that the Department of the Interior do the due diligence that will be needed to make sure that the recommendations coming out of the RPC are in the broader public interest.

Greg Broyles

Hello, my name is Greg Broyles. I am here as a concerned citizen. I am the great grandson of Mormon pioneers. I am a former Boy Scout and an ex-Marine. I have operated a number of small businesses in the Houston area. I am a life-long environmentalist and 20+ year climate change activist. I support the comments made just before me by Stephanie Thomas of Public Citizen and Sandra Cisneros Peters, another concerned citizen. Most of all, I am a father.

I grew up in the west where there are BLM lands unlike here in Texas. I grew up surrounded by the indigenous people of that land from whom many of the assets being described today were stolen.

I am the grandson of a worker in the Kennecott Copper Mine in eastern Nevada. I have seen the destruction of mining activity my whole life.

My daughters will continue to grow up in a world already showing the consequences of climate change. The fossil-fuel industry is outdated and should not be supported any more than it already is. The activities of this industry will continue to endanger the futures of all humans. One of my daughters recently completed the Pacific Crest Trail. She's tough as nails. She will need to be in the future I fear is coming.

Many of you in this room have kids and grandchildren. Will you not think about their futures? This committee is ready to give a 33% discount to assets that are already practically given away. This is all about greed and short-term thinking.

This past summer, the San Joaquin Valley came very close to burning. Americans take for granted our food independence. Why are we making it easier and more lucrative for the fossil-fuel industry that is already playing the largest role in the calamitous effects of climate change? What will all of the people in this room do when Americans become global refugees after our food independence collapses and our forests and agricultural areas become scorched deserts?

Jayni Foley Hein, Institute for Policy Integrity, NYU School of Law
The Institute for Policy Integrity at New York University School of Law submits these comments to the Department of the Interior's Royalty Policy Committee (RPC). Policy Integrity is a non-partisan think tank dedicated to improving the quality of government decision making through advocacy and scholarship in the fields of administrative law, economics, and public policy.

The Department of the Interior is required to earn "fair market value" for the use and development of federal natural resources. How royalties are set and assessed is critical to ensuring receipt of fair market value for the public. We write to make the following comments:

- Interior should not lower the offshore royalty rate, which was raised during the George W. Bush administration and is necessary to ensure fair market value for the public's resources;
- Interior should end area-wide leasing, which has led to record-low bids and little to no competition for offshore tracts, breaking with fair market value and competitive leasing requirements;
- Interior should increase federal fossil fuel royalty rates, as multiple studies show that higher royalty rates will increase total revenue for the public;
- Interior should adjust royalty rates upward for coal, oil, and natural gas leases to recoup some of the environmental and social costs of production; and
- Interior must recognize that fossil fuel development is only one statutory purpose of our public lands that must be balanced with other, equally important uses, including preservation, recreation, and renewable energy development.

Editor's note: Additional detail is provided in Appendix B, which contains Ms. Foley Hein's full public comment.

Amelia Strauss, Project on Government Oversight
I'm with the Project On Government Oversight, a nonprofit watchdog. POGO has been investigating offshore leasing. As part of our investigation, we've analyzed data on thousands of bids and scores of Interior Department auctions spanning more than half a century.

Last week, POGO published a report explaining how the Interior Department's management of offshore leases is deeply dysfunctional and benefits oil companies at the expense of the American people.

We hope this committee will consider our findings and the recommendations we've submitted based on our research. I'd like to share a brief overview.

1. First, when the government leases tracts of the ocean floor—tracts that belong to the American people—it is required by law to ensure that it receives "fair market value." However, under the so-called area-wide leasing system the Interior Department has been using since 1983, the average price paid per acre in the Gulf of Mexico has plunged by almost 96 percent. On an inflation-adjusted basis, it has declined from more than $9,000 under the prior system to less than $400 under the current system. Federal revenue from auction payments has declined by tens of billions of dollars.

2. Second, the government is required by law to award leases through "competitive bidding." However, the Interior Department's auction system delivers little more than an illusion of competition. Over the past 20 years, more than three quarters of the leases awarded in the Gulf of Mexico were awarded on the basis of single, unopposed bids.

3. Third, in the absence of truly competitive bidding, making sure the public receives fair market value depends on the government accurately estimating the value of the tracts. However, the Interior Department's estimates inspire no confidence. For example, over the past 20 years, the government has classified almost 80 percent of the Gulf of Mexico tracts on which companies bid as "non-viable"—in other words, worthless. Many of those tracts went on to produce oil and/or gas. More than two-thirds of the leases that became energy-producing had been classified by the government as non-viable.

4. Fourth, some people have justified the giveaway of offshore drilling rights by arguing that oil companies pay royalties. However, the government has a history of letting oil companies have their cake and eat it too—by awarding drilling rights at fire-sale prices and then cutting leaseholders a break on the royalties. This committee's recommendation to cut royalties would be adding insult to injury.

5. Finally, one of the Interior Department's primary aims is to promote energy production, but on that count, too, the leasing system gives cause for concern. The system makes it relatively inexpensive for oil companies to speculate in offshore leases—to snap them up and then sit on them instead of drilling. Speculation produces neither energy nor royalties.

We recommend that this committee scrutinize the Interior Department's auctioning of offshore drilling rights and determinations of bid adequacy.

For a more detailed explanation, please see POGO's report Drilling Down at pogo.org.

Thank you.

Editor's note: Additional detail is provided in Appendix B, which contains Ms. Strauss' full public comment.

John Frederick
The Secretary needs to address the issue of dual taxation. We can't allow massive wealth to leave Indian Country. It can be addressed under the Indian Trader regulations or through rulemaking. With regard to transportation allowance under current ONRR regulations, this needs to be removed. We are requesting rulemaking on that as well.

V. Committee Vote

Rachel Milner Gillers, independent facilitator of the Royalty Policy Committee, outlined the process for voting: 1) Review the recommendation under consideration, 2) RPC members voice any outstanding concerns, 3) RPC is operating by consensus, so if any outstanding concerns cannot be easily resolved, the issue will be sent back to subcommittee(s) for further discussion, and 4) if there are no outstanding concerns, consensus is reached and the RPC has voted in favor of the recommendation.

1. Tribal Affairs Subcommittee Recommendation

Ms. Milner Gillers introduced the first recommendation for consideration, which would be an internal decision, by the RPC:

- ➢ *Change Subcommittee name from Tribal Affairs Subcommittee to Tribal Energy Subcommittee.*

Mr. DeVito asked if there were any objections to the first recommendation. Hearing none, the committee adopted the decision by unanimous consent.

2. Fair Return and Value Subcommittee Recommendations

Mr. DeVito proceeded through the recommendations put forth by the Fair Return and Value Subcommittee.

<u>Recommendation #1:</u>

- ➢ *Create "evergreen" handbook which can be updated regularly and link to recent rules and decisions.*

Mr. DeVito asked if there were any objections to the first recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

<u>Recommendation #2:</u>

- ➢ *Pursue rulemaking to define simplified index price rules for Federal gas.*

Mr. DeVito asked if there were any objections to the second recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

<u>Recommendation #3:</u>

- ➢ *Exclusively with regard to federal lands, Department of the Interior resolve an ambiguity in its current regulations by publishing a proposed rule to amend the regulation at 30 C.F.R. 1202.151(b) to reexamine language specific to the boosting of residue gas.*

Mr. DeVito asked if there were any objections to the third recommendation. In response, RPC members provided the following comments:

- There are public interests that may have not been addressed during the meeting. It was contemplated that the subcommittee reach out to additional subject matter experts as deemed necessary.
- The recommendation should be rephrased such that the word "reexamine" follows directly after "Department of the Interior." This would clarify the meaning of the recommendation.

After discussion Mr. DeVito again asked whether there were objections to approving the recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #4:

- *Reinforce the principle that arm's length transactions are the best indication of market value by amending the regulation at 30 CFR 1206.257(c)(2)(i) to read: "The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition by other than an arm's-length contract), provided that those gross proceeds are the equivalent to the gross proceeds derived from, or paid under comparable arms-length contracts for sale, purchases, or other dispositions of like-quality coal in the area."*

Mr. DeVito asked if there were any objections to the fourth recommendation. In response, an RPC member asked the following question:

- What would the practical implications of this recommendation be?
    - In response, RPC members explained that currently, the coal valuation regulations are inconsistent with the regulations for gas and oil. The intent of the recommendation is to reinforce the principal that the best indicator of value is the first arm's-length sale. RPC members also added that the implications of the proposed rule change would be further explored through the rulemaking process, including an economic analysis and hearing from the public.

Mr. DeVito asked again if there were any objections to the fourth recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #5:

- *Consider a Secretarial Order / Dear Payor Letter indicating that a company's own arm's length sales are preferential under coal benchmark 4.*

Mr. DeVito asked if there were any objections to the fifth recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #6:

- *Updated Solids Handbook indicating the same.*

Mr. DeVito asked if there were any objections to the sixth recommendation. In response, an RPC member provided the following comment:

- There are public interests that may need to be addressed by the Department of the Interior during the rulemaking process.

After discussion Mr. DeVito again asked whether there were any objections to approving the recommendation. Hearing no objection, the committee adopted the recommendation by unanimous consent.

3. Planning, Analysis, and Competitiveness Subcommittee Recommendations

Mr. DeVito proceeded through the recommendations put forth by the Fair Return and Value Subcommittee.

Recommendation #1:

- ➢ *Reduce timelines for project approval, including APDs, ROWs, sundries, lease nominations and unit agreements.*

Mr. DeVito asked if there were any objections to the first recommendation. In response, an RPC member provided the following clarification:

- The RPC is voting only on the succinct high-level recommendation from the subcommittee and not on the accompanying background material provided by the working group.

After discussion Mr. DeVito again asked whether there were any objections to approving the recommendation. Hearing no objection, the committee adopted the recommendation by unanimous consent.

Recommendation #2:

- ➢ *Limit the federal nexus of wells without a majority federal interest.*

Mr. DeVito asked if there were any objections to the second recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #3:

- ➢ *Improve land use planning and NEPA Approvals.*

Mr. DeVito asked if there were any objections to the third recommendation. In response, an RPC member provided the following observation:

- The recommendation would require statutory change.

After discussion Mr. DeVito again asked whether there were any objections to approving the recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #4:

- ➢ *Revise and simplify Onshore Orders, 3, 4, and 5 to ensure more equitable and timely implementation.*

Mr. DeVito asked if there were any objections to the fourth recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #5:

- *Set future OCS lease sales through 2024 at 12.5% royalty rate.*

Mr. DeVito asked if there were any objections to the fifth recommendation. In response, RPC members provided the following comments:

- There are public interests that may not have been addressed during the meeting. It was contemplated that the subcommittee reach out to additional subject matter experts as deemed necessary.
- If the committee were to pass this recommendation, the Department of the Interior should consider the public interest, as a whole, when considering whether to implement this recommendation.

After discussion Mr. DeVito again asked whether there were any objections to approving the recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #6:

- *Revise, clarify and simplify process for granting varying royalty rate for declining or particularly costly fields.*

Mr. DeVito asked if there were any objections to the sixth recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #7:

- *Increase offshore acreage available for oil and natural gas leasing.*

Mr. DeVito asked if there were any objections to the seventh recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #8:

- *Interior should conduct a lease sale in the 1002 area of ANWR ahead of statutory deadlines.*

Mr. DeVito asked if there were any objections to the eighth recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #9:

- *The Department of the Interior should contract for a study to compare the U.S GOM, Guyana and Mexico royalty rates, total revenue, block sizes and recent lease sales (last 3 years).*

Mr. DeVito asked if there were any objections to the ninth recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

Recommendation #10:

- *The Department of the Interior should contract to update the IHS-CERA 2011 study, for both onshore and offshore data.*

Mr. DeVito asked if there were any objections to the tenth recommendation. Hearing none, the committee adopted the recommendation by unanimous consent.

VI. Wrap Up / Closing

Mr. DeVito thanked RPC members and shared appreciation for their productivity. He also remarked that the committee is operating under the same model as the Trump Administration in pushing forward aggressively in minimal time. Mr. Schindler asked for members to contact the RPC staff if they wish to modify their subcommittee enrollment, reviewed the timeline for the next full committee meeting dates, and closed the meeting.

VII. Meeting Participants

Chairman

Vincent DeVito, DOI

Designated Federal Officer

James Schindler, DOI

Ex-Officio

Gregory Gould, ONRR
Scott Angelle, BSEE
Walter Cruickshank, BOEM
Mike Nedd, BLM
Joe Balash, DOI
John Melhoff, ONRR
Kevin Karl, BSEE
John Tahsuda, ASIA
Ben Simon, DOI
Adam Stern, DOI

Ex-Officio *(Alternate)*

Renee Orr, BOEM

States

Andrew McKee, WY

John Crowther, AK
William Darby, TX
John Andrews, UT

<u>States *(Alternate)*</u>
Lynn Helms, ND
Daniel Saddler, AK

<u>Tribal</u>
President Russell Begaye, Navajo Nation
Councilman Christopher Adam Red, Southern Ute Indian Tribe
Charles Robertson, Choctow Nation of Oklahoma
Chairman Everett Waller, Osage Minerals Council

<u>Tribal *(Alternate)*</u>
Bidtah Becker, Navajo Nation

<u>Academia/Public Interest</u>
Roderick Eggert, CO School of Mines
Monte Mills, University of Montana Law
Van Romero, NM Institute of Mining
Daniel Rusz, Wood Mackenzie

<u>Academia/Public Interest *(Alternate)*</u>
Graham Davis, CO School of Mines

<u>Industry</u>
Randall Luthi, National Ocean Industries Association
Patrick Noah, ConocoPhillips
Stella Alvarado, Anadarko Petroleum Corporation
John Sweeny, VWR Corporation
Matthew Adams, Cloud Peak
Marisa Mitchell, Intersect Power

<u>Industry *(Alternate)*</u>
Kevin Simpson, Shell Exploration and Production Co.
Greg Morby, Chevron
Kathleen Sgamma, Western Energy Alliance
Gabrielle Gerholt, Concho Resources

<u>Royalty Policy Committee Staff</u>
Jennifer Malcolm, ONNR

<u>Facilitation Team</u>

Rachel Milner Gillers, Facilitator
Tushar Kansal, Facilitator

<u>Members of the Public in Attendance</u>
Sandra Peeters, Houston DSN
Lem Smith, Gulf Energy Alliance
John Fredericks, MHA Nation
Lexia Worley, Statoil
Jackson Brossy, Navajo
Mike Foster, Conoco Phillips
Matt Harlan, J. Connor Consulting
Dan Bucks, Citizen (IP)
Tom Shipps, Southern Ute Indian Tribe
Triscilla Taylor, BP
Rebecca Paris, WPX Energy
Jason Modglin, TX House of Representatives
Williamson Turner, BP Exp + Prod
Renee Crosby, Chevron
Suzanne Shank, BP
Jim Steward, ONRR
Laura Logan, Exxon Mobil
Kevin Bruce, Fieldwood Energy
Emily Hague, API
Stephanie Thomas
Foster Wane, Statoil
Allen Paulson, BLM, HPDO-WY
David Romig, Ryan LLC
Greg Broyler, Air Alliance Houston (+ Citizen)
Chris Stolte, DOI
Bonnie Robson, ONRR
Pam Eaton, TWS
John Northington, Northington Strategy Group
Benton Arnett, Exxon Mobil
Ryan Alexander, Tax Payers for Common Sense
Keith Godwin, Arena Energy
Michele Scahill, Arena Energy

<u>Members of the Public Participating Remotely</u>
Alex Thompson, New Wilderness Society
Allen Kovski, Bloomberg
Amelia Strauss, Project on Government Oversight
Amy Hines, NYU School of Law
Amy Lunt, ONRR
Andy Radford, API

Aneesa Khan, The Wilderness Society
Ann Stevens, US GAO
Ben Lefave, Politico
Bonnie Briggs, ONRR
Brian Bex, Navaho Nation
Brittany Patterson, E&E News
Building 53, ONRR
Carl Wonderly, Office of Natural Resources Revenue
Chris Anight, RGUS Media
Chris Carey, ONRR
Chris Mentasti, ONRR
Christina Yumbuji, ID
Cindy Gothberg, ONRR
Dan Smith, Consultant Technologies
David Hilzenrath, Project on Government Oversight
David Read, State of Wyoming
Denver Office, Office of Natural Resources Revenue
Ed Longanecker, Tipro
Eli Lewine, Government Accountability Office
Elizabeth Klein, NYU
Estella Cote, ID
Grant Fisher, US GAO
Herb Black, ONRR
James Witkop, ONRR
Jason, DOI
Jason St. John, Cloud Peak Energy
Jen Dlouhy, Bloomberg
Jennifer, Bureau of Ocean Management
Jeremy Dillon
Jeremy Norton, Devon Energy
Jonathan Wicks, Montana Dept of Revenue
Joshua Laren, SMP Global Market Intelligence
Judy Wilson, ONRR
Katherine Schmidt, Upstream Newspaper'
Kimberly Levat, Latham & Watkins
Laura Peterson, Project on Government Oversight
Lauren Craft, Energy Intelliegence
Lauren Craft, Oil Daily
Lesley Shaft, FATFF
Leslie Shakespeare, Business Council
Linda Obeya, Office of Natural Resources Revenue
Lori Millstide, Anadarko
Margaret Corrigan
Mark Edwards, New Mexico Legislative Council Service

Maroya Saied, ONRR
Meghan Trujillo, Office of Natural Resource Revenue
Michael Mouton, ONRR
Mike Matthews, State of Wyoming
Mike Reese, Student
Monte Mason, Montana Dept of Natural Resources & Conservation
Morgan Bosch, Performance Engineering
Nicole Lizzie
Nicole Samole
Nicole Goodkine, Newsweek
Pamela King, E&E News
Patty Burg, BP America
Ryan Shubiner, Taxpayers for Common Sense
Samuel Herbert, ONRR
Shannon Anderson, Cutter River Basin Resource Council
Shawn Thomas, Montana DNRC
Stella, Excel Mobil
Steve Dilsaver, State of Wyoming
Steve Velgus, Health and Natural Resources Committee
Steven Payson, DOI
Susan Farrell, The Wilderness Society
Valerie Volcovici, Reuters
William Duncan, XTO Energy
Zach Valdez

Appendix A: Meeting Materials

Appendix B: Written Public Comment

Appendix A:

Meeting Materials

From

February 28, 2018

RPC Meeting

Royalty Policy Committee Meeting
U.S. Department of the Interior
Hyatt Regency North Houston
425 North Sam Houston Pkwy E, Houston, TX 77060

February 28, 2018, 9:00am-5:00pm (Central Time)

Domestic Conference Line: 888-455-2910 Passcode: 7741096
International Conference Line: 1-210-839-8953 Passcode: 7741096
Webex: https://onrr.webex.com/onrr/j.php?MTID=me35a6530f291ed484884a82e74e92d35

AGENDA

Chair: Vincent DeVito, Counselor to the Secretary for Energy Policy, Interior

DFO: James Schindler, Executive Director, RPC

Meeting Goals:

- Report out and recommendations from Tribal Affairs subcommittee
- Report out and recommendations from Fair Return and Value subcommittee
- Report out and recommendations from Planning, Analysis, and Competitiveness subcommittee
- Receive public comments
- Full committee discussion on subcommittee recommendations
- Timeline review

Meeting Materials:

- Agenda
- Tribal Affairs subcommittee presentation
- Fair Return and Value subcommittee presentation
- Planning, Analysis, and Competitiveness subcommittee presentation
- FY2018 Timeline

8:30am–9:00am, Registration

Registration

9:00am-9:30am, Welcome and Overview

Call to Order
James Schindler, Designated Federal Officer / Executive Director

Welcome and Introductions
Vincent DeVito, Counselor to the Secretary for Energy Policy, Interior
All Committee Members

Agenda Review
James Schindler, Designated Federal Officer / Executive Director

9:30am – 10:15am, Tribal Affairs Subcommittee Presentation

- Co-Director's Introduction: President Russell Begaye, Navajo Nation
- TERA: Bidtah Becker, Navajo Nation Office of Natural Resources
- Model Congressional Statute: Prof. Monte Mills, University of Montana School of Law
- 1938 Act: Chairman Everett Waller, Osage Minerals Council
- Taxation: Jackson Brossy, Navajo Nation Washington Office

10:15am–10:30am, Break

10:30am-12:15pm, Fair Return and Value Subcommittee Presentation

- Co-Director's Introduction: Matthew Adams, Cloud Peak Energy
- Oil and Gas Payor Handbook: Gabrielle Gerholt, Concho Resources
- Index Pricing: Pat Noah, ConocoPhillips Company
- Marketable Conditions: Stella Alvarado, Anadarko Petroleum
- Coal Benchmarks: Matthew Adams, Cloud Peak Energy
- Audit: Greg Morby, Chevron
    - ONRR OMT: Shawna Schimke, ONRR

12:15pm-1:15pm, Break for Lunch

1:15pm-3:00pm, Planning, Analysis, and Competitiveness Subcommittee Presentation

- Co-Director's Introduction: Colin McKee, State of Wyoming
- Onshore Oil & Gas: Kathleen Sgamma, Western Energy Alliance
- Offshore Oil & Gas: Patrick Noah, ConocoPhillips Company
- Alaska: John Crowther, State of Alaska
- Coal: Matthew Adams, Cloud Peak Energy
- Non-Fossil and Renewables: Colin McKee, State of Wyoming
- Studies: Emily Kennedy Hague, American Petroleum Institute

3:00pm-3:15pm, Break

3:15pm-3:45pm, Opportunity for Public Comment

3:45pm-4:30pm, Committee Vote

4:30pm-5:00pm, Wrap-up, Timeline, Conclusion and Next Steps, Adjourn

Appendix A

Royalty Policy Committee

Wednesday, February 28, 2018

U.S. DEPARTMENT OF THE INTERIOR

Registration

8:30a.m. – 9:00a.m.

Welcome, and Overview

9:00a.m. – 9:30a.m.

Tribal Affairs Subcommittee Presentation

Co-Director's Introduction: President Russell Begaye, Navajo Nation
TERA: Bidtah Becker, Navajo Nation Office of Natural Resources
Model Congressional Statute: Prof. Monte Mills, University of Montana
1938 Act: Chairman Everett Waller, Osage Minerals Council
Taxation: Jackson Brossy, Navajo Nation Washington Office

9:30a.m. – 10:15a.m.

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9:30a.m. – 10:15a.m.

Break

10:15a.m. – 10:30a.m.

Fair Return and Value Subcommittee Presentation

Co-Director's Introduction: Mathew Adams

Oil and Gas Payor Handbook: Gabrielle Gerholt

Index Pricing: Pat Noah

Marketable Conditions: Stella Alvarado

Coal Benchmarks: Matthew Adams

Audit: Greg Morby, Chevron

- OMT Update: Shawna Schimke, ONRR

10:30a.m. – 12:15p.m.

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- **OMT Update: Shawna Schimke, ONRR**

10:30a.m. – 12:15p.m.

Lunch

12:15p.m. – 1:15p.m.

Planning, Analysis, & Competitiveness Subcommittee Presentation

Co-Director's Introduction:

Onshore Oil & Gas: Kathleen Sgamma, Western Energy Alliance

Offshore Oil & Gas: Patrick Noah, ConocoPhillips Company

Alaska: John Crowther, State of Alaska

Coal: Matthew Adams, Cloud Peak Energy

Non-Fossil and Renewables: Colin McKee, State of Wyoming

Studies: Emily Kennedy Hague, American Petroleum Institute

1:15p.m. – 3:00p.m.

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Appendix A

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1:15p.m. – 3:00p.m.

Break

3:00p.m. – 3:15p.m.

Public Comment

3:15p.m. – 3:45p.m.

Committee Voting

3:45p.m. – 4:30p.m.

Tribal Affairs Subcommittee

Recommendation	Accept	Reject
Change Subcommittee name from Tribal Affairs Subcommittee to Tribal Energy Subcommittee	X	

3:45p.m. – 4:30p.m.

Return &Value Subcommittee

Appendix A

Recommendations	Accept	Reject
Create "evergreen" handbook which can be updated regularly and link to recent rules and decisions	X	
Pursue rulemaking to define simplified index price rules for Federal gas	X	
Exclusively with regard to federal lands, Department of the Interior resolve an ambiguity in its current regulations by publishing a proposed rule to amend the regulation at 30 C.F.R. 1202.151(b) to reexamine language specific to the boosting of residue gas	X	
Reinforce the principle that arm's length transactions are the best indication of market value by amending the regulation at 30 CFR 1206.257(c)(2)(i) to read: "The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contact (or other disposition by other than an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under comparable arm's-length contracts for sales, purchases, or other dispositions of like-quality coal in the area; including arm's length sales from the lessee."	X	
Consider a Secretarial Order / Dear Payor Letter indicating that a company's own arm's length sales are preferential under coal benchmark 4.	X	
Updated Solids Handbook indicating the same	X	

3:45p.m. – 4:30p.m.

Analysis, & Competitiveness Subcommittee

Appendix A

Recommendations	Accept	Reject
Reduce timelines for project approval, including APDs, ROWs, sundries, lease nominations and unit agreements	X	
Limit the federal nexus of wells without a majority federal interest	X	
Improve land use planning and NEPA Approvals	X	
Revise and simplify Onshore Orders, 3, 4 and 5 to ensure more equitable and timely implementation	X	
Set future OCS lease sale s through 2024 at 12.5% royalty rate	X	
Revise, clarify and simplify process for granting varying royalty rate for declining or particularly costly fields	X	
Increase offshore acreage available for oil and natural gas leasing	X	
The Department of the Interior should contract for a study to compare the U.S GOM, Guyana and Mexico of royalty rates, total revenue, block sizes and recent lease sales (last 3 years)	X	
The Department of the Interior should contract to update the IHS-CERA 2011 study, for both onshore and offshore data	X	
Interior should conduct a lease sale in the 1002 area of ANWR ahead of statutory deadlines	X	

3:45p.m. – 4:30p.m.

Wrap-up, Timeline, Conclusions, and Next Steps

Adjourn

4:30p.m. – 5:00p.m.

Tribal Affairs Subcommittee

Presentations of the Tribal Energy Subcommittee Planned for the Meeting of the Royalty Policy Committee in Houston on February 28, 2018

1. Leading Committee vote on the proposed name change of the Subcommittee, from "Tribal Affairs Subcommittee" to "Tribal Energy Subcommittee"

2. Status Updates for Future Recommendations to be Made by the RPC

   Updates will be given on the work of each of the following four working groups:

   a. TERA (Tribal Energy Resource Agreements) Working Group Update

      The TERA working group is addressing specific changes that DOI needs to provide for additional guidance on the activities that would be considered inherently federal functions so that tribes would utilize TERAs. It will enhance the definition on what constitutes inherently federal functions. For example, it will determine whether ESA compliance can be implemented by tribes through a TERA or otherwise.

   b. Model Statute Working Group Update

      The Model Statute Working Group is exploring what a model Congressional statute might look like and how it would improve upon current statutes. (See Appendix A below for background.)

   c. 1938 Act Working Group Update

      1938 Act Working Group is considering what congressional changes to the 1938 Act are necessary so that tribes can take control over mineral leasing. (See Appendix B below providing background on the 1938 Act.)

   d. Taxation Working Group Update

      The Taxation Working Group is analyzing necessary updates to the Indian Trader Regulations to eliminate the economic barriers to energy development on tribal land. (See Appendix C, which provides a Briefing Summary of this analysis.)

Appendix A: Background on the Model Congressional Statute Working Group

Concept

Promoting both tribal self-determination and economic self-sufficiency through the development of natural resources, including minerals, has been the goal of the federal government since at least 1934. In the intervening 80+ years, three significant federal statutes and numerous other more narrowly focused laws have all sought to achieve those objectives, with varying degrees of success.

Despite a range of current statutory options, including the Indian Mineral Leasing Act, the Indian Mineral Development Act, and the Indian Tribal Energy Development and Self-Determination Act, Indian tribes continue to express concern about their ability to pursue development of their energy resources. A 2015 Government Accountability Office report (available here) highlighted many of these concerns, including the complexity of the regulatory and bureaucratic framework involved in tribal energy development. Although the challenges presented by this framework vary, the GAO report highlights the central role that the federal government plays in reviewing and approving various parts of the tribal development transaction.

As a result of the federal role in Indian tribal energy development (the extent of which varies depending on the specifically applicable statute), other federal laws are implicated, such as the National Environmental Policy Act and Endangered Species Act, and the National Historic Preservation Act, and development transactions may suffer from federal funding shortfalls or administrative issues.

Notwithstanding the potential problems posed by the federal government's role in Indian tribal energy development, the federal government's trust responsibility to Indian Country remains a central tenet of federal Indian law.[1] The federal government's role in tribal energy development is rooted in this responsibility and the trust obligation remains a central aspect of federal-tribal relations.

Therefore, any "Model Congressional Statute" regarding tribal energy/mineral development must balance the complications of federal involvement in the development process with the potential consequences of limiting federal involvement. In addition to pursuing other tasks, the Tribal Energy Subcommittee established a workgroup to explore what such a statute might look like and how it would complement existing statutory structures rather than replace them.

Work Product

The workgroup recognizes the challenge of the legislative (rather than executive agency or regulatory) focus of its objective. The workgroup aims to solicit input from the Tribal Energy Subcommittee and other stakeholders in order to maximize the efficacy of and support for any final proposal. The workgroup aims to begin with a list of principles or concepts that interested parties believe must be addressed in any comprehensive model statute. The workgroup has already begun compiling research and background materials to compile the first draft of such a list and proposes the following concepts for further discussion among interested parties:

[1] *See*, *e.g.*, 25 U.S.C. § 5601.

Initial Draft List of Concepts to be Considered in Developing a Model Statute.

- Expressly recognizing tribal sovereignty and authority over tribal lands and resources;
- The distinct status of each federally recognized Indian tribe, including differences among governmental structures, land/property status (including subsurface interests), and technical capacity;
- Drafting a statute that avoids a "one size fits all" legislative approach;
- Developing avenues for the federal trust responsibility to be both responsive to Indian tribal energy development and other tribal priorities while still providing a robust federal role to serve and protect the best interests of tribes;
- Ensuring and respecting the need for tribal consent and self-governance, whether implemented through an opt-in/opt-out or individual tribal negotiations; and
- Allocating between an Indian tribe and the federal government any potential liability that may result from resource development decisions.

Timeline

The workgroup, with the input of the Subcommittee and federal partners, aims to develop a draft legislative concept proposal for a subsequent meeting of the full RPC. Therefore, the workgroup proposes the following timeline:

January 22-February 9: Survey and solicit input from Tribal Energy Subcommittee on principles/concepts.

February 9-23: Tribal Energy Subcommittee reviews draft principles prior to full RPC meeting make any addition to preliminary principles/concepts

February 28: Present proposed principles to full RPC for consideration and input.

April: Draft legislative proposal

May: Circulate draft proposal for review by Tribal Energy Subcommittee and revise

June 5-6: Present draft proposal to full RPC for consideration

Appendix B: Background on the 1938 Act

Amendment to the Act of May 11, 1938
The U.S. Supreme Court has repeatedly recognized tribal sovereignty in court decisions for more than 150 years. In 1831, the Supreme Court agreed, in Cherokee Nation v. Georgia, that Indian nations had the full legal right to manage their own affairs, govern themselves internally, and engage in legal and political relationships with the federal government and its subdivisions.

In 1942 Supreme Court Justice Felix Cohen wrote, "Indian sovereignty is the principle that those powers which are lawfully vested in an Indian tribe, are not delegated powers granted by express acts of Congress, but rather inherent powers of a limited sovereignty which can never be extinguished."

Today, tribal governments still exist for the same reasons they were originally founded: To provide for the welfare of the Indian people.

Appendix C: Taxation Working Group of the Tribal Energy Subcommittee

Briefing Document on the Economic Barriers to Energy Development in Indian Country

1. Dual Taxation

Legal Background on Dual Taxation

Federal courts currently apply the "Bracker balancing test" to determine whether State taxation of non-Indians engaging in activity or owning property on the reservation is preempted.[2] The balancing test requires a particularized examination of the relevant state, Federal, and tribal interests. In 2012 the Department of the Interior (DOI) determined that, in the case of leasing on Indian lands, the Federal and tribal interests are very strong, and so when DOI updated its regulations governing leasing on trust/restricted land, it included the provision: "162.017(b). Subject only to applicable Federal law, activities conducted under a lease of trust or restricted land that occur on the leased premises are not taxable by states or localities, regardless of who conducts the activities."[3] However, that provision does not establish a bright-line rule that activities conducted under a lease of trust or restricted land are not taxable by States or localities. Rather, the provision is intended to influence the decision in the direction of no state taxation when a Federal court applies the Bracker balancing in any given case. Consistent with DOI's intention, there may be individual instances where a court determines that a state and locality cannot tax activities on leased trust/restricted property. Nevertheless, the mere uncertainty that the court could rule in the other direction, by allowing state and local taxation of these activities on Indian land, is often enough to drive away economic development in such areas.

In spite of Bracker balancing, however, Indian tribes have a recognized legal right to tax economic activity in Indian country, which has been upheld in a number of Supreme Court cases, including energy resource development (e.g. *Merrion*, *Kerr Magee*). In 1987 the Supreme Court handed down a decision in the *Cotton Petroleum* case which also upheld state authority to tax non-Indian oil and gas production from leases on Indian trust Land.

A Proposed Solution the Problem of Dual Taxation

DOI has moved to limit dual state taxation in business leases and rights of way—see 25 CFR Parts 162 and 169. A similar regulatory fix should be undertaken to eliminate dual taxation in the area of the energy development and affirming the tribes' exclusive right to tax energy development on trust land. Recently the DOI solicited public comments on potential updates to the Indian Trader Regulations. These DOI regulations manage taxation on Indian lands.

2. Natural Gas Flaring

Background

[2] This balancing test is based on White Mountain Apache Tribe v. Bracker, 448 U.S. 136, 143 (1980).
[3] Residential, Business, and Wind and Solar Resource Leases on Indian Land Rule, section 162.017.

Indian tribes with significant oil and gas development are losing millions of dollars in royalty and tax revenue as a result of flared natural gas. The BIA has delegated authority to the BLM to regulate flaring on Indian land (25 CFR §§ 211.4, 212.4, 225.4). The problem is the BLM is a public land regulatory agency, BLM's current flaring regulations are inefficient and are not designed to adequately protect the interests of tribes and Indian mineral owners. The Secretary cannot fulfill his trust responsibility by lumping the federal trust responsibility together with federal public land policy. The two are distinctly separate and, in many cases, diametrically opposed. Tribes are in the best position to determine how to deal with the flaring problem, in consultation with their Indian mineral owners and industry partners.

A good part of the flaring problem is the lack of infrastructure to move gas from the well head to processing facilities or transmission lines, which in turn creates a better market for the gas. Affirming tribes' exclusive taxing authority by eliminating the threat of dual taxation would generate additional tax revenue for tribes to allow them to invest in needed physical and governmental infrastructure to process rights of way for pipelines and enhance the recovery and marketability of gas. This in turn generates more royalty and tax revenue for tribes and Indian mineral owners and more revenue for lessees.

Proposed Solution

DOI should support tribal self-government by recognizing and deferring to tribes as the primary regulatory authority, not the BLM. DOI regulations should be revised to give proper deference to the regulatory authority of the tribes and eliminate dual taxation to allow tribes to generate sufficient tax revenue to reinvest in the infrastructure that is needed to capture and create better markets for their natural gas resources.

3. Property Tax Transportation Allowance

Background

Current regulations of DOI's Office of Natural Resources Revenue allow property taxes as a transportation cost in the royalty valuation analysis. This results in a reduction in the value of oil and gas prior to the calculation of the mineral owner's royalty which equates to a lower royalty payment. Allowing state property taxes to reduce the Indian mineral royalty equates to an indirect tax on the royalty interest, which is a violation of Federal law.

Proposed Solution

DOI should eliminate the property tax allowance in the Federal royalty valuation regulations.

4. Restrictions on Tribal Tax Exempt Bonds

Background

One of the most important tools the government has to promote economic development is the ability to issue tax exempt bonds. Tax exempt bonds can be an important tool in promoting Indian energy development, especially the development of facilities to enhance the value of energy resources, such as refining and processing facilities, gathering and transportation facilities, etc. Under the Indian Tribal Governmental Tax Status Act, tribes are authorized to issue tax exempt bonds to finance some tribal infrastructure projects. However, current regulations restrict the authority of tribes to issue a tax exempt private activity bond when state and local governments are not so constrained.

Solution

The U.S. government should remove the regulatory restrictions on private activity bonds to allow Indian tribes to issue tax exempt bonds to the fullest extent allowed under the existing Act and, if necessary call on Congress to amend the Act to allow for the issuance of tax exempt private activity bonds to promote Indian energy development.

Tribal Affairs / Tribal Energy Subcommittee

Of the DOI Royalty Policy Committee

Report and Recommendations

Houston, Texas
February 28, 2018

Proposed Name Change from "Tribal Affairs Subcommittee" to "Tribal Energy Subcommittee"

Reasons:

1. **The term "tribal affairs" could be rather ambiguous and encompass a wide range of topics, but our subcommittee is interested only in exploring topics that relate to tribal energy development.**
2. **"American energy dominance" is a principle that is receiving a great deal of attention and interest these days, and our name change will help promote the concept as it relates to tribes.**
3. **As the Royalty Policy Committee was established to promote the energy independence of the United States and to ensure fair value to the United States through royalty payments, and nearly all of the royalties that are collected by tribes involve energy production, this is an opportune time to address impediments to energy development on tribal lands..**

Focus Areas

1. **To develop new options for Congress to consider so that tribes can take control over mineral leasing**

2. **To develop Department of Interior (DOI) changes to the regulations that implement the Indian Tribal Energy Development and Self-Determination Act of 2005 so that tribes can control more aspects of mineral leasing through the option of Tribal Energy Resource Agreements (TERAs)**

3. **To develop DOI changes to the Indian trader regulations to eliminate barriers to energy development in many tribal areas**

Working Groups

1. **TERA**
2. **Model Statute**
3. **1938 Act**
4. **Taxation**

TERA Working Group Update

1. **Addressing specific changes that DOI needs to make for additional guidance on the activities that would be considered “inherently federal functions” so that tribes would utilize TERAs.**

2. **Enhancing the definition on what constitutes inherently federal functions.**

3. **For example, determining whether ESA compliance can be implemented by tribes through a TERA or otherwise.**

4. **Additional details are provided in a separate slide presentation.**

Model Statute Working Group Update

1. **Exploring what a model Congressional statute might look like and how it would improve upon current statutes.**

2. **Appendix A provides background on this effort.**

1938 Act Working Group Update

1. **Considering what Congressional changes to the 1938 Act are necessary so that tribes can take control over mineral leasing.**

2. **Appendix B provides background on the 1938 Act.**

Taxation Working Group Update

1. **Analyzing necessary updates to the Indian Trader Regulations to eliminate the economic barriers to energy development on tribal land.**

2. **Appendix C provides a Briefing Summary of this analysis.**

Preliminary Recommendation: TERA

Tribal Energy Subcommittee

Royalty Policy Committee

TERAs: Tribal Energy Resource Agreements

- Authorized through the Indian Tribal Energy Development and Self-Determination Act, Title V of the 2005 Energy Policy Act
- Authorizes Secretary of the Interior and a tribe to enter into a TERA
- Authorizes tribe to develop and approve its own leases, business agreements, or rights-of-way for a broad range of activities related to development of energy resources **without requiring secretarial approval** for each lease, agreement, or right-of-way

No Tribe Has Yet to Enter into a TERA: some of the hurdles

- Undefined limitation on the scope of TERA: a tribe cannot assume “inherently federal functions”
- Tribal Environmental Review Process, similar to the federal National Environmental Policy Act process
- Unknown funding for tribes to engage in NEPA like compliance
- Demonstration of tribal capacity
- Opportunity for Review and Comment of TERA

As of 2015, at least six (6) tribes had requested preapplication meetings to discuss establishing a TERA

Preliminary Recommendation: 2015 GAO Report Indian Energy Development

- For the Department of the Interior to provide additional energy develop-specific guidance on provisions of TERA regulations that tribes have identified as unclear.
- Specifically:
  - TERA regulations authorize tribes to assume responsibility for energy development activities that are not "inherently federal functions."
  - DOI has not provided guidance on what are non inherently federal functions
  - Lack of guidance prevents tribes from knowing what it can and cannot perform and where to build capacity

Preliminary Recommendation

- For the Department of the Interior to enhance the definition of what constitutes inherently federal functions and what functions tribes will be able to perform under a TERA.

Preliminary Recommendation is Provided because:

- Development of energy resources on tribal lands is critical to develop energy independence of the United States.
- Clarifying TERA is wholly within the authority of DOI to do.
- TERA is an existing tool that in theory can be refined relatively quickly so that it can fully utilized and tested as a tool for enhancing tribal flexibility in energy development.

TERA Work Group

- John Andrews
- Bidtah Becker
- Kathleen Sgamma
- Chris Stolte

Fair Return and Value Subcommittee

Fair Return and Value Subcommittee
Oil and Gas Payor Handbook
February 28, 2018

1. Background

The Secretary of the Interior has been granted authority by Congress to inspect, collect, account for and audit oil and gas royalties from lease sites on Federal and Indian lands.[1] This authority has been delegated to the Office of Natural Resources Revenue (ONRR) which "collects, accounts for, and verifies natural resource and energy revenues due to States, American Indians, and the U.S. Treasury."[2] In order to assist Federal and Indian oil and gas lessees, the Minerals Management Service[3] published the first Oil and Gas Payor Handbook (Payor Handbook) in 2000. The Payor Handbook was last updated in February of 2001 and since then a variety of decisions have been announced pertaining to the payment of royalties as well as new regulations and statutes. Due to the need to update the Payor Handbook to reflect current law, ONRR started reviewing it with the idea of revising the Handbook at about the same time as the formation of the Royalty Policy Committee.

2. Payor Handbook Outline Review and Suggestions

Record Keeping and Information Protection

- ONRR should alert payors to how ONRR protects their information
- ONRR should alert payors to the FOIA process and ways that ONRR protects proprietary data in that process

Definitions Section

- ONRR's definitions have legal significance and ONRR should link the definitions to the CFR.

Valuation Basics

- Point of Royalty Settlement
  - Terminology can be confusing for some producers. For example, Point of Royalty Settlement can be confused with allocation meter, FMP, point of measurement, or sales meter.

- Beneficial Use
  - ONRR may need to reevaluate this section in light of new BLM regulations.

- Marketable Condition
  - Add examples

[1] 29 USCA § 1701 and § 1711
[2] https://www.onrr.gov
[3] The Minerals Management Service was the predecessor to ONRR

- Because the Payor Handbook was published before the *Devon* decision, ONRR should address marketable condition and unbundling here at a high level and reserve the more nuanced items for the appropriate gas and oil sections.
- ONRR should add a section on the lessee's duty to market production separate from, but linked to, the marketable condition section.

- Quantity/Quality
  - ONRR should incorporate wet versus dry gas reporting and add sample calculations or link to the Minerals Revenue Reporter Handbook

Federal Oil Valuation

- Valuation Determinations
  - ONRR should distinguish between guidance and determinations by adding a table that can be copied into or linked to for each commodity

Oil Transportation Allowances and Adjustments

- Oil Differentials
  - ONRR should research industry terminology relating to differentials to ensure readers understand what is properly deductible

- Transportation Allowances without arm's-length contracts
  - Update with recent ONRR training examples

Federal Gas Valuation

- Unbundling and UCAs
  - Section may move from this location

- Percentage of Index and/or Percent of Retainage Example
  - ONRR is planning on creating a POP Contracts Dear Reporter Letter that will address some of these issues.

- Tariff (Transportation and Processing)
  - only applies to transportation, not processing

- Guidance for pipeline fuel, gas plant fuel, unbundling UCA
  - ONRR should separate into the following sections:
    - Fuel (to include all categories of fuel—pipeline, gas plant, etc.)
    - Unbundling
    - UCAs
  - ONRR should make a distinction between beneficial use fuel, plant fuel, and pipeline fuel.
  - ONRR incorporate electricity within the UCA section of the Handbook.

Indian Oil and Gas

- ONRR is planning to separate the Indian Oil and Gas section into its own Handbook. It will have unique sections as to Indian payors (Major portion, e.g.) along with sections identical to those provisions in common with general Federal Oil and Gas royalty requirements.

- Fiduciary Trust responsibilities
  - Links should direct users to the source material used for the presentations
  - Add history
  - Add Indian Mineral Development Act (IMDA) agreements
  - Add non-standard lease section

- Indian Dual Accounting and Major Portion Sections:
  - Add detailed, comprehensive examples with reporting
  - ONRR should clearly instruct Industry on timing surrounding Indian gas reporting
  - ONRR should include sample lease language
  - ONRR should incorporate text, visuals, and sample problems into the Handbook to accommodate different styles of learning.

- Major Portion
  - ONRR should add information on lease language
  - ONRR should add a map of the Index Zone areas in the gas section
  - ONRR should add a table illustrating Indian form filing requirements.

3. Recommendations

The recommendations with regard to updates to the Payor Handbook are:

- The Department of Interior should create separate Federal and Indian Payor Handbooks.
- The Department of Interior should engage users of the Payor Handbook to support ONRR in the re-write of the Handbook.
- The Department of Interior should invest in a process by which 'evergreen' Handbooks can be created and updated as regulations change.

Fair Return and Valuation Committee

Index Pricing Working Group

Summary Recommendation

The repealed 2017 Federal valuation rule ("Valuation Rule") included an index pricing provision for Federal gas production. While energy companies generally supported the concepts of an index price, the specific price provisions contained within the Valuation Rule were not widely supported due to concerns that (1) the highest reported price was unachievable and reflected index points not representative of how the gas was actually marketed; (2) transportation cost deductions were unreasonably low; and (3) the resulting price could only be used for non-arms-length sales types.

The Index Pricing Working Group ("IPWG") is charged with exploring the potential to make recommendations for an index price that addresses the issues associated with the index pricing provision in the repealed Valuation Rule and more effectively achieves a simple, certain, clear and concise index price solution.

The IPWG noted the relative administrative ease involved with use of the 2000 Indian Gas Valuation Rule, and its recommendation generally relies on that approach. It was also noted within IPWG discussions that the adoption of a simplified index price has the potential to address many of the separate issues regarding "marketable condition" currently consuming significant resources.

RECOMMENDATION: Pursue rulemaking to define simplified index price rules for Federal gas. Key factors to be addressed by this rule would be:

- A standardized average single (per defined geographic area) price acceptable to both industry and DOI/ONRR
- Calculated (by ONRR) from generally accepted index price publications or other acceptable market-sensitive source
- Apply price to wellhead (or royalty measurement point) MMBTUs
- Incorporate reasonable geographically sensitive transportation deductions
- Apply price to all Federal gas sales types

Additional factors for consideration in the rulemaking process:

- Should the utilization of the price be mandatory or optional by payors?
- Should the "bump" approach of Indian Alternate dual accounting be utilized?

Fair Return and Value Committee
Marketable Condition Work Group
February 12, 2018

1. Background on Marketable Condition

A lessee is required to put gas into marketable condition once at its own expense. ONRR regulations define marketable condition as "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchase under a sales contract typical for the field or area." 30 C.F.R. 1206.151 (federal gas), 1206.171 (Indian gas). When raw or wet gas is produced in the field, then travels by pipeline to a gas processing plant, where the heavier components are extracted from the wet gas stream as liquids, and the remaining dry or residue gas is delivered into a mainline pipeline, ONRR uses the requirements the mainline pipeline imposes for entry into its pipeline as the measure of marketable condition. Courts have affirmed ONRR's use of mainline pipeline requirements as the measure of marketable condition for residue gas.

To meet a mainline pipeline's requirements, a lessee may be required to compress it gas to a higher pressure, dehydrate the gas to reduce its water content, and "sweeten" the gas by reducing its carbon dioxide (CO_2) and hydrogen sulfide (H_2S) content. Often, a lessee does not incur or pay a separate fee to compress, dehydrate, and sweeten its gas. Instead, a pipeline transporting gas from the field to the processing plant may provide not only transportation services, but also compress and dehydrate the gas for a single fee that covers all its services. And a processing plant may not just process the gas to extract liquids, but also compress, dehydrate, and sweeten the gas for a single fee that covers all its services. In calculating and paying royalties, a lessee may not deduct the costs to compress, dehydrate, and sweeten its gas as necessary to put the gas into marketable condition, but it may deduct transportation and processing costs, subject to certain limits. As a result, a lessee must allocate the costs or fees it pays for services rendered between the field (or royalty measurement point) and the tailgate of a processing plant between non-deductible costs to put gas into marketable condition and deductible costs for transportation and processing. ONRR and industry frequently disagree on the need to allocate costs as well as on acceptable methods for allocation.

2. Compression Required for Marketable Condition or Otherwise

a. **Three disputes.** For at least three reasons, ONRR and industry currently disagree on the compression a lessee must provide at its own expense to put gas into marketable condition:

- **Is boosting residue gas part of the marketable condition requirement or a separate requirement?** ONRR interprets its regulation on compressing or "boosting" residue gas to mean that even if a lessee carries the full cost to meet the pressure requirements for marketable condition before its gas enters a processing plant, the lessee still must pay the full cost to compress or boost residue gas at or after the plant. Industry argues that in many instances

ONRR's interpretation of its regulation requires a lessee to pay the full cost to compress its gas twice through the same pressure range when it should have to pay the full cost only once.

- **Achieve marketable condition or sum to marketable condition?** ONRR does not allow a lessee to deduct any compression costs as gas moves from upstream to downstream until the gas reaches (or "achieves") the pressure requirement of a mainline pipeline, and then also disallows the cost to compress or boost residue gas. Industry argues that at most it must pay the full cost to compress its gas once from the pressure in the field to marketable condition, but if it compresses the gas more than once through any portion of the pressure range between the royalty measurement point and the mainline pipeline, it may choose which compression to deduct and which compression to not deduct to meet its marketable condition requirements.

- **Compression needed to put NGLs into marketable condition?** A pipeline that runs from the field to a processing plant may compress the raw or wet gas stream. At the processing plant, liquids are extracted from the wet gas stream, resulting in residue gas and natural gas liquids (NGLs). In reporting and paying royalties, the lessee allocates its transportation cost or fee between residue gas and NGLs, then deducts separately from residue gas value and NGL value the transportation fee, except that portion of the fee attributable to compression and dehydration needed to put gas into marketable condition. Even though the mainline pipeline only carries the residue gas to market, ONRR uses that pipeline's pressure requirements to determine the non-allowable portion of the transportation fee for both residue gas and NGLs. Industry argues that the mainline pipeline pressure requirements may be relevant to determine the non-allowable portion of the transportation fee for residue gas, but not for NGLs, as NGLs are delivered into a different pipeline with a much lower pressure requirement.

b. <u>Analysis of boosting dispute and recommendation</u>.

ONRR's regulation on boosting residue gas applies only to federal gas. It currently reads:

> (b) A reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant, <u>but no allowance shall be made for boosting residue gas or other expenses incidental to marketing, except as provided in 30 CFR part 206.</u> In those situations where a processing plant processes gas from more than one lease, only that proportionate share of each lease's residue gas necessary for the operation of the processing plant shall be allowed royalty free.

ONRR interprets and applies this regulation to require a lessee to pay the full cost to compress or boost residue gas, regardless of whether the lessee has otherwise met the pressure requirements for marketable condition. Also, ONRR has not recognized any exception in part 206 or elsewhere to date. Industry disagrees with ONRR's interpretation and application of the boosting regulation for several reasons:

- The language on boosting, when viewed in the content of paragraph (b) and the section and part in which paragraph (b) appears, speaks to royalty-free use of gas, not the costs of capital, operation, and maintenance of a booster compressor.

- The only rationale that supports disallowance of a booster compressor is the lessee's obligation to put gas into marketable condition at its own expense. If ONRR disallows a deduction for the capital, operation, and maintenance of a booster compressor, it should allow upstream compression costs covering the same pressure range as the booster compressor, as a lessee must put gas in marketable condition only once.

- ONRR cannot apply a regulation that includes exception language as if there is no exception. There is an exception that allows a transportation deduction for "supplemental compression" in 30 C.F.R. 1206.157(f)(9). Supplemental compression, though not defined in the regulations, is any compression beyond that needed to put gas into marketable condition once.

- While the regulation on boosting residue gas applied to both federal and Indian gas from 1942 to 1999, in 1999 ONRR amended its Indian gas valuation regulations, and deleted any reference to boosting as a unique type of compression that must be disallowed regardless of whether a lessee has already met the requirements for marketable condition.

ONRR's interpretation and application of the boosting regulation may increase a lessee's royalty obligation, and hence revenues to the federal government, but:

- It requires lessees to allocate more transportation and processing fees between allowable and non-allowable deductions than would be the case if the boosting regulation was repealed and boosting residue gas was treated just like every other form of compression. Each cost allocation is difficult, expensive, and subject to dispute.

- It generates numerous appeals to ONRR's Director, the Interior Board of Land Appeals, and federal courts. These appeals may continue for a number of years absent resolution of the issue through new rulemaking.

- If this matter is left for resolution though the courts and industry ultimately prevails, lessees may be entitled to amend their royalty reports to lower their royalty obligations for the six preceding years, at significant administrative cost to both ONRR and industry, as well as loss of revenues to the federal government.

Recommendation #1. The voting members of the marketable condition work group recommend that the Department of the Interior resolve an ambiguity in its current regulations by publishing a proposed rule to amend the regulation at 30 C.F.R. 1202.151(b) to remove language specific to the boosting of residue gas:

> **Revise 30 C.F.R. 1202.151(b) to read as follows:**
>
> A reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant. In those situations where a processing plant processes gas from more than one lease, only that proportionate share of each lease's residue gas necessary for the operation of the processing plant shall be allowed royalty free.

3. Unbundling vs Standardized Table for Calculating Allowances and Disallowances

The marketable condition work group continues its efforts to resolve the other compression issues identified above. It is also evaluating whether ONRR-generated plant-specific and region-specific unbundling cost allocations (UCAs), together with any index-based valuation formula the RPC may recommend, will resolve the remaining marketable condition issues. Because they may not, and also for possible use as a component of any index-based valuation formula, the marketable condition work group is evaluating whether to develop and recommend a standardized table a lessee may or must use to calculate the non-allowable portion of a transportation or processing fee to cover its costs to compress, dehydrate, and sweeten gas to marketable condition.

ONRR continues to make progress in generating UCAs for gas plants and transportation systems. ONRR has unbundled and published UCAs for approximately twenty-five gas plants—some with included transportation systems. ONRR plans to continue its efforts and provide additional UCAs that are not limited to specific plants, but cover either geographic regions or categories of plants ("standardized UCAs"). ONRR's experience with unbundling is allowing it to streamline the process.

For those plants where there is not an ONRR-generated UCA, and even where there is an ONRR-generated UCA, but a lessee concludes that an ONRR-generated UCA disallows too much of its transportation or processing costs, the lessee may or must unbundle itself, though with difficultly, particularly where it transports or processes its gas under an arms-length transportation or processing contract. In these instances, a lessee often finds unbundling:

- Very difficult to perform due to lack of information except on an estimated basis which creates disagreements.
- Very burdensome and costly to calculate an estimate, and burdensome to audit; many companies are enlisting consultants.
- Legal differences exist between ONRR's unbundling method resulting in ONRR disallowing transportation or processing costs even when the lessee has otherwise already put the gas in marketable condition at its own expense.
- ONRR often generates a single UCA for a specific plant (and possibly the connected transportation system), which is a one-size-fits-all approach, but gas that enters the plant or system may differ as to the amount of compression, dehydration, and sweetening it requires, and may have to travel more miles through more expensive pipe than some other gas entering the same plant or system.
- ONRR's standardized UCAs have the same accuracy and legal issues as ONRR's plant-specific unbundling – this is a nice attempt, but it may not be the answer due to the inherent problems and limitations of calculations.

Standardized Table for Calculating Allowances /Disallowances

A standardized table brings certainty and administrative simplicity and would provide an option for using a table rather than unbundling when ONRR-generated UCAs are not available. ONRR would calculate and post these rates for costs to be carved out of otherwise-allowable transportation and processing fees so as to cover the cost to compress, dehydrate, and sweeten gas to marketable condition. The rates would be based upon the difference between the lessee's gas at the royalty measure point and marketable condition requirements, and possibly differences in pipeline and plant technologies and volumetric throughput, as well as other factors. Producers would consult this table to determine the total compression, dehydration, and sweetening costs deemed necessary to place gas into a marketable condition and hence not deductible as a part of a transportation or processing allowance.

Path Forward: The marketable condition work group will further discuss and evaluate a standardized table to calculate allowances and disallowances, building on the many hours the work group has spent to date. Evaluation may include an economic analysis to support a future recommendation.

Fair Return and Value Committee
Coal Valuation Work Group
February 27-28, 2018

1. Background on Coal Valuation Benchmarks

The coal valuation benchmarks are promulgated under the Mineral Leasing Act of 1920. As such, a background discussion of both law and regulation is beneficial to understand the framework.

Mineral Leasing Act of 1920

When Federal royalty is based on the value of the mineral, it has always been based on the value of the mineral "at the mine." When the Mineral Leasing Act of 1920 (MLA), 30 U.S.C. §§ 181-287, was first enacted, the royalty on most minerals (but not coal) was set as a percentage of the value of the mineral. *See, e.g.,* 41 Stat. 437, 443 (1920) (royalty for oil and gas "shall not be less than 12 1/2 per centum in amount or value of the production"). For the value-based royalties, the legislative history is replete with evidence that Congress and the Department of Interior intended the value to be determined "at the mine." For example, for Federal phosphates and phosphate rock reserves, the legislative history provides that value is based "at the mine." *See, e.g.*, 53 CONG. REC. 1098 (1916) (royalties shall be based on "the gross value of the output of phosphates or phosphate rock at the mine"); H.R. REP. No. 17, 11 (1916) (Secretary Lane's report provides that phosphate royalty should be based on "the gross value of the output at the mine"); 58 CONG. REC. 4055 (1919) ("the gross value of the output of phosphates or phosphate rock at the mine"). The MLA legislative history is the same for potassium and sodium. *See, e.g.*, H.R. REP. No. 17, 8 (1916) (potassium or sodium royalty is based on "the value of the output at the point of production").

In 1920, royalty on coal under the MLA was based on a cents per ton calculation that had little to do with the value of the coal. 41 Stat. 437, 439 (1920) (royalty for coal "shall not be less than 5 cents per ton of two thousand pounds"). It was not until the Federal Coal Leasing Act Amendments of 1976 (FCLAA), Pub. L. 94-377, 90 Stat. 1083, that Congress changed the royalty basis for coal to a percentage of its value. H.R. REP. No. 94-681, 81 (1975) ("the revised language changes the minimum royalty from $.05 per ton to twelve and one half per centum of the value of the coal, except that the Secretary may determine a lesser amount for underground mining operations").

When Congress adopted a value-based royalty for coal, it reiterated its intent that when royalty is based on the value of the mineral, the value is determined "at the mine." The legislative history for the FCLAA amendments regarding advance royalty payments provides that standard royalty rates are based on "the gross value of the coal at the mine." *See* Senate Rep. No. 94-296, 49 (1976). One year after the FCLAA was enacted, Congress passed the Abandoned Mine Reclamation Fund, Pub. L. 95–87, 91 Stat. 445 (1977), which is administered by the Secretary of the Interior and imposes a reclamation fee on all coal mines. The fee is assessed as a percentage of "the value of the coal at the mine." 30 U.S.C. § 1232.

Consistent with legislative and Departmental intent, courts since the 1940s have held that the government's royalty interest is limited to the value of production at the mine. *United States v. Gen. Petroleum Corp. of Cal*., 73 F. Supp. 225, 258 (S.D. Cal. 1946) (gas royalty obligation is determined "at the leases, that is before it left the field"), *aff'd sub. nom. Cont'l Oil Co. v. United States*, 184 F.2d 802, 820 (9th Cir. 1950) ("royalties were to be calculated at values at the wells, not at the . . . destination"); *Indep. Petroleum Ass'n of Am. v. Armstrong*, 91 F. Supp. 2d 117, 119 (D.D.C. 2000) ("the essential bargain embodied in federal and Indian leases entitled the lessor to a royalty based upon the value of production at the lease"), *aff'd in part, rev'd in part on other grounds Indep. Petroleum Ass'n of Am. v. DeWitt*, 279 F.3d 1036 (D.C. Cir. 2002).[1]

Further, courts have consistently invalidated any Department of Interior regulation or policy that is contrary to the MLA's intent. *See, e.g., Plateau, Inc. v. Dep't of Interior*, 603 F.2d 161, 164 (10th Cir. 1979) (invalidating regulation governing Federal royalty oil because, based on legislative history, the court found the regulation "goes beyond what Congress authorized"); *Marathon Oil Co. v. Andrus*, 452 F.Supp. 548, 552-53 (D. Wyo. 1978) (invalidating agency oil and gas royalty policy as conflicting with "the legislative history of the Mineral Leasing Act, together with its many enactments and re-enactments"); *Indep. Petroleum Ass'n*, 91 F. Supp. 2d at 125 (invalidating MMS regulation which disallowed transportation deduction for unused pipeline firm transportation charges, which MMS claimed were not "actual" costs incurred to move gas downstream, because the disallowance led to a definition of "value" inconsistent with the MLA's intent that royalty should be based at the lease), *rev'd on other grounds,* 279 F.3d at 1042-43.

Coal Valuation Regulations

The current Federal and Indian coal regulations have been in effect since 1989. *See Revision of Coal Product Valuation Regulations and Related Topics,* 54 Fed. Reg. 1492 (January 13, 1989). Under the existing regulations, if the lessee sells coal under a non-arm's-length arrangement, the regulations prescribe an ordered series of "benchmarks" that look to outside indicia of market value. The value of the coal is based on the first applicable benchmark, as follows:

1. Under the first of those benchmarks, the gross proceeds accruing to the lessee under its non-arm's-length contract will be accepted as value, if they are within the range of the gross proceeds derived from or paid under comparable arm's-length contracts (from other producers, i.e. not comparable sales by the lessee) for the sale or purchase of like-quality coal produced in the area. 30 C.F.R. §§ 1206.257(c)(2)(i) (Federal coal) and 1206.456(c)(2)(i) (Indian coal).
2. The second benchmark establishes value based on "[p]rices reported for that coal to a public utility commission." *Id.* §§ 1206.257(c)(2)(ii) and 1206.456(c)(2)(ii).
3. Under the third benchmark, value is established based on "[p]rices reported for that coal to the Energy Information Administration of the Department of Energy." *Id.* §§ 1206.257(c)(2)(iii) and 1206.456(c)(2)(iii).
4. If the third benchmark does not apply, then value is based on "other relevant matters," which include, but are not limited to, "published or publicly available spot market prices" or "information submitted by the lessee concerning circumstances unique to a particular lease operation or the saleability of certain types of coal." *Id.* §§ 1206.257(c)(2)(iv) and 1206.456(c)(2)(iv).
5. Lastly, if none of the four preceding benchmarks apply, then "a net-back method or any other reasonable method shall be used to determine value." *Id.* §§ 1206.257(c)(2)(v) and 1206.456(c)(2)(v).

Of note, if application of the benchmarks result in a value less than the gross proceeds from the non-arm's length transaction between lessee and its affiliate, then the non-arm's length transaction will govern value for royalty purposes. 30 C.F.R. 1206.257(g).

These benchmarks have been applied since 1989 with little indication that the benchmarks are not workable. At most, there has been occasional disagreement between lessees and ONRR over whether sales are considered arm's-length or non-arm's-length or over which is the first applicable benchmark. For example, in *Decker Coal Co.*

[1] Although these cases involve royalty on oil and gas, the stated principles are equally applicable to coal royalty valuation. *See Black Butte Coal Co. v. United States*, 38 F. Supp. 2d 963, 971 (D. Wyo. 1999) ("Simply because [prior cases] involve gas and oil as opposed to coal is not a compelling reason to ignore them. The decisions' discussion of the assessment of royalties is functionally indistinguishable . . .").

v. United States, No. CV-07-126-BLG-RFC, 2009 WL 700221 (D. Mont. Mar. 17, 2009), the issue was not that the benchmarks were unworkable or led to unreliable valuations; the issue was that ONRR's predecessor, the Minerals Management Service (MMS), erred by proceeding to the fourth benchmark when the first benchmark was applicable, contrary to the regulation's mandate. *Id.* at *2, *9. However, coal lessees not being allowed to use their own arm's-length sales to value non-arm's-length sales of coal from the same mine, which has led to a lack of clarity and significantly enhanced costs and administration due to avoidable audit issues, appeals and litigation.

Coal Valuation Rulemaking History

When the valuation benchmarks were first proposed in 1987, the first benchmark would allow for consideration of the lessee's own comparable sales. The 1987 preamble (52 Fed. Reg. at 1843 (Jan 15, 1987)) provides:

- "Hence, for the first benchmark, pursuant to proposed § 206.259(c)(2)(i), if the gross proceeds under a non-arm's-length contract are equivalent to the lessee's gross proceeds derived from, or paid under, comparable arm's-length contracts for the sale or purchase of like-quality coal in the area, then the gross proceeds would be acceptable as value."

Again in 1988, when the benchmarks were proposed for the second time, the first benchmark would allow consideration of the mine's own comparable sales. MMS explained:

- "The-first benchmark is still based upon the lessee's gross proceeds from the disposition of the coal. However, the proposed rule has been modified so that, before the lessee's gross proceeds would be acceptable as value, they must be equivalent not just to the gross proceeds under the lessee's other arm's-length contracts, but they must be equivalent to the gross proceeds under arm's-length contracts involving other buyers and sellers in the area." 53 Fed. Reg. at 26951 (July 15, 1988).

The proposed language of the first benchmark provided:

- "(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition by other than an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under...comparable arm's-length contracts for sales, purchases, or other dispositions of like-quality coal in the area." 53 Fed. Reg. at 26960.

In 1989, when the valuation benchmarks were finalized, MMS eliminated the ability to consider the mine's own comparable sales; however, the preamble does not describe the reason for the change. MMS noted that some comments were raised by Tribes on the issue:

- "Two Indian commenters recommended ignoring arm's-length contracts of the lessee and seeking "[t]he highest gross proceeds" in "the same coal field" or alternatively "from other coal fields" as being the first two preferred valuation criteria." 54 Fed. Reg. at 1514.

But ultimately the rule's preamble does not acknowledge the change and actually contains some language that is inconsistent with the change:

- "Therefore, the first criteria to be applied are market-based value determinants. The lessee would be required to compare its non-arm's-length contract with its comparable arm's-length contracts and to other comparable arm's-length contracts of coal producers in the same area." *Id.* at 1515.

Further, MMS's decision to exclude the lessee's own comparable arm's-length sales from the first coal benchmark was inconsistent with the valuation benchmarks that were adopted for non-arm's-length sales of natural gas, which have always allowed an oil and gas lessee to determine value based on its own comparable arm's-length sales. *See* 30 C.F.R. § 1206.152(c)(1).

Value at the Mine is Best Determined By Examining Comparable Arm's-Length Sales

The current benchmarks reflect the long-held and universal view that the best method for determining value at the mine is examining comparable arm's-length sales. *See* 54 Fed. Reg. 1,492, 1,500 (Jan. 13, 1989) ("The arm's-length valuation standard is the most commonly utilized and the most accurate representation of any good's true worth . . ."); *see also* 76 Fed. Reg. 30881, 30882 (May 27, 2011) ("The Department of the Interior has long held the view that the sales prices agreed to in arm's-length transactions are the best indication of market value. The 1989 regulations reflect that view.").

As mentioned above, when the benchmarks were adopted, MMS included a comparison to arm's-length sales in the same area as the producer's mine in the first benchmark. 54 Fed. Reg. at 1506. Accordingly, it was MMS's intent that arm's length sales in the area should be viewed as the most reliable indicator of value for purposes of valuing non-arm's length sales from the same location.

Consistent with reliance on a comparable sales approach, MMS's 1996 guidance on affiliate sales of coal provides that affiliate resales of coal may be used to determine value, but only where the resale occurs in the same area as the mine. *See* "General Guidance for Auditing Affiliate Sales of Coal" at 1 (November 26, 1996) ("If a resale of production from the affiliate to a third party occurs *in the same field or area* as the sale from the lessee to its affiliate, the proceeds under the arm's-length resale contract may be used in calculating the applicable benchmark value." (emphasis added)).

In royalty cases on private lands involving affiliate sales, courts have applied the comparable arm's–length sales approach to determine market value at the lease as "[t]he first, and most desirable" approach. *Potts v. Chesapeake Exploration, L.L.C.*, No. 3:12-CV-1596-O, 2013 WL 874711, at *5 (N.D. Tex. Mar. 11, 2013), *aff'd*, 760 F.3d 470, 474 (5th Cir. 2014) ("The most desirable method is to use comparable sales"). In other valuation cases, not involving affiliate sales, courts similarly prefer the comparable sales valuation approach to determine a value at the lease. *E.g., Ashland Oil, Inc. v. Phillips Petroleum Co.*, 554 F.2d 381, 387 (10th Cir. 1975) ("It is obvious that the comparable sales-current market price is by far the preferable method when it can be used."); *Bice v. Petro-Hunt, L.L.C.*, 2009 ND 124, ¶ 14, 768 N.W.2d 496, 501 ("Most courts prefer the comparable sales method."); *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 463 F. Supp. 619, 620 (N.D. Okla. 1978) ("Optimally, a product's 'fair market value' is determinable by examining comparable sales of the same product."), *aff'd in part, rev'd in part,* 607 F.2d 335 (10th Cir. 1979); *Anderson Living Trust v. ConocoPhillips Co., LLC*, 952 F. Supp. 2d 979, 1040 n.9 (D. N.M. 2013) ("evidence of comparable wellhead sales is the best possible evidence for analyzing market value at the well.").

2. Issue: Coal Companies Cannot Value Non-Arm's Length Sales Using the Most Reliable Method

Although the first benchmark under the current regulations allows a lessee to value its coal sold under a non-arm's-length contract based on the value of comparable arm's-length contracts in the area, the first benchmark limits the lessee's comparability analysis to "comparable arm's-length contracts (<u>from other producers, i.e. not comparable sales by the lessee</u>)." 30 C.F.R. §§ 1206.257(c)(2)(i) (Federal coal) (emphasis added) and 1206.456(c)(2)(i) (Indian coal).

This limitation is problematic for two main reasons. First, by excluding the lessee's own comparable arm's-length contracts, it prevents consideration of the most reliable data for determining value – the mine's own comparable arm's-length sales at the mine for the same quality coal. Second, by limiting the comparability analysis to other producer's contracts, the first benchmark becomes virtually impossible for the lessee to apply. Lessees typically do not have access to their competitors' sales contracts; therefore, at the time a lessee makes its royalty payments, the lessee is unable to determine whether its gross proceeds are comparable to its competitors' sales contracts.

As a result, the first benchmark currently prevents coal lessees from using the most reliable valuation method – a comparable sales approach – to value its non-arm's-length sales.

3. Recommendations

The recommendations with regard to coal valuation by the voting members of the Fair Return and Value Subcommittee are as follows:

1. The Department of the Interior reinforce its consistent principle that arm's length transactions are the best indication of market value by amending the regulation at 30 C.F.R. 1206.257(c)(2)(i) to read:

    a. "The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition by other than an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under comparable arm's-length contracts for sales, purchases, or other dispositions of like-quality coal in the area."

2. The Department of the Interior issue a Secretarial Order, Dear Payor Letter and/or a Policy Memorandum indicating that a lessee's own arm's length sales are preferential under 30 C.F.R. 1206(c)(2)(iv) at least until the rulemaking process has run.

3. The Department of the Interior update the Solids Minerals Reporting Handbook in accordance with items 1 and 2 above.

These changes would ensure that valuation methodology of non-arm's length coal sales is consistent with the "at the mine" legislative intent and would conform the coal valuation methodology to substantially similar terms as gas and oil. Further, this change would ensure that the most consistent and reliable non-arm's length valuation methodology would be utilized. The resulting clarity and consistency would significantly increase efficiencies within the coal royalty payment process – reducing the time of audits, eliminating a number of unnecessary appeal issues and significantly lower the likelihood of costly and inefficient litigation.

Appendix A

Payor Handbook Update

Royalty Policy Committee
Fair Return and Valuation Sub-Committee
Payor Handbook Working Group
February 2018

Payor Handbook Working Group

- ONRR participants:
  - Amy Lunt
  - Megan Hessee
  - Jodie Peterson
  - Helen Virene
  - Gina Liles
  - Kimberly Jackson
  - Cindy Gothberg
- Tribal participants:
  - Adam Red
  - Rowena Cheromiah
  - Brian Bex
- State participant:
  - Representative Drew Darby
- Academia/Public Interest participant:
  - Van Romero
- Industry participants:
  - Greg Morby
  - Matthew Adams
  - Stella Alvarado
  - Gabrielle Gerholt
- Technical Resource participant:
  - Judy Matlock

Background

- Last updated in 2000
- General support from ONRR and Industry for update
- ONRR had started update prior to formation of RPC

Current Status

- Corrections and updates needed
  - Wet versus dry
  - Valuation basics
- Create two handbooks
  - Indian
  - Federal

Recommendation

- Create “evergreen” handbook which can be updated regularly and link to recent rules and decisions

RECOMMENDATION SUMMARY

Royalty Policy Committee
Fair Return and Valuation Sub-Committee
Index Pricing Working Group
February, 2018

Index Price Working Group

ONRR participants:

- *Chris Carey*
- *Robert Sudar*
- *Nicholas Van Gundy*
- *Karl Wunderlich*

Tribal participants :

- *Adam Red (Southern Ute Indian Tribe)*
- *Lorelyn Hall (Southern Ute Indian Tribe)*

Academia/Public Interest participants:

- *Rod Eggert (Colorado School of Mines)*
- *Van Romero (NM Institute of Mining)*

Industry participants :

- *Matthew Adams (Cloud Peak Energy)*
- *Estella Alvarado (Anadarko)*
- *Gabrielle Gerholt (Concho)*
- *Greg Morby (Chevron)*
- *Pat Noah (ConocoPhillips)*

Technical Resource participant:

- *Mike Foster (ConocoPhillips)*

Background

- General support among Payors for Index Pricing concept
- Potential to resolve many Marketable Condition issues
- Index Price provision contained within repealed 2017 Federal Valuation Rule was not received well by Payors
  - *the highest reported price was unachievable and reflected index points not representative of how the gas was actually marketed;*
  - *transportation cost deductions were unreasonably low; and*
  - *the resulting price could only be used for non-arms-length sales types*

Work Flow

- Reviewed and discussion of comments collected from 2017 COPAS/ONRR valuation meeting
- Review and discussion of a valuation rules matrix
- Review and discussion of Indian Index Price approach
- Review and discussion of potential considerations in potential Index Price rulemaking
- Draft, review and discussion of draft proposal
- Discussion of potential approach (negotiated rulemaking versus rulemaking)

Recommendation

Pursue rulemaking to define simplified index price rules for Federal gas.

Key factors to be addressed by this rule:

- A standardized average single price (per defined geographic area) acceptable to both payors and DOI/ONRR
- Calculated (by ONRR) from generally accepted index price publications or other market-sensitive source
- Apply price to wellhead (or royalty measurement point MMBTUs
- Incorporate reasonable geographically sensitive transportation deductions
- Apply price to all Federal gas sales types

Recommendation

Additional factors for consideration in the rulemaking process:

- Should utilization of the price be mandatory or optional by payors?
- Should the “bump” approach of Indian Alternate dual accounting be utilized?

Royalty Policy Committee
Fair Return and Valuation Sub-Committee

Work Group

Marketable Condition

February 28, 2018

Marketable Condition

Discussion

Background & Boosting

A lessee is required to put gas into marketable condition once at its own expense.

Boosting has commonly been accepted throughout Industry as meaning the compression of natural gas in a Gas Processing Plant from its pressure (expressed in pounds per square inch or PSI) after the extraction of Natural Gas Liquids (NGLs) to PSI levels sufficient to allow the Residue Gas (gas remaining after the extraction of NGLS) to flow into natural gas pipeline(s) that will transport it to downstream markets.

ONRR and industry currently disagree on the interpretation of the current boosting regulation. Current ONRR interpretation requires that Industry condition gas to mainline pipeline specifications **twice**, once in an unprocessed condition as it is produced from the ground and a second time after the gas is processed at a downstream Natural Gas Processing plant. A recommendation to change the boosting language will resolve the difference of interpretation between industry and the Department.

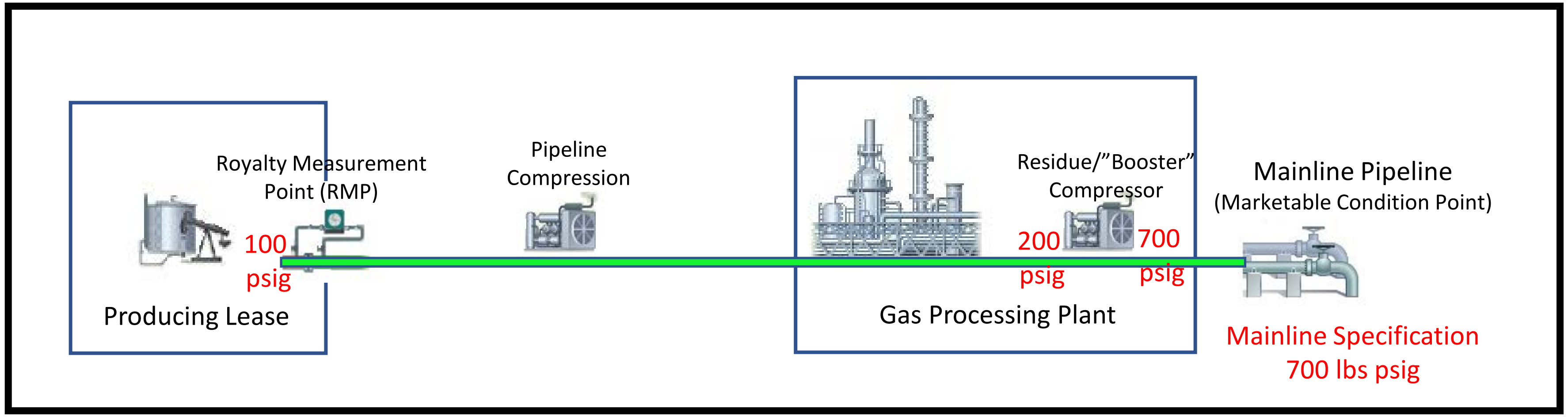
Marketable Condition

Boosting Regulations – Compression Required for Marketable Condition or otherwise

Three disputes. For at least three reasons, ONRR and industry currently disagree on the compression a lessee must provide at its own expense to put gas into marketable condition:

- Is boosting residue gas part of the marketable condition requirement or a separate requirement?
- Achieve Marketable condition or sum to marketable condition?
- Compression needed to put NGLs' into marketable condition?

Marketable Condition Example



Placing Gas in Marketable Condition Once

Compressor	Calculation	Total Disallowed Pressure
Booster Compression	(Booster Discharge – Booster Inlet) (700 – 200)	500 lbs psig
Compression	(Booster Inlet –Pipeline Compression)(200 - 100)	100 lbs psig
Total Disallowed	(Mainline Receipt – Pipeline Compression) (700 – 100)	600 lbs psig

- Allows lessee to use booster to reach mainline pressure
- Pressure needed to reach mainline specs is disallowed
- Lessees will not deduct cost of booster nor 100 lbs of pipeline compression. Hence, we are not charging ONRR for boosting.

Placing Gas in Marketable Condition Twice

Compressor	Calculation	Total Disallowed Pressure
Booster Compression	(Discharge – Inlet) (700 – 200)	500 lbs psig
Compression	(Mainline Receipt – Pipeline Compression) (700 - 100)	600 lbs psig
Total Disallowed	(Mainline Receipt – Pipeline)+ (Booster)	1100 lbs psig

- Requires lessee to reach marketable condition pressure prior to the plant AND after processing (i.e. twice)
- Lessee are not allowed to use booster to reach mainline pressure
- Requires lessee to provide more pressure 'free-of-cost' than is necessary to reach mainline pipeline (marketable condition) specifications

Marketable Condition

ONRR's regulation on boosting residue gas applies only to federal gas. It currently reads:

> (b) A reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant, <u>but no allowance shall be made for boosting residue gas or other expenses incidental to marketing, except as provided in 30 CFR part 206.</u> In those situations where a processing plant processes gas from more than one lease, only that proportionate share of each lease's residue gas necessary for the operation of the processing plant shall be allowed royalty free.

Marketable Condition

Recommendation

The voting members of the marketable condition work group recommend that the Department of the Interior resolve an ambiguity in its current regulations by publishing a proposed rule to amend the regulation at 30 C.F.R. 1202.151(b) to remove language specific to the boosting of residue gas:

Revise 30 C.F.R. 1202.151(b) to read as follows:
A reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant. In those situations where a processing plant processes gas from more than one lease, only that proportionate share of each lease's residue gas necessary for the operation of the processing plant shall be allowed royalty free.

Marketable Condition

Discussion

Unbundling

ONRR continues to make progress in generating unbundling cost allocations (UCAs) for gas plants and transportation systems. ONRR has unbundled and published UCAs for approximately twenty-five gas plants—some with included transportation systems.

For those plants where there is not an ONRR-generated UCA, and even where there is an ONRR-generated UCA, but a lessee concludes that an ONRR-generated UCA disallows too much of its transportation or processing costs, the lessee may or must unbundle itself, though with difficultly, particularly where it transports or processes its gas under an arms-length transportation or processing contract.

Marketable Condition

Standardized Table for Calculating Allowances/Disallowances

A standardized table brings certainty and administrative simplicity and would provide an option for using a table detailing cost for the various marketable condition services (i.e. compression, treating, dehydrating) rather than requiring individual companies to determine their own costs for these services.

Path Forward

The marketable condition work group recommends that it further discuss and evaluate a standardized table to calculate allowances and disallowances, building on the many hours the work group has spent to date. Evaluation may include an economic analysis to support a future recommendation.

Marketable Condition

ONRR participants:

- Bonnie Robson
- Karl Wunderlich
- Sara Corman

Tribal participants :

- Adam Red (Southern Ute Indian Tribe)

Industry participants :

- Matthew Adams (Cloud Peak)
- Stella Alvarado (Anadarko)
- Greg Morby (Chevron)
- Pat Noah (ConocoPhillips)

Academia:

- Roderick Eggert, CO School of Mines

Technical Resource participant:

- Mike Foster (ConocoPhillips)

Royalty Policy Committee
Fair Return & Value Subcommittee

Coal Valuation Working Group

February 27-28, 2018

ISSUE

- Unlike the gas and oil valuation rules for non-arm's length sales, the coal valuation benchmarks do not expressly state that a lessor's arm's length sales are the preferred valuation methodology for non-arm's length sales. Without a clear 'best' valuation methodology, different methodologies are being used by lessors and ONRR without guidance on what is 'most reasonable'.
  - The consequence has been an increase in appeals, uncertain reporting methodologies, lack of consistency in valuation determinations and an upcoming dramatic increase in time and expense associated with litigation. Additionally, the current environment is making federal coal less competitive than state or private coal when non-arm's length sales are contemplated.

Why Lessees use Logistics Companies

- Logistics companies are typically used to provide services to customers when the delivery point is remote from the lease in order to mitigate various risks and costs from impacting the lessee. Logistics companies incur substantial cost and risks associated with transporting coal significant distances to coal ports, including:
  - Inherent increased risk of dealing with overseas customers,
  - Retaining legal title to the coal and risk of loss until it is loaded on the customer’s vessel at the terminal,
  - Incurring terminal and rail fees,
  - Risking rail interruptions,
  - Paying demurrage charges,
  - Rail and port requirements force logistic companies to commit to long-term contracts, which include take-or-pay provisions.

Non-Arm's Length Coal Valuation Benchmarks - Summary

1. The gross proceeds accruing to the lessee under its non-arm's-length contract will be accepted as value, if they are within the range of the gross proceeds derived from or paid under comparable arm's-length contracts (from other producers, i.e. not comparable sales by the lessee) for the sale or purchase of like-quality coal produced in the area. 30 C.F.R. §§ 1206.257(c)(2)(i) (Federal coal) and 1206.456(c)(2)(i) (Indian coal).
2. The second benchmark establishes value based on "[p]rices reported for that coal to a public utility commission." *Id.* §§ 1206.257(c)(2)(ii) and 1206.456(c)(2)(ii).
3. Under the third benchmark, value is established based on "[p]rices reported for that coal to the Energy Information Administration of the Department of Energy." *Id.* §§ 1206.257(c)(2)(iii) and 1206.456(c)(2)(iii).
4. If the third benchmark does not apply, then value is based on "other relevant matters," which include, but are not limited to, "published or publicly available spot market prices" or "information submitted by the lessee concerning circumstances unique to a particular lease operation or the saleability of certain types of coal." *Id.* §§ 1206.257(c)(2)(iv) and 1206.456(c)(2)(iv).
5. Lastly, if none of the four preceding benchmarks apply, then "a net-back method or any other reasonable method shall be used to determine value." *Id.* §§ 1206.257(c)(2)(v) and 1206.456(c)(2)(v).

Of note, if application of the benchmarks result in a value less than the gross proceeds from the non-arm's length transaction between lessee and its affiliate, then the non-arm's length transaction will govern value for royalty purposes. 30 C.F.R. 1206.257(g).

1987/1988 / 1989 Valuation Rulemaking

- When the valuation benchmarks were first proposed in 1987, the first benchmark provided for consideration of the lessee's own comparable sales. The 1987 preamble (52 Fed. Reg. at 1843 (Jan 15, 1987) provides:
- · "Hence, for the first benchmark, pursuant to proposed § 206.259(c)(2)(i), if the gross proceeds under a non-arm's-length contract are equivalent to the lessee's gross proceeds derived from, or paid under, comparable arm's-length contracts for the sale or purchase of like-quality coal in the area, then the gross proceeds would be acceptable as value."
- <u>1988 Coal Valuation Rulemaking</u>: Again in 1988, when the benchmarks were proposed for the second time, the first benchmark would allow consideration of the mine's own comparable sales. MMS explained:
- · "The-first benchmark is still based upon the lessee's gross proceeds from the disposition of the coal. However, the proposed rule has been modifed so that, before the lessee's gross proceeds would be acceptable as value, they must be equivalent not just to the gross proceeds under the lessee's other arm's-length contracts, but they must be equivalent to the gross proceeds under arm's-length contracts involving other buyers and sellers in the area." 53 Fed. Reg. at 26951 (July 15, 1988).
- The proposed language of the first benchmark provided:
- · "(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition by other than an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under...comparable arm's-length contracts for sales, purchases, or other dispositions of like-quality coal in the area." 53 Fed. Reg. at 26960.
- <u>1989 Coal Valuation Final Rule</u>: In 1989, when the valuation benchmarks were finalized, MMS eliminated the ability to consider the mine's own comparable sales; however, the preamble does not describe the reason for the change. MMS noted that some comments were raised by Tribes on the issue:
- · "Two Indian commenters recommended ignoring arm's-length contracts of the lessee and seeking "[t]he highest gross proceeds" in "the same coal field" or alternatively "from other coal fields" as being the first two preferred valuation criteria." 54 Fed. Reg. at 1514.
- But ultimately the rule's preamble does not acknowledge the change and actually contains some language that is inconsistent with the change:
- · "Therefore, the first criteria to be applied are market-based value determinants. The lessee would be required to compare its non-arm's-length contract with its comparable arm's-length contracts and to other comparable arm's-length contracts of coal producers in the same area." *Id.* at 1515.

Recommendations

1. The Department of the Interior reinforce its consistent principle that arm's length transactions are the best indication of market value by amending the regulation at 30 C.F.R. 1206.257(c)(2)(ii) to read:
   - "(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition by other than an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under comparable arm's-length contracts for sales, purchases, or other dispositions of like-quality coal in the area."
2. The Department of the Interior issue a Secretarial Order, Dear Payor Letter and/or a Policy Memorandum indicating that a lessee's own arm's length sales are preferential under benchmark 4 while the rulemaking process has run.
3. The Department of the Interior update the Solids Minerals Reporting Handbook in accordance with items 1 and 2 above.

Royalty Policy Committee

Fair Return & Value Subcommittee

Audit Work Group Report– February 7, 2018

Audit Work Group

Overview

The Audit Work Group ("AWG") industry members initially met to discuss audit related problems, concerns, and areas for improvement broadly categorized as follows:

- Audit coordination and timing
- Audit conduct and resource allocation
- Audit closure

Subsequent meetings provided ONRR staff the opportunity to outline improvements expected from the recently developed Operations Management Tool (OMT) being implemented during Fiscal Year 2018. Further OMT highlights are noted on the next slide. ONRR staff further communicated:

- The cost of performing audits, and a related Return on Investment, has been tracked since the mid 1990s.
- Improvements are an ongoing concern, and effort, with recommendations periodically being received from GAO, OIG, and past and present RPCs.
- During the last Fiscal Year, 153 audits and more than 600 compliance reviews were completed. Approximately 2/3rds of disagreements resolved before completion of Preliminary Determination.

Audit Work Group

Scope of Work

AWG identified problem

- Overlap of audits -different ONRR and State delegated teams auditing or reviewing the same periods and properties at the same, or different, times.
- Allocating sufficient and experienced resources for the efficient conduct of the audit.
- Audits do not begin soon enough or conclude in a timely manner.

Status – the ONRR Operations Management Tool should address the above problems through improvements such as:

- Better audit management through improved categorization of audits beyond New / Open / Closed.
- Assigning milestone activities and due dates necessary to keep efforts progressing at a pre-established pace
- A reduction in audit cycle time from 2-3 years to 16 months.
- Payor provided source documentation will be stored electronically and available to associated agencies.
- Consistent data request based on one template

Audit Work Group

Scope of Work - continued

AWG identified problem **-** Inconsistent interpretation and application of valuation regulations among ONRR, States, Tribes, and companies.

Status **-** The ONRR Asset Valuation Group is developing an electronic database capturing and cross-referencing guidance by keyword / issue with read only access available to other groups such as compliance and audit.

AWG identified problem **-** Unresolved issues and guidance can lead to a logjam open audit periods.

Status **-** Filling vacant appeals analyst positions should aid with the appeals backlog.

Recommendation –As a result of the ONRR efforts referenced above, the AWG concluded no recommendation for RPC consideration is required at this time. The AWG will monitor the expected improvement.

Additionally, the AWG sees the potential for lessening audit burden, time, and expense, in the recommendations developed by the other Fair Return and Valuation Subcommittee Work Groups (Coal, Index Pricing, Marketable Condition and the Payor Handbook).

Audit Work Group

Members

• John Barder	ONRR
• Adam Red	Tribes
• Kwame Awuah-Offei	NGO
• Greg Morby	Industry
• Pat Noah	Industry
• Stella Alvarado	Industry
• Matthew Adams	Industry

ONRR COMPLIANCE PROCESS IMPROVEMENT

February 28, 2018

Audit Management

Paul Tyler
Program Director

Coordination & Support/ OMT Sponsor
Roman Geissel
Program Manager

Indian & State Audit
Patrick Milano
Program Manager

Southern Federal Audit
Shawna Schimke
Program Manager

Western Federal Audit
Judith Clark
Program Manager

Process Improvement Initiative

- Improve Compliance Business Processes

- Align Sufficient & Skilled Resources

- Provide the Foundation for Development of the Operations Management Tool (OMT)

Process Improvement Focus

- Increase Productivity/Compliance Coverage
  - Eliminate unnecessary steps & duplication
  - Reduce cycle times
- Maximize Results
  - Focus resources on areas of potential misreporting
- Enhance Quality of Audits
  - Ensure a favorable peer review opinion

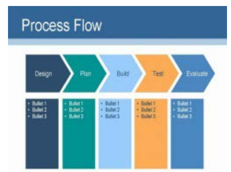
Process Improvement Focus

- Implement Status Tracking and Transparency
- Track Cases from Beginning to Closure
  - Including appeals and other enforcement activities
- Leverage Technology (OMT)
  - Work planning coordination
  - Workflow structure
  - Electronic workpapers
  - Automated notifications
  - Information sharing

OMT is an Integrated ONRR-Wide Tool

Automates planning, execution, monitoring, measurement, and reporting on all compliance processes

Increase Management visibility and insight into processes.



Simplify processes while increasing quality.

Reduce time to perform compliance activities.

ONRR-Wide Benefits:

Work Management

- ONRR-wide (and STRAC) automation
- Automated work management & risk analysis
- Business process metrics to drive process improvement
- Optimized for multiple users
- Enhanced automation to speed process closure
- Mitigation of overlapped work

Standardized Process

- Consistent Work Products
- Process standardization and sustainability
- Standardized Milestones
- Electronic document & case file storage in one central tool
- Electronic "workpapers"

Transparency

- Data security
- Electronic file backups
- Fast accumulation of data for metrics tracking
- Ease of high level activity transparency
- Shared view of case & status

Process Improvements

- Introduces Phases, Milestones and Tasks to Track Audit Status and Progress
- Establishes a Standard Audit Process and Eliminates Unnecessary Steps
  - Uniform workflow and custom audit procedures for each audit
  - Consistent file index and workpaper structure
- Utilizes ONRR-Wide Work Products
  - Consistent communication to industry; system generated work products

Process Improvements

- Addresses Audit Process Consistency
  - Structures supervisory/management review process
  - Defines escalation process when companies do not respond
  - Outlines systemic issues
  - Establishes sampling standards
  - Uses thresholds to manage work
  - Distinguishes closure letters verses audit reports

Process Improvements

- Reduces Audit Cycle Times
  - Provides structure and clear guidance leading to a more efficient process
  - Decreases review and processing time by using system generated work products
  - Minimizes time lost when transferring cases between employees
  - Allows audit closure where no findings exist (RSFA)
  - Ensures GAGAS standards are met reducing the risk of peer review findings
  - Improves management oversight

Appendix A

OMT Schedule

Compliance Reviews (ONRR)	January 2017
Audit (ONRR - Process only)	March 2017
Compliance Reviews (STRAC)	Pilot Dec 2017
Data Mining	January 2018
Audits (ONRR - OMT)	June 2018
Appeals (Assessment)	FY 2019
Enforcement (Assessment)	FY 2019
Valuation (Assessment)	FY 2019
Audits (STRAC)	FY 2019

Audit Work Group Issues

Appendix A

Issue	Response
Overlap of audits, meaning different ONRR and State delegated teams auditing/ reviewing the same periods and properties at the same or different times.	**Process Improvements** ➢ Realign ONRR, States and Tribes organizationally ➢ Focus assignments on attributes **OMT** ➢ Centralizes Work Management – Provides view of all compliance work (AM, STRAC, Compliance Management) – Identifies and flags overlap properties and companies – Shows current production/royalty information – Identifies compliance targets

Audit Work Group Issues

Issue	Response
Allocating sufficient and experienced resources for efficient conduct of audit.	**Process Improvements** ➢ Continue to pursue filling vacant positions ➢ Improve resource management ➢ Utilize internal experts to provide consistent guidance and training

Audit Work Group Issues

Issue	Response
Efficient conduct of audit, beginning and ending sooner. How can we aid or influence acceleration of audit start and end?	**Process Improvements** ➢ Reduce audit cycle time from 2-3+ years to 16 months ➢ Tailor audit methodology ➢ Enhance escalation process to enforce timely responses **OMT** ➢ Implements standard processes ➢ Employees status tracking and transparency – Expands case status categories – Establishes milestones and due dates ➢ Provides document sharing across offices ➢ Standardizes correspondence -data requests, preliminary determinations, order letters

Process Improvement Results

Appendix A

- **Audit**
  - Reduction of backlog
    - FY 17: 80% of audits over 3 years old completed
    - FY 18: 100% of audits over 3 years old scheduled for completion
  - Completion of new audit process pilot
    - Cycle times significantly reduced
  - Application of new audit process across AM
- **Compliance Reviews**
  - OMT implementation
    - Cycle times reduced by 20%
    - Prior to the process improvement project 20% of assignments resulted in findings
    - In FY 16: 40% of assignments resulted in findings

Questions

Planning, Analysis, & Competitiveness Subcommittee

Recommendations from the Onshore Working Group to the Planning, Analysis, and Competitiveness Subcommittee for the February 2018 Royalty Policy Committee

February 5, 2018

The sense of the Onshore Working Group is that rather than consider a royalty rate increase at this time, which would further decrease the competitiveness of federal lands that already carry higher regulatory costs, the Department of the Interior (DOI) should instead focus its efforts on removing obstacles. By making federal lands more attractive and increasing certainty, DOI could spur more development. The Onshore Working Group proposes the following recommendations:

1. Reducing timelines for project approvals, including Applications for Permit to Drill (APD), Rights-of-Way (ROW), sundries, lease nominations, and unit agreements.

Slow approvals, including APDs, ROWs, unit agreements, sundries, etc., are a major distortion in the federal onshore process. APDs can be delayed for several months to years, even after potentially years of delay obtaining NEPA approvals. BLM admits to a 257-day average processing time, but that number is likely much higher if better data were collected. State permits usually take around 30 days, on average, depending on the state. Shorter approval times are crucial for federal lands to increase their competitiveness with nonfederal lands. Below are several recommendations related to various permitting and approval processes:

- Operators must obtain a state permit for all new wells within the state's borders, including on federal lands. The state permit is largely redundant with the federal permit. The Interstate Oil & Gas Compact Commission (IOGCC), a multi-state government agency representing oil and natural gas producing states, has issued a resolution urging delegation to the states for approval of drilling permits on federal public land. The House Natural Resource Committee has passed the Secure Energy Act, which includes delegation of APDs to the states, out of committee. DOI should embrace this concept and work with Congress to get it passed. Short of legislation, BLM could enter into memoranda of understanding (MOU) with states to delegate many downhole permitting aspects to the states while retaining the final official approval.

- BLM field offices arbitrarily add new requirements to APDs and require producers to conduct new and redundant analysis without a basis in law or regulation. Companies have been asked to perform extra cultural, wildlife, flood plain or other surveys, even after complying with existing regulations. Arbitrary requirements lengthen the APD processing time both for the operator and for BLM. Requirements vary greatly from field office to field office, further frustrating operators. In an overall permitting IM or further guidance resulting from Secretarial Order 3354, BLM should direct field offices to follow established regulations and onshore orders when requesting information from operators for their APDs, and prohibit them from requiring extraneous analysis and surveys.

- Lengthy APD timeframes often occur because BLM is conducting redundant NEPA analysis. BLM is not granting Categorical Exclusions (CX) when companies meet the criteria under Section 390 of the Energy Policy Act of 2005 and in many situations automatically requires another Environmental Assessment, rather than even considering a CX. In contravention of EPAct, BLM is requiring duplicative NEPA for: 1) wells involving less than five acres of disturbance with total lease disturbance of less than 150 acres that already have site-specific NEPA; 2) new wells on pads drilled within the last five years; and 3) areas covered by an existing NEPA document that is five years old or less. As a result, APDs are delayed months and years awaiting redundant NEPA analysis, in direct violation of statute. In an overall permitting IM or further guidance resulting from Secretarial Order 3354, BLM should direct all field offices to issue CXs when any of the Section 390 criteria are met. BLM's NEPA handbook already provides that direction, so a rewrite is not required.

- Over the past several years decision making has been moved from the field office level to Washington, and as a result many different types of approvals are being held up indefinitely. Washington should devolve more decision making to the state and field offices, while enabling support when field offices struggle due to lack of staff or expertise. For example, unit applications have been particularly slow and could benefit from support from state office personnel who handle unit issues on a more regular basis.

2. Limiting the federal nexus for wells without a majority federal interest, i.e., reducing the situations in which the full gamut of federal approvals is required

BLM requires NEPA approvals and APDs for wells on private or state lands even when only a minority of the oil and natural gas resources being accessed are federal, using the "federal nexus" as a way for BLM to become involved in wells in which it has only a minority of mineral interest. Once the federal nexus is invoked, the full gamut of BLM processes applies, resulting in long delays.

- BLM should work with Congress on the Secure Energy Act, which has passed out of the House Natural Resources Committee, which would limit the federal nexus to situations only where federal lands are involved and/or there is a majority of federal minerals. The federal government would then receive royalties as any other minority mineral owner through a normal pooling/unitization agreement.

- Short of legislation, BLM could adjust guidance to the field and reduce the number of situations considered a major federal action requiring NEPA, such as redefining just the obtaining of a federal right-of-way as a minor action.

- BLM uses the federal nexus to require tribal consultation for cultural artifacts on private land, even when there's no federal public or tribal lands in the area and only a minority of federal minerals interests. When private landowners refuse access to their lands, it puts operators in a bind because BLM won't let the process move forward.

- Furthermore, BLM arbitrarily defines the Area of Potential Effects (APE) to incorporate a broad area of land so that the need to consult is triggered even when the actual cultural site is avoided. In the Powder River Basin in particular, BLM is conducting far-reaching tribal consultations for 23 tribes who do not have tribal lands in the area. These consultations can hold up project NEPA and APDs indefinitely.

- The Fish & Wildlife Service should review its final rule, "Management of Non-Federal Oil and Gas Rights," 81 FR 79948 (Nov. 14, 2016) to determine whether revision would be appropriate to reduce burden on energy. In particular, FWS should streamline Rights-of-Way (ROW) for pipelines and electricity transmission. The approval process for new ROW access can be overly restrictive and excessively lengthy. The FWS should work with stakeholders to revise its ROW regulation to streamline the current ROW granting process to significantly decrease the time to obtain ROW approval from the current 3-12 month time frame.

3. Improving land use planning and NEPA approvals

- Issue an IM specifying that State Directors and Field Office Managers must move forward with processing nominations in accordance with existing RMPs until amended RMP Records of Decision are signed, and end the practice of deferring lease parcels while RMPs are being amended. The IM should clearly state that ongoing RMP updates, amendments, supplements, or Master Leasing Plans are not legitimate reasons for lease deferral.

- When finalizing RMPs and RMP amendments, only impose resource development restrictions that accord with FLPMA, the Mineral Leasing Act (MLA) and other statutory authority.

- BLM should adhere to the principles established in the 2005 Desk Guide to Cooperating Agency Relationships and Coordination with Intergovernmental Partners. Many counties across the West have planning processes that are not given full consideration by BLM. BLM should improve the recognition and incorporation of state and local government land use plans, data, and policies in RMP amendments.

- BLM should follow existing law and utilize Resource Management Plans and their associated EISs, programmatic EAs/EISs, and project EAs/EISs that are less than five years old, and grant Categorical Exclusions (CX) in all cases that meet the Energy Policy Act of 2005 criteria, rather than requiring redundant NEPA analysis. BLM's NEPA handbook already specifies that this is allowed, so simple direction to the state and field offices is all that is required.

- Project NEPA documents often take several years, and are usually a longer source of delay than APD delays. BLM should incorporate the following project-specific NEPA improvements:

    - Provide proactive initial guidance to proponents when they announce projects that are likely to require an EA or EIS. Proactive coordination between BLM and the proponent would increase efficiencies and save time once the environmental analysis begins.

    - Establish clear criteria for what constitutes extraordinary circumstances for project NEPA documents and implement these criteria through an Instructional Memorandum and the NEPA handbook. BLM should also implement an appeal process to enable project proponents to challenge decisions regarding the level of environmental analysis required for a project.

    - Identify known anticipated impacts from proposed projects ion NEPA documents, and should not incorporate or require information based on purely speculative impacts. The scope of NEPA documents should be limited to information that is truly required for NEPA compliance. Field offices should be directed to stop requesting ad hoc information not required by regulation, statute or official BLM policy.

    - Develop stipulations and restrictions attached to NEPA documents in coordination with the project proponent and based on operator-committed measures. BLM should also finalize EISs based on currently identifiable impacts, and not postpone completion while awaiting new information to surface.

- Assign strike teams to EAs that exceed six months and EISs that exceed eighteen months. These strike teams could be composed of planning specialists, perhaps at the state office level, who have the expertise to move forward expeditiously with NEPA documents, as often staff at the field office level are not as experienced in the NEPA process and focused on other tasks.

- Inform project proponents at least every four to six weeks regarding where NEPA documents are in the process, the cause of delays, and what BLM is doing to move forward.

- Issue an IM directing state and field offices to develop NEPA templates for both EAs and EISs, including questions related to on-the-ground factors in the states and planning areas that can be answered simply. The IM could also include a template for common aspects nationwide as a starting point.

- Provide project proponents with draft documents before the public. BLM should accept clarifications from companies and make any adjustments before they are published in the Federal Register for official public comment. Doing so would reduce the amount of work BLM must spend responding to public comments and allow for additional collaboration and problem solving between the project proponent and BLM, saving resources and time.

- The Secretary should rescind Secretarial Order 3310 on Protecting Wilderness Characteristics on Lands Managed by the Bureau of Land Management. Congress has explicitly denied funding for the implementation of this order because the designation of "Wild Lands" is a violation of FLPMA's multiple-use mandate, yet BLM still treats "lands with wilderness characteristics" as de facto wilderness.

- BLM should also rescind IM 2011-154, Requirements to Conduct and Maintain Inventory for Wilderness Characteristics and to Consider Lands with Wilderness Characteristics in Land Use Plans, and IM 2011-147, Identification of Areas with Broad Public Support for Possible Congressional Designation as Wilderness.

- BLM has identified over 60 different land use designations used in RMPs, many of which may lead to additional restrictions on the use of the land. One example is the Area of Critical Environmental Concern (ACEC) designation, which is authorized by FLPMA but are often identified without adequate public comment. The Eastern Interior RMP, finalized on January 3, 2017, designated over 2 million acres of ACEC, much of which was recommended for closure to mineral entry and mineral leasing. BLM should further evaluate the need for these numerous land use designations as a part of the ongoing review of its planning process working with state, local, and tribal partners to incorporate efficiencies and update policies on the use of land use designations that may burden or hinder energy development on Federal lands.

- Furthermore, FLPMA defines a withdrawal as "withholding an area of Federal land from settlement, sale, location, or entry, under some or all of the general land laws. . .." 43 U.S.C. § 1702(j). For tracts of lands greater than 5,000 acres, the Interior Secretary must provide Congress a variety of information in order to fully disclose the closure's impacts, costs, and need so that Congress can decide whether to disapprove the withdrawal. A withdrawal also requires public notice and hearing, and consultation with state and local governments. 43 U.S.C. at § 1714(c)(1)-(12), (h); 43 C.F.R. Parts 2300, 2310. BLM should not continue to effect a *de facto* closure of thousands of acres of public lands to oil and gas leasing without following FLPMA's Section 204 withdrawal procedures.

4. **Revising and simplifying Onshore Orders 3, 4 and 5 to ensure more equitable and timely implementation**

BLM should make common-sense changes to onshore orders 3,4, and 5 to reduce their overly burdensome nature.

- Recommended Overall Policy and Approach: The simplest and most equitable means of modifying the regulations would be to adopt the American Petroleum Institute (API) and GPA Midstream (GPA) standards in their entirety. The API and GPA standards are based on proven measurement technologies and constitute the consensus of industry's foremost experts in oil and gas measurement. Participation by government agency representatives in the API standards program allows for input by these representatives on the standards referenced by BLM.

- Facility Measurement Points (FMP): Implement a phase-in approach for FMP approvals, with one year to comply for wells with greater than 5,000 MCFD/500 BOPD; two years for 1,000 – 5,000 MCFD/100-500 BOPD; and three years for less than 1,000 MCFD/100 BOPD.

- Cancellation of all Variances, Commingling Agreements, and Off-Site Measurement Agreements: Continue to honor all variances, commingling agreements, and off-site measurement agreements approved prior to the effective dates of the new rules and the new rules should only be applied to applications submitted after the effective date of the new rules.

- Site Facility Diagrams: Each operator is responsible for compliance with the requirements of the Rules and the BLM should not hold one operator responsible for information that is the duty of another operator to provide the agency. We urge removal of the requirement to submit information on non-operated facilities, and clarification that the obligation arising under these subsections of the rules does not require a regulated party to submit information on a facility that it does not operate.

- Existing Commingling and Allocation Approval: The practice of commingling offers a number of operational benefits. Adding unnecessary operational barriers and/or costs to commingling would result in otherwise recoverable oil and gas reserves being left in the ground, a matter of physical and economic waste for both operators and the federal government as the steward of public lands and collector of royalty and other revenues therefrom on behalf of the nation. BLM should incorporate into the rule a definition of "economically marginal" that would establish when commingling of production is always allowed from a property meeting that definition.

Royalty Policy Committee
Planning, Analysis and Competitiveness Subcommittee
Offshore Oil and Gas working group
Proposed recommendations

1. **Set future OCS lease sales through 2024 at 12.5% royalty rate to bring into parity with new GOM shallow water rate.**
    a. The Western and Central GOM planning areas have been leased in whole or part multiple times on an annual basis (with very few exceptions) for decades. In this sense they are maturing basins with only the most challenging prospects remaining.
    b. "Frontier" area risks, challenging reservoir characteristics, Paleogene discoveries with massive new engineering requirements, HPHT issues, record depths, tight rock, and other 21st century factors (including seasonal restrictions in Alaska) contribute to substantially more cost-and-time-intensive projects to safely appraise, develop, and produce.
    c. In spite of these obstacles and challenges, there are substantial additional resource volumes still accessible and producible under the right leasing, fiscal, and regulatory terms.

2. **Establish a clearer, more workable process for royalty relief or reduced royalty rate for declining or particularly costly fields.**
    a. Similar rationale as above.
    b. BSEE has discretion to offer post-lease royalty relief to increase production as noted in "Designing Offshore Oil and Gas Lease Sales" of Dec. 15, 2017. However, it is reported widely that the process for obtaining such relief is not in practice clear, and not exercised with any frequency.
    c. A recommendation is that BSEE hold a workshop to discuss how it might provide transparent guidelines for granting relief, especially for deepwater projects with complex reservoirs and high appraisal costs.

3. **Increase the offshore acreage available for oil and natural gas leasing.**
    a. Without expanded acreage, the urgency of above recommendations grows and there is less opportunity to compare frontier/underexplored opportunities with those in mature regions.
    b. DOI should set and abide by targets to keep OCS resources competitive by regularly making the best acreage available under reasonable timelines.

Royalty Policy Committee
Planning, Analysis and Competitiveness Subcommittee
Alaska Working Group
Proposed recommendation

DOI Should:

1) Conduct a lease sale in the 1002 Area of the Arctic National Wildlife refuge as soon as practicable and ahead of the statutorily required timeline.
    a. The Department of Interior should expeditiously and carefully take all the necessary steps to conduct the first lease sale within the 1002 as soon as is reasonably practicable and consistent with all required due diligence and review.
    b. A prompt first lease sale will allow industry to more quickly initiate exploration and potentially field development, which in turn will more quickly realize federal royalty production and return to the federal treasury.

Royalty Policy Committee
Planning, Analysis and Competitiveness Subcommittee
Non-fossil/Renewables working group
Preliminary recommendations

This work group was established to analyze opportunities to improve the economics of non-fossil and renewable energy development on federal lands. To date, two issues have been identified which the work group supports for further investigation, though not yet prepared to provide concrete suggestions for improvement to the RPC. We wanted to provide the RPC with an opportunity to review and provide input on these preliminary recommendations.

Preliminary recommendation #1: BOEM should conduct additional offshore wind lease sales on a scheduled basis to increase predictability and opportunities for developing this resource in the U.S. Outer Continental Shelf.

- Increasing opportunities for offshore wind development will increase revenue generation to the U.S. Treasury. It will also spur investments in local economies, creating job growth and avoiding the need to export hard-earned energy dollars. Harnessing this resource and engaging industry requires a significant commitment from the agencies responsible for leasing and opening the OCS. Experience from Europe has shown that a significant and consistent commitment to annual leasing is necessary to establish a supply chain in the offshore wind industry. By making this commitment, the Administration will demonstrate a long-term interest in investing in the domestic offshore wind industry. Input and dialogue with interested parties should establish parameters for determining the necessary amount of developable resource leasing and timing intervals for lease offerings.

Preliminary recommendation #2: BOEM needs to review and, if appropriate, revise the operating fee it assesses on offshore wind development.

- BOEM is required to receive a “fair return” for development of its resources. For its offshore wind energy program, the three primary revenue sources include a bonus bid, a rental and an operating fee.
- The operating fee is comprised of five components: nameplate capacity, hours per year, capacity factor, power price and an operating fee rate. On its face, this computation seems simple. But in practice it has been difficult to calculate and to find agreement on proper inputs.

- BOEM has indicated that this is an area worth further investigation. Advice from the RPC in support this effort should align with the concepts of simplicity, predictability and understandability.

Royalty Policy Committee
Planning, Analysis and Competitiveness Subcommittee
Studies Work Group
Proposed recommendation

1) **(Short-term)** The following recommendation was developed with the objective of providing DOI/BOEM with insight into what factors BOEM should consider in order for the U.S to remain competitive with emerging areas. The RPC recommends that:
    a. The Department of the Interior procures a study that assesses and compares 3 regimes (U.S. GOM, Guyana and Mexico).
    b. The study will assess the following factors: current tax laws, royalty/royalty equivalents (e.g. profit sharing) and other revenues, and lease block sizes.
    c. The study will use recent lease sales (conducted over the last ~3 years) within each regime, examining trends – particularly if there were big finds within an area – and seek to assess if there are common drivers across the regimes encouraging development or widely divergent drivers for development.

2) **(Long-term)** The following recommendation was developed with the objective to provide the Department of the Interior (DOI) and the RPC with information based on current market conditions and regulatory policies. The RPC recommends that:
    a. The Department of the Interior pursue a contract with a 3rd party consultant to update the IHS/CERA Comparative Assessment of the Federal Oil and Gas Fiscal System (October 2011) so that the assessment reflects current market conditions and regulatory policies.
    b. DOI staff, with advice from RPC members as appropriate, should review the U.S. locations as well as the international locations selected in the original study and consider whether to update the selected locations to ensure that relevant and emerging markets are properly covered. Possible U.S locations that could be considered for inclusion within the study are onshore Federal, State and/or private lands and offshore shallow and deepwater Federal lands.

Royalty Policy Committee

Planning, Analysis and Competiveness Subcommittee (Economics) Recommendations

Economic Subcommittee Members

Colin McKee – co-chair	Lynn Helms
Randall Luthi – co-chair	Alby Modiano
Clinton Carter	Chris Crowley
Stella Alvarado	Kevin Simpson
Kathleen Sgamma	John Crowther
Jennifer Cadena	John Sweeney
Emily Hague	Matthew Adams
Patrick Noah	Marisa Mitchell

Ex Officio & Federal Members

Vincent DeVito – IOS – Chairman

Katharine MacGregor – IOS

Scott Angelle – BSEE

Walter Cruickshank – BOEM

Tim Spisak – BLM

Ben Simon – IOS

Chris Stolte – IOS

Renee Orr – BOEM

Adam Stern – IOS

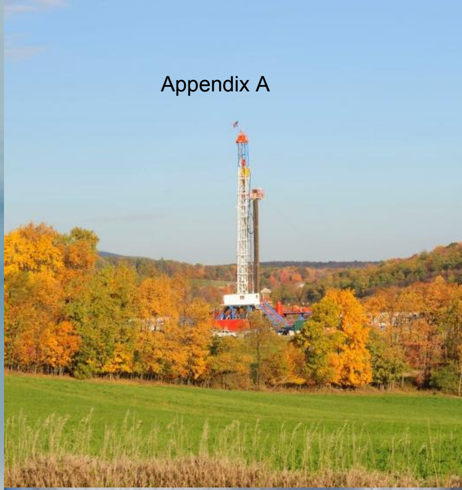
Christian Crowley – IOS


Economics Subcommittee Working Groups

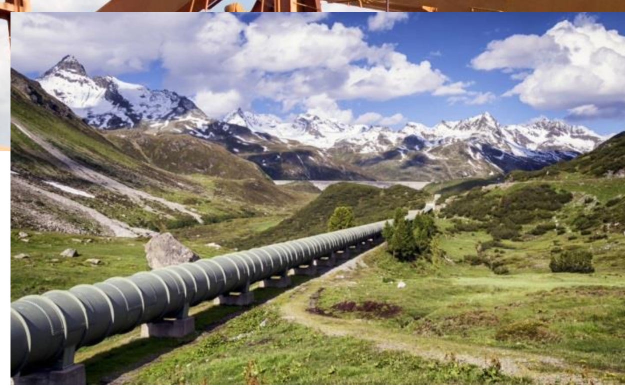
- Onshore Oil & Natural Gas
  Kathleen Sgamma
- Offshore Oil & Natural Gas
  Kevin Simpson
- Coal
  Matthew Adams
- Non-fossil/Renewables
  Colin McKee
- Future Studies
  Emily Hague

Onshore Recommendations

- Reduce timelines for project approval, including APDs, ROWs, sundries, lease nominations and unit agreements
- Limit the federal nexus of wells without a majority federal interest
- Improve land use planning and NEPA Approvals
- Revise and simplify Onshore Orders, 3, 4 and 5 to ensure more equitable and timely implementation



Onshore



Onshore Next Steps

- Continue to study and make recommendations from the Review of the Department of the Interior Actions that Potentially Burden Domestic Energy

968+

Offshore Recommendations

- Set future OCS lease sales through 2024 at 12.5% royalty rate
- Revise, clarify and simplify process for granting varying royalty rate for declining or particularly costly fields
- Increase offshore acreage available for oil and natural gas leasing

Offshore

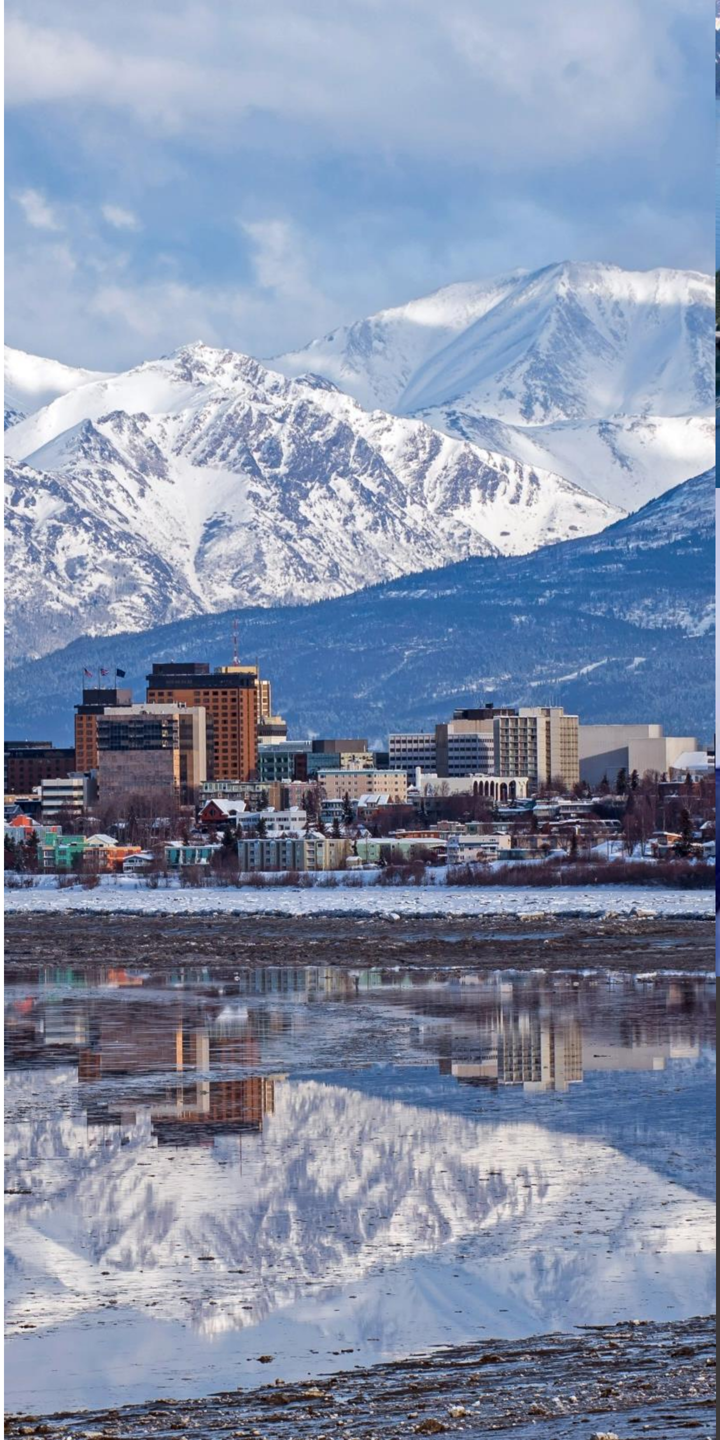
Appendix A

Offshore Next Steps

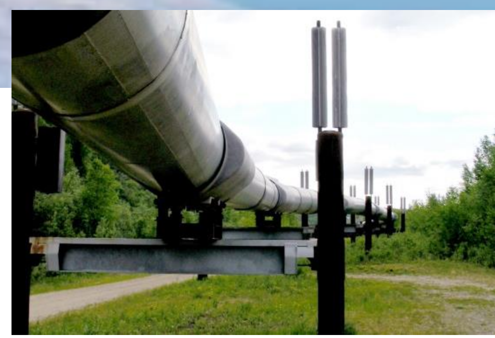
- Continue to evaluate recommendations to Interior including consideration of varying size of lease blocks
- Other

Alaska Recommendations

- Interior should conduct a lease sale in the 1002 area of ANWR ahead of statutory deadlines



Alaska



Alaska Next Steps

- Will continue evaluation of recommendation concerning implementation of executive and secretarial orders regarding the NEPA process in Alaska
- Will continue evaluation of recommendation to revise ONRR regulations and policies regarding transportation costs for Alaska offshore and remote

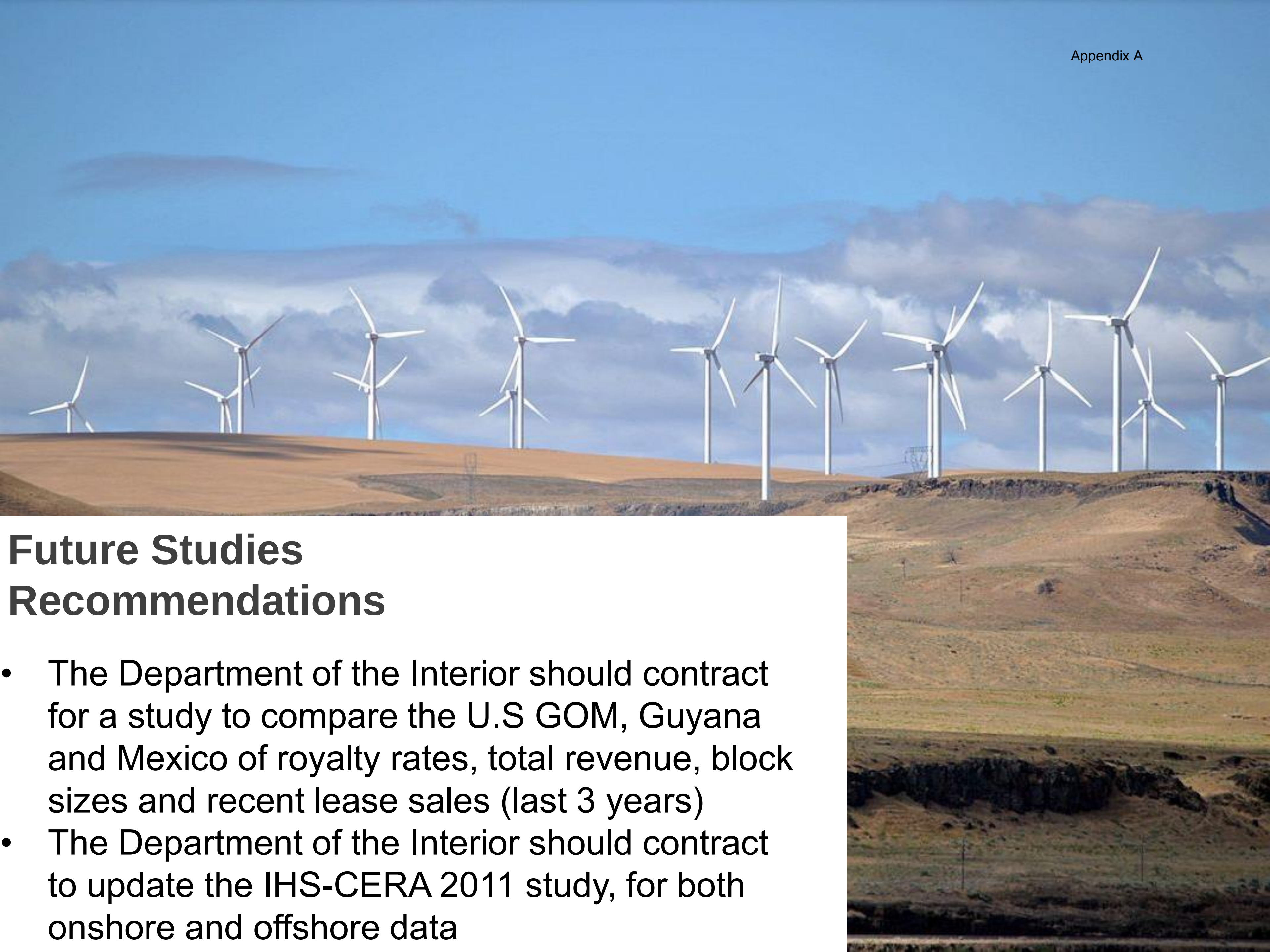
Coal Next Steps

- No recommendations at this time
- Will continue to evaluate recommendations concerning determination of fair market value for third party transactions
- Evaluate bonus bid payment schedule

Non-Fossil/ Renewables Next Steps

- Continue evaluation of recommendation for Interior to set long-term goal of twenty gigawatts of offshore wind resources

- Continue evaluation of recommendation to revise the operating fee

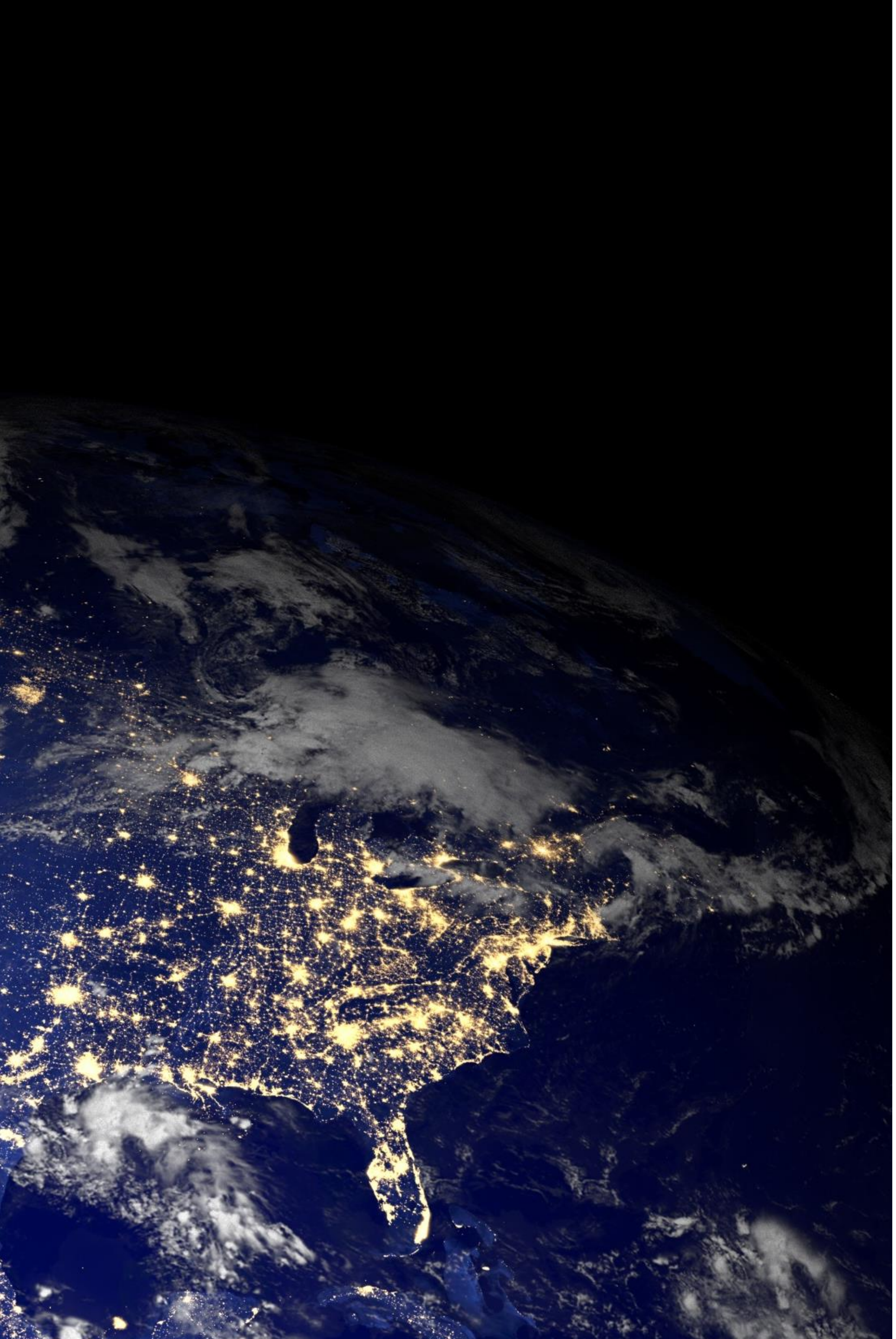


Future Studies Recommendations

- The Department of the Interior should contract for a study to compare the U.S GOM, Guyana and Mexico of royalty rates, total revenue, block sizes and recent lease sales (last 3 years)
- The Department of the Interior should contract to update the IHS-CERA 2011 study, for both onshore and offshore data

Future Studies
Next Steps

- Receive recommendations from the other work groups on potential areas for study

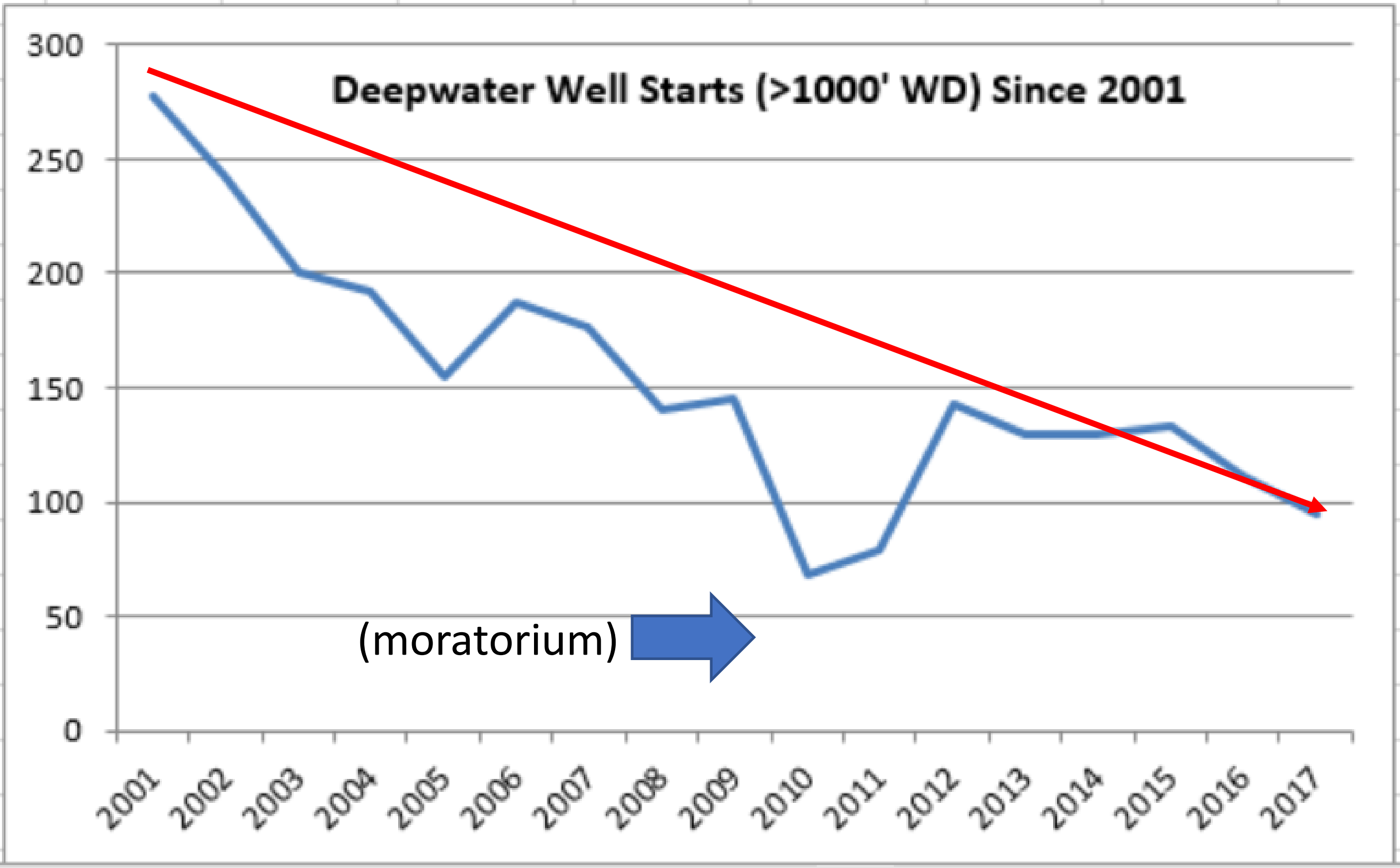


Conclusion

15 year sustained decline in deepwater well starts.

Appendix A

	Deepwater Wells (>1000') Since 2001
2001	277
2002	243
2003	200
2004	192
2005	155
2006	187
2007	176
2008	140
2009	145
2010	68
2011	79
2012	143
2013	129
2014	129
2015	133
2016	111
2017	95



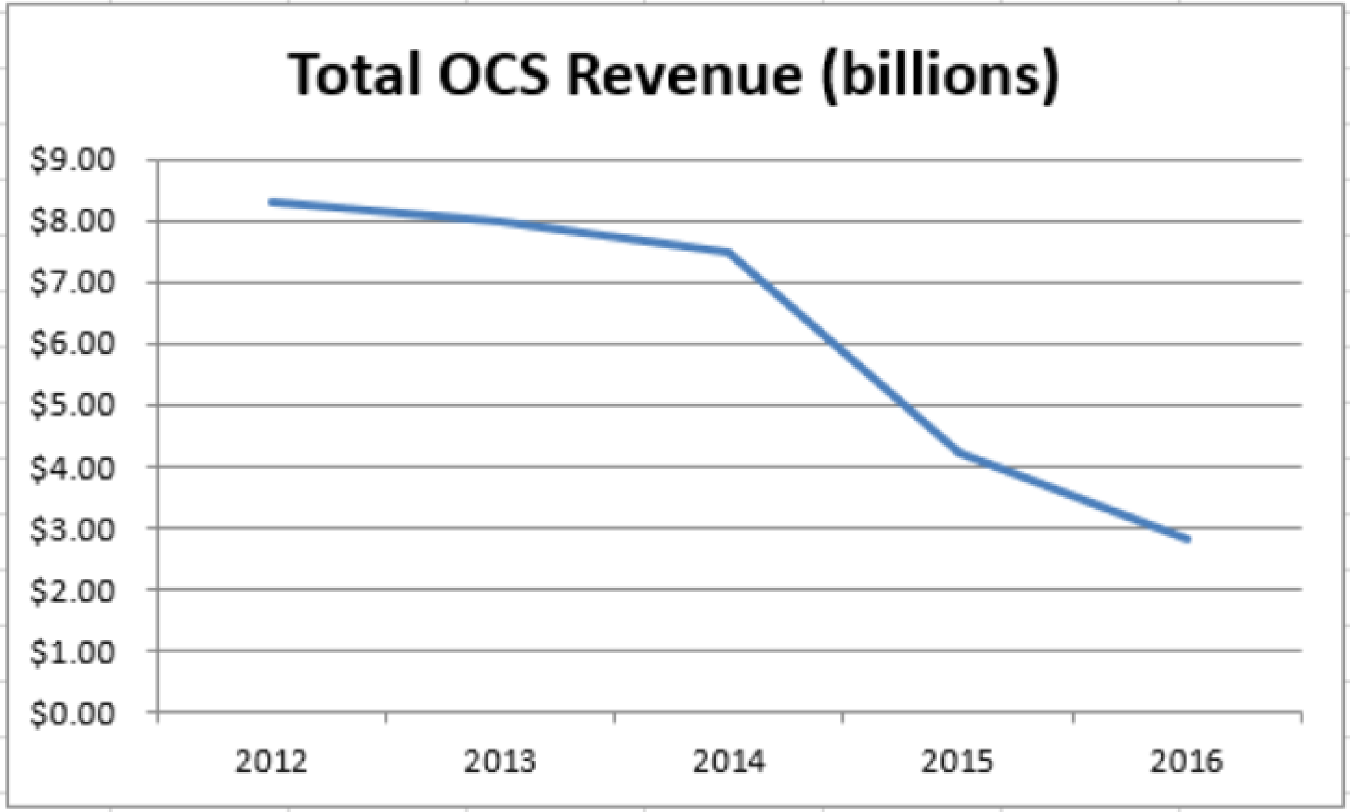
GOM faces rapid increases in depletion rates as reported by Schlumberger (March 2017). According to Schlumberger, deepwater GOM depletion rate is approaching 25%. These rates will accelerate further absent increases in drilling and reserve additions. The OCS program's survival is hinges on increased exploration activity.

10 year sustained decline in revenue

Appendix A

	Total OCS Revenue
2006	$8,214,724,747.76
2007	$7,299,243,627.21
2008	$17,174,236,772.66
2009	$4,523,979,142.05
2010	$6,536,890,231.64
2011	$6,656,578,120.94
2012	$8,325,530,575.18
2013	$7,958,969,927.54
2014	$7,489,351,623.25
2015	$4,189,584,797.18
2016	$2,813,832,536.24

	Total OCS Revenue (billions)
2012	$8.30
2013	$8.00
2014	$7.50
2015	$4.20
2016	$2.80



Source: ONRR Data. (CY 2017 data not yet available)

- Leasing revenue declining

- $538 million/central sale 235/March 2015

- $22 million/western GOM 246/aug 2015

- $176 millon/ central sale 241/March 2016

- $18 million/western sale 248/August 2016

- $274 million/central sale 247 /March 2017

- $121 million/areawide sale 249/August 2017

What might drive the decline which is in control of the gov't?

"The wide ranges of **<u>government takes between 53% for profitable projects to 86% for marginal projects in Deepwater GOM suggests a highly regressive fiscal system that penalizes marginal fields</u>**." P.5

"**<u>The GOM is an attractive investment environment; however it is also among the most expensive</u>** next to Alaska and other arctic environments. As exploration and production move beyond 5,000 feet, which seems to be the area with the greatest growth potential in the GOM according to EIA and DOI, achieving desirable rates of return is going to be quite challenging. P. 60

"...the **<u>GOM nominal royalty rate is already higher than all offshore oil and gas jurisdictions</u>** outside the United States." P. 133

-IHS CERA BOEM (https://www.boem.gov/Oil-and-Gas-Energy-Program/Energy-Economics/Fair-Market-Value/CERA-Final-Report.aspx)

However, the challenge is that the key to unlock the next phase of significant volumes in the GoM lies with ultra-high-pressure exploration and development. What is still especially relevant to move projects forward in deepwater GoM are potential policy incentives specific to these ultra-highpressure developments. Without some stimulus, these volumes will struggle to compete with more attractive reservoirs in Brazil and Mexico.

Wood Mackenzie
A Verisk Analytics Business

Where does 12.5% come from?

"Despite the risk of instability, **the introduction of a 12.5% royalty rate significantly improves the attractiveness of the GOM fiscal systems.** However, this rate reduction may not prove sufficient to bring the GOM marginal fields on stream." P.147

"**The 12.5 percent royalty alternative improves the competitive position of the GOM fiscal systems** by placing them in the middle of the select peer group." P. 150

"Any increase of the already high royalty rate levied in the GOM will increase the risk of system instability. **Any potential gains from higher royalty rates are likely to be offset by reduced revenue** from signature bonuses and the slower pace of leasing." P. 150

-IHS CERA BOEM (https://www.boem.gov/Oil-and-Gas-Energy-Program/Energy-Economics/Fair-Market-Value/CERA-Final-Report.aspx)

What is different since 2011 Studies?

- GOM is more mature/developed.
- Sustained downturn results in projects being harder to finance. (Higher price environment enabled more options.)
- Mexico now a competitor.

Supporting non-industry commissioned studies

OCS Study
BOEM 2011-xxx

IHS CERA

Comparative Assessment of the Federal Oil and Gas Fiscal System

Final Report

U.S. Department of the Interior
Bureau of Ocean Energy Management

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

Wood Mackenzie
A Verisk Analytics Business

January 2018

Deepwater GoM: 5 things to look for in 2018

OCS Study BOEMRE 2011-013

Final Report

Policies to Affect the Pace of Leasing
And Revenues in the Gulf of Mexico
Summary Report

Economic Analysis, Inc.
91 Pt. Judith Rd., Suite 334
Narragansett, RI 02882

And

Marine Policy Center
Woods Hole Oceanographic Institution
Woods Hole, MA 02543

JAN 2018	FEB 2018	MAR 2018	APR 2018	MAY 2018	JUNE 2018	JULY 2018	AUG 2018	SEPT 2018	OCT 2018	NOV 2018	DEC 2018

Subcommittees continue work.

Subcommittees continue work.

February 27-28, 2018

2nd Committee Meeting

Houston, TX

June 5-6, 2018

3rd Committee Meeting

Albuquerque, NM

September 12-13, 2018

4th Committee Meeting

Denver, CO

2018

TENTATIVE TIMELINE FOR FUTURE COMMITTEE MEETINGS

Appendix B: Written Public Comment From February 28, 2018 RPC Meeting

TAXPAYERS for COMMON SENSE

February 28, 2018

Prepared Comments of Ryan Alexander, president of Taxpayer for Common Sense, to the Royalty Policy Committee at its second meeting in Houston, Texas

Good afternoon. Thank you for the opportunity to offer comments today. My name is Ryan Alexander and I am president of Taxpayers for Common Sense (TCS), a non-partisan budget watchdog organization based in Washington D.C. My organization's mission is to achieve a government that spends taxpayer dollars responsibly and operates within its means.

For more than two decades, TCS has worked to ensure that taxpayers receive a fair return on the natural resources extracted from federally owned lands and waters. Royalties and fees collected from resource development are a valuable source of income for the federal government and should be collected, managed, and accounted for in a fair and accurate manner. As the resource owners, taxpayers have the right to fair market compensation for the assets extracted from our lands and waters, as would any private landowner.

For decades, royalty and leasing policies have cost taxpayers billions of dollars in lost revenue. Poorly managed federal energy and mineral programs at the Department of the Interior have led to years of reduced and royalty-free disposition of oil and gas, and undervalued coal. The RPC has the opportunity to recommend important reforms to the revenue collection and resource valuation processes.

But the recently released subcommittee meeting notes and recommendations have raised several areas of concern. In general, it is apparent that some of the subcommittees' materials exclusively reflect the perspective of industry stakeholders, rather than a consensus from the wide range of interests affected by natural resource policy. For example, several pages in the Fair Return and Value Subcommittee's materials exactly mirror a single company's comments to ONRR's 2016 Valuation rulemaking. Proposals from the subcommittee's other working groups regarding index pricing, allowable deductions for transportation costs, and coal valuation methodology also seem to largely represent a single perspective. Of course industry can and should advocate for their own interests and the interests of their shareholders. But the RPC and the DOI have a fiduciary duty to taxpayers and must make efforts to include broader perspectives in its recommendations and policy changes.

In addition to noting this general trend, we have specific concerns with the recommendations released by the Planning, Analysis, and Competitiveness Subcommittee.

Offshore oil and gas royalty rate

The recommendation from the Planning, Analysis, and Competitiveness Subcommittee to reduce the royalty rate for oil and gas leases on the Outer Continental Shelf to 12.5 percent is particularly troubling. If agreed to, this rate decrease would reverse more than a decade of policy first set by Secretary Dirk Kempthorne in 2007. The subcommittee states the recommendation is intended to create parity with shallow water royalty rates, but the reduction in the shallow water rate introduced in July of last year, broke with more than 30 years of precedent. Parity alone should not justify a royalty rate decrease, especially when it is likely to dramatically reduce revenue for taxpayers for decades to come without any guarantee of increased industry interest in OCS leases or production from them.

In short, the recommendation would move federal resource management policy in the wrong direction. The royalty rate for onshore federal oil and gas leases should be *increased* to match the offshore rate, rather than the other way around. Right now, the onshore federal royalty rate is lower than the rates imposed by the seven states in which 80 to 90 percent of all federal oil and gas is produced. Increasing the onshore rate would increase revenue to taxpayers by $200 million over the first 10 years, according to the Congressional Budget Office, and by much more in subsequent decades.

Increased Leasing

Another recommendation from the PAC subcommittee calls for increased acreage for leasing. Promoting the development of federal natural resources could lead to increased revenue from bonus bids, rents, and royalties. However, expanding access to federal lands and waters for resource development without rectifying critical flaws in the systems and agencies managing that development would not serve the public interest. In fact, expanding access in the absence of a demonstrated shortage, in conjunction with royalty rate reductions and generous lease term modifications, will cost taxpayers valuable revenue.

At the beginning of February, more than 70 percent of active leases, and acres under active lease, in federal waters were not producing oil or gas and not earning taxpayers any royalties. There is no demonstrated shortage of available acreage for offshore oil and gas development, and in this environment, increased leasing does not equal increased revenue.

Further, the repeal of the 2016 valuation rule issued by the Office of Natural Resources Revenue will decrease royalty collection from offshore oil and gas at current rates. Lowering royalty rates would only further erode taxpayers' return from offshore oil and gas development. In short, increasing the offshore acreage available for oil and gas leasing under current conditions would, and could only, benefit oil and gas companies at taxpayers' expense.

Reduced Royalty Rates

The PAC subcommittee also states that royalty rates for "costly" fields should be addressed. But if a lease is uneconomic using current technology and under current prices, then federal taxpayers cannot afford to step in and make it profitable.

Taking Increased Royalty Revenues off the table

Taxpayers for Common Sense is also concerned that significant rule changes at the Department of Interior are happening before review of the Royalty Policy Committee.

In the summer of 2016, the Office of Natural Resource Revenue finalized a new rule to update how the production of oil, gas, and coal on federal land would be measured and valued for royalty purposes. Taxpayers would have received an increase of $78 million in additional royalty revenues annually. The rule was first postponed and finally repealed by the Department of Interior, effective September 6, 2017. Though the charge of this committee squarely overlaps with the ONRR rule, the rule was fully repealed before the Royalty Policy Committee convened its first meeting.

Similarly, the Bureau of Land Management's Methane Waste Rule offered a much needed update to policies that date back to 1979. The rule updated reporting standards and embraced modern technologies like fracking that allow for the economic capture of natural gas that has been wasted for decades through leaks, venting, and flaring during energy production on federal lands. Provisions of the rule, if allowed to take effect, could have netted taxpayers tens of millions of dollars annually. The rule went into effect in January of 2017. Despite Congress rejecting an attempt to throw out the rule that May, the rule was postponed and suspended by the administration. And last week, the BLM proposed a new rule, which largely reverts backs to the outdated guidance that allowed taxpayers to lose billions. All of this without advisement of the Royalty Policy Committee.

These actions will cost taxpayers valuable royalty revenue. Going forward the RPC, as an independent entity, should examine all actions Interior undertakes that impact federal royalty collections and leave the harmful recommendations from these early subcommittee meetings on the table. There's still time to provide fair value for the American taxpayer and make recommendations that federal taxpayers can stand behind.

The Wilderness Society

February 28, 2018

My name is Pam Eaton. I am Senior Advisor for Energy and Climate at The Wilderness Society. TWS has more than one million members and supporters, and its mission is to protect wilderness and inspire Americans to care for our wild places. We support solutions that balance extractive uses like energy development with conservation through open, sustainable and science-based land management practices to maintain the long-term integrity of our landscape.

Our nation's public lands provide tremendous value to the American people—awe-inspiring wild places like the Arctic National Wildlife Refuge with its caribou herds and polar bears and Wyoming's Red Desert with its antelope and sage grouse; sacred landscapes like the Greater Chaco Canyon Region in New Mexico with its ancient ruins and roadways and the Bears Ears Region with its rock art and cliff dwellings and fossil finds. Communities depend on public lands for clean water and expect them to provide clean air and opportunities to experiences the joys of the outdoors and nature.

Protecting these incredible values is not a burden on industry, it is a duty that Congress entrusted to the Department of the Interior on behalf of the American people.

I am here today because this committee has the administration's ear.

As the Chairman noted, you have had 20 subcommittee meetings, hundreds of working group meetings and calls, meetings with ONRR staff in Denver, and these full committee meetings. You have 40 Department of the Interior staff members assigned to work with you, including more than a dozen from the Office of Natural Resource Revenue. You have a chairman, an executive director, facilitators, and a sizable budget provided by the Department of the Interior.

Other committees that afford opportunities for the public to share their knowledge and insight with the Department have not been so fortunate. Here are just two examples. The Department hasn't convened the National Parks Advisory Board, a board established in 1935 to bring together people committed to the mission of the National Park Service to provide advice to the Park Service Director, in over a year; BLM has not convened many of its resource advisory councils, created by law in 1995 to offer consensus suggestions on local issues to the BLM, in more than a year, because of delays in getting meeting dates, issuing council charters and filling council vacancies. But you, with considerable material and staff support from DOI, are meeting.

So I have come to Houston to urge that as you work to meet the charge set out in your charter—"to ensure the public receives the full value of the natural resources produced from Federal lands"—that you consider the public interest—taxpayers, public land owners, and the environment—as part of value Americans receive from public lands.

Proposals currently on the table for a vote today, have significant implications for the public's purse and for the other wealth provided by our public lands. These include proposals to:

- cut the OCS royalty rate by a 1/3
- to allow coal companies to set the value they pay for coal in three different ways
- rush forward with leasing in the Arctic National Wildlife Refuge
- reduce the protections available to protect public lands in the name of "improving the land use planning process"

At a minimum, as part of your deliberations and before you vote, you should have an analysis of each of these proposals and how each affects the focus of your charter: "the fair market value of and on the collection of revenues derived from the development of energy and mineral resources on Federal and Indian lands."

I am glad to hear some committee members asking about the revenue impacts of recommendations—and dismayed to hear that those implications have not been considered, even in a basic manner.

The current system costs taxpayers millions in lost revenue, and compromises access to public lands. Most Western states charge a higher and fairer royalty than DOI charges for onshore oil and gas. State oil and gas royalty rates average between 16.67 percent and 18.75 percent - up to 50 percent higher than the current, minimum federal rate of 12.5 percent. Notably, Texas charges 25 percent royalty for its lands. And recently Colorado raised its royalty rate on state trust lands to 20 percent in 2016. Raising the federal oil and gas rate to at least the rates charged by states would ensure that the American people receive the revenue they deserve for their land and resources; and that state budgets and local community coffers can fund public activities and programs.

And I am glad that the committee limited the scope of the recommendation to "Improve the Land Use Planning Process and NEPA Approvals," and not the laundry list of proposed changes that attack the consideration of the lands values in the process, like consideration of wilderness values. Ensuring that the public receives fair value from public lands is not limited to royalty rates.

At least one member of the committee asked for recommendations on issues to address. In the petition below, which we filed in September 2017 and provided to this committee back in October, we identify fiscal terms and management processes regarding oil and gas leasing that need reform to yield the legally fair market value return to the American people for the resources they own and to fulfill the Department's multiple use mandate.

In addition to charging higher royalty rates, the petition asks Interior to meet its legal obligations to manage public lands for multiple uses and ensure a fair return of revenues to the public in the following ways:

Addressing unproductive, speculative leasing. Today, many leases in the West are speculative, held for years without production. TWS research shows that 90% of BLM managed subsurface mineral acres are open to oil and gas leasing and of the 27 million acres under lease in 2016, only 12.7 million acres were actually producing energy. That means 14 million acres of publicly owned minerals under lease to oil and gas companies were just sitting there. The industry is also sitting on top of 7,950 approved drilling permits that are not being used. In 2016 alone, BLM issued 2,184 drilling permits, of which only 847 were used. In addition to unused permits and non-producing leases, industry is holding approximately 3.25 million acres of federal leases in suspension; meaning an additional 10% of the total acreage under lease nationally is not being put to productive use.

We propose several reforms to encourage leaseholders to produce or give up their speculative leases. These include:

- **Increasing rental rates** on federal leases to a level sufficient to incentivize oil and gas production so that the percentage of federal leases that produce energy would rise well above the current, unsatisfactory levels (e.g., only 50 percent in the Rocky Mountain states).
- **Increasing minimum lease bids**, as recommended by the Congressional Budget Office, to deter companies from purchasing leases for speculative purposes only.
- **Reforming lease suspension practices** to establish rigorous standards guaranteeing that undeveloped oil and gas leases are either diligently placed into production or cancelled so that the land can be managed for other beneficial uses.
- **Updating lease reinstatement practices** to require consistent and higher standards of justification for reinstating lapsed leases, with minimal tolerance for defaults on rental payments.

Other recommendations include:

- **Updating bonding requirements** to reflect current costs associated with reclamation and restoration of lands used for oil and gas production. In the West, the number of orphan wells is increasing, with developers getting what they want and leaving states and their taxpayers to pick up the tab for cleanup. That has to end.
- **Stopping the leasing of lands** with low potential for oil and gas production or with significant conflicts with wildlife, cultural, scenic, recreation, or other values.

If there is any talk of “dominance” in this committee, we urge that it be about the dominant and over-riding importance of conserving all of the values of America’s public lands, not just promoting fossil energy and maximizing private value at public expense.

PETITION TO THE DEPARTMENT OF THE INTERIOR AND BUREAU OF LAND MANAGEMENT TO INITIATE RULE-MAKING AND ISSUE GUIDANCE TO MODERNIZE THE ONSHORE OIL AND GAS PROGRAM FOR THE BENEFIT OF ALL AMERICANS

Submitted September 14, 2017

I. Executive Summary

This petition is submitted under the Administrative Procedure Act, which gives citizens the right to request action from a federal agency to issue, repeal or amend a rule, and entitles them to a prompt response. The petition asks the Department of the Interior to reform the fiscal terms and management processes regarding oil and gas leasing to yield the legally-required fair market value return to the American people for the resources they own and to fulfill the Department's multiple use mandate. The proposals made here are intended to maintain oil and gas production from public lands most suitable for that purpose while generating greater revenues and greater public benefits through more productive use of certain lands for other commercial, recreational, and conservation uses.

These beneficial results will result from more rigorous, market-oriented fiscal terms and management practices that ensure public lands are efficiently, productively and appropriately used for public purposes and that the waste and neglect of resources due to speculative holding of chronic, non-producing oil and gas leases are minimized if not eliminated. The proposals will not detract from oil and gas production. To the contrary, the cumulative effect of the proposed changes is to better ensure that economically-feasible, oil and gas leases end up in the hands of diligent and competent producers of oil and gas, and are not held unused by non-producing speculators.

The problem: current practices tie up lands without producing energy or revenues.

Poor, indecisive and inefficient Interior management of oil and gas resources provides hidden subsidies to speculators who do not diligently pursue development. Because Interior often fails to actively manage public lands with dormant oil and gas leases for other public uses, it effectively denies the public—persons, organizations, and companies—the certainty they need to use these lands for beneficial economic, conservation, recreational or other purposes. When the federal agencies leave lands in limbo because of the remote possibility that a long dormant, low-value oil or gas lease might be developed some day, uncertainty reigns, and neither the public nor other industries can make long-term commitments to alternative uses of those lands. The economic, social and environmental benefits of those other uses are thus lost.

Below market royalty and rental rates, low minimum lease bids, inadequate bonds, lengthy and lax lease suspensions, unjustified reinstatements of lapsed leases, and leasing low potential lands encourages speculators to tie up federal lands often for decades—preventing decisions to either expeditiously develop the oil and gas resources for energy or, alternatively, maximize the benefits flowing from other uses of public lands. By subsidizing and enabling dormant leases, current practices tie up lands without producing energy or revenues for the American people and simultaneously preventing those lands from being used for other purposes. Scattered in checkboard fashion across the American West are neglected public lands not utilized for the greatest good because of Interior's mismanagement and misguided subsidies for non-beneficial uses. Interior's neglect of these lands fails the multiple use standard of federal law.

The solution: charging market rates and discouraging unproductive leasing will yield the right balance of uses and returns.

To provide the greatest benefit to the American public, Interior should incentivize the timely production of oil and gas from public leases by charging market rates at every stage of the leasing and production process, and also decisively managing land and resources to support the most appropriate combination of multiple uses. Federal leases are issued for terms (ten years) that are longer than those used by many states or private parties so the industry already has ample time to develop leased lands. Interior, as manager of all leases of public lands and minerals, should focus on making sure those leases are ended if they are not being used productively and ensure leases are yielding a fair return while they are tying up public lands. Accordingly, this petition asks Interior to more effectively meet the standards of multiple use management and a fair return of revenues to the public by:

1. Charging higher, market-tested royalty rates (such as those used by states and the private sector) instead of the inadequate, subsidy-providing 12.5% rate;
2. Increasing rental rates on federal leases to a level sufficient to incentivize oil and gas production so that the percentage of federal leases that produce energy would rise well-above the current, unsatisfactory levels (e.g. only 50% in Rocky Mountain States);
3. Increasing minimum lease bids, as recommended by the Congressional Budget Office, to deter companies from purchasing leases for speculative purposes only;
4. Updating bonding requirements to reflect current costs associated with reclamation and restoration of lands used for oil and gas production;
5. Reforming lease suspension practices to establish rigorous standards guaranteeing that undeveloped oil and gas leases are either diligently placed into production or cancelled so that the land can be managed for other beneficial uses;
6. Updating lease reinstatement practices to require consistent and higher standards of justification for reinstating lapsed leases, with minimal tolerance for defaults on rental payments; and
7. Stopping the leasing of lands with low potential for oil and gas production and managing those lands for other purposes of greater benefit to the public.

The combination of these policies will generate millions of dollars annually for the American people, as well as states and local communities that benefit from federal oil and gas production. As numerous economic and fiscal studies indicate, higher royalty rates will generate large amounts of additional revenue with negligible impact on production. Indeed, several of the other changes proposed here will ultimately incentivize more timely production of oil and gas from federal lands and minerals, which raises the prospect for a net increase in energy production overall. Finally, and more importantly, a diversity of beneficial uses of federal land will expand as the waste and neglect of lands with dormant, speculative leases decline. Overall, better management of public lands will result in better uses in the right places, including renewable energy, recreation and conservation. More rigorous, decisive and efficient management will greatly increase the revenues and benefits to the American people from public lands and minerals.

II. Context and Overview

Petitioners request the Department of the Interior (Interior) and Bureau of Land Management (BLM) develop regulations and policies to update the fiscal aspects of its management of onshore oil and gas leasing and development.

On April 15, 2015, BLM issued an Advanced Notice of Proposed Rulemaking (ANOPR) seeking input on potential changes to fiscal policies related to its onshore oil and gas leasing program. As the agency stated: "The anticipated updates to BLM's onshore oil and gas royalty rate regulations and other potential changes to its standard lease fiscal terms address recommendations from the Government Accountability Office (GAO), and will help ensure that taxpayers are receiving a fair return from the development of these resources." 80 Fed. Reg. 22148 (Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements, and Civil Penalty Assessments). BLM should follow up on this recognition, as well as similar findings related to other aspects of managing its onshore oil and gas program, to both provide a fair return to the taxpayers who own these resources and also better fulfill its broader obligations as stewards of our public lands. BLM should issue updated policies and commence or continue rulemakings to address these major inadequacies in its onshore oil and gas program.

This Petition identifies two types of policies that need to be updated:

(1) Revenue-generating policies, which involve payments that are being made but not at sufficient levels to ensure a fair return to the American people and to encourage timely development of resources. These policies include royalty, rental and bid rates.
(2) Hidden subsidies, which are causing lost revenues needless giveaways to the oil and gas industry and are undermining multiple use management. These policies include bonding rates, lease suspensions, lease reinstatements and leasing low potential lands.

Through the requested rulemaking, Interior and BLM have an opportunity to structure a fiscally responsible oil and gas program that reflects multiple use and sustained yield in the 21st century. BLM must modernize fiscal elements of its oil and gas program to responsibly steward our public lands and ensure a fair return to American taxpayers.

BLM's onshore oil and gas leasing program has been plagued with economic and environmental problems, stemming from low leasing rates, low royalty rates, low bonding rates and high emissions and gas waste. The Government Accountability Office has repeatedly concluded that "the inflexibility of royalty rates to changing oil and gas prices has cost the federal government billions of dollars in foregone revenues." GAO-08-691 (Oil and Gas Royalties) at 16. Furthermore, GAO has found that Interior can recoup these revenues with "negligible" impacts on oil and gas production. GAO-17-540 (Oil, Gas, and Coal Royalties) at 16.

Additional systemic problems contribute to BLM's failure to recover revenue for federal resources and ensure producers are diligently developing leased lands. For example, inappropriate use of lease suspensions and unitization allows industry to hold leases indefinitely without production. As of March 2015, there were 3.25 million acres of federal minerals in suspended leases, many dating back to the 1980s and 1990s.[1] Because BLM regularly declines to adopt conservation management for lands encumbered by leases, holding leases in undue suspension is tantamount to removing those lands from multiple use. Similarly, the thousands of idle and orphaned federal wells could be better addressed by sufficient bonding, but instead are risking environmental damage and putting a financial burden on the BLM. Through this rulemaking process, BLM should take the opportunity to address these issues in a way that makes sound economic *and* environmental sense.

BLM is modernizing into an agency that embraces conservation as an integral element of multiple use and sustained yield. As provided in the Federal Land Policy and Management Act (FLPMA), 17 U.S.C. § 1701, et seq., multiple use management does not require the balance of uses on every tract of public land, but rather a combination of resource conservation and uses to "best meet the present and future needs of the American people." The notion that resource development must be balanced with conservation management is explicit in the definition of "multiple use":

> [T]he management of the public lands and their various resource values so that they are utilized in the combination that will best meet the present and future needs of the American people; . . . *the use of some land for less than all of the resources;* a combination of balanced and diverse resource uses that takes into account the long term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish*, and natural scenic, scientific and historical values*; and harmonious and coordinated management of the various resources without permanent impairment of the productivity of the lands and the quality of the environment with consideration being given to the relative values of the resources and not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output.

43 U.S.C. § 1702(c) (emphasis added).

Managing and planning for multiple use and sustained yield necessarily means that there must be a significant portion of public lands devoted to conservation in order to sustain public resources. Sustained yield does not support a focus on outputs from resource extraction or industrial uses. FLPMA specifically directs BLM to maintain in perpetuity "a high-level annual or regular periodic output of the various renewable resources of the public lands consistent with multiple use." FLPMA, 43 U.S.C. § 1702(h). Therefore, sustained yield requires BLM to sustain high-level yields of natural landscapes, scenic resources, clean air and water, wildlife, night skies, soundscapes, and opportunities for solitude, quiet-use, and primitive types of recreation.

BLM's current oil and gas leasing policies recognize that oil and gas development is but one use of the public lands which should be balanced with other multiple uses and considered on equal

[1] Data accessed through LR2000.

ground. Instruction Memorandum 2010-117 explicitly states that in some cases, oil and gas leasing is inconsistent with protection of other public lands resources and values. IM 2010-117 goes on to affirm that, **"Under applicable laws and policies, there is no presumed preference for oil and gas development over other uses."**

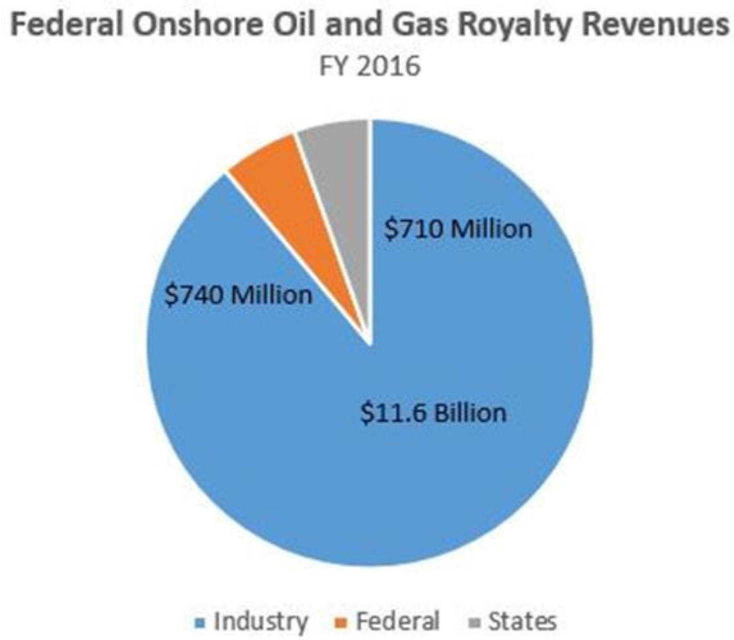
Courts have confirmed the agency's discretion and obligation to consider protecting environmental values. For example, in *New Mexico ex rel. Richardson v. Bureau of Land Mgmt.*, 565 F.3d 683 (10th Cir. 2009), the court rejected the BLM's argument that its analysis under the National Environmental Policy Act (NEPA) did not have to include an alternative that closed Otero Mesa to oil and gas drilling because doing so would violate the its multiple use mandate. *Id.* at 710. Noting that "a delicate balancing is required," the court explained that "[d]evelopment is a *possible* use, which BLM must weigh against other possible uses – including conservation to protect environmental values." *Id. (*emphasis in original).

BLM's onshore oil and gas program must be modernized to ensure that the agency is meeting its broader obligations to the American people. Public lands should not be automatically ceded to the oil and gas industry upon demand. Where public lands and minerals are turned over to the oil and gas industry, other resources must be protected and responsible development diligently pursued.

As has been shown by numerous studies, many aspects of the program are outdated and inadequate; key rates have not been updated for decades. Consequently, BLM is conservatively leaving millions of dollars on the table every year that should be compensating the American taxpayer for turning public lands and minerals over to the oil and gas industry. Instead of providing a fair return to taxpayers, oil and gas companies are reaping the benefits of the increased levels of oil and gas production from public resources. State, private and even offshore rates of return are significantly higher, showing that the BLM's approach can and should be improved.

A recent study found that, due to many of these outdated policies, including royalty rates, the oil and gas industry shares a very small percentage of what they collect from producing federal minerals with taxpayers. In FY 2016, companies developing federal lands and minerals gained some $11.6 billion selling oil and gas from public lands and minerals, but BLM collected only $1.4 billion in royalties.[2] The resulting half of this portion shared with states and counties is thus unfairly decreased, as well; these are unnecessarily small pieces of the pie.

[2] https://www.gao.gov/assets/690/685335.pdf; *see also* http://westernvaluesproject.org/rigged-taxpayers-pay-for-big-oil-companies-profits-from-public-lands/



Overall, modernizing the policies that are central to the federal onshore oil and gas program will boost revenues without hindering development while better fulfilling the BLM's legal obligations under FLPMA and the Mineral Leasing Act (MLA), as discussed in more detail below.

III. Interests of Petitioners

All Americans have a vested interest in the management and use of their public lands and minerals. To the extent that these public resources are being turned over to the oil and gas industry, taxpayers are entitled to a fair return. Lands and minerals held by the oil and gas industry general deprive citizens of the use and enjoyment of public and private split estate lands and resources for hunting, fishing and other types of recreation, solitude, clean air and water, renewable energy development, grazing, and other activities to support their own businesses. BLM's obligations including ensuring this interference with multiple use is justified. The parties submitting this petition are seeking to enforce those obligations, because the current onshore oil and gas program does not fulfill them.

Dan Bucks is an expert in public revenue and land management issues with over forty years of experience in state government administration. Over this period, he advised elected officials on natural resource revenue and growth management policies. He administered Montana's state and local revenue laws for coal, oil, gas, and other minerals. He initiated and oversaw Montana's participation in the joint federal-state mineral auditing program. He actively engaged Interior's policy making processes from 2015 forward on mineral leasing and royalty issues and testified to Congress on such matters. He has been a witness to four decades of changes in energy production on the Northern Plains—from the growth in Powder River Basin coal, to the Bakken oil boom in Bakken and the emergence of commercial wind farms. From this experience, he acquired a deep understanding of the relationship of these changes to the human and natural environment. He served as Director (2005-2013) and Deputy Director (1981-1988) of the Montana Department of Revenue, Executive Director of the Multistate Tax Commission (1988-

2004), Director of Science and Natural Resources, National Conference of State Legislatures (1980-81), Consultant to the Montana Governor's Office (1979-80), Bush Leadership Fellow (1977-1979) South Dakota State Planning Commissioner (1974-77), and South Dakota Director of Executive Reorganization (1971-1974).

The **Powder River Basin Resource Council** ("Resource Council") is a grassroots community conservation and family agriculture organization in Wyoming. Resource Council members live throughout the state of Wyoming, but the majority of them are rural landowners, many of whom live in a split estate situation with federally-controlled minerals underlying their lands. Resource Council members thus have a keen interest in the BLM's management of oil and gas resources.

Marjorie West is a member of the Resource Council. Along with her husband, Bill, Marge owns a ranch on Spotted Horse Creek in the Powder River Basin of Wyoming, where they grow dry land wheat and raise cattle. Her ranch was homesteaded by Bill's father and expanded by the family over the generations. The Wests' ranch includes a combination of private and federal oil and gas, and the family has been living with the impacts of development of these resources since the coalbed methane boom in the early 2000s. Now that coalbed methane has busted, the Wests are dealing with idle and orphaned wells that have been left on their land.

Leland (L.J.) Turner and his family own a 10,000-acre ranch near the town of Wright, Wyoming in the heart of the one of the largest oil and gas fields in the country. L.J.'s grandfather homesteaded the ranch in 1918 and it has been in the family ever since. The ranch currently has sheep and cattle, and is impacted by oil and gas development from a mix of privately owned and federally owned minerals.

The Wilderness Society is the leading conservation organization working to protect wilderness and inspire Americans to care for our wild places. Founded in 1935, and now with more than one million members and supporters, The Wilderness Society is committed to sound management of our shared national lands, which includes recognizing the values of some lands for conservation and recreation, while also continuing responsible energy development.

IV. <u>Policies requiring new rulemakings</u>

A. Revenue-generating Policies

1. <u>BLM has the duty and authority to modernize its revenue-generating policies for onshore oil and gas development.</u>

BLM has a legal obligation under FLPMA, the MLA and related authorities to modernize its revenue-generating policies for onshore oil and gas development. Under FLPMA, BLM must ensure that American taxpayers "receive fair market value of the use of the public lands and their resources. . . ." 43 U.S.C. § 1701(a)(9). This requirement is also found in the MLA, which demands regular adjustments to royalty and rental rates and minimum bids, in order to "enhance financial returns to the United States. . . ." 30 U.S.C. § 225(b)(1)(B); *see also id*. §§ 225(b)(1)(A), 225(d) (authorizing royalty and rental rates increases). Thus, BLM has a clear duty to update its revenue-generating policies and must do so now, given how outdated those policies have become and the significant amount of revenue that is not going to American taxpayers.

Congress never intended for onshore royalty rates to remain stagnant. That is why onshore royalties are set "at a rate of *not less than* 12.5 percent. . . ." 30 U.S.C. § 225(b)(1)(A) (emphasis added). This rate represents a floor which Interior must adjust upward as oil and production rises and to avoid the oil and gas industry enjoying windfall profits that rightfully belong to the American people. For instance, in 2009, Interior raised the offshore royalty rate from 12.5 percent to 18.75 percent, in response to rising oil prices.[3] However, even though onshore oil production has nearly doubled since 2008, the onshore royalty rate has not changed.[4]

BLM has a similar duty to increase rental rates. All federal leases are "conditioned upon payment . . . of a rental *not less than* $1.50 acre per acre" for the first five years and $2.50 per acre for the remaining years. 30 U.S.C. § 225(d) (emphasis added). These rates are well below what is currently needed to incentivize oil and gas development, as less than half of the leased acres on public lands are actually producing oil or gas.[5] As the Congressional Budget Office (CBO) recently explained: "A higher rental fee increases the cost of holding a lease, giving leaseholders an incentive to either explore parcels or return them to the government. In practice, the current incentive is weak because the fees are small relative to the cost of developing a lease."[6] Thus, current rental rates are not creating the necessary incentives to maximize revenue from the development of publicly owned oil and gas resources.

Finally, BLM must increase minimum bids, which are encouraging wasteful speculation by companies that are not diligently developing their leases. Under the MLA, minimum bids must be adjusted to "enhance financial returns to the United States. . . ." 30 U.S.C. § 225(b)(1)(B). Yet, the minimum bid for a competitive lease is just $2.00 per acre. This is well-below the level needed to deter companies from purchasing leases for speculative purposes. According to CBO, over one-quarter of competitive leases sold for the minimum bid between 2003 and 2012.[7] A separate analysis found that over half of the companies that currently hold federal leases in the Rocky Mountain states are not even recognized as "active" operators by state oil and gas commissions.[8] Not only would higher minimum bids help deter these companies from locking-up public lands to the detriment of other income-generating activities, like outdoor recreation, but they would also generate more revenue for taxpayers:

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[3] Congressional Research Service, Mineral Royalties on Federal Lands: Issues for Congress at 4 (Jan. 2015), *available at* https://www.everycrsreport.com/files/20150119_R43891_3bd50f51ada1b53821153ce674b442bc7df659de.pdf.
[4] Office of Natural Resources Revenue, Production Data, *available at* https://onrr.gov/About/production-data.htm.
[5] BLM, Oil and Gas Statistics, *available at* https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics#quickset-programs_oil_and_gas_statistics__5.
[6] Congressional Budget Office, Options for Increasing Federal Income from Crude Oil and Natural Gas on Federal Lands at 8, *available at* https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/51421-oil_and_gas_options.pdf.
[7] *Id*. at 18.
[8] Western Values Project, Rigged: Industry already has the keys to the kingdom, *available at* http://westernvaluesproject.org/industry-already-has-the-keys-to-the-kingdom/.

> Raising the minimum bid in an auction to $10 per acre and requiring that same amount to be paid for parcels leased noncompetitively would boost net federal income by an estimated $50 million over 10 years, CBO estimates. That effect is the net result of increases in federal income from higher bonus bids for some parcels, including all parcels leased noncompetitively, and decreases in rental and royalty income for parcels that attract no bids (though such parcels would have generated relatively little production and royalty income).[9]

For all of these reasons, BLM has an obligation under FLPMA and the MLA to modernize its royalty and rental rates and minimum bids, and to ensure that American taxpayers are receiving a fair return from onshore oil and gas development.

2. <u>BLM's revenue generating-policies are woefully outdated and no longer ensure that the American people are receiving fair market value for the use of public lands and resources.</u>

BLM's revenue-generating policies for oil and gas development are woefully outdated, have not kept pace with inflation, and are weaker than equivalent policies for offshore oil and gas development and those used by many western states. As a consequence of these weak and outdated fiscal policies, CBO predicts that taxpayers could miss out on roughly $1 billion in revenue over the next decade.

BLM has never updated its royalty rates for onshore oil and gas development. They have remained at 12.5% ever since 1920, when Congress first passed the Mineral Leasing Act. Since that time, oil and gas development – along with the oil and gas industry's profits – have grown exponentially. Oil production from onshore oil and gas wells has soared in recent years – more than doubling since 2007.[10] And there are nearly twice as many active wells on public lands – more than 94,000 – as there were 30 years ago.[11] Yet, in spite of this surging production, Interior has made little effort to increase royalty rates to ensure that taxpayers are getting their fair share.

Rental rates and minimum bids have also not been updated since 1987, and have not kept up with inflation. According to Taxpayers for Common Sense (TCS), a nonpartisan budget watchdog organization, rental rates

> should at the least be raised to follow inflation, and adjusted annually by regulation. According to the Bureau of Labor Statistics inflation calculator, $1.50 in 1987 is now $3.12, and $2.00 is now $4.17. An immediate increase in rental rates to these levels would not only increase income to ensure fair return to taxpayers, but would also create incentive for timely development rather than speculation on federal leases.[12]

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[9] CBO, Options for Increasing Federal Income from Crude Oil and Natural Gas on Federal Lands at 32.
[10] ONRR, PRoduciton Statistics, *available at* https://onrr.gov/About/production-data.htm.
[11] BLM, Oil and Gas Statistics, *available at* https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics.
[12] TCS, **Comments to the Bureau of Land Management (BLM) on the Oil and Gas Leasing; Royalty on Production, Rental Payments, Minimum Acceptable Bids, Bonding Requirements,**

TCS recommended similar adjustments for minimum bids. Not only would this generate increased revenues for taxpayers, it would also deter companies from engaging in wasteful speculation.

Interior's failure to modernize the fiscal structure for onshore development contrasts sharply with its approach for offshore development. In 2007, Interior initiated a series of updates to its offshore fiscal policies, "in an effort to ensure a fair return on oil and gas resources."[13] These included royalty rate increases of 50 percent, escalating rental rates in order "to encourage faster exploration and development of leases" and minimum bid increases "to account for increases in oil prices. . . ."[14] These changes are expected to generate several billion dollars in additional revenue over the next 30 years, and thus far, "demand [has] remained strong for newly offered leases. . . ."[15]

Private mineral leases typically have a royalty rate of 18 percent to 20 percent. Several western states have also taken steps to modernize their fiscal policies for oil and gas development, and to ensure that taxpayers are receiving a fair return on the development of publicly owned oil and gas resources. For example, in February 2016, the State of Colorado increased its royalty rate from 16.67 percent to 20 percent.[16] Since then, demand for state leases in Colorado has actually increased by 22 percent, based on the average number of acres leased per sale.[17] State officials agree with this conclusion, which is not limited to Colorado:

> according to state officials, there had been no slowdown in interest in new leases as of August 2016. In fact, Colorado state officials said they were unsure whether the higher royalty rate played much of a role in companies' decision making. Additionally, Texas officials told us that over 30 years ago, Texas began charging a 25-percent royalty for most oil and gas leases on state lands, and this increase has not had a noticeable impact on production or leasing.[18]

At this point, federal onshore royalty rates are lower than the rates used by every major western oil and gas producing state.[19] Thus, Interior's fiscal policies must be modernized, in keeping with recent changes for offshore development and by several western states.

3. BLM's outdated fiscal policies are costing taxpayers millions in revenue every year.

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and Civil Penalty Assessments (June 19, 2015), *available at* http://www.taxpayer.net/library/article/comments-to-blm-on-oil-and-gas-rulemaking

[13] GAO, Actions Need for Interior to Better Ensure a Fair Return 13 (Dec. 2013), *available at* http://www.gao.gov/assets/660/659515.pdf.

[14] *Id*. at 13-15.

[15] *Id*. at 14.

[16] *Id*. at 21.

[17] Colorado State Land Board, Oil & Gas Auction Information and Results, *available at* https://docs.google.com/document/d/1A8yfmfXmcMtx802wRxktdSuzkFeCrF5tE9XT8ms3Qa0/edit.

[18] *Id*. at 22.

[19] *Id*. at 9.

Raising federal onshore royalty, rental and bid rates to match or exceed federal offshore rates and rates charged on state and private lands would increase overall revenues and receipts generated by the federal onshore oil and gas program. Recent studies find that outdated federal onshore rates are costing taxpayers tens of millions of dollars in revenues every year.

Royalties, rents and bids are the primary source of revenue for the federal onshore oil and gas program. In FY 2016, the Office of Natural Resources Revenue (ONRR) collected $1.4 million in royalty payments, $123 million in bonus bids and $21 million in lease rental payments. Royalties provide the largest share of federal onshore oil and gas receipts.

Recent studies also find that raising the federal onshore royalty rate to levels consistent with state and private lands leases would generate tens of millions of dollars in additional revenues each year. An April 2016 CBO study found that raising the royalty rate to 18.75 percent would increase net ONRR income by $200 million over the next 10 years, with an identical amount going to the states.

An earlier, 2011 report by Enegis, LLC examined the effect of increasing the royalty rate to 16.67, 18.75 and 22.5 percent. Like the CBO study, the Enegis report found that net revenue would increase in each of the three scenarios, from $125 million to as much as $939 million over the next 25 years. Both the CBO and Enegis reports accounted for any decrease in leasing or production that might result from increasing federal rates.

Raising federal onshore rental and bid rates would also increase net revenues. In addition to analyzing royalty rates, the April 2016 CBO Report estimated that raising the minimum bid to $10/acre (for competitive and non-competitive leases) would increase revenues by $50 million over the next 10 years. This same study found that increasing the rental rate by $6/acre/year would generate an additional $200 million.

Raising the federal royalty, rent and bid rates would significantly increase revenues and receipts generated by the onshore oil and gas program. If these rates were updated to reflect rates charged on state and private lands, the federal onshore program would likely gain at least half a billion dollars in net revenues over the next decade, with similar amounts going to the states.

4. There are significant revenue-related benefits to modernizing the onshore program's fiscal policies.

Updating royalty, rent and bid rates would also confer other, less obvious benefits. ONRR splits half of all royalty, bid and rental revenues with state governments based on where federal leases are located. So state governments, many of which are struggling with budget shortfalls caused by the downturn in energy prices, would realize about half of increased revenues from reforming federal onshore rates.

Increasing bid and rental rates would also discourage speculation and encourage diligent development of federal leases. On average, operators on federal lands drill on only 1 in 10 leases issued by the BLM. At present, there are more than 16,000 unused, non-producing oil and gas leases on federal lands, covering more than 14 million acres. By making it more expensive to speculate, increasing bid and rental rates would encourage operators to drill and explore these unused leases, putting more leases into production and generating more royalty revenues.

Finally, by discouraging speculation, increasing bid and rental rates would help address opportunity costs associated with public lands oil and gas leasing. In making planning decisions, BLM often declines to manage lands with oil and gas leases for other resources and resource values, even when leases in these areas are unused and non-producing. Raising bid and rental rates would incentivize companies to purchase leases where they actually intend to develop, so that other, un-leased areas could be devoted to other important public lands uses. In this way, increasing bid and rental rates would help reduce opportunity costs associated with speculative leasing.

5. New revenue-generating regulations and policies

BLM should act on its own findings, as well as those of numerous external reviewers, and commence new rulemakings to update its royalty, bid and rental rates.

B. Hidden Subsidies

1. BLM has the duty and authority to update its policies regarding bonding rates, lease suspensions and reinstatements, and leasing low potential lands.

As noted above, FLPMA requires that BLM ensure a fair return for use of public lands and resources. BLM also has an obligation to ensure that the public lands are managed in accordance with principles of multiple use and sustained yield, such that the variety of uses and users of the public lands are given due consideration. Oil and gas leasing and development may not be treated as the dominant use of public lands at the expense of these statutory mandates.

Further, in leasing public resources, oil and gas companies agree to diligently develop those resources while also protecting the other resources of the public lands, while acknowledging the authority of the BLM to require such diligence. As stated in Section 4 of BLM's standard lease terms (Form 3100-011), when leasing public lands:

> Lessee must exercise reasonable diligence in developing and producing, and must prevent unnecessary damage to, loss of, or waste of leased resources. Lessor reserves right to specify rates of development and production in the public interest…

In addition, BLM's regulations and guidance set out obligations that require BLM to update these policies, as discussed in detail below.

2. BLM's policies on bonding rates, lease suspensions and reinstatements, and leasing low potential lands are essentially providing subsidies to the oil and gas industry and encouraging the speculative holding of dormant leases.

By not updating and clarifying policies on bonding, lease suspensions, lease reinstatements and leasing low potential lands, BLM is subsidizing the oil and gas industry's costs to hold inactive leases for excessive periods and to operate on public lands – in spite of the billions of dollars in industry profits from public lands drilling – and undermining the industry's obligations of diligent development. The failure to update and clarify these policies especially encourages non-active speculators to retain a large share of leases involving substantial land areas in an undeveloped state for years and even decades on end.

(a) Bonding

BLM's regulations require that bond amounts are to be set:

> …to ensure compliance with the act, including complete and timely plugging of the well(s), reclamation of the lease area(s), and the restoration of any lands or surface waters adversely affected by lease operations after the abandonment or cessation of oil and gas operations…

43 C.F.R. § 3104.1(a). BLM's guidance provides that the regulatory levels are minimums and also for adjusting bonding levels based on different risk factors that may arise on existing leases or existing unit, statewide or nationwide bonds. However, the agency's practice is to charge the regulatory minimum.[20]

BLM's bonding policies have not been updated in almost sixty years. Minimum bond amounts set in statute no longer reflect the true cost of reclamation or inflation and the agency's review and tracking procedures for determining bond adequacy and the government's own liabilities fall far short of where they need to be. As a result, orphaned and abandoned wells are left unclaimed while American taxpayers are left to cover the costs of the oil and gas industry's negligence.

The bond minimum of $10,000 for individual bonds was last set in 1960, and the bond minimums for statewide bonds—$25,000—and for nationwide bonds—$150,000—were last set in 1951. According to a 2010 GAO report, "If adjusted to 2009 dollars, these amounts would be $59,360 for an individual bond, $176,727 for a statewide bond, and $1,060,364 for a nationwide bond."[21] Based on inflation alone, current bond minimums are far lower than originally intended. Taking into account the increasing costs of reclamation further highlights the benefits given to oil and gas companies. A report by Inside Energy shows that the cost of reclaiming a single well can cost up to $527,829 and that some newer, deeper wells may cost more than $17 million per well to reclaim.[22] It is important to note that minimum individual bond amounts are set per lease not per well. With many leases containing multiple pads and multiple wells per pad, that $10,000 is even more inadequate. A later 2011 GAO report concluded, "Specifically, the minimum bond amounts—not updated in more than 50 years—may not be sufficient to encourage all operators

[20] *See, e.g.*, BLM overview of bonding, setting out only the minimum amounts as amounts to be posted. http://www.blm.gov/es/st/en/prog/minerals/bonds.html

[21] GAO-10-245

[22] Stephanie Joyce, Wyoming Public Radio and Jordan Wirfs-Brock. (2016, October 17). The Rising Cost Of Cleaning Up After Oil And Gas. Retrieved July 17, 2017, from http://insideenergy.org/2015/10/01/the-rising-cost-of-cleaning-up-after-oil-and-gas/

to comply with reclamation requirements."[23] And BLM field office managers agree. BLM officials interviewed by GAO at 12 of the 16 field offices agreed that these minimum bond amounts are inadequate for managing potential liability.[24] This is because the minimum amounts are not sufficient to serve as an incentive to encourage operators to comply with reclamation requirements and the cost to reclaim a well site far outweighs the value of the existing bonds. Unfortunately, this creates a perverse financial incentive for an oil and gas operator to walk away from a well and leave it orphaned, forcing taxpayers to pick up the plugging and reclamation tab.

In addition to staggeringly low bond amounts, the BLM is not properly tracking or reviewing bond adequacy. According to GAO, "limitations with the data system BLM uses to track oil and gas information on public land restrict the agency's ability to evaluate potential liability and monitor agency performance."[25] To manage potential liability BLM has policies for reviewing bond adequacy and for managing idle wells (wells that have not produced for at least 7 years) and orphan wells (wells that generally have no responsible or liable parties). These policies direct field offices to develop an inventory and rank and prioritize wells for reclamation. According to a 2011 GAO report, "BLM has not consistently implemented its policies for managing potential liabilities."[26] As an example, GAO notes that according to their own survey of field offices, as of 2009 there were approximately 2,300 idle wells that had been inactive for seven or more years. However, Interior databases showed the number of idle wells was nearly double that amount.[27] Moreover, states like Wyoming consider a well idle after a lack of production of only one year. Waiting until year seven not only underestimates the number of wells, but also makes it more likely that the oil and gas operator has already abandoned the well site, and the wait makes it more difficult to start collection from a leaseholder or other responsible party.

The 2015 ANOPR referenced above stated: "the intent of any potential bonding updates would be to ensure that bonds required for oil and gas activities on public lands adequately capture costs associated with potential non-compliance with any terms and conditions applicable to a Federal onshore oil and gas lease." The ANOPR further acknowledged that the current minimums "do not reflect inflation and likely do not cover the costs associated with the reclamation and restoration of any individual oil and gas operation."[28] The current bonding rates and practices allow oil and gas companies to develop public resources without having to post sufficient bonds or otherwise reclaim drilling sites.

(b) Lease suspensions

[23] Government Accountability Office. (2011). Oil and Gas Bonds: BLM Needs a Comprehensive Strategy to Better Manage Potential Oil and Gas Well Liability. (GAO Publication No. 11-292). Washington, D.C.: U.S. Government Printing Office
[24] Ibid
[25] Ibid
[26] Ibid
[27] Ibid
[28] Ibid

Federal leases already have longer terms than many state and private leases, and are supposed to be terminated at the end of their ten-year terms. Lease suspensions result in companies holding federal lands and minerals for longer (often much longer) time periods without paying rentals or generating energy or royalties.

BLM's current policy guidance governing lease suspensions, set forth in BLM Manual 3160-10, was issued in 1987. The manual does not provide clear direction to BLM for how and when to exercise its discretion to reject lease suspension requests, and therefore the agency routinely grants suspensions that are not warranted or required by law. This has led to an extensive portfolio of suspended leases on federal lands. As of March 2015, there were 3.25 million acres of federal minerals in suspended leases, many dating back to the 1980s and 1990s.[29]

The manual also does not direct BLM on how to manage currently suspended leases. Without such direction, BLM rarely evaluates the status of actively suspended leases to determine whether suspensions should be lifted, allowing suspensions to remain in place long after the circumstances that originally justified the suspension no longer exist. Thus, the 1987 manual does not provide direction or assurance that BLM holds suspension requests to the high standard set out in the regulations, provides limited terms for suspension and actively monitors and ends suspensions when they are no longer necessary.

This outdated guidance contributes to BLM's failure to recover revenue for federal resources and ensure producers are diligently developing leased lands. Inappropriate use of lease suspensions allows industry to hold leases indefinitely without making rental payments or producing energy. In this way, lease suspensions can allow industry to evade Congressional intent to diligently develop and provide timely and reasonable access to federal oil and gas resources.

The outdated guidance is also inconsistent with BLM's multiple use mandate. Because BLM regularly declines to adopt conservation management for lands encumbered by leases, holding leases in undue suspension is tantamount to removing those lands from multiple use.

(c) Lease reinstatements

BLM's current policy guidance for reinstatements, set forth in BLM Manual Handbook 3108-1, was last revised in 1995. The guidance does not provide clear direction for BLM to evaluate and approve or deny reinstatements to ensure consistency with the Mineral Leasing Act and agency regulations. Oil and gas leases are automatically terminated "by operation of law" if annual rental rates are not paid by the anniversary date of the lease.[30] However, the BLM "may" reinstate these leases under several conditions.[31] By law, the BLM is only to reinstate leases in cases in which the failure to timely submit the rental was "justified" or "not due to lack of reasonable diligence" by the lessee.

[29] Data accessed through LR2000.
[30] 43 C.F.R. § 3108.2-1
[31] *Id.* §§ 3108.2-2, 3108.2-3, and 3108.2-4

According to the BLM Handbook, justification can occur if "sufficiently extenuating circumstances or factors beyond the control of the lessee [ ] occurred at or near the lease anniversary date."[32] BLM's regulations provide for three types of reinstatements: Class I (reinstatement at existing rental and royalty rates), Class II (reinstatement at higher rental and royalty rates), and Class III (conversions of unpatented oil placer mining claims). However, the agency's guidance does not clearly direct which type of reinstatement is appropriate, what specific criteria must be met for a reinstatement to be authorized, or when the agency should exercise its discretion to deny reinstatement requests. Due to the outdated guidance, BLM is permitting oil and gas leases that have been terminated to be reinstated without sufficient basis, providing the oil and gas industry with an extra opportunity to retain leases at the expense of diligent development, and frequently in situations where industry has intentionally defaulted on rental payments because of low prices, only to apply for reinstatements when prices increase.

(d) Leasing low potential lands

As shown in a recent analysis conducted by The Wilderness Society[33], more than 90% of minerals managed by the BLM are currently available for oil and gas leasing - an allocation that is clearly not based on reasonably foreseeable development potential or a strategic evaluation of other multiple uses. The root of this problem is outdated planning guidance that leads BLM to make the vast majority of federal minerals available to leasing in land use plans, regardless of the likelihood of development and in conflict with multiple use management and fiscal responsibility.

BLM's handbook for fluid minerals planning (Handbook H-1624-1) directs BLM to plan for oil and gas development on federal lands in light of where recoverable deposits of oil and gas are most likely to exist. Chapter III of the handbook requires that BLM use development potential to predict where future drilling activity will take place and where impacts from oil and gas development are likely to be focused within a planning area. Using this information, the handbook directs BLM to assign lease stipulations and other management prescriptions to protect competing resources and mitigate unwanted impacts from drilling and development.

However, when faithfully applied, the handbook often produces illogical management prescriptions that result in significant resource conflicts. With respect to management prescriptions, the handbook leads BLM to *open* low and no potential lands to leasing, and, in many instances, applies weaker protections and stipulations in these areas than high potential areas. Since low potential lands are open to leasing with weak stipulations, they are frequently targeted for speculative leasing. In turn, speculative leases in low potential areas often preclude designations and management decisions that might benefit alternative resources, including decisions for protecting wilderness quality lands and conserving wildlife.[34]

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32 BLM Handbook H-3108-1 at 31

33 *Open for Business* (October 2014), available at http://wilderness.org/sites/default/files/TWS%20--%20BLM%20report_0.pdf

34 See TWS Development Potential Technical Report for detailed analysis and case studies: http://wilderness.org/sites/default/files/Development%20Potential-Technical%20Report%20.pdf.

BLM Handbook H-1624-1 has not been overhauled since 1990. BLM's guidance for considering and making decisions based on development potential in land use planning must be updated to take a more comprehensive approach to oil and gas allocations.

3. These outdated policies are harming taxpayers and our public lands.

(a) Bonding

Pursuant to 43 CFR 3104.8 "The authorized officer shall not give consent to termination of the period of liability of any bond unless an acceptable replacement bond has been filed or until all the terms and conditions of the lease have been met." According to Onshore oil and Gas Order No. 1 final abandonment will not be approved until "the surface reclamation work required in the Surface Use Plan of Operations or Subsequent Report of Plug and Abandon has been completed…"[35] The BLM Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development or "Gold Book" states, "In most cases, this means returning the land to a condition approximating or equal to that which existed prior to the disturbance."[36] For a variety of reasons, as noted above, operators may not complete final reclamation or receive approval for final abandonment resulting in an abandoned or orphaned well. A well is considered orphaned when the bond is not sufficient to cover well plugging and surface reclamation and there are no responsible or liable parties to cover the costs. These wells pose serious environmental fiscal threats.

From an environmental standpoint, orphaned wells can leak methane, provide a pathway for surface runoff, brine, or hydrocarbon fluids to contaminate surface water and groundwater, and contribute to habitat fragmentation and soil erosion.[37] There are already a staggering number of unreclaimed or improperly reclaimed sites across the country. An assessment of ecological recovery at oil and pads on the Colorado Plateau found that more than half of well pads were below the 25th percentile of reference areas.[38]

Fiscally speaking, once a well is considered orphaned BLM must use federal dollars to fund reclamation. However, "there is no dedicated budget line item to fund orphaned well reclamation; instead, it is dependent on whatever funds are available from BLM state offices and the BLM Washington office…"[39] Additionally, reclamation costs have been found to range from $300 to $580,000 per well with newer deeper wells costing as much as $17 million. A 2010 GAO study showed "as of December 2008, oil and gas operators had provided 3,879 bonds, valued at $162 million, to ensure compliance with lease terms and conditions for 88,357 wells." That's only $1,833 per well. For context, the state of Wyoming may be looking at a price tag of between $14.7 and $19 million, or an average cost of more than $100,000 per well to plug its

[35] Onshore Oil and Gas Order No. 1 (XII.B)
[36] BLM Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, Ch. 6
[37] Ho, J., et al., (2016). *Plugging the Gaps in Inactive Well Policy.* Washington, D.C.: Resources for the Future
[38] Nauman, T.W., et al., Disturbance automated reference toolset (DART): Assessing patterns in ecological recovery from energy development on the Colorado…, Sci Total Environ (2017), http://dx.doi.org/10.1016/j.scitotenv.2017.01.034
[39] GAO 2010

newest and deepest wells.[40] It is for this very reason that Wyoming, along with several other western states, recently increased its bonding rates, which are now several times higher than the federal rates.[41]

Outdated requirements are costing taxpayers. The same 2010 GAO report found "For fiscal years 1988 through 2009, BLM spent about $3.8 million to reclaim 295 orphaned wells in 10 states..." The report also identified 144 orphaned wells in 7 states that need to be reclaimed. The total cost to reclaim just 102 of those wells is estimated at $1,683,490.[42] And this problem is not going away. A subsequent 2011 GAO analysis of OGOR data as of July 7, 2010, showed that of the approximately 5,100 wells idle for 7 years or longer, roughly 45 percent, or about 2,300 wells, have not produced oil or gas for more than 25 years.[43] Many of those wells may need government resources to be properly plugged and reclaimed, such that the BLM is subsidizing the oil and gas industry at the expense of taxpayers.

(b) Lease suspensions

Lease suspensions, particularly those that are unwarranted, harm US taxpayers primarily in two ways: lease suspensions cheat U.S. taxpayers of rental and royalty payments; and lease suspensions can preclude the BLM's ability to manage the public lands for multiple uses.

Unmanaged lease suspensions are fiscally imprudent. A federal mineral lease suspension, under the Mineral Leasing Act, tolls the operating and production requirements of a lease, including the obligations to make rental and royalty payments, and extends the primary term of the lease by the length of the suspension – and longer, given the lax enforcement of suspension terms by BLM. As of March 2015, 2.65 million acres of federal minerals were held in suspended leases and not generating rental or royalty payments for the federal government. These suspensions include millions of acres that have been on hold for decades and have already cost taxpayers more than $80 million in lost rents alone. This practice deprives US taxpayers of revenue that should be paid for holding these public lands in lease.

In addition to being fiscally imprudent, maintaining suspensions that are not justified based on BLM's regulations interferes with multiple use management. Unwarranted lease suspensions can and do prevent recreation, conservation and other uses from occurring on these lands. For example, in the Proposed Resource Management Plan for the Grand Junction Field Office, the BLM proposed not to manage South Shale Ridge to protect its wilderness characteristics based at least in part on the presence of suspended oil and gas leases.[44]

Unwarranted suspensions granted for ordinary and foreseeable agency delays "relieve [lessees and/or operators] of the consequences of their poorly timed decisions and actions," while

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[40] Inside Energy 2016

[41] http://trib.com/business/energy/wyoming-raises-bonding-requirements-for-oil-and-gas-wells/article_74fe1dff-3305-5e5d-881a-27a6d6b874c8.html

[42] GAO 2010

[43] GAO 2011

[44] *See* Grand Junction Proposed Resource Management Plan at Appendix F, p. F-6.

inadequate agency oversight of suspended leases allows suspensions to remain in place years after the reason for the suspension has passed. *See Vaquero Energy*, 185 IBLA at 237. These failures are precluding land management opportunities that might otherwise confer valuable benefits to the public at the same time as they deprive the public of valuable tax revenue.

(c) Lease reinstatements

Federal regulations provide that the BLM has discretion in whether to reinstate leases that were terminated for non-payment. Research indicates that the BLM exercises this discretionary authority frequently – there are 703 currently-authorized federal leases covering 530,000 acres that were terminated and subsequently reinstated. More than one thousand leases affecting over one million acres of federal minerals have been reinstated since the year 2000. This indicates there is a widespread pattern of industry failing to pay rents due the US government, and American public, and not being penalized.

Failing to pay rent to the federal government is contrary to the interests of the United States and cheats American taxpayers. Lease reinstatements allow for oil and gas companies to hold publicly-owned lands and minerals for free – and then simply pay back rent penalty-free if and when the BLM completes the process of terminating the lease. This practice comes at significant cost to the American public, who are owed these rental payments and unable to prosecute the lack of payment.

The failure to pay rentals on time also raises a significant question about whether operators are being diligent in the pursuit of development of their oil and gas leases, which is required under BLM regulations and the Mineral Leasing Act. Leases are supposed to have the purpose of insuring "reasonable diligence, skill, and care."[45] It can hardly be argued that companies are exercising diligence and care when they are failing to even make rental payments, and are simply speculating in public lands owned by all Americans while they wait for more favorable market conditions. In addition, federal leases contain provisions to ensure the "protection of the interests of the United States" and the "safeguarding of the public welfare."[46] The agency's current guidance for considering and authorizing reinstatements does not achieve either of these directives.

(d) Leasing low potential lands

Application of the current guidance results in land use planning decisions that make low potential areas open to leasing with relatively weak lease stipulations, regardless of the presence of other resources that could be harmed should development happen, and[47]regardless of whether BLM's own data show there is low—or even no— potential for oil and gas. This fundamental flaw in BLM's guidance has led to a current total of 27 million acres leased for oil and gas development, with less than half in production.[48] A Congressional Budget Office report recently found that, for parcels leased between 1996 and 2003 (all of which have reached the end of their 10-year exploration period), only about 10 percent of onshore leases issued competitively and

[45] 30 U.S.C. 187.
[46] *Id.*
[47] http://wilderness.org/sites/default/files/Development%20Potential-Technical%20Report%20.pdf
[48] https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/oil-and-gas-statistics

three percent of those issued noncompetitively actually entered production.[49] This means 90% of competitively-issued onshore leases never generated royalties for the US government.

As demonstrated in The Wilderness Society's technical report, the practice of making areas with low development potential available to oil and gas leasing frequently leads to these areas becoming encumbered with speculative leases. Since low potential lands have favorable lease stipulations and can be acquired and held for minimal cost, low potential areas are often targeted for speculative leasing, though rarely drilled and developed. Speculative leasing ties up public lands, creates unnecessary public conflict, and generates minimal revenue.

These decisions have real impacts on multiple use management. For example, in the Proposed Resource Management Plan for the Colorado River Valley Field Office, the BLM proposed not to manage the "Grand Hogback Unit" to protect its wilderness characteristics based on the presence of oil and gas leases, stating:

> The Grand Hogback citizens' wilderness proposal unit contains 11,360 acres of BLM lands. All of the proposed area meets the overall required criteria for wilderness character…There are six active oil and gas leases within the unit, totaling approximately 2,240 acres. None of these leases shows any active drilling or has previously drilled wells. The ability to manage for wilderness characteristics in the unit would be difficult. If the current acres in the area continue to be leased and experience any development, protecting the unit's wilderness characteristics would be infeasible…[50]

In the Proposed White River Field Office Resource Management Plan Amendment, the BLM acknowledged that oil and gas leases "preclude other land use authorizations not related to oil and gas…in those areas," including authorizations for renewable energy projects, stating: "Areas closed to leasing…indirectly limit the potential for oil and gas developments to preclude other land use authorizations not related to oil and gas (e.g., renewable energy developments, transmission lines) in those areas."[51] As these examples show, oil and gas leases, even when not developed, preclude other uses of the public lands.

Speculative leases are also fiscally burdensome. Leases in low potential areas generate minimal revenue but can carry significant cost. In terms of revenue, they are most likely to be sold at or near the minimum bid of $2/acre, and they are least likely to actually produce oil or gas and generate royalties.[52] *See* Bighorn Basin PRMP (2015) at p. 73 ("Leasing may be based on

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[49] https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/51421-oil_and_gas_options.pdf

[50] *See* Colorado River Valley Proposed Resource Management Plan (2014) at Chapter 3, p. 3-135.

[51] *See* White River Proposed RMP, Chapter 4 at p. 4-498.

[52] Center for Western Priorities, "A Fair Share" ("Oil Companies Can Obtain an Acre of Public Land for Less than the Price of a Big Mac. The minimum bid required to obtain public lands at oil and gas auctions stands at $2.00 per acre, an amount that has not been increased in decades. In 2014, oil companies obtained nearly 100,000 acres in Western states for only $2.00 per acre. . . .Oil companies are sitting on nearly 22 million acres of American lands without producing oil and gas from them. It only costs $1.50 per year to keep public lands idle, which provides little incentive to generate oil and gas or avoid land speculation.").

speculation, with leases within high risk prospects usually purchased for the lowest prices."); White River PRMP (1996) at p. A-7 ("At any given time, most of the acreage that is available for oil and gas leasing in the WRRA is under lease. . . . Most of the area is leased for speculative purposes and consequently only a small percentage of leases will ever be developed."). Nonproducing leases generate less than two percent of total revenue generated by the federal onshore system; 90 percent comes from royalties paid on producing leases.[53] In terms of costs, leasing in low potential areas requires processing lease nominations, preparing environmental reviews, and resolving protests and resource use conflicts.

In summary, leasing lands and minerals with low potential for oil and gas development – speculative leasing – carries significant costs by precluding BLM from managing for other multiple uses, creating unnecessary public conflict, and wasting agency resources while generating minimal revenue.

4. Updating these policies will benefit taxpayers and the public lands.

(a) Bonding

The benefits associated with updating the BLM's bonding policies are obvious. If bond minimums are set at an amount equal to the estimated cost of reclamation the government limits the chance it will have to bear the expenses associated with reclaiming orphaned wells. This in turn means that American taxpayers will not be left footing the bill for the industry's negligence. This will also help deter financially unstable companies or companies that are only interested in speculation from purchasing federal leases. Additionally, proper reclamation of wells pads will help restore federal lands for other uses like recreation and grazing and will help to restore wildlife habitat and limit fragmentation. Improving tracking and review of bond adequacy will also help the government periodically assess liabilities and increase bond amounts or adjust agency practices in response to findings.

A common refrain from the oil and gas industry is that raising bond minimums will discourage development. However, there is little if any evidence of such a result. In fact, many states have higher minimum bond amounts or more practical methods for determining bond amounts but have not seen a decrease in permitting or drilling as a result. For example, Wyoming calculates individual bonds based on well characteristics and depth and California bases statewide bond amounts on the number of wells a company operates. North Dakota, South Dakota, and Utah all have bonding amounts for single wells and all are over $50,000 and operators continue to drill in those states.[54]

(b) Lease suspensions

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[53] https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/51421-oil_and_gas_options.pdf, p. 2.

[54] Western Organization of Resource Councils. Weak Oil and Gas Bonding Will Contribute to Reclamation Crisis. (2016, August 15). Retrieved July 17, 2017, from http://www.worc.org/weak-oil-gas-bonding/

Updating the agency's policy governing suspensions would ensure BLM is recovering owed rental payments and returning undeveloped lands to multiple use management. By issuing new guidance that directs BLM to exercise its discretion to reject unjustified lease suspensions and monitor existing suspensions to remove those that are no longer justified, BLM would eliminate a hidden subsidy that is currently available to the oil and gas industry. Agency and public scrutiny of lease suspensions would also ensure that public lands are not removed from multiple use management as a result of oil and gas companies illegitimately holding them in suspended status.

In addition to benefiting the public by managing lease suspensions in a fiscally responsible way and protecting multiple use management, updating the agency's policy governing suspensions would help BLM demonstrate that it is managing oil and gas resources consistent with the Mineral Leasing Act and diligent development requirements.

(c) Lease reinstatements

BLM would prevent oil and gas companies from cheating American taxpayers out of rental payments by ensuring lease reinstatements are appropriately evaluated, issued under the proper classification, and exercising discretion to deny reinstatements when warranted. Updating policy guidance for reinstatements would also ensure the BLM is complying with Section 187 of the MLA. Leases are supposed to have the purpose of insuring "reasonable diligence, skill, and care" and to seek the "protection of the interests of the United States" and the "safeguarding of the public welfare." 30 U.S.C. 187. Updating BLM's guidance for reinstating leases would allow the agency to ensure these directives are being upheld.

(d) Leasing low potential lands

Under current agency guidance, BLM is supposed to use development potential to formulate lease stipulations and management prescriptions that will mitigate conflicts between fluid mineral development and other competing uses. However, in its current form, the guidance leaves low and no potential areas open to leasing with weaker protections than moderate and high potential areas. The result is oil and gas management allocations that leave the door open to future resource conflicts and allow speculative oil and gas leasing in low/no potential areas to limit alternative management decisions. Updating the agency's guidance would allow for BLM to better achieve its objective of mitigating oil and gas conflicts and realize multiple use management.

Limiting leasing in low potential areas conflicts the least with industry objectives and can confer significant public benefits. Low potential lands are the "low-hanging fruit" by which BLM can fulfill other objectives of its multiple-use mission, such as managing for wilderness, wildlife and recreation. Yet, as described above, speculative leases on low potential lands can prevent the BLM from otherwise managing lands for alternative purposes and fulfilling its multiple-use mandate. *See also* White River DRMPA (2012) at p. 4-377 (". . . authorized oil and gas uses would likely preclude other incompatible land use authorizations"). In addition, limiting exploration and development on low potential lands necessarily conflicts the least with industry objectives. As discussed in the Bighorn Basin PRMP (2015):

> [A]lternatives D and F place additional stipulations on oil and gas-related surface disturbances in the Absaroka Front, Fifteenmile, and Big Horn Front MLP analysis areas for the protection of big game, geologic features, and LRP soils. As a result, alternatives D and F could have additional adverse impacts on oil and gas development in these MLP analysis areas. . . . However, because of the generally low to very low potential for oil and gas development and redundancies with other restrictions on mineral leasing from the management of other program areas, management specific to the MLP is less likely to adversely affect oil and gas development in these areas.

Bighorn Basin PRMP at p. 4-87*; see also* White River DRMP (1994) at p. 4-21 ("Prohibiting development in Class I areas would not affect oil and gas production because oil and gas potential in these areas is low.").

Eliminating the presumption that all lands, regardless of development potential, should be open to leasing would help ensure that other resources and uses of the public lands, such as wildlife, recreation and water, are on equal footing with oil and gas development. Doing so would also create opportunities to enhance the management of those other resource and uses, particularly in areas with low/no development potential.

5. <u>New regulations and policies are needed to halt hidden subsidies to the oil and gas industry.</u>

(a) <u>Bonding</u>

Common sense reforms are necessary to protect taxpayers and the environment. BLM's new regulations and guidance should include the following:

- <u>*Increase the minimum bond amount.*</u> At the very least the minimum should be adjusted to reflect inflation. Using a simple consumer price index (CPI) conversion that would set the individual bond at $81,000, the statewide bond at $231,000, and the nationwide bond at $1,390,000. However, we recommend that bond amounts be set on a case by case basis at an amount that will cover the estimated cost of reclamation. This approach is similar to that employed in federal coal and hardrock mining regulations. Bond amounts could be reviewed periodically and adjusted up for new development on a lease or down for completion of final reclamation of a pad.
- <u>*Bond amounts should be set per well.*</u> This would bring the regulation in line with current oil and gas drilling practices where operators often drill multiple pads per lease and multiple wells per pad. This is similar to many state regulations. Additionally, bonds should take into consideration the relevant characteristic of a well that might impact reclamation costs; including among other things type, depth and target formation.
- <u>*Improve review of bond adequacy and liability tracking.*</u> This recommendation mirrors that made by GAO in 2011. BLM must "and improve its data system to better evaluate potential liability and agency performance…"[55]

[55] GAO 2011

- *Improve reclamation standards.* In addition to the bonding regulations themselves, BLM's reclamation standards pose a significant issue. BLM's lack of clear reclamation standards has created a piecemeal approach, where standards change from land use plan to land use plan, creating inconsistent reclamation requirements on federal lands. BLM should adopt broad, uniform, performance-based standards that ensure that all wells drilled on federal lands meet acceptable minimum requirements for reclamation. This approach allows operators to employ their considerable resources and expertise to achieve satisfactory reclamation. It will provide a consistent and more flexible standard across field offices to promote better and more frequent reclamation potentially reducing an operator's desire to shirk responsibilities if they find current reclamation requirements too prescriptive or rigid.

(b) Lease suspensions

BLM should issue new guidance for managing suspensions that includes clear direction for considering suspension requests and denying unwarranted suspensions; monitoring existing suspensions on a regular basis and removing those that are no longer justified; and providing for public review of lease suspensions. BLM is currently not holding suspension requests to the high standard set out in the regulations, and revised guidance is necessary to ensure compliance.

- *Update criteria for granting suspensions*: BLM should issue revised direction for considering suspension requests that includes clear criteria for when the agency does and does not have discretion to grant a suspension request. Pursuant to 43 C.F.R. § 3103.4-4(a), obligations regarding all operations and production of oil and gas leases may be suspended "only in the interest of conservation of natural resources" and obligations regarding either operations or production may be suspended only when "the lessee is prevented from operating on the lease or producing from the lease, despite the exercise of due care and diligence, by reason of force majeure, that is, by matters beyond the reasonable control of the lessee"; and must be justified by the applicant. Revised policy should provide the agency with guidance for implementing these regulations and appropriately considering whether to approve lease suspension requests.
- *Establish a monitoring and tracking system for suspensions:* A lease suspension is not intended to be unending; BLM requires that a suspension terminates when it is "no longer justified in the interest of conservation, when such action is in the interest of the lessor, or as otherwise stated by the authorized officer in the [suspension] approval letter." 43 C.F.R. § 3165.1(c). BLM's existing manual directs the agency to "monitor the suspension on a regular basis to determine if the conditions for granting the suspension are extant, and should terminate the suspension when it is deemed no longer necessary." BLM Manual 3160-10.3.31.C.3. However, in practice this requirement is not applied through any regular or consistent mechanism. More explicit guidance should direct when and how this monitoring occurs. A verification system to ensure regular oversight including directing state offices to evaluate suspended leases on a quarterly basis and report to DC in a publicly available format should also be incorporated into the suspended lease management strategy.

- *<u>Increase transparency and opportunities for public involvement in lease suspensions and monitoring</u>*: BLM should be required to post documentation of lease suspension requests and decisions, including on its NEPA log, but also in a dashboard available via state office websites. Information on suspended leases, including status and reason for suspension, should also be made public to provide for public oversight and accountability on the length of suspensions in annual oil and gas program reports. A summary of lease suspensions should be included in the BLM's annual reporting of oil and gas statistics, as well.
- *<u>Evaluate need for NEPA review</u>*: Finally, BLM should evaluate whether categorical exclusions are appropriate for individual suspensions, applying the "extraordinary circumstances" criteria, and if any of those criteria are met, then an environmental assessment or environmental impact statement must be prepared.

(c) <u>Lease reinstatements</u>

BLM must update its guidance for evaluating and approving or denying lease reinstatements to ensure oil and gas companies are complying with the directives set forth in the Mineral Leasing Act and that taxpayers are receiving rental payments for leased public mineral resources. The practice of reinstating leases that have been terminated for failure to pay the annual rental fee needs to be evaluated by the BLM and much more stringent provisions for reinstatement should be put in place. By law, the BLM is only to reinstate leases in cases in which the failure to timely submit the rental was "justified" or "not due to lack of reasonable diligence" by the lessee. In updating the agency's guidance, BLM should establish narrow and specific guidelines for when these criteria may be considered to be met.

- *<u>Require evidence of extenuating circumstances and reasonable diligence</u>*: According to the BLM Handbook, justification can occur if "sufficiently extenuating circumstances or factors beyond the control of the lessee [ ] occurred at or near the lease anniversary date."[56] BLM should ensure that any excuse of non-payment of rent is in fact beyond the control of the lessee—any claimed basis for failure to pay on time must be a "causative factor" showing control had been lost.[57] Failing to pay rent on time also can only rarely be excused as having occurred despite the exercise of reasonable diligence. To claim diligence, a lessee must be able to show they sent the rental "sufficiently in advance of the due date to account for normal delays."[58] Lessees seeking lease reinstatements must be required to provide detailed support that they meet these criteria, and only in the rare circumstances in which they are clearly met should reinstatements be authorized.
- *<u>Class I reinstatements should be generally unavailable</u>*: BLM should exercise its discretion to not authorize Class I reinstatements (reinstatement at existing rental and royalty rates), except in the most extraordinary circumstances.
- *<u>Define "inadvertence" to mean "not duly attentive"</u>*: Regarding Class II reinstatements, the failure to pay rent on time should only rarely be excused as having occurred because of inadvertence. Inadvertent means "not duly attentive." While inadvertence may be

[56] BLM Handbook H-3108-1 at 31
[57] *Id.*
[58] *Id.*

unintentional, it is synonymous with "careless." This lack of attention should not be readily excused for such a simple task as paying your rent on time. If an oil and gas lease has real value to the operator, certainly they should be attentive enough to pay their rent on time. The failure to pay rent on time is evidence the lease is not valuable to the operator, and therefore leaving the termination in place is justified. The failure to pay rent on time probably signals a general lack of diligence, such as not seriously engaging in actual drilling operations. *See* 43 C.F.R. § 3107.1 (allowing for extension of lease terms if actual, diligent drilling is commenced prior to the end of the primary term).

BLM's guidance defining when inadvertence can be excused is so broad as to be meaningless. ""Inadvertence" is viewed by the BLM to include failure to pay due to carelessness, negligence, an unintentional or accidental oversight, inattention, a mistake, a financial inability to pay timely, or any other reason." BLM Handbook H-3108-1 at 37. This meaningless view of what constitutes inadvertence must be abandoned. A definition that recognizes inadvertence means "not <u>duly</u> attentive" needs to be put in place. Being careless, negligent, inattentive or not having the financial inability to pay on time are not due reasons to excuse nonpayment.[59]

- <u>*Reinstated leases should not have their terms extended or royalty rates reduced*</u>. The BLM should not extend the terms of the lease or reduce the royalty rate when a lease is reinstated. Reinstatement of oil and gas leases for failure to pay rent should be an exception rather than a rule in the interest of multiple-use management of our public lands.

(d) <u>Leasing low potential lands</u>

BLM should use development potential to plan for oil and gas development on federal lands in ways that mitigate resource conflicts, accommodate multiple uses of public lands without preference, and encourage development in areas that are most economic for oil and gas production. Limiting leasing in areas with low or no development potential would reduce administrative costs, mitigate conflicts between competing resources, and be more faithful to BLM's multiple-use mandate.

This approach would also be consistent with the MLA, which directs BLM to hold periodic oil and gas lease sales for "lands…which are known or believed to contain oil or gas deposits…" 30 U.S.C. § 226(a); *see also Vessels Coal Gas, Inc.*, 175 IBLA 8, 25 (2008) ("It is well-settled under the MLA that competitive leasing is to be based upon reasonable assurance of an existing mineral deposit."). These sales are supposed to foster responsible oil and gas development, which lessees must carry out with "reasonable diligence." 30 U.S.C. § 187; *see also* BLM Form

[59] The Interior Board of Land Appeals has ruled that being financially unable to pay rent is not considered inadvertent and is, therefore, not grounds for Class II reinstatement. Dena F. Collins, 86 IBLA 32 (1985). But BLM policy is nevertheless that "if a lessee does later secure the financial ability and timely files a petition for reinstatement, the petition is to be processed." BLM Handbook H-3108-1 at 37. BLM should expect that lessees will maintain an ability to meet and abide by their lease terms on a continuous basis; lessees should be ready to pay rent when due, and if they cannot they should be willing to give up the lease and move on to other business opportunities.

3100-11 § 4 ("Lessee must exercise reasonable diligence in developing and producing…leased resources.").

- *BLM plans should set out a framework for oil and gas development that supports closing lands to leasing where development is unlikely to occur:* If BLM closes or defers leasing in low-potential areas, and conditions change to make development in those areas more likely, the agency can then complete additional analysis and planning to ensure that development occurs responsibly and accounts for current resource conditions. An updated approach to planning for oil and gas leasing should meaningfully account for development potential and conflicts with other resources.[60]
- *Modernize the handbook with an approach that provides for closing lands to leasing and limits leasing in low- or no-potential areas:* Updating the handbook would not only support BLM's obligation to consider managing lands for fish and wildlife, recreation and wilderness values, but also have minimal impacts on industry objectives. In locations like the Ely District in Nevada, where federal minerals are almost 90 percent open to leasing, only 32 wells were authorized over the past 101 years (as of May 21, 2014), even though there are 936 active leases covering just over two million acres of public land.[61] Closing these lands to speculative leasing will not harm responsible oil and gas development.
- *Consider basing oil and gas lease sales on a "List of Lands Available for Competitive Nominations," as authorized by BLM regulations*: BLM currently allows the oil and gas industry to nominate any public lands for leasing, which encourages widespread speculation in low potential areas and creates unnecessary conflicts with other multiple uses. This is extremely inefficient and wasteful system for leasing public lands is not the only model available to BLM, however, as current rules also permit BLM to create and utilize a "List of Lands Available for Competitive Nominations." 43 C.F.R. § 3120.3-1. Such a list would allow BLM to proactively direct industry to areas with better odds of development and with lower resource conflicts, while eliminating areas from consideration that are clearly speculative and unlikely to generate any oil and gas revenues for American taxpayers.

Limiting development in low/no potential areas would allow BLM to minimize the risk of impacts and conflict altogether in areas where development is likely to be minimal in the first place. This practice would also limit speculative leasing practices by the industry, which can foreclose alternative management decisions and burden the BLM with increased administrative costs and conflicts associated with leasing in low potential areas. Under a more strategic approach to making oil and gas allocations in land use planning, lands would be made available for leasing by evaluating both an estimate of oil and gas potential and the conflicts with or

[60] See TWS No Exit Report for detailed recommendations on an updated approach to making oil and gas allocations in land use planning: http://wilderness.org/sites/default/files/TWS%20No%20Exit%20Report%20Web_0.pdf
[61] See BLM Nevada Preliminary EA for the Dec. 2015 Oil and Gas Lease Sale, p. 1.4.

potential harm to other resources present on those same lands. We direct BLM to and incorporate by reference the recommendations made in the TWS reports cited above (attached and incorporated herein by reference).

III. Conclusion

This petition is presented under the Administrative Procedure Act, which provides that each agency "shall give an interested person the right to petition for the issuance, amendment, or repeal of a rule"[62] and the United States Constitution, which protects the right to "petition the Government for the redress of grievances."[63] Interior must respond to this petition "within a reasonable time"[64] and Interior regulations state that petitions will be given "prompt consideration."[65] Courts have found that "a reasonable time for agency action is typically counted in weeks or months, not years."[66]

The agency must notify petitioners of the denial of a petition, in whole or in part, and with limited exception, a denial must include an explanation on the grounds for denial.[67] A reviewing court shall compel agency action "unlawfully withheld or unreasonably delayed."[68] We request that Interior and BLM respond to this petition and commence both rulemaking and issuance of new guidance in no less than three months of the date of receipt. We also notes that Interior regulations authorize the Secretary to publish this petition in the Federal Register to solicit public comments on the proposed rule-making if those public comments "may aid in the consideration of the petition."[69] In light of the BLM's previous acknowledgment of the need for many of these updates to regulations and policies, and the suitability of a public process, we request that Interior and BLM also public this petition for comment.

The current regulations and guidance underpinning the BLM's onshore oil and gas leasing program are in dire need of updating. Analyses of these decades-old policies has shown that they are harming the taxpayers that the BLM is obligated to ensure receive the benefits of leasing and the public lands that BLM is obligated to ensure are managed for multiple use and sustained yield. Additionally, updating these rules will help cure widespread violations of the diligent development requirement that is an essential obligation in every federal lease. Updating these

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[62] 5 U.S.C. § 553(e).
[63] U.S. Const., amend. I.
[64] 5 U.S.C. § 555(b)
[65] 43 C.F.R. § 14.3.
[66] *In Re: American Rivers and Idaho Rivers United*, 372 F.3d 413, 419 (D.C. Cir. 2004) (internal citation and quotations omitted). *See Midwest Gas Users Asso. v. Federal Energy Regulatory Com.*, 266 U.S. App. D.C. 91, 833 F.2d 341, 359 (D.C. Cir. 1987) ("This court has stated generally that a reasonable time for an agency decision could encompass 'months, occasionally a year or two, but not several years or a decade.'" (quoting *MCI Telecommunications Corp. v. Federal Communications Com.*, 200 U.S. App. D.C. 269, 627 F.2d 322, 340 (D.C. Cir. 1980))); *Fund for Animals, et. al. v. Norton, et. al*., 294 F.Supp. 2d 92, 115 (D.D.C 2003) (petitioners are "entitled to *an* answer within a reasonable amount of time.") (emphasis in original)

[67] 5 U.S.C. § 555(e); 14 C.F.R. § 14.3.
[68] 5 U.S.C. § 706(1). *See Telecommunications Research and Action Center v. F.C.C.*, 750 F.2d 70, 76-77 (D.C. Cir. 1984).
[69] 14 C.F.R. § 14.4.

policies will not harm the oil and gas industry, which is currently receiving unnecessary subsidies while profiting at the expense of the American public.

Institute *for* Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

February 28, 2018

Comments to Royalty Policy Committee, Department of the Interior

The Institute for Policy Integrity at New York University School of Law[1] respectfully submits these comments to the Department of the Interior's Royalty Policy Committee (RPC). Policy Integrity is a non-partisan think tank dedicated to improving the quality of government decisionmaking through advocacy and scholarship in the fields of administrative law, economics, and public policy.

The Department of the Interior is required to earn "fair market value" for the use and development of federal natural resources. How royalties are set and assessed is critical to ensuring receipt of fair market value for the public. We write to make the following comments:

- Interior should not lower the offshore royalty rate, which was raised during the George W. Bush administration and is necessary to ensure fair market value for the public's resources;
- Interior should end area-wide leasing, which has led to record-low bids and little to no competition for offshore tracts, breaking with fair market value and competitive leasing requirements;
- Interior should increase federal fossil fuel royalty rates, as multiple studies show that higher royalty rates will increase total revenue for the public;
- Interior should adjust royalty rates upward for coal, oil, and natural gas leases to recoup some of the environmental and social costs of production; and
- Interior must recognize that fossil fuel development is only one statutory purpose of our public lands that must be balanced with other, equally important uses, including preservation, recreation, and renewable energy development.

Each of these recommendations and comments are discussed in turn.

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[1] No part of this document purports to present New York University School of Law's views, if any.

I. Interior should not lower the offshore royalty rate, which was raised during the George W. Bush administration and is necessary to ensure fair market value for the public's resources.

The Committee's meeting materials indicates that it is considering lowering the current 18.75 percent royalty rate for deepwater offshore oil and gas leases to 12.5 percent. This would be an irresponsible change that would deliver an unjustified windfall to private industry at the expense of the public, in violation of the Outer Continental Shelf Lands Act (OCSLA)'s fair market value requirement.

The deepwater offshore royalty rate was raised from 12.5 percent to 18.75 percent during the George W. Bush administration.[2] At the time, Interior estimated that the rate increase would raise revenue by $8.8 billion over the next 30 years.[3] Interior increased the rate in response to technological improvements that made exploration and production more efficient, increased oil and gas prices, and strong interest in offshore leases. A former Secretary of the Interior stated that increasing the offshore rate was necessary to ensure that "the American taxpayer is getting a fair return for the oil and gas that the American people own."[4]

This is a bipartisan issue. Interior has a duty to ensure a fair return to the public for its public lands and resources, and to balance fossil fuel production with conservation, pursuant to OCSLA.[5] Interior has stated that "fair market value" is not only the market value of the oil or gas eventually discovered or produced, but the value of the right to explore and, if there is a discovery, to develop and produce the energy resource.[6] OCSLA itself states that "Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government."[7]

The Committee does not have any rational basis for lowering the royalty rate for offshore leases. Indeed, all available evidence points to the opposite conclusion: lowering the

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[2] *See* CONG. RES. SERV., OUTER CONTINENTAL SHELF: DEBATE OVER OIL AND GAS LEASING AND REVENUE SHARING at CRS-2 (2008), http://www.au.af.mil/au/awc/awcgate/crs/rl33493.pdf; U.S. Bureau of Ocean and Energy Mgmt., Proposed Final Outer Continental Shelf Oil & Gas Leasing Program 2012-2017 96 (2012), https://perma.cc/NTZ6-HRBQ.
[3] Government Accountability Office, OIL AND GAS ROYALTIES: THE FEDERAL SYSTEM FOR COLLECTING OIL AND GAS REVENUES NEEDS COMPREHENSIVE REASSESSMENT 17 (Sept. 2008), https://www.gao.gov/assets/280/279991.pdf.
[4] Hon. Ken Salazar, Secretary of the Interior, "Interior, Environment, and Related Agencies Appropriations for 2013," Testimony before the House Committee on Appropriations, Subcommittee on Interior, Environment, and Related Agencies (Feb. 16, 2012), pp. 46–47, http://www.gpo.gov/fdsys/pkg/CHRG-112hhrg74739/pdf/CHRG-112hhrg74739.pdf ("The underlying principle is we are mandated by statute, mandated by fairness to make sure the American taxpayer is getting a fair return for the assets the American people own.").
[5] 43 U.S.C. § 1344(a)(3)-(4).
[6] Government Accountability Office, OIL AND GAS ROYALTIES, *supra* note 3.
[7] 43 U.S.C. § 1344(a)(4).

royalty rate would lead to less total revenue for the public's natural resources, while *raising* it would *increase* total revenue.[8]

Interior should also eliminate royalty rate reductions and royalty relief that hinders receipt of fair market value. Interior should not be in the business of subsidizing uneconomical drilling or mining. Public resources belong to all taxpayers, not to private developers.

II. Interior should end area-wide leasing, which has ushered in record-low bids and little to no competition for offshore leases, violating its mandates to earn "fair market value" and hold competitive auctions.

Instead of offering more or larger offshore areas open for bidding, which is contemplated in Interior's draft proposed program for 2019-2024 and this Committee's meeting agenda, Interior should offer fewer tracts for lease and end its practice of "area wide leasing," in order to hold competitive auctions and ensure receipt of fair market value, both of which are required by OCSLA.

Interior leaves a staggering sum of money that belongs to the public on the table by holding uncompetitive fossil fuel leasing auctions. As just one example, in Interior's last offshore lease sale, held in August 2017, more than 90 percent of tracts had only one bidder.[9] In one of the rare instances where there were two bidders for a tract, one company bid $3.5 million and the second, winning company bid more than triple that amount—$12.1 million.[10]

Unfortunately for the public, the August 2017 auction was not unique. Interior has held uncompetitive offshore lease sales ever since the agency adopted "area wide leasing" in 1983. Adjusted for inflation, the average price paid per offshore tract since 1983 has declined from $9,068 to $391 per acre in each Gulf of Mexico auction—a decline of 95.7 percent.[11] The Project on Government Oversight's analysis shows the American people have lost tens of billions of dollars in revenue over the last three decades because of area wide leasing and Interior's failure to reject inadequately low bids.[12]

Interior's Bureau of Ocean Energy Management (BOEM), which manages offshore drilling, has even acknowledged that some bidders have received windfalls due to its own methodological shortcomings, stating, "[I]n some cases BOEM issued leases where it

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[8] *See* Part III, *infra*.
[9] https://www.usnews.com/opinion/economic-intelligence/articles/2018-01-10/oil-wins-american-coast-and-people-lose-under-offshore-drilling-expansion.
[10] Bureau of Ocean Energy Management, Oil and Gas Lease Sale 249, Preliminary Bid Recap, Gulfwide Lease Sale (August 16, 2017) at 16, https://www.boem.gov/Sale-249-Preliminary-Bid-Recap-by-Area-and-Block-for-All-Bids/.
[11] Project on Government Oversight, Drilling Down: Big Oil's Bidding (Feb. 22, 2018), http://www.pogo.org/our-work/articles/2018/drilling-down-big-oils-bidding.html.
[12] Project on Government Oversight, Press Release: Offshore Giveaway to Big Oil Cheats Taxpayers out of Billions (Feb. 22, 2018), http://www.pogo.org/about/press-room/releases/2018/press-release-offshore-giveaway-to-big-oil-cheats-taxpayers-out-of-bilions.html.

estimated the block [lease tract] values to be negative, the blocks were issued for near minimum bid, and the lessees made discoveries of substantial size."[13]

Interior's systematic failure to hold competitive auctions violates its statutory mandates to hold competitive auctions[14] and to earn fair market value for the use of public lands and resources[15] Taking actions that will further exacerbate these issues runs counter to legal requirements.

III. Interior should increase federal fossil fuel royalty rates, as multiple studies show that higher royalty rates will increase total revenue for the public.

Several reports by the U.S. Government Accountability Office ("GAO") have concluded that raising federal royalty rates for federal oil, gas, and coal resources would substantially *increase* total federal revenue. Interior must consider policies that will increase the public's fair share, as revenue from leasing supports public schools, community infrastructure, municipal budgets, and environmental protection.

As recently as July 2017, GAO reported that "state oil and gas rates tend to be higher than federal royalty rates," and that raising federal fossil fuel royalty rates would *increase total revenue* for the federal government and the states with which it shares that revenue.[16]

One of the studies that GAO reviewed estimated that raising the federal royalty rate for onshore oil and gas to 16.67 percent, 18.75 percent, or 22.5 percent could increase net federal revenue by $125 million to $939 million over 25 years. The Congressional Budget Office estimated that if the royalty rate for onshore oil and gas parcels were raised from 12.5 percent to 18.75 percent, net federal revenue would increase by $200 million over the first 10 years, and potentially by much more over the following decade.[17] And for federal coal, GAO found that raising the royalty rate to 17 percent or 29 percent could increase federal revenue by up to $365 million per year after 2025.[18]

In addition, the White House Council for Economic Advisors ("CEA"), found that maximizing federal revenue from federal coal leasing would require royalty rates of 304 percent (equal to approximately a $30 per short ton royalty charge on Powder River Basin

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[13] Bureau of Ocean Energy Management, https://www.boem.gov/2017-2022-OCS-Oil-and-Gas-Leasing-PFP/.
[14] *See* 43 U.S.C § 1337(a)(1).
[15] *See* 43 U.S.C. § 1344(a)(4).
[16] U.S. GOVT. ACCOUNTABILITY OFFICE, GAO-17-540, OIL, GAS, AND COAL ROYALTIES (2017) at 1, 16, https://www.gao.gov/assets/690/685335.pdf.
[17] *Id*. at 22 (citing Congressional Budget Office (CBO), Options for Increasing Federal Income from Crude Oil and Natural Gas on Federal Lands (Washington, D.C.: April 2016), https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/51421-oil_and_gas_options-OneCol-3.pdf).
[18] *Id*. at 1.

coal), which would limit some future federal coal production while still increasing total revenue by $2.7 to $3.1 billion when fully phased in by 2025.[19]

Further, analysis by the Institute for Policy Integrity at NYU School of Law found that increasing the federal royalty rate to 18.7% for Powder River Basin coal would have earned up to $1.2 billion in additional royalty revenue over the five years between 2011 and 2015.[20]

Officials from Texas and Colorado interviewed by GAO noted that the history of increasing royalty rates for oil and gas production on state lands suggests that increasing the federal royalty rate would not have a clear impact on production. In particular, officials from Colorado and Texas said that they raised their state royalty rates for oil and gas (to 20 and 25 percent, respectively) without any significant effect on production on state lands.[21] One study that GAO reviewed found that onshore oil and gas production could decrease by less than 2 percent per year if royalty rates increased from their current 12.5 percent to 22.5 percent, based on fiscal year 2016 production data. Another study stated the effect on production could be "negligible" over 10 years if royalty rates increased to 18.75 percent.[22]

The studies cited here show that lowering royalty rates would only take away from the public's fair share. Instead, the Committee should be considering raising royalty rates for fossil fuel resources in order to earn *more revenue* for the federal government, states, and local communities. The Royalty Policy Committee is tasked with ensuring the public's receipt of fair market value for the use and development of public lands and resources.[23] We urge the Committee to follow its own charter which identifies its core objective as: "to ensure the public receives the full value of the natural resources produced from Federal lands."[24]

IV. Interior should adjust royalty rates upward for coal, oil, and natural gas leases to recoup some of the environmental and social costs of production.

Fossil fuel leasing is not all upside. There are real costs—including climate change costs—that should be taken into consideration in managing these programs to earn fair market value and protect environmental values.

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[19] THE WHITE HOUSE, OFFICE OF THE PRESIDENT, THE ECONOMICS OF COAL LEASING ON FEDERAL LANDS: ENSURING A FAIR RETURN TO TAXPAYERS (2016) at 3, 4, 25, https://obamawhitehouse.archives.gov/sites/default/files/page/files/20160622_cea_coal_leasing.pdf%22%22.
[20] *See* Jayni Foley Hein and Peter Howard, *Illuminating the Hidden Costs of Coal*, INSTITUTE FOR POLICY INTEGRITY, NYU School of Law (Dec. 2015), http://policyintegrity.org/files/publications/Hidden_Costs_of_Coal.pdf.
[21] *Id*. at 21-22.
[22] U.S. GOVT. ACCOUNTABILITY OFFICE, GAO-17-540, OIL, GAS, AND COAL ROYALTIES (2017) at 1, 16, https://www.gao.gov/assets/690/685335.pdf.
[23] Of course, the complete absence of any public interest or conversation organization on the Committee itself is highly problematic.
[24] Interior, Royalty Policy Committee Charter, https://www.doi.gov/sites/doi.gov/files/uploads/2017_charter_royalty_policy_committee.pdf.

The federal government, states, and tribes bear many of these costs directly, through fighting wildfires on public lands and dealing with the effects of reduced snowpack that threaten water resources. As just one example, climate change has led to fire seasons that are now on average 78 days longer than in 1970, and an increasing portion of the U.S. Forest Service budget is directed to fighting wildfires on public lands.[25]

Current royalty rates are inefficiently low because they do not account for environmental and social impacts. Interior can and should price environmental externality costs into royalty rates using metrics like the Social Cost of Carbon and the Social Cost of Methane.[26] By raising royalty rates to include these externality costs, the Secretary can better fulfill his or her statutory mandate to balance environmental values and development, and ensure fair market value for the lands leased.[27]

V. Interior must recognize that fossil fuel development should be balanced with other, equally important uses of our public lands, including preservation, recreation, and renewable energy development.

Pursuant to both the Federal Land Policy and Management Act ("FLPMA") and OCSLA, fossil fuel development is only one of a suite of possible uses for our public lands. Natural resources fiscal policy—including royalty rates—directly affects how our public lands and resources are developed, including resulting resource consumption, revenue, and environmental effects. Therefore, when providing recommendations on royalties and other fiscal components of our public lands, this Committee must consider the "multiple use" mandate that Congress established.

FLPMA requires agencies to manage public lands in accordance with the "principles of multiple use and sustained yield." The Act defines "multiple use" as:

> [T]he management of the public lands and their various resource values so that they are utilized in the combination that will best meet *the present and future needs of the American people*; . . . the *use of some land for less than all of the resources*; a combination of balanced and diverse resource uses that takes into account the *long-term needs of future generations* for *renewable and nonrenewable resources*, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values.[28]

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[25] U.S. DEP'T OF AGRICULTURE, THE RISING COST OF WILDFIRE OPERATIONS: EFFECTS ON THE FOREST SERVICE'S NON-FIRE WORK (2015), https://www.fs.fed.us/sites/default/files/2015-Fire-Budget-Report.pdf.
[26] Jayni Foley Hein, *Federal Lands and Fossil Fuels: Maximizing Social Welfare in Federal Energy Leasing*, 42 HARV. ENVTL. L. REV. __ (2018), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2919094.
[27] *See id.; see also* Jayni Foley Hein & Caroline Cecot, *Mineral Royalties: Historical Uses and Justifications* (August 2017), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2919094.
[28] 43 U.S.C. § 1702(c) (emphasis added).

"Multiple use" also refers to the "harmonious and coordinated management of the various resources *without permanent impairment of the productivity of the land and the quality of the environment* with consideration being given to the relative values of the resources and *not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output*."[29]

Managing and planning for multiple use and sustained yield means that there must be a significant portion of public lands devoted to conservation in order to sustain public resources—particularly for the "present and future" needs of the American people. Fossil fuel development is only one use of our public lands that must be balanced with other multiple uses and considered on equal footing.

Similarly, Section 18 of OCSLA directs that management of the Outer Continental Shelf be "conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer continental shelf, and the potential impact of oil and gas exploration on other resource values of the outer continental shelf and the marine, coastal, and human environments."[30] Congress also directed the Secretary of the Interior to "select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone."[31]

Thus far, this administration appears intent on carrying out a willfully blind "energy dominance" strategy that strongly preferences fossil fuel development over other compelling uses, such as preservation and renewable energy production. This strategy may enrich a small number of fossil fuel industry executives, but it will leave our children and grandchildren with scarred landscapes and a costly, intractable climate change problem. This Committee must consider the multiple use mandate of FLPMA, as well as OCSLA's required balancing as it continues to examine federal fiscal policy for natural resources.

Sincerely,

Jayni Foley Hein

Policy Director
Institute for Policy Integrity
NYU School of Law

[29] *Id*.
[30] 43 U.S.C. § 1344(a)(1).
[31] 43 U.S.C. § 1344(a)(3).

Drilling Down: Oil Companies Are Having Their Cake and Eating It, Too

pogo.org/our-work/articles/2018/drilling-down-having-their-cake-and-eating-it-too.html

U.S. Cuts Oil Companies a Break on Royalties

Topics: Government Accountability, Energy and Natural Resources
Related Content: Department of the Interior, Drilling Down Series, Oil & Gas Royalty Revenue, Extractive Industries Transparency Initiative (EITI)

February 22, 2018 | David S. Hilzenrath , Nicholas Pacifico

(Photos: Shutterstock, Pixabay; Illustration by POGO)

In theory, even if the government auctions offshore drilling rights for a song, taxpayers could benefit.

That's because the Interior Department collects royalties on the oil and gas that energy companies extract from federal property. The royalties are meant to ensure that the public shares the wealth that flows from public resources.

However, the Interior Department has a history of letting energy companies have their cake and eat it, too—by issuing drilling rights at liquidation-sale prices and cutting companies a break on royalties.

The government has foregone royalties as a matter of deliberate policy. It has also had a variety of troubles collecting royalties. For a while, it used a slipshod system to collect them, allowing itself to get shortchanged. In some instances, it has fumbled, letting companies off the hook. And, in still other cases, companies knowingly underpaid, the Justice Department has alleged. The Project On Government Oversight has reported extensively on those problems over the years.

The Government Accountability Office (GAO) has estimated that federal revenues foregone through one particular royalty snafu could total billions of dollars, if not tens of billions.

The policy of reducing or forgiving royalties has taken different forms over the years and is generally known as "Royalty Relief."

Under the Trump Administration, more "relief" may be on the way.

In March 2017, Interior Secretary Ryan Zinke established a "Royalty Policy Committee" to advise him on potential policy changes. The committee's members include several representatives of energy companies.

The committee is scheduled to meet in Houston on February 28, and at that meeting it may vote on recommendations, according to a notice in the Federal Register.

"The Secretary seeks to ensure the public receives the full value of the natural resources produced from Federal lands," the committee's charter says.

A Trump appointee who serves on the committee has signaled that the goal is "to make certain the royalty rate the government charges is competitive."

"And it's important to understand what was competitive yesterday may not be competitive today," Scott A. Angelle, Director of the Bureau of Safety and Environmental Enforcement (BSEE), said in the prepared text of a December speech.

"If it's good policy for America to have a lower royalty rate on new leases, it's great for America to have a lower royalty rate on existing leases," Angelle said in a September speech. "And there is some policy that allows BSEE director on a case-by-case basis . . . to evaluate those opportunities."

POGO obtained a video of the September speech, which was delivered to the Louisiana Oil & Gas Association, through the Freedom of Information Act.

"It ought to be about lowering royalty rates to get more production under the Reagan model that if you cut taxes you end up with more revenue for the government," Angelle said.

(Angelle appeared to be repeating a myth about Reagan-era tax cutting. Citing research conducted by the Treasury Department during the George W. Bush Administration, *The Washington Post*'s Fact Checker has reported that "the tax cut itself was a money-loser for the government." In response to an inquiry from POGO, BSEE spokesman Gregory Julian said Angelle's statements "were very general and intended to be thought-provoking.")

The government sent another signal that royalty rates could be in play while seeking public input for a new five-year plan on offshore leasing. It said royalty rates and "structures" were "subject to change." In a January draft of the plan, the Interior Department said it was considering an alternative to the current royalty system.

There's a lot of money on the line. Data POGO obtained from the government for fiscal years 2003 through 2016 tell the story. Over that 14-year period, under U.S. offshore leases, energy companies extracted oil and gas worth $547 billion. The royalties paid to the federal government on those sales amounted to $99 billion.

In the run-up to the most recent auction of drilling rights in the Gulf of Mexico, the Trump Administration sweetened the deal for bidders by lowering the royalty rate on wells in relatively shallow water by a third, from 18.75 percent to 12.5 percent.

Within parameters, the government has been willing to go even lower.

A 2007 letter from the Louisiana state government to the Interior Department bemoaned a federal "royalty relief" policy that allowed the royalty rate for certain deep water drilling "to go as low as a 0%."

Louisiana offered a pithy assessment.

"It seems imprudent for the federal government to allow the oil companies to take the people's minerals completely royalty-free."

Drilling Down: Big Oil's Bidding

pogo.org/our-work/articles/2018/drilling-down-big-oils-bidding.html

For decades, there has been a virtual giveaway of offshore drilling rights. And the Trump Administration is planning to put much more on the auction block.

Topics: Government Accountability, Energy and Natural Resources
Related Content: Department of the Interior, Drilling Down Series, Oil & Gas Royalty Revenue, Energy & Environment, Extractive Industries Transparency Initiative (EITI)

February 22, 2018 | David S. Hilzenrath , Nicholas Pacifico

When the government awards energy companies the rights to drill for offshore oil and gas, it's supposed to make sure the American public, which owns the resources, doesn't get screwed.

The government is required by law to use "competitive bidding" and to ensure that taxpayers receive "fair market value."

However, decades of data suggest that the government has been falling down on the job, a Project On Government Oversight analysis found.

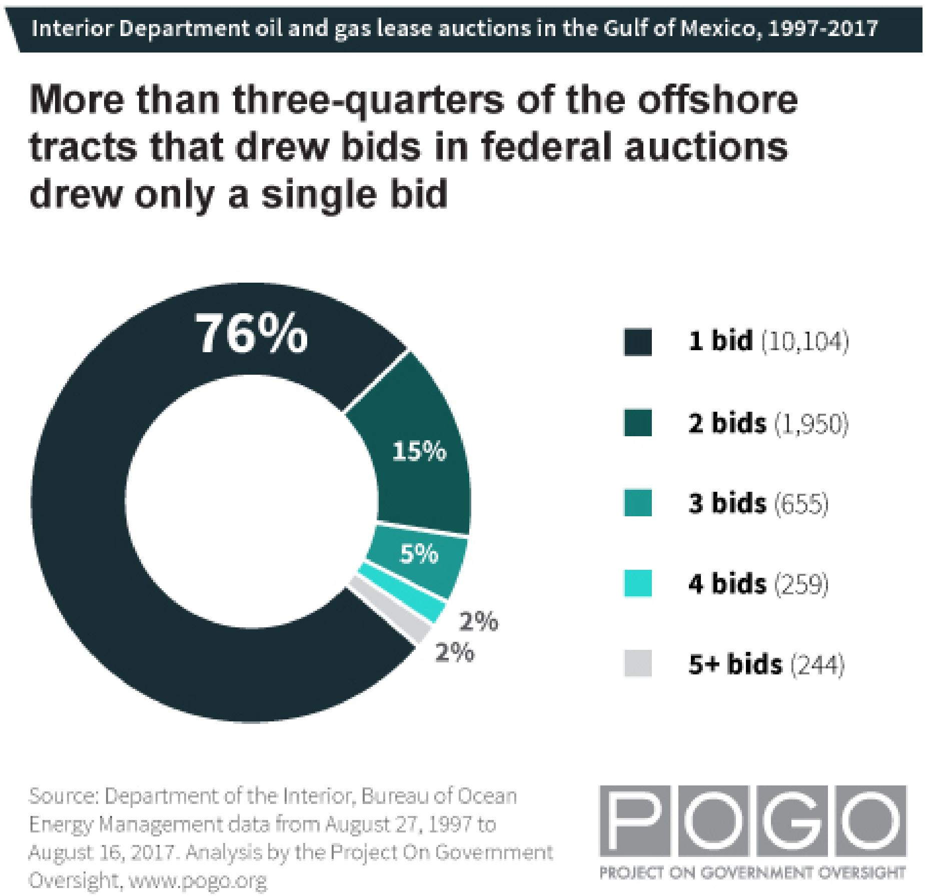
The system the government has been using to auction drilling rights since 1983 has enabled energy companies to secure offshore leases for a pittance. On an inflation-adjusted basis, comparing the era before the change to the era since, the average price paid per acre in each Gulf of Mexico auction has declined by 95.7 percent, from $9,068 to $391, POGO found.

Over the decades, that has added up to a decline in auction payments of tens of billions of dollars.

With the Trump Administration planning to open immense stretches of ocean floor to oil and gas companies, the stakes are rising. If the past is any indication, more publicly owned resources could be turned over to industry at bargain-basement prices.

Far from fostering real competition for drilling rights, the system in place since the Reagan Administration has delivered little more than an illusion of competition. In this Alice-in-Wonderland version of an auction house, the low bid generally wins, because the low bid and the high bid are typically one and the same—the only bid.

For example, in the most recent auction, companies placed bids on 90 tracts. Of those tracts, 81 drew only a single bid. The vast majority of winning bids were unopposed.



Over the past 20 years, more than three-quarters of the leases awarded in the Gulf of Mexico —76.6 percent—were awarded on the basis of single bids, POGO found.

Those general problems have been documented by experts in the past, but, if they ever achieved any widespread recognition, seem to have been all but lost in the current debate over offshore drilling.

POGO's analysis shows that the patterns have continued to the present.

More importantly, POGO's analysis shows why the near absence of head-to-head bidding could be a much bigger problem than the government has acknowledged.

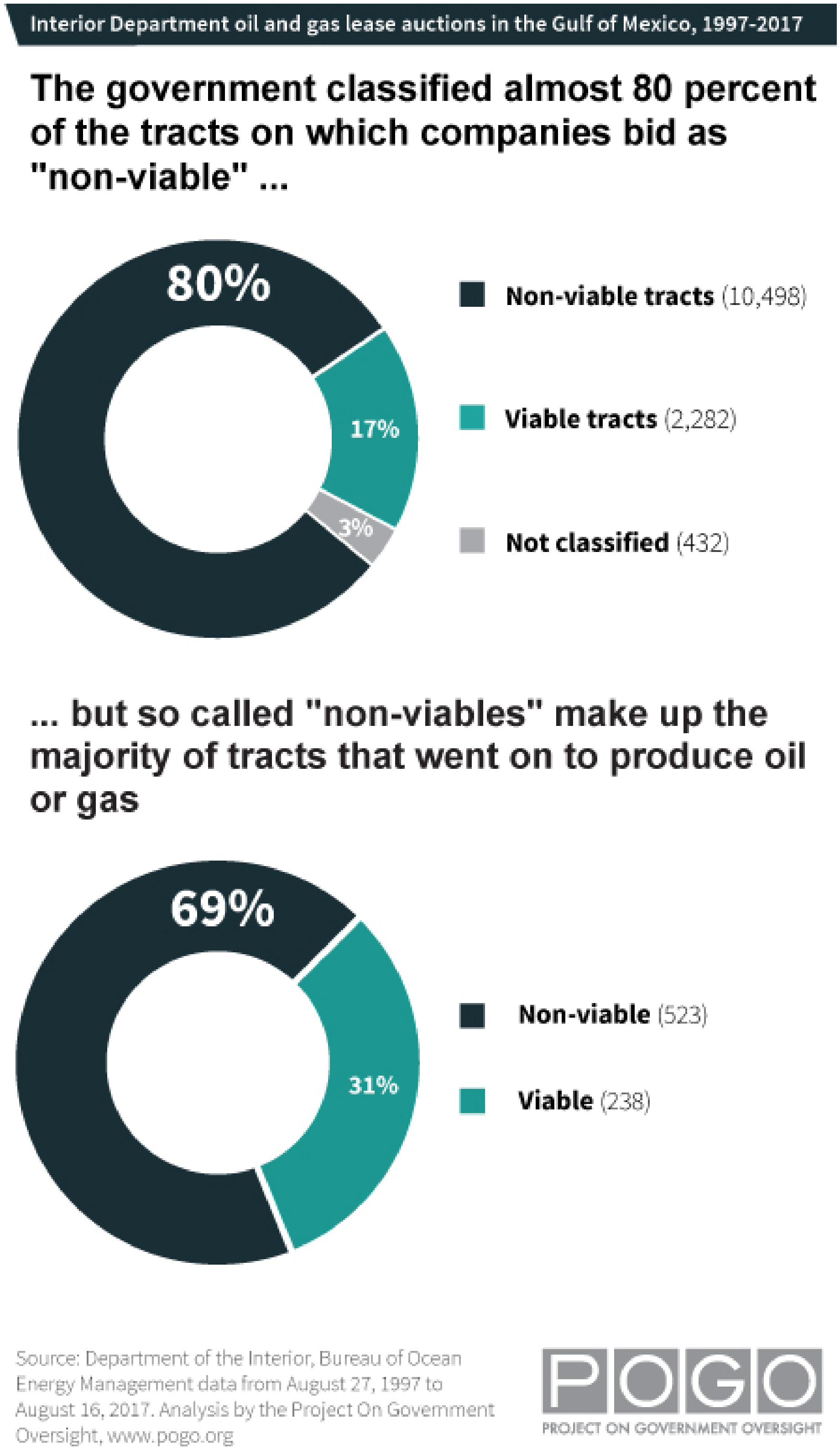
The government says that, before it accepts any bid, it studies the tract of ocean floor to make sure the bid delivers fair market value. The government's "bid adequacy" assessments supposedly protect the taxpayers if the market does not. But, in light of POGO's findings, it is unclear why the public should take any comfort in the government's bid adequacy determinations.

Under published procedures, the Interior Department can automatically accept the high bid for certain tracts if it considers the tracts "non-viable," which the Department defines as lacking "the potential capability of being explored, developed and produced profitably." If the Interior Department considers the tracts non-viable, it need not perform a full valuation, according to federal disclosures.

In 79.5 percent of the more than 13,000 bid adequacy determinations that POGO examined, the Department categorized the tract as non-viable and accepted the "high bid" on that basis, according to government disclosures.

Over the past 20 years, companies placed high bids totaling $7.8 billion on Gulf of Mexico tracts the Interior Department categorized as non-viable, POGO found.

Evidently, energy companies saw value that the government did not.



In many cases, companies doubled down on the investments they made in supposedly non-viable tracts—and then doubled down again. First, they drilled costly exploratory wells on those tracts. Then, they shifted into production mode to extract oil or gas, POGO found.

Most of the leases that ultimately became energy-producing—68.7 percent—involved tracts the Interior Department had classified as non-viable, according to POGO's analysis.

For the Interior Department, disposing of tracts as non-viable—that is to say, worthless—can be the easy way out. It can involve less work and less risk than declaring the tracts viable and coming up with valuations that energy companies could force the Department to defend.

When the government concludes that tracts are viable, it conducts a more thorough geological and economic assessment. It decides whether to accept the high bids based on measures it generates to appraise individual tracts. A pivotal measure is the awkwardly named “Adjusted Delayed Value,” or “ADV.”

On average, for tracts the Interior Department considered viable, the high bids that companies placed were over six and a half times that measure of market value, POGO found.

For example, in the most recent auction, for one of the few tracts that drew competing bids, the high bid was $5.7 million. That was almost six times the government valuation of $980,000, according to a government document.

POGO’s examination of Interior’s bid adequacy determinations is based on data available online detailing the government’s treatment of 13,212 high bids that companies submitted for Gulf of Mexico tracts since 1997.

One way to look at this picture: The government consistently got more money than it thought the tracts were worth. Another way of looking at it: The government consistently underestimated the market.

Either way, the numbers beg the question: How much more could the government have gotten if it set higher expectations or ran more competitive auctions?

Further research by POGO supports the theory that more head-to-head bidding could yield higher bids. When there was only one bid on a tract—by far the most common scenario—that bid was, on average, more than double the ADV. When there were two bids on the same tract, the high bid was, on average, more than triple the ADV. When there were three bids, the high bid was, on average, almost quadruple the ADV. And, when there were four bids, the high bid was, on average, more than quintuple the ADV. Beyond that range, the number of bids trailed off and the consistency of the pattern faded.

It is of course possible that the tracts drawing multiple bids were more valuable to begin with.

Interior’s Bureau of Ocean Energy Management (BOEM), which manages offshore drilling rights, acknowledges that some bidders have gotten bargains. “[I]n some cases BOEM issued leases where it estimated the block values to be negative, the blocks were issued for near minimum bid, and the lessees made discoveries of substantial size,” Bureau planning documents say.

The most recent auction, held in August 2017, showed how different companies can attach different values to drilling rights and illustrated the potential value of competition. In one of those rare cases in which companies went head to head for the same tract, one bid $3.5 million and the other bid more than triple that amount—$12.1 million.

A 2008 auction for drilling rights in Alaska's Chukchi Sea made the point even more vividly. For a tract called block 6763, the lowest of several bids was just over $100,000. The highest was more than $100 million. The unusually robust competition came amid a spike in oil prices.

The data POGO analyzed suggest that, to divine or demand market value, there may be no substitute for a truly competitive market.

The problems are particularly worthy of attention now. Last month, the Trump Administration unveiled the first draft of a new five-year plan for issuing offshore leases, and, as part of that effort, it proposed opening almost all of the U.S. outer continental shelf to drilling. That includes previously off-limits parts of the Arctic, Atlantic, and Pacific, as well as Florida's Gulf Coast.

Expanding drilling while using the same uncompetitive leasing system could perpetuate the problems on a larger scale.

Art of the Deal?

President Donald Trump, accompanied by Vice President Mike Pence, Environmental Protection Agency Administrator Scott Pruitt, and Interior Secretary Ryan Zinke, announces his "energy independence" executive order, March 28, 2017. (Photo: Department of the Interior)

The latest auction of drilling rights illustrated the system's flaws. The Trump Administration has been spinning it as a success and has tried to take credit for it.

A March 2017 news release from the Interior Department heralded the offering.

"Secretary Zinke Announces Proposed 73-million Acre Oil and Natural Gas Lease Sale for Gulf of Mexico," the headline on the release said. The August 16 auction "would include all available unleased areas in federal waters of the Gulf of Mexico," the announcement said.

In the news release, Interior Secretary Ryan Zinke offered this explanation: “Opening more federal lands and waters to oil and gas drilling is a pillar of President Trump’s plan to make the United States energy independent.”

On its face, the proposed liquidation sale raised some basic questions. Why dump the entire inventory at a time of relatively low energy prices? For a president who titled his first autobiography *The Art of the Deal*, what kind of deal-making was that? Would it amount to a giveaway? And how much inventory could energy companies buy at any one time?

As it turns out, the announcement was misleading. The problems ran deeper.

Since 1983, the government has been holding auctions in which all unleased tracts in vast areas of the outer continental shelf—rather than just a select subset —have been up for bid. The approach is known as “area-wide leasing.” Planning for the August 16 auction began during the Obama Administration. The results were typical.

Companies bid on less than 1 percent of the 76 million acres up for sale.

Among the small number of tracts that drew any bid, only 10 percent drew more than one bid, and none drew more than two bids. For tracts on which anyone bid, the average number of bids was 1.1.

As the government tells it, the auction showcased the Trump Administration’s good work: making the Interior Department “a better business partner” and ensuring that taxpayers receive “a fair return” on federal resources.

“Let’s make some money for the American people,” Katherine MacGregor, a Trump appointee at the Interior Department, declared as she opened the auction.

But the dearth of competition echoed monotonously as MacGregor opened and read aloud bidding results, identifying swatches of the sea floor by their names and numbers.

“Garden Banks Block 78, one bid . . . .”

“Garden Banks Block 121, one bid . . . .”

“Garden Banks Block 122, one bid . . . .”

With almost no head-to-head bidding, more than 80 percent of the bidders came out as the high bidder for every offshore lease on which they bid. One bidder went 10 for 10.

The companies bidding in the auction included Chevron, Exxon Mobil, BP, and Shell.

The winning bids averaged $235.12 per acre, which on an inflation-adjusted basis was only 2.6 percent of the average under the prior leasing system.

Companies bid millions of dollars on tracts the government called “non-viable.”

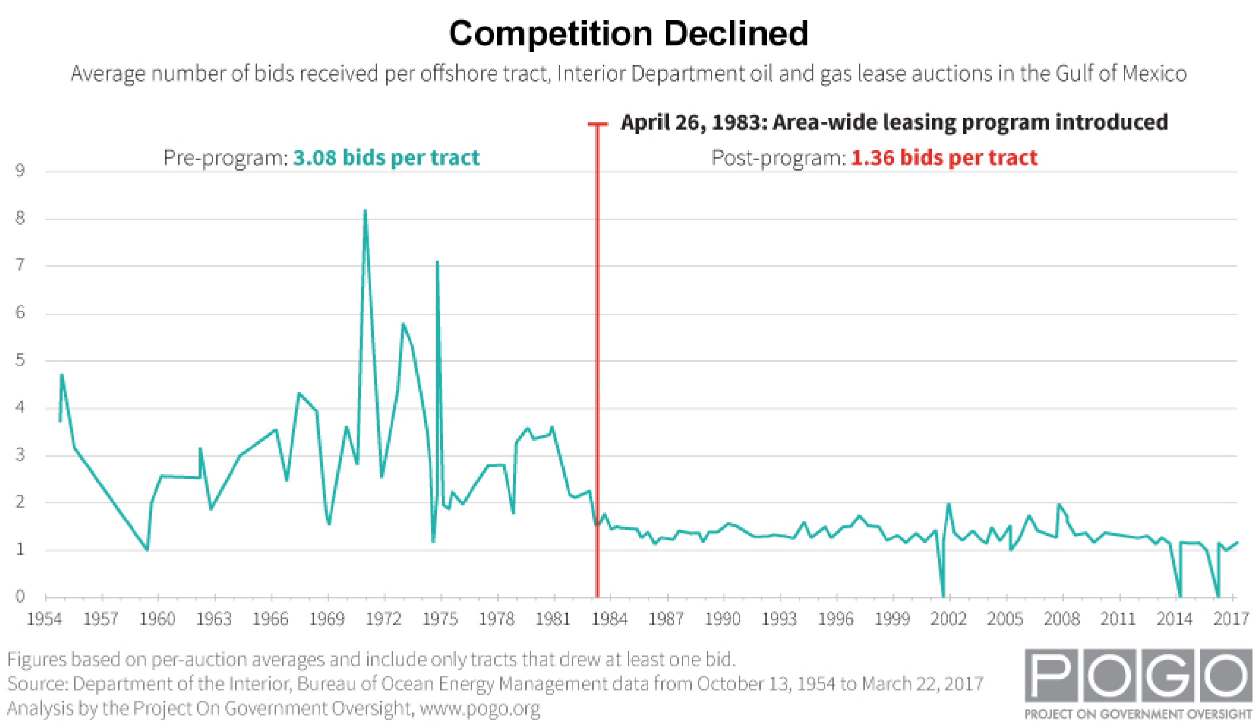
The lack of competitive bidding in the August auction could be ascribed in part to depressed fossil fuel prices. It could also reflect diminishing returns in the Gulf of Mexico, where shallow-water drilling has been going on since the 1930s. However, it fits a pattern since so-called “area-wide leasing” was introduced in 1983.

For decades, even when oil prices were higher, sales of Gulf of Mexico leases have been defined by a near absence of actual competition.

POGO’s analysis of auction competitiveness focused on the Gulf of Mexico because, in recent decades, that has been by far the main arena for U.S offshore oil and gas production and lease sales.

In almost every sale since the Reagan Administration redesigned the auction system, **just a small percentage of the Gulf tracts put up for auction have been bid upon**. On average, over the nearly 30 years preceding the change, 62 percent of tracts offered were bid upon in each auction. For the 34 years since the change, that average has fallen to 8 percent.

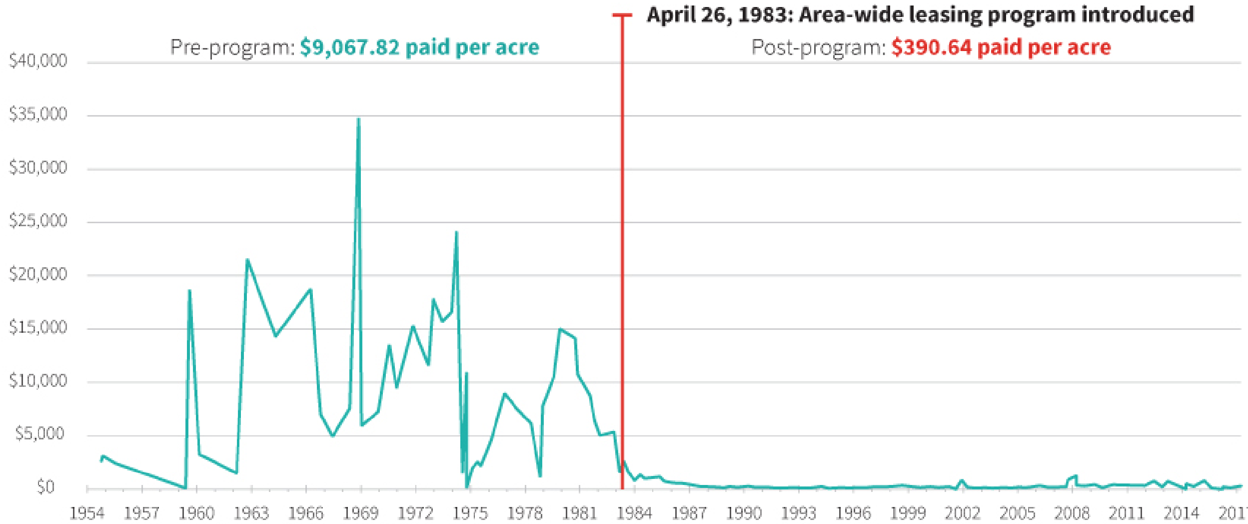
For the era before the change, the number of bids per tract leased in each auction averaged 3.08. For the era since then, it has plummeted to 1.36, POGO’s analysis of federal data found.



Meanwhile, the average price per acre leased in each auction—as measured in 2016 dollars—**plunged by 95.7 percent**.

Oil Companies Paid Less

Average amount paid per offshore acre, Interior Department oil and gas lease auctions in the Gulf of Mexico



Figures, based on per-auction averages, have been adjusted for inflation and are expressed in 2016 dollars.
Source: Department of the Interior, Bureau of Ocean Energy Management data from October 13, 1954 to March 22, 2017
Analysis by the Project On Government Oversight, www.pogo.org

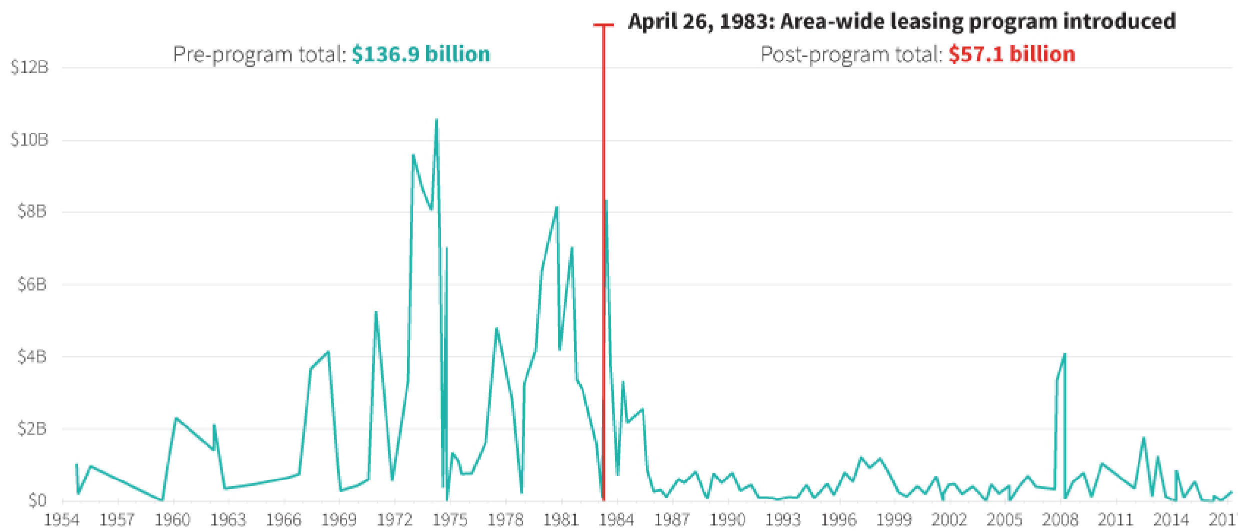
POGO PROJECT ON GOVERNMENT OVERSIGHT

To assess whether the government has made up through the amount of leasing what it has lost on prices, POGO compared the period of roughly 29 years before area-wide leasing was introduced to the period of roughly 34 years since. (The relevant data available online go back to 1954.) Overall, the number of acres leased rose from about 17 million in the earlier era to about 128 million in the more recent era.

On an inflation-adjusted basis, **the government's revenue from auction payments declined** from about $137 billion over a period of less than 30 years to about $57 billion over a period of more than 30 years.

Public Revenue Decreased

Revenue collected per auction, Interior Department oil and gas lease auctions in the Gulf of Mexico



Figures have been adjusted for inflation and are expressed in 2016 dollars.
Source: Department of the Interior, Bureau of Ocean Energy Management data from October 13, 1954 to March 22, 2017
Analysis by the Project On Government Oversight, www.pogo.org

POGO PROJECT ON GOVERNMENT OVERSIGHT

The system has amounted to “a clumsy and wasteful form of corporate welfare,” Juan Carlos Boue, an industry consultant and researcher at the Oxford Institute for Energy Studies, said in an email to POGO. The government’s approach has “transferred billions of taxpayers’ dollars into the coffers of major oil companies,” he added. Boue was reiterating the assessment he expressed in a 2006 book on offshore economics.

Instead of vying for the same tracts, potential rivals have generally pursued different targets. Some potential rivals have teamed up to submit joint bids.

POGO has no evidence that bidders have colluded to steer clear of each other. However, in research presented at a January 2018 economics conference, a team of professors used statistical tools to study the issue. “The bidding patterns are consistent with collusion,” co-author Robert H. Porter, a Northwestern University economist, summarized in an email to POGO.

The bidding patterns do not necessarily reflect illegal activity or explicit communication among potential bidders, Porter added. If tracts in particular areas or having particular characteristics “are commonly understood to be associated with particular firms,” companies don’t have to communicate to stay out of each other’s way, he explained.

A former Congressional investigator also expressed concern.

“I think when you get single bids all over the place, that would raise a red flag . . . . It caused me concern,” said Reece Rushing, who examined offshore leasing when he was director of oversight and investigations on the Democratic staff of the House Natural Resources Committee.

“You would want a system where you have competing bids to the maximum extent possible, and that’s clearly not the system that we have,” Rushing said.

Reagan Revolution

The current auction system has its roots in a push to transfer public assets into private hands.

“I want to open as much land as I can,” James Watt, who at the time was Reagan’s Interior Secretary, told *The New York Times* in 1982. “We are trying to bring our abundant acres into the market so that the market will decide their value,” Watt said.

Major oil companies were lobbying for something along those lines. They wanted to reduce competition, bring down the cost of acquiring leases, and offset the soaring costs of deepwater development, oil historian Tyler Priest has written. At Watt’s Interior Department, representatives from Shell laid out a proposal for “broad-area leasing,” Priest recounted in his book, *The Offshore Imperative: Shell Oil's Search for Petroleum in Postwar America*.

Watt delivered, and Shell in particular “could take some credit for helping bring about this major policy change,” Priest wrote.

Before the 1983 shift, companies nominated and the government chose offshore tracts for inclusion in auctions. That limited the number of tracts for sale at any one time, and it focused prospective bidders on tracts that at least someone had identified as potentially valuable. It forced companies to tip their hands about the tracts that interested them.

Area-wide leasing swept that aside. Under the new system, everything in, for example, the Western Gulf of Mexico or the Central Gulf would be up for grabs at one time. The last five-year leasing plan, drafted by the Obama Administration in 2016, called for even bigger auctions featuring every tract in the Gulf of Mexico not subject to a ban on drilling. The August 2017 sale followed that plan.

The states of Texas and Louisiana sued the Reagan Administration over area-wide leasing, which they argued decreased competition for leases and thus would reduce revenue flowing into public coffers.

In an affidavit supporting Texas's lawsuit, economist Joseph Stiglitz, who later won a Nobel Prize and is now a professor at Columbia University, stated, "Seldom have I encountered situations, however, where the evidence of the significant cost of a program (areawide leasing) is so overwhelming while the benefit—if indeed there is any—is so weak."

The state of Louisiana continued its opposition to area-wide leasing into the 21st century. In a 2007 letter to the Interior Department, the head of Louisiana's Department of Natural Resources wrote, "[A]lternative leasing strategies could moderate the boom and bust effect that areawide leasing has on the oil industry and supporting communities and infrastructure, as well as increase competition for, and revenue from, the finite oil and gas resources in the Gulf of Mexico."

Marshall Rose, who served as BOEM's chief economist from 1983 through 2016, told POGO that, today, the number of bids per tract is "barely more than one." That is the nature of area-wide leasing, Rose said. But Rose said he doesn't think the picture "is quite as bad as it looks." As a measure of competition, the number of bids per tract doesn't reflect the number of companies that looked at the tracts and considered bidding on them, he said.

POGO asked Rose why it has been commonplace for BOEM to accept bids on the grounds that it considers tracts non-viable.

The government declares tracts non-viable—meaning "worthless"—when evidence suggests that they contain no hydrocarbons or too little to make drilling worthwhile, Rose said.

But determining what tracts are worth isn't always easy, he said.

Under area-wide leasing, "there are so many tracts out there that the Bureau in some cases just has very little data on which to base its evaluations," he said.

When its information is thin, the Bureau "is inclined to be cautious" about declaring a tract viable, Rose said. If it declares a tract viable, it must come up with an estimate of its value. If the estimate causes a bid to be rejected, the bidder could appeal, forcing the Bureau to justify its valuation, he explained.

“Where it leads is that the Bureau tends to be careful about coming up with values that might be questioned,” Rose said.

POGO also asked Rose why companies generally bid much more than BOEM estimates the tracts are worth. Part of the explanation, Rose said, is that the Bureau “has been pretty conservative in terms of its estimates” because it “considers the market fairly competitive.”

In deciding how aggressively to set valuations, Rose said, the Bureau balances goals: assuring that it gets fair market value and issuing leases.

“And it doesn’t want to have an excessive amount of bid rejections after it goes through the trouble of holding a sale,” he said.

Underestimated

In the federal auctions, bidders submit sealed bids, and there is no opportunity for them to drive up prices through back-and-forth bidding. Companies deciding how much to bid can factor in this knowledge: in most instances, if more than three decades of history is any guide, no one will bid against them.

The scarcity of head-to-head bidding might be less of a problem if the government had other robust means of making sure that energy companies pay a fair price for drilling rights.

The Interior Department sets a floor on the bidding. Currently, the minimum bid the government will consider accepting for tracts in water at least 400 meters deep is $100 per acre. That’s up from minimums of $25 to $37.50 per acre from early 1987 to early 2010.

But it’s still down by a third from $150 per acre in the early years of area-wide leasing, and that comparison doesn’t take into account the effect of inflation. In 2016 dollars, the minimum from years ago would amount to more than $360 per acre.

Before declaring winners in the auctions, the Bureau reviews the high bids in an effort to make sure they are adequate. For tracts it deems non-viable, the minimum bid is all it takes to win a lease.

The Bureau rejects hardly any bids as too low. In the most recent auction, 7.8 percent of the high bids—7 of 90—were rejected. That was more than usual. Since 1984, the Bureau’s reviews “have resulted in an average rejection rate of bids of approximately 3.7 percent,” BOEM has disclosed.

(Using BOEM data, POGO arrived at a slightly lower average rejection rate. Since area-wide leasing was introduced, an average of 3.2 percent of bids per auction in the Gulf of Mexico have been classified as rejected or withdrawn, according to a POGO analysis of government data that lumps the two categories together. That’s down by more than half from 6.9 percent in the period before area-wide leasing.)

The rejection rate is generally "way too low," Rose said. To deter companies from submitting lowball bids, the rejection rate should be "much higher," he said. For the same reason, he said, the government should raise the minimum bid.

The government evaluates companies' bids based in part on seismic research and other data obtained from the oil and gas industry. Individual bidders are required to submit data they used as part of their decision to bid.

However, without a competitive market, it may be hard for anyone to know the market value of a lease or whether a particular bid meets it.

In an October 2017 presentation to an Interior Department advisory committee, Department economist Benjamin Simon put it this way: "Determining FMV [fair market value] is challenging in situations where competition is limited."

One of the measures the government uses to determine fair market value, known by the technical term "Mean Range of Values" or "MROV," is defined in a 2016 document as the "maximum" amount that a bidder could offer and still expect a normal rate of return on its investment. Yet many of the bids have exceeded that estimated maximum by wide margins.

POGO found that 93.3 percent of more than 10,000 high bids over the past 20 years exceeded what was listed as the MROV for those tracts. On average, they exceeded the MROV by 392.9 percent. Meanwhile, 95.2 percent of them exceeded another valuation measure, the ADV mentioned above. On average, they exceeded what was listed as the ADV by 399.0 percent.

BOEM's website describes the elaborate efforts the Bureau makes to determine a tract's fair market value, at least in certain cases. It says BOEM uses "a computer simulation model," and that federal "geologists, geophysicists, petroleum engineers, economists and computer scientists prepare detailed estimates of the economic value of oil and gas resources on each tract."

Nonetheless, most of the posted estimates look like they were made with a cookie cutter.

For example, over the past six years, 56.9 percent of the posted government estimates were identical: $576,000. That equated to $100 per acre, which for those years was the floor the government had set on bids for tracts in deeper water.

What's behind the cookie-cutter numbers?

Based on explanations of the process published in the Federal Register and on the BOEM website, it appears that the government does not generate specific valuations for some or all tracts it considers non-viable.

Rose, the former chief economist, said that when he was at the Bureau it did not develop valuations for tracts it considered non-viable.

For other tracts, BOEM has been less than transparent.

Where BOEM's estimate was lower than the minimum bid, BOEM hasn't disclosed its estimate, Rose said. Instead, it has listed the minimum as its estimate. "[T]here's a hidden value that you don't see," Rose said.

The lack of transparency limits the Bureau's accountability. It also contrasts with information that the Bureau gave to a Member of Congress in 2012. In written answers to questions from Edward J. Markey (D-MA), who was then Ranking Member of the House Committee on Natural Resources and has since been elected to the Senate, BOEM said it "publishes its estimates of tract values" in a report on "each sale."

Lowering the Bar

Digging deeper into the arcane process of bid evaluation, POGO noticed another oddity. To understand it, one must slog through potentially eye-glazing technicalities. Bear with us.

In simplest terms, if bids don't clear the bar, the government can lower the bar.

Under procedures BOEM has published, even bids that fall short of the Bureau's MROV estimates can be accepted if they meet an alternative estimate.

That alternative is known as the "Delayed MROV" or "DMROV."

The delayed measure is BOEM's effort to account for the potential cost of rejecting a bid and waiting to offer the tract again in the next available auction. It is BOEM's estimate of what the tract would be worth then, taking into account payments foregone or delayed and any draining of energy deposits that might occur in the meantime—say, as a result of other wells tapping the same oil reservoir.

(The number that ultimately counts is the lesser of the MROV or the DMROV. At the risk of drowning you in alphabet soup, the lesser of the two is called the Adjusted Delayed Value or ADV, referenced above.)

The government's use of that alternative measure can result in head-scratching outcomes.

When the Bureau considered bids placed in the August 2017 auction, it determined that the MROV for one tract was $17 million and that the delayed value of the tract was $6.9 million. In other words, BOEM estimated that, over several months, an unusually valuable tract would lose more than half its value. On that basis, BOEM accepted a bid of $12.1 million, much less than it said the drilling rights were worth at that time.

Given that oil prices can rise or fall unpredictably over time, it isn't obvious that delaying the sale of drilling rights would reduce their value. In fact, by the government's own account, rejecting bids and offering the tracts again later "has consistently resulted in higher average returns in subsequent lease sales for the same tracts, even when those tracts not receiving subsequent bids were included in the calculation of the average returns."

In the Gulf of Mexico from 1984 through 2017, BOEM has stated, the Bureau "rejected total high bids of $638 million, but when the blocks were reoffered, they drew subsequent high bids of $1.8 billion, for a total net gain of $1.2 billion, or an increase of 187 percent."

The government has cited those gains as evidence that the system is working.

The Statistician's Take

(Photo: Bureau of Safety and Environmental Enforcement)

When POGO analyzed the government's treatment of thousands of bids spanning decades, it found that the government accepted a large majority of the bids on the grounds that the tracts were non-viable. Searching for an explanation, POGO discovered that someone else had noticed the same trend: Ted D. Tupper, a statistician and data miner who played an inside role in the process.

Tupper retired in 2007 after more than 20 years at the Minerals Management Service, which was a predecessor to BOEM. During his time at MMS, he managed software the government used to evaluate bids, he told POGO.

In 2014, when BOEM issued a highly technical notification that it was planning to tweak its bid review procedures, three parties filed comments. One was an oil company. Another was an oil industry lobby. The third was Tupper.

"On the topic of improving the FMV [Fair Market Value] process, the principle [sic] problem is the viability/non-viable decision," Tupper wrote.

The majority of producing tracts had been classified as non-viable at the time they were leased, Tupper added, citing research he had done in 2012.

The Bureau’s resource evaluation unit “needs to understand why so many non-viable tracts become productive,” he wrote.

When it comes to the software and hardware used to interpret geologic data, the private sector’s deeper pockets give it an edge over the government, and there are cases in which companies have an information advantage, Tupper told POGO in an interview. If companies have a better understanding of the data than the government does, “they may be able to get something for real cheap,” he said. Tupper also said he identified four cases “where the oil companies got away with a big steal,” making major oil discoveries on tracts originally classified as non-viable.

Tupper told POGO that studying policy issues like these is his hobby in retirement, and he has a recommendation for the government: It should reject bids for tracts it considers non-viable. Then, if companies want to lease them anyway, they should be required to explain to the government why they believe the tract is worth something.

“It would make us smarter,” Tupper said.

Asked about the government’s procedures for evaluating bids, Tupper said, “The system is designed to try to get things accepted.” That has been the philosophy since Jim Watt’s day, he added.

Nonetheless, Tupper said it’s relatively rare for the government to make a big mistake, and he said energy companies have generally been overpaying.

“In general, we’re getting market value and much better than market value,” Tupper said.

“The reason is that the private sector is bidding on lots of stuff which is extremely speculative,” he said. “They’re buying lottery tickets.”

Public Assets, Private Upside

(Photo: U.S. Coast Guard)

One of the Interior Department's primary aims is to promote energy production, but on that count, too, the leasing system gives reason for concern. It allows companies to gain control of drilling rights for years and then sit on them instead of drilling.

The system makes it relatively inexpensive for companies to speculate in offshore leases—to snap them up and then hold them in case, say, a nearby discovery or an increase in oil prices gives them a compelling reason to drill.

One could argue that, from the government's standpoint, getting anything for the leases is better than getting nothing. One could also argue that putting the tracts in companies' hands moves them a step a closer to producing oil or gas.

On the other hand, if a tract proves more valuable than the auction payment reflects, it's the company that is shrewd or lucky enough to have leased it that reaps the gain rather than the U.S. taxpayer. In that scenario, the company isn't just making a profit; it's receiving a windfall at the public's expense.

Also, the public might be served better if the drilling rights were in the hands of someone who would actually use them—instead of tying them up and preventing others from using them.

POGO's analysis of the most recent auction showed how leasing can play out.

All but two of the 90 tracts that drew bids in the August auction had previously been under lease, and many of them had been leased multiple times, POGO found. More than three quarters of the tracts that had been leased before had no history of ever having been drilled, according to searches of a government database that goes back to 1947.

For most of the tracts that had been leased before, no one had even taken an initial step toward drilling: submitting exploration plans for review. At least as reflected in a federal database that goes back to 1972.

Instead, while they were under lease, the tracts were left dormant.

By encouraging energy companies to lock in drilling rights when oil prices are relatively low, the Trump Administration could be passing up the chance to sell the rights for more money later. Though still lower than they have been for much of the past decade, oil prices are already up substantially since the last auction.

Rose, the former chief economist at BOEM, said that, inside the Bureau, he argued against rushing to lease as much as possible as soon as possible. He said the optimal time is not always the present, and some deposits should be held for future generations.

“I always maintained that we don’t need to lease everything now,” he said.

Political people at the Bureau saw it differently, he added. They seemed to equate success with leasing as much as they could.

Leasing portions of the Outer Continental Shelf incrementally instead of all at once would enable the government to gather information about potential energy deposits as drilling unfolds, Rose told POGO. That would help the government to make better assessments of what tracts are worth, he said.

As it is, with so many tracts potentially in play in each auction, the government is left to make rushed evaluations once the bids are in, Rose said.

No Comment

POGO sought input for this report from the Interior Department and industry representatives but met almost complete silence.

Interior Department Press Secretary Heather Swift did not respond to interview requests. The Bureau did not grant requested interviews or answer written questions. For a time, BOEM spokeswoman Tracey Blythe Moriarty held out hope. “Working it,” she emailed on December 6. However, almost a month after POGO submitted written questions, Moriarty wrote:

“Most of the information you are seeking is available on our website, but it will take a considerable amount of time to compile. Please send your questions as a FOIA request, and we will be happy to process the request.”

FOIA—the Freedom of Information Act—governs the release of records. According to a federal primer on the law, “The FOIA does not require agencies to … answer questions.” In addition, agencies routinely deny FOIA requests on the grounds that the requestors are asking questions instead of requesting records that they have adequately described.

The law does not prevent the government from answering questions such as:

Could the system be improved? If so, how? If not, why not?

Why has there been so little head-to-head bidding for offshore leases?

How does BOEM respond to criticism that the system amounts to a giveaway of public resources to energy companies?

The Bureau did not respond to a set of follow-up questions sent in January.

The American Petroleum Institute (API), a trade association for the oil and gas industry, did not respond to interview requests.

A spokesman for another industry group, the National Ocean Industries Association (NOIA), said that the group's president was not available for comment on the subject of offshore leasing. When asked if anyone else at the organization would talk to POGO, the spokesman, Justin Williams, did not respond. (The president of the organization, Randall Luthi, symbolizes the Bureau's historically close relationship with industry. Luthi formerly headed the Interior Department's Minerals Management Service, a predecessor to BOEM.)

Several energy companies acknowledged but did not follow up on inquiries from POGO.

In an August 2017 letter to the government, API, NOIA and other industry groups weighed in on how the next five-year plan for offshore leasing should be drafted.

"The Associations do not see a need to move away from the current lease-sale construct," they said. "The Associations fully support continued use of the current area-wide leasing program in all OCS [Outer Continental Shelf] areas," they added.

Tradeoffs?

Secretary of the Interior Ryan Zinke's newly-reestablished Royalty Policy Committee meets for the first time in Washington, DC, October 4, 2017. (Photo: Taxpayers for Common Sense)

Is there a better way?

Requiring that tracts be nominated for auction would raise federal income by $150 million over 10 years, the Congressional Budget Office (CBO) estimated in 2016. In the world of federal budgets, that may seem like small potatoes. However, it is much more than the federal agency that oversees offshore drilling, the Bureau of Safety and Environmental Enforcement (BSEE), spends on environmental enforcement. In the 2017 fiscal year, BSEE's budget for that amounted to $8.3 million.

More fundamentally, the $150 million estimate was influenced by the relatively low price of energy when the CBO report was written, said former CBO economist Andrew Stocking, co-author of the report. As energy prices rise, so do the stakes, he said.

According to information obtained from CBO, when CBO prepared its estimate, it was using economic projections from January 2016 that began with the price of oil (specifically, West Texas Intermediate crude) at $40 per barrel and anticipated it rising to $48.50 in the fourth quarter of 2017. As it turned out, by the end of 2017, that price had risen to more than $60. (As recently as 2008, it was north of $145.)

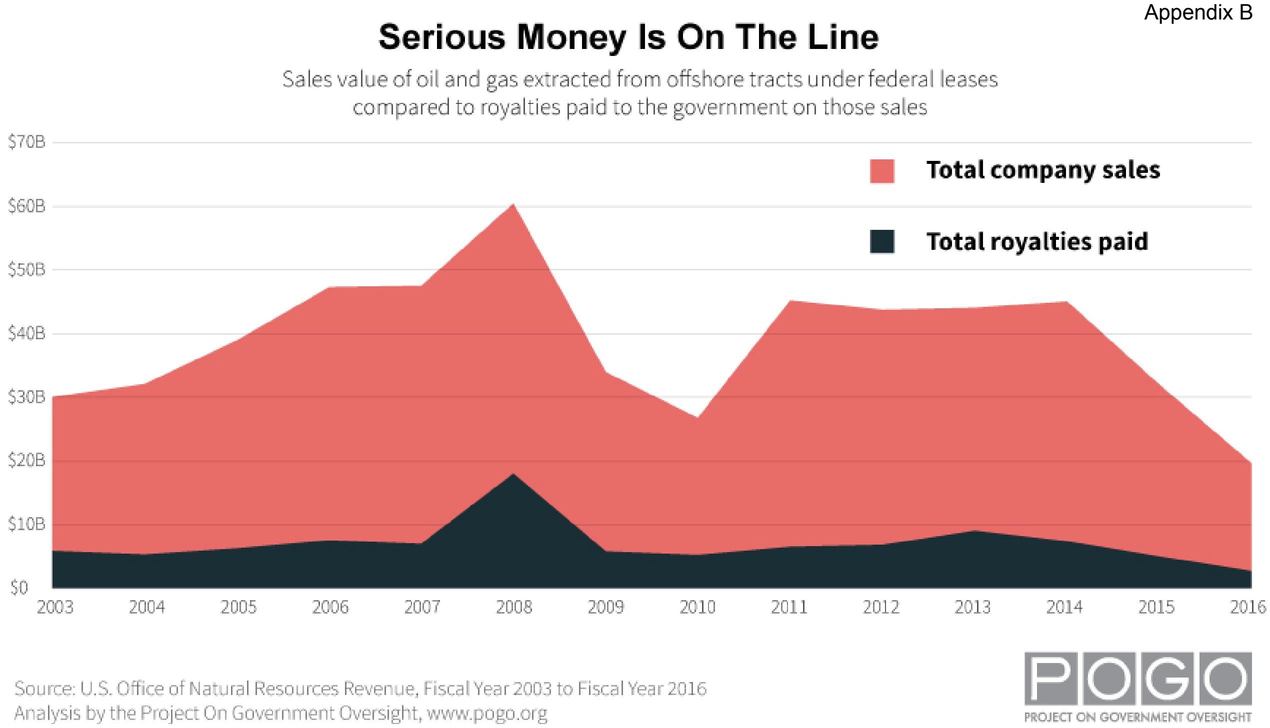
The thinking behind CBO's estimate remains largely opaque, and POGO is unable to explain how it squares with the tens of billions of dollars by which auction payments have declined since area-wide leasing was introduced.

In October 2017, while POGO was working on this report, the ranking Democrat on the House Committee on Natural Resources, Representative Raul M. Grijalva (D-AZ), asked the Government Accountability Office to study the advantages and disadvantages of returning to the old leasing system.

Some contend that the government faces potential tradeoffs—that allowing bidders to pay less up-front for drilling rights could lead to increased production and higher revenues of a different kind over the long run, and vice versa.

By way of context, the sums the winning bidders pay at auction (known as "bonuses") are not the government's only revenue stream from offshore drilling rights. While the tracts are under lease, the government collects relatively modest annual rents. Once the tracts start producing oil or gas, the government collects a percentage of the sales in the form of royalties.

Further, the government's goals go beyond generating a financial return for taxpayers. Other objectives, which may be at odds with each other, include protecting the environment and boosting energy production.



Based on a study commissioned by the government and completed in 2010, reverting to auctions in which only select tracks are offered would increase revenues from auction bidding, industry associations told the government. However, they said, the study also indicated that those revenue gains "would likely be offset by lower revenues in the future."

The last five-year leasing plan developed by the Obama Administration discusses the same research. As the plan boils it down, the research suggests that, if the government went back to the old auction system, higher up-front payments "would be largely offset by" fewer tracts leased, less drilling, slower discovery of energy deposits, less future production of oil and gas, and lower revenues from rent and royalty payments.

But the planning document also undercuts that reasoning. It shows why any connection between up-front auction payments and long-term production or royalty levels may be highly attenuated.

"Activities such as the eventual exploration or production in these regions will be based on other factors (e.g., prices, rig availability, company operating budget) rather than on the number of lease sales," the plan says.

Whether companies invest in costly offshore drilling is influenced by factors as varied as the price of oil and gas, economic growth rates, world events, and technological advances, the plan notes. Royalty payments, in turn, are a function of prices and production volumes.

From the time a tract is leased to the time production of oil or gas begins, a decade or more can pass, the plan says.

The 2016 CBO report showed how far removed royalty payments can be from auction payments—time in which the industry, the market, and the world can change dramatically. In 2013, about 8 percent of offshore royalty income came from parcels that were leased in the previous 10 years, and the majority of the income came from parcels that were leased more than 20 years earlier, CBO reported.

Even over shorter periods, forecasts of oil prices can be wildly off the mark. For example, in a set of economic projections from August 2014, CBO estimated that, in the fourth of quarter of 2017, by one measure (Refiner's Acquisition Cost of Crude Oil, Imported), the price of oil would be $93.40 per barrel. As of November 2017, mid-way through the fourth quarter, it was actually $56.21, a difference of almost 40 percent.

Since area-wide leasing was introduced, production of oil in the Gulf of Mexico—including any production from tracts leased earlier—has increased, according to data from the U.S. Energy Information Administration.

Boue, the researcher at the Oxford Institute for Energy Studies, sees no causal connection. In the once inaccessible deep waters of the Gulf, technological progress would likely have led to increased production with or without area-wide leasing, he said.

Meanwhile, federal data that go back only as far as the 1990s show that natural gas production in the Gulf has declined.

The government seems to have recognized at times that it had a problem with companies sitting on drilling rights. Over the years, it has tried to give companies stronger incentives to use those rights. For example, it has raised minimum bids, adopted annual rental rates that escalate over time, and shortened the length of time that companies can hold certain leases without drilling.

The government also has called for exceptions to area-wide leasing in areas off Alaska. Plans drawn up during the Obama Administration prescribed a more targeted approach to leasing there that would take into account considerations such as environmental protection.

When all possible drilling sites in a vast area are up for grabs, it's harder for the government to study any particular site, said Michael LeVine, an attorney with the group Ocean Conservancy.

The Trump Administration has acknowledged that tradeoff. Lease sales limited to selected tracts "would tend to sell fewer leases and allow more focused environmental analyses," the recently released first draft of the Trump Administration's five-year plan says.

The draft indicates that important decisions lie ahead.

"BOEM will continue to analyze the use of area-wide leasing and focused leasing," it says. The Bureau will consider fair market value, environmental factors, and the use of waters for subsistence hunting and fishing "when determining whether to hold area-wide or more focused lease sales in a particular area," the draft says.

Alarms

From the beginning, critics worried that the Reagan Administration's leasing program would amount to a fire sale, as the *New York Times* article from 1982 noted.

Before long, the Government Accountability Office, then known as the General Accounting Office, was reinforcing those concerns. A 1985 GAO report on the first 10 area-wide sales found that the government received about $7 billion less than it would have under the former system. "GAO's analyses indicated that the stepped-up pace of area-wide leasing, by itself, significantly decreased competition and government bid revenues for individual tracts," the report said.

The Interior Department hoped to make up the money over the long run, the GAO noted.

(At the time, the Interior Department had a rule of thumb for assessing whether bidding was competitive enough to ensure that the public was getting a decent price. It defined adequate competition as at least three bids per tract, the GAO noted. But even the receipt of three bids was no guarantee that the government was receiving fair value—partly because some companies were clearing the hurdle by bidding against themselves, the GAO said. In any event, "relatively few tracts are expected to meet this criterion in future sales," the GAO added.)

Since then, other researchers have drawn conclusions similar to GAO's based largely on some of the same types of Interior Department data that POGO analyzed.

"Our results suggest that the mechanism for allocating leases worked reasonably well prior to 1983," Kenneth Hendricks of the University of Wisconsin-Madison and Robert H. Porter of Northwestern University, who have studied offshore leasing in a series of academic papers going back to 1988, wrote in 2013. "Most of the auctions were competitive, auction revenues were high, and the government captured most of the economic rents through a combination of [auction] and royalty payments," they wrote.

By "economic rents," a term used by economists, they essentially meant "upside."

"The mechanism did not perform nearly as well since 1983," Hendricks and Porter added. "Most of the auctions were not competitive, auction revenues were low, and a large share of the economic rents was captured by the bidders, especially on deep water tracts."

Much of the leasing had been speculative, the professors found.

They recommended switching to auctions with multiple rounds of ascending bids.

They did, however, find a point potentially in favor of area-wide leasing.

"The wide-spread availability of tracts generated a lot of speculative bidding and much lower drill rates, but it also increased the rate of exploration and development," they wrote. "The number of tracts drilled in the twenty year period from 1983 to 2003 was approximately twice the number drilled in the almost thirty year period from 1954 to 1983," they said.

Researchers Robert Gramling and William R. Freudenberg called area-wide leasing "the Great Offshore Giveaway."

“Watt’s strategy worked in that it provided a mechanism to transfer publically owned resources to some of the wealthiest corporations in the world quickly, efficiently, and cheaply,” they wrote in a 2011 article published by the *American Behavioral Scientist*.

In 2012, Markey, then the ranking Democrat on a House oversight committee, noted the lack of competitive bidding and asked the Interior Department about it. Was the government doing all it could to make sure the public received fair value for leases? And were there signs of collusion?

BOEM responded, in essence, that the system was functioning well and that efforts to improve it were likely to backfire.

Only a relatively small number of companies have the ability to operate in deep water, and the costs limit the number of deep water projects those companies will take on, the Bureau wrote. Auctioning fewer tracts to boost competition “may have the adverse effect” of reducing energy production over the long term, the Bureau added. What’s more, the Bureau argued, holding multiple rounds of bidding would probably reduce lease prices because merely edging out the runner-up would be enough to win.

As for collusion, BOEM offered a more qualified answer. The Bureau’s analysis of lease sales in Alaska “has not been able to preclude the possibility that simple chance” explains “the small number” of dueling bids. In the Gulf of Mexico, in light of the number of tracts up for bid, “many non-overlapping bids are expected,” BOEM said.

Yet, perhaps unintentionally, BOEM also showed why giving up auction revenues for hypothetically higher royalties way down the road could be a bad bet.

“True tract values emerge only after a 20 to 30 year period for those leases that are drilled successfully and result in production,” BOEM said. “Forecasts of the dollar value of tracts are unreliable because of the volatility over time in the numerous variables that affect actual tract value.”

Loose translation: What happens over the long run is anybody’s guess.

The government may be sacrificing a proverbial bird in the hand—higher auction revenues—for a bird in a distant bush, and the bush may be a shimmering mirage.

In the meantime, the auction goes on.

The Interior Department has scheduled another sale for March. In a recent Department news release, Republican politicians touted it as a bold stroke by an Administration that understands the benefits of expanding offshore energy—an Administration determined “to open a vast tract of American waters to oil and gas exploration.”

“Secretary Zinke Announces Largest Oil & Gas Lease Sale in U.S. History,” the news release said. “March 2018 sale to offer 76.9 million acres in Gulf of Mexico.”

RECOMMENDATIONS

Based on its investigation of offshore leasing, POGO makes the following recommendations to the federal government:

1. **Reject bids on tracts the government considers worthless, or "non-viable,"** as former Interior Department statistician Ted Tupper has proposed. Currently, when the government classifies tracts as non-viable, it lets companies lease them for its minimum price. Instead, the government should require bidders to explain why they see value where the government does not. That would help the government overcome a potential information disadvantage and insist on receiving fair value.

2. **Investigate the Interior Department's system for determining whether offshore tracts are viable.** The Department has classified almost 80 percent of the Gulf of Mexico tracts on which companies bid as worthless. It has awarded the drilling rights on that basis. Many of the supposedly worthless tracts have gone on to produce oil and/or gas. Why does the Interior Department so rarely see value where energy companies see opportunity? Over the long run, how valuable have the non-viable tracts proven to be? Congressional committees, the Government Accountability Office, and the Interior Department Inspector General should investigate.

3. **Investigate the Interior Department's system for valuing those offshore tracts deemed viable.** The government's valuations are generally much lower than the values industry places on the tracts. Why? The Interior Department and independent authorities should examine the methods the Department uses to ensure that winning bids deliver fair market value. As part of that analysis, the government should take a close look at Interior's willingness to accept bids that are lower than its own initial estimates; in some cases, Interior does so on the questionable theory that the tracts would fetch even less money if held and offered for sale at the next auction.

4. **Don't engage in fire sales.** When energy prices are low, the government should preserve the option of auctioning offshore tracts later, when they might command higher prices. That way, the American people—as well as the companies that lease the tracts—could reap the gains. Holding fire sales is a bad idea for another reason: It makes it cheaper and more tempting for companies to snap up leases on a speculative basis and then tie up the tracts even if those companies are not motivated to drill or produce energy any time soon.

5. **Hold targeted auctions instead of area-wide auctions.** Auctioning fewer tracts at once would promote more head-to-head bidding, which could yield higher payments to the government and, by extension, the American people. If auctions were more competitive, the government could rely more on the market to value drilling rights, and it could rely less on its own limited ability to determine how much money tracts are worth. In addition, focusing auctions on a smaller number of tracts would enable the government to perform more focused economic and environmental analyses of the tracts actually in play. Also, if vast new areas were opened to drilling, as the Trump Administration has proposed, an incremental approach

to leasing would allow the government to learn from drilling results and gather information over time about oil and gas deposits in those areas. Otherwise, the government risks parting with crown jewels before it has any inkling of their true value.

6. **Charge companies a fee to nominate tracts for inclusion in auctions**, as former Interior Department economist Marshall Rose has proposed. That would discourage companies from nominating tracts that don't really interest them just to divert other bidders.

7. **Charge companies a fee for bidding on tracts that they did not nominate**, as Rose has also proposed. That would give prospective bidders an incentive to focus the auctions—and the government's attention—on tracts in which they see the most potential. It would also penalize free riders—those bidders merely piggy-backing on the research of others. (But doing that without the other changes proposed here could backfire by reducing the number of bids.)

8. **Raise the minimum bids.** In the absence of head-to-head bidding, the minimum bids required by the government are often the only price hurdles bidders must clear to win drilling rights. The current minimums are too low to ensure that the public receives appropriate compensation for public assets.

9. **Reject more bids.** Combined with the low price hurdles and the general absence of competitive bidding, the low rejection rate encourages companies to underbid.

10**. Strengthen incentives for energy companies to use their offshore leases instead of sitting on them.** Only by drilling do companies produce oil and gas and generate royalty payments for the government. The current system makes it too easy for companies to tie up leases even if they lack the motivation or means to drill any time soon. To discourage speculation in offshore leases, the government should require companies to pay more money for the leases up front. Then, it should charge higher annual rents, and it should make sure the rents continue to escalate until drilling begins.

11. **Investigate whether bidders are sharing enough information with the government.** Bidders are required to disclose to the government information that goes into their bidding decisions. That's supposed to help the government assess how much the tracts are worth and whether the bids deliver fair value. It's supposed to protect the public from an information imbalance. Yet the government consistently places a lower value on tracts than bidders do, and it classifies many of the tracts on which companies bid as worthless. Is there something the bidders know that the government does not? Is there something the bidders aren't telling the government?

Finally, a word on priorities: **Focus on the bird in hand, not just the bird in the bush.** If there is a tradeoff between the revenue the government collects up-front through auction payments and the revenue the government has the potential to collect eventually through royalties on oil and gas production, the current system gives up too much on the front end. The long-term revenue is likely to be far off—if it materializes at all. The government should strike a healthier balance.

POGO's methodology in acquiring and analyzing Department of Interior data can be found here.

GULF ENERGY ALLIANCE

Gulf Energy Alliance (GEA) Testimony
before the
Department of Interior's Royalty Policy Committee
February 28, 2018
Houston, Texas

Thank you for the opportunity to provide comment to the Royalty Policy Committee.

My name is Lem Smith and I am here today to represent and provide input on behalf of the Gulf Energy Alliance. Our members are large independents operating mostly on the Gulf of Mexico shelf, principally in the shallow and intermediate water depths of the Gulf. In fact, GEA members represent over 80 percent of the production from the Shelf.

First, I would like to commend the Department for the actions taken last summer with regard to Lease Sale 249, which called for a reduced royalty rate of 12.5% for shallow water assets. This was an encouraging signal to the market and to our members.

Today, however, I would like to encourage the Department to review and consider all current existing authorities available to it, which if properly leveraged could result in attracting critical new capital to this mature basin. More specifically, I would like to request the Committee consider utilizing existing tools in the toolbox, if you will, and its discretion pursuant to Royalty Relief upon new production from existing leases such as is the case via special case royalty or end of life royalty relief.

Since 1947, production from the Gulf of Mexico shelf has produced more than 12 billion barrels of oil and 160 TCF of natural gas. Similarly, this largely American investment has generated billions of dollars in royalties, reduced U.S. dependence upon foreign oil imports, provided thousands of high-paying jobs for Americans and generated billions of dollars in corporate and payroll taxes.

Today, the shelf - originally developed by large integrated major oil companies - is now dominated by Independents, which make-up approximately 93% of current Shelf production. That's worth repeating – 93% of existing production from the Shelf comes from Independents who have taken over these declining assets and, like their predecessors, have continued to produce them responsibly and efficiently.

The reality of the Shelf today finds unfavorable economics relative to other basins - particularly onshore - higher operating costs, more restrictive regulations (such as Obama-era financial assurance) and general/protracted regulatory uncertainty.

For this reason, we encourage the Committee and the Department to consider these existing tools in the toolbox. Appropriate use for which could improve drilling economics upon the Shelf, which is critically necessary to attract new capital to the basin and reinvigorate drilling operations on the Gulf Shelf.

The Gulf Energy Alliance will be filing more substantive comments into the record, but we wanted to formally express our thoughts in-person. We thank you for the opportunity today and for your important work on the Royalty Policy Committee.

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