November 30, 2020

Submitted via email

Ms. Kimbra G. Davis
Director
Office of Natural Resource Revenue
U.S. Department of the Interior

Re: ONRR 2020 Valuation Reform and Civil Penalty Rule
Docket No. ONRR-2020-0001, RIN 1012-AA27

Dear Director Davis:

Western Energy Alliance submits these comments on the proposed targeted amendments (2020 Targeted Amendments) to the Office of Natural Resources Revenue's (ONRR) regulations for valuing oil and natural gas produced from federal leases. The regulations were most recently amended by the 2016 Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform Rule (2016 Valuation Rule), and we greatly appreciate these proposed revisions.

Western Energy Alliance represents 200 companies engaged in all aspects of environmentally responsible exploration and production of oil and natural gas across the West. The Alliance represents independents, the majority of which are small businesses with an average of fourteen employees.

The stated goal of the 2016 Valuation Rules was to provide regulations that (1) offer greater simplicity, certainty, clarity, and consistency in product valuation for mineral lessees and mineral revenue recipients; (2) are more understandable; (3) decrease industry's cost of compliance and ONRR's cost to ensure industry compliance; and (4) provide certainty to industry and ONRR that companies have paid the amount of royalties due under their leases. Unfortunately, some of the provisions of the 2016 Valuation Rule had the opposite effect.

The 2020 Targeted Amendments address some of the provisions that did not achieve the goal of the 2016 Valuation Rules. For the reasons discussed in more detail below, the Alliance supports the goals of the 2020 Targeted Amendments including, but not limited to, expanding the index-based valuation options to arm's-length transactions and returning other regulations to the longstanding and familiar valuation framework in effect prior to the 2016 Valuation Rule.

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Extending the Index Based Option to Arm's-Length Sales

The Alliance supports the proposal to extend the index-based option to arm's-length sales even though it is expected that this option, if elected, will result in higher royalties than if royalties are based upon gross process less unbundled transportation and processing allowances.

Extending the index-based method to arm's-length contracts would reduce regulatory compliance costs for both lessees who elect this option and ONRR. To the extent lessees have hired third-party consultants and/or attorneys to assist them in unbundling gas marketing arrangements, there is an increased regulatory burden. And this burden is on-going as new contracts are negotiated or existing contracts are amended.

Index-Based Option for Gas. As to the index-based option for sales of unprocessed gas and residue gas, the Alliance acknowledges and appreciates the updating of the allowed adjustment to the index-based price (the 10%/10 cents minimum/40 cents maximum for OCS GOM and 15%/10 cents minimum/50 cents maximum for all other sales). This adjustment is in lieu of an unbundled transportation allowance (capped at 50% of the value of the product) that would otherwise need to be calculated.

While the updated adjustment percentages and maximums will more closely align to actual unbundled transportation costs for gas sold under percentage of proceeds or similar types of contracts (e.g., percentage of index), it is expected that the adjustment will still be less than an unbundled transportation allowance. The tradeoff for this change is simplicity and certainty. Under these types of contracts, the transportation and processing bundled "fees" are the value of the percentage of residue gas and liquids retained and, therefore, there is a relationship between proceeds and allowances. Similarly, in this context, there is a relationship between the index price and an adjustment based on a percentage of the index price.

However, in the last several years, the owners of transportation systems and processing plants have changed their contracting approach and many are no longer willing to enter into percentage of proceeds or similar types of contracts because they do not want to take commodity price risk. Instead, many contracts are now fixed fee contracts with little or no percentage of proceeds retained by the owners of the transportation systems and processing plants. With fixed fee contracts, there is no nexus between proceeds and fees. The fees do not change as commodity prices increase or decrease. These fixed fees are set so that the owners and their investors make their targeted profits regardless of commodity prices. As a result, the adjustment in the index-based valuation method for unprocessed gas and residue gas will not come close to capturing what would otherwise be an unbundled transportation allowance under a fixed fee contract.

Additionally, the fixed fees that owners are requiring tend to vary by producing region with fixed fees in the Bakken, for example, being higher than fixed fees in the Permian Basin. This may reflect the fact that in the Permian Basin many of the fixed fee contracts involve facilities that have already been constructed where the purpose of the fixed fee is to lock in the level of profit that was historically realized under POP contracts in a higher priced commodity environment. In the Bakken, the higher fixed fees are required in order for companies to be willing to construct infrastructure in the first instance and reflect the return on investment required to incent such construction.

Furthermore, the development of fixed fee contracts in recent years points out another limitation of the index-based option, which is that there is a lag between the information available to ONRR and actual costs being incurred in real time. The lag is a result of the fact that information available to ONRR comes in through audits which can occur as much as six years after royalties are paid (to fit a seven-year statute of limitations).

The disconnect between the adjustment formula in the index-based option and fixed fee contracts means that the option may not be utilized as widely as ONRR anticipates because the value of simplicity and certainty will be more than offset by the significant additional royalties. This does not mean the targeted amendments should not be adopted; it simply means that participation may be lower than anticipated.

A mechanism is needed to deal with a fixed fee arrangement since many transportation contracts are structured in that manner. It would be preferable to have a rate structure similar to what was derived for the Natural Gas Liquids (NGL) index-based method where a rate per gallon was provided. A study could be done to determine region specific transportation rates for gas (considering unbundling and caps as well) and these could then be escalated over time using an economic factor (like the Consumer Price Index or Producer Price Index). The Alliance does not wish to delay the current rulemaking. Instead, it proposes that development of a mechanism to deal with fixed fee arrangements be the subject of a subsequent rulemaking.

<u>Index Price Instead of Bid Week High Price.</u> The 2020 Targeted Amendments propose to change the index value from the bid week high to the index price. This is a welcomed change. The highest monthly bid-week price of any pricing point your gas could flow to is not a pricing formula that any contract uses, nor would any reasonable counter party agree to such a formula. Also, in order to obtain the information to calculate the bid week high price, lessees would have to pay several thousand dollars a year to subscribe to one of the authorized publications. (In contrast, because gas is typically sold at index-based prices, lessees can know from their statements what the index price was for a particular month.) This was a major impediment to the use of the index-based option for non-arm's-length contracts under the 2016 Value Rules.

<u>Identifying index pricing points.</u> But there still remains a significant challenge to using the index-based method to value unprocessed gas and residue gas, and that is the difficulty of identifying the index-pricing points to consider in selecting the correct index price to use. Determining the applicable index-pricing points is difficult, ambiguous, uncertain, and unnecessary.

The difficulty is caused by the following language in the 2016 Valuation Rules:

> (1)(i) If you can only transport gas to one index pricing point published in an ONRR-approved publication, available at www.onrr.gov, your value, for royalty purposes, is the published average bidweek price to which your gas may flow for that respective production month.
>
> (ii) If you can transport gas to more than one index pricing point published in an ONRR-approved publication available at www.onrr.gov, your value, for royalty purposes, is the highest of the published average bidweek prices to which your gas may flow for that respective production month, whether or not there are constraints for that production month.
>
> (iii) If there are sequential index pricing points on a pipeline, you must use the first index pricing point at or after your gas enters the pipeline.

There is uncertainty about the meaning of the phrase "if you can transport," which is further increased by the phrase at the end of (ii) "whether or not there are constraints for that production month." The concern is about whether this is supposed to be a hypothetical inquiry (i.e., what are all of the index pricing points to which gas could theoretically flow, without regard to constraints, from a particular producing region) or an inquiry based upon the actual index pricing points to which gas is flowing. Does "whether or not there are constraints for that production month" include or exclude index pricing points associated with pipelines that are fully subscribed, not just for one month but for every month?

Determining how many index pricing points to which gas could be hypothetically transported requires a knowledge of the nationwide pipeline grid and the midstream business that most lessees do not have. Most producers, and particularly small independent producers, are not in the midstream business and do not have the information and resources necessary to determine all of the index pricing points to which gas from a particular region could hypothetically flow without regard to constraints. And if a producer guesses wrong - misses an index pricing point that ONRR thinks should have been considered - then the simplicity and certainty of the index-based method is lost.

If a well is already connected to a system, the relevant index pricing point should be the one to which the gas is actually flowing. For example, if the residue gas from a New Mexico Permian Basin gas plant is delivered into the El Paso interstate pipeline at the outlet of the plant, the relevant index pricing point should be the applicable El Paso Permian Basin index even if other producers in the area or other producers whose gas flows through the same plant have their residue gas delivered at the outlet of the plant into the Transwestern system. If the gas was actually nominated for delivery into the El Paso Permian Basin system, it is a fiction that the gas could have been transported to other index-pricing points as well. Wells are physically connected to transportation systems and their gas physically flows to a specific gas plant. The residue gas has to be nominated into specific residue gas (generally interstate) pipelines. The actual facts should determine the relevant index-pricing point under the index-based methodology.

In the situation in which a transportation system is temporarily down and a flare goes off for safety purposes, if that flaring does not qualify as royalty free use, ONRR's position is that the index-based option is mandatory. But in this situation, it is submitted that the relevant index pricing point is still the one to which the gas was flowing and will flow again once the temporary situation is resolved.

For wells waiting on pipe for which a contract has been executed, if there is avoidably lost gas that must be reported and valued, under the 2016 Rules and the proposed amendments, the index option is mandatory. It is submitted that the relevant index pricing point should be the one to which the gas will flow once the connection is completed.

For wells waiting on pipe for which a contract has not yet been executed, if there is avoidably lost gas that must be reported and valued, under the 2016 Rules and the proposed amendments, the index option is mandatory. It is submitted, however, that the facts on the ground are relevant. If there is no existing infrastructure or what infrastructure there is, is fully subscribed, it is a fiction that the gas could have been transported on any of the existing infrastructure. There is no actual index pricing point for this gas.

The regulations should provide that this gas be valued the way it was historically valued prior to the 2016 Rules - i.e., based upon other publicly available indicators of value including, but not limited to, prices received by the lessee for its arm's-length sales of gas in the same field or area. This is the same valuation methodology as is in the 2016 Rules for valuing FL&U and residue gas retained by a gas plant under a POP contract. See 1206.141(d) and 142(e).[1]

<u>Index-Based Option for NGLs.</u>

Another factor affecting the decision whether to use the index-based option for gas is the impact on royalties under the index-based option for plant products (NGLs). If the additional royalties owed under this option is too much in excess of the royalties that would be owed based upon gross process less unbundled transportation and processing, then there is no simplicity or certainty advantage to electing to use the index-based option for residue gas. This is because, in order to calculate the royalties for the plant products, a full unbundling will have to be performed including allocating bundled fees between transportation and plant and further allocating them between allowed and disallowed costs. If that has to be done in order to report and value the plant products, then all the work required to report and pay royalties on the residue gas based on gross proceeds less an unbundled transportation allowance will already have been done as well.

Unfortunately, the index-based option for plant products has several problems. First, the post-plant liquids transportation and fractionation rates are out of date. Liquids

1 These regulations provide, "[i]f some of your gas is used, lost, unaccounted for, or retained as a fee under the terms of a sales or service agreement, that gas will be valued for royalty purposes using the same royalty valuation method for valuing the rest of the gas that you do sell."

transportation rates can be found in FERC tariffs available on the FERC website and they are quite a bit higher than the current post-plant transportation rates under the index-based method.

Liquids fractionation rates are also significantly higher than the data ONRR is using. Fractionation rates increased over the last several years due to shortages in fractionation capacity, followed by new fractionation construction that had to be supported by higher-priced fractionation contracts. Second, the processing allowances are also based on outdated information. As noted above regarding transportation rates, the industry has had to move to fixed fee contracts in the last several years as existing POP contracts expired and new contracts had to be negotiated. Third, it is our understanding that ONRR is interpreting the 2016 Valuation Rules to prohibit a lessee who elects the index-based option from taking any transportation allowance for pre-plant transportation of the liquids component of the gas stream to the gas plant.

Steps that the Alliance proposes for consideration to address these issues are:

(1) The Mineral Leasing Act, lease terms, and decades of decisions establish that lessees are entitled to an allowance for their reasonable actual costs of transportation. This includes transportation of NGLs entrained in the gas stream from the lease to a processing plant. An additional adjustment is required to capture pre-plant transportation. One option would be to use the same transportation adjustment per MMBtu under the index-based option for gas to calculate a pre-plant transportation adjustment for NGLs (by multiplying the rate times the NGL shrinkage).

(2) A mechanism is needed for updating the index-based adjustment factors. For example, a noted above, liquids transportation rates are generally FERC tariff rates. They are adjusted every July 1 based on the FERC Index. It is not reasonable to continue to use the outdated post-plant transportation rates in the index-based option indefinitely when actual liquids transportation rate information is available in FERC tariffs. A selection of liquids transportation tariffs by producing region could be used to update the post-plant liquids transportation component under the index-based method. Post-plant transportation is an allowed cost and does not require unbundling. Only the transportation allowance cap would be applicable.

(3) A mechanism is needed for updating the index-based adjustment factors for fractionation and processing. At a minimum, these factors could be updated annually by using widely published economic factor like the Consumer Price Index ("CPI") or Producer Price Index ("PPI") to handle these adjustments. But periodically, the agency should update these adjustment factors based upon the more current information the agency obtains during the course of its auditing activities or through other information discovery mechanism.

Keepwhole Contracts and the Index-Based Option for NGLs.

Another concern with the index-based option for plant products is the application of this option to keepwhole contracts. While the index-based option is just that - an option - ONRR's position in its training under the 2016 rules is that it is mandatory to use the index-based option to value the liquids portion of the gas stream when gas is subject to a keepwhole contract.[2] Industry still does not understand why gas sold under a keepwhole contract cannot be valued based upon the gross proceeds accruing to the lessee.

Under a keepwhole contract, the lessee receives at the outlet of the gas plant, the thermal equivalent (i.e., in MMBtus) of the gas delivered to the plant and that is the quantity that the lessee sells. The lessee's gross proceeds are the proceeds from the sale of the thermal equivalent quantity. But the agency requires the lessee to invent the quantity and value of liquids, by component, that were recovered and kept by the plant and to report and pay royalties on that value and the value of the residue gas (without counting the keepwhole shrinkage quantity).

The agency recognizes a processing allowance equal to the difference between the value of the liquids retained by the plant and the value of the keepwhole shrinkage delivered with the residue gas at the outlet of the plant. The agency's position is inconsistent with the economics of the contract that was negotiated. Furthermore, if the index-based option is mandatory for a keepwhole contract and if the agency's interpretation of the index-based option is that no pre-plant transportation is allowed, then the result is significant excessive additional royalties.

The Alliance recommends the following:

(1) Allow royalties to be paid on the gross proceeds received by lessees whose gas is subject to a keepwhole contract.

(2) If (1) is not adopted, at least return to the approach prior to adoption of the 2016 Valuation Rules which allowed lessees to deduct both pre and post liquids transportation costs and well as liquids fractionation costs. See the 2018 Dear Reporter Letter regarding keepwhole contracts.

Reinstating provisions allowing lessees to request authority to exceed the 50% transportation allowance cap and the 66 2/3% processing allowance cap

The Alliance supports this proposed targeted amendment. As to the situations where lessees had received approval to exceed the allowance caps, removal of those approvals by the 2016 Valuation Rules meant that those lessees could no longer rely on

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2 The only exception shown in the training slides was the situation in which gas *from the same lease* is sold partly under a keepwhole contract and partly under a contract under which the lessee is paid for liquids. In this situation, the training slides stated that the liquids under the keepwhole contract could be valued based upon the non-keepwhole contract. The situation in which gas from the same lease would be sold under two different contracts is rare.

approvals that they had at the time investment decision were made. This is problematic, and there is no reason not to leave open the option for lessees to seek approval to exceed allowance caps in appropriate situations.

Restoring this option does not guarantee that the allowance caps can be exceeded in any particular case but returns to the prior regulations which allowed lessees to present their facts and request authority to exceed an allowance cap. This promotes the maximum recovery of oil and gas from wells that have already been drilled by preventing the waste associated with premature abandonment due to costs exceeding the allowance caps with no opportunity to seek approval for a higher allowance.

As the industry struggles in the current low commodity price environment coupled in some cases by fixed fee contracts, there is a need to have a process by which the agency can consider allowances based upon specific facts.

<u>Removing the misconduct definition and associated default provisions</u>

Prior to the 2016 Valuation Rule, the federal oil and gas regulations included an exception to valuation on the basis of gross proceeds when the gross proceeds did not reflect reasonable value due to <u>misconduct</u> or breach of the duty to market or when the transportation or processing costs did not reflect the reasonable value of transportation or processing due to <u>misconduct</u> or breach of the duty to market. There was no definition of "misconduct" in the pre-2016 Valuation Rule regulations.

The 2016 Valuation Rule added a definition of "misconduct" and default rules specifying the consequences of "misconduct." Misconduct was defined as "any failure to perform a duty owed to the United States under a statute, regulation, or lease, or unlawful or improper behavior, regardless of the mental state of the lessee or any individual employed by or associated with the lessee."

This definition of misconduct is so broadly written as to include clerical errors or any technical or inadvertent violation of law even if such error or violation has nothing to do with a contract for the sale of production or transportation or processing. For example, if a lessee makes a mistake and submits a royalty report in which coalbed methane gas is reported as product code 04 instead of product code 39, that would fall within the definition of "misconduct" but has nothing to do with whether a contract for the sale of production reflects reasonable consideration.

There was nothing wrong with the pre-2016 Valuation Rule context in which the term "misconduct" was used - it was understandable from the context (i.e., "gross proceeds did not reflect reasonable value due to <u>misconduct</u>") without definition. A Westlaw search in Gowers Federal Services for decisions in which "consideration" and "misconduct" appear in the same sentence only identified five decisions and in none of those was there even a claim of misconduct let alone a dispute about what misconduct meant.

The fact that not only was a definition included in the 2016 Rules but it was so broadly written as to include any and all errors that might possibly occur appeared to give the agency the utmost discretion to determine the value of production and allowances without regard to the lessee's gross proceeds and its reasonable actual transportation and processing costs. The definition of "misconduct" and the associated default provisions created extreme and unnecessary uncertainty. It is submitted that no definition is required of the term "misconduct" because it is even more understandable in the context of the use of the term in the 2016 Valuation Rules which refer to "misconduct by or between the contracting parties."

Removing the other default provisions and all references thereto

Default provisions were also added in the 2016 Valuation Rules allowing ONRR to determine the value of production or the amount of allowances in situations triggered by 10% comparisons as follows:

> (2) You have breached your duty to market the oil, gas, residue gas or gas plant products for the mutual benefit of yourself and the lessor by selling the products at a value that is unreasonably low. ONRR may consider a sales price to be unreasonably low if it is 10 percent less than the lowest reasonable measures of market price including—but not limited to—index prices and prices reported to ONRR for like quality products;
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> (2) ONRR determines that the consideration that you or your affiliate paid under an arm's-length transportation or processing contract does not reflect the reasonable cost of the transportation or processing because you breached your duty to market for the mutual benefit of yourself and the lessor by transporting or processing at a cost that is unreasonably high. We may consider a transportation allowance or processing allowance to be unreasonably high if it is 10 percent higher than the highest reasonable measures of transportation costs or processing costs including, but not limited to, transportation allowances or processing allowances reported to ONRR and, in the case of transportation allowances, tariffs for gas, residue gas, or gas plant product transported through the same system;

The 10% tests in the default provisions are also so broadly written as to be cause for concern. The language gives the agency discretion (a "blank check") to determine when a value is unreasonably low, or allowances are higher than its determined highest reasonable measures of transportation or processing costs. The default provision 10% tests could even be triggered by transactions that have the same economic effect but are structured differently.

Consider, for example, the situation in which one lessee sells its residue gas at the outlet of a gas plant for $2.00 per MMBtu and another lessee transports its residue gas to a downstream market for transportation costs of $0.30 per MMBtu and sells its gas at the end of the transport for $2.30 per MMBtu. Both producers end up with $2.00 of revenue after the second producer deducts its costs. But the first producer's sales price is more than 10% below the second producer's sales price.

The concern is that that could trigger application of the default provision and allow ONRR to determine the value of the first producer's residue gas, and the second producer has transportation costs whereas the first producer has none. The concern is that that could trigger application of the default provision and allow ONRR to determine the second producer's transportation allowance. But the two transactions have the same economic effect, and no default provisions should be triggered.

The default provisions ignore the fact that lessees have every incentive to maximize their revenue from the sale of production. Under a 12.5% royalty rate federal lease, the lessee's net revenue interest is seven times larger than the federal share. No one sells for a lower value in order to save on royalties.

Finally, the 2016 Valuation Rules Default provisions allow ONRR to determine the value of production or the amount of allowances if:

> (3) ONRR cannot determine if you properly valued your oil, gas, residue gas or gas plant products for any reason including—but not limited to—your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.
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> (3) ONRR cannot determine if you properly calculated a transportation allowance under § 1206.111 or § 1206.112 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.
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> (3) ONRR cannot determine if you properly calculated a processing allowance under § 1206.160 or § 1206.161 for any reason, including, but not limited to, your or your affiliate's failure to provide documents that ONRR requests under 30 CFR part 1212, subpart B.

This provision has also been very controversial because it is so broadly written as to allow ONRR to determine the value of production or amount of allowances because a lessee cannot provide a document requested by ONRR that a lessee has no legal or practical ability to obtain. For example, an auditor in a compliance review concerning unbundling could request a lessee to provide the capital costs, depreciation, and Operating and Maintenance ("O&M") costs for the transportation system and gas plant handling the lessee's gas. No lessee can obtain such information. The owners of the transportation systems and gas plants consider such information to be confidential and proprietary and will not provide that information to counter parties in the contracts.

The United States Supreme Court has held that the void for vagueness doctrine addresses at least two connected by discrete due process concerns: "first, regulated parties should know what is required of them so that they may act accordingly; second, precision and guidance are necessary so that those enforcing the law do not act in an arbitrary or discriminatory way." *Grayned v. City of Rockford,* 408 U.S. 104, 108-109 (1972). The concern with the definition of misconduct and the default provisions was that they were so broadly written as to create the potential for enforcement in an arbitrary or discriminatory way. Elimination of the definition of misconduct and the default provisions will not prevent ONRR from enforcing its regulations but it will remove the potential for second guessing of marketing arrangements and potential abuses that could result from these overly broad, open ended provisions.

Eliminating the requirement that written contracts be signed by all parties

The provision added by the 2016 Valuation Rules requiring a written contract signed by all parties has been problematic since it was enacted because it is inconsistent with how production is sometimes sold. For example, in 2016 after the 2016 Rules were first finalized, some lessees began telling their oil purchasers that they were going to need written and signed contracts because of new federal royalty requirements. Oil purchasers were not willing to change their contracting practices to accommodate this change. Oil and gas can be sold on a spot basis with confirmation of terms exchanged by emails. ONRR's signed written contract requirement would not be met by the exchange of emails. Producers were told to go elsewhere if they had to have written signed contracts.

The signed written contract requirement of the 2016 Rules is stricter than what is required to establish a contract under general commercial law. For example, course of dealing could not be used to satisfy ONRR's signed written contract requirement but can be sufficient to establish a binding contract in a court of law in the event of a contract dispute. ONRR's requirement was thus interfering with the functioning of the commodities markets.

The Alliance agrees with ONRR's comments that it has broad authority evaluating contracts under general commercial law. ONRR had decades of experience evaluating contracts before the 2016 Valuation Rule requirement was adopted. It is submitted that any contract that is sufficient to be enforced in a court of law should be sufficient for federal royalty purposes.

Eliminating the requirement that companies cite legal precedent when seeking a valuation determination

This requirement added by the 2016 Valuation Rules particularly impacted smaller producers because it requires a lessee desiring to obtain a valuation determination to have an attorney to assist with locating legal precedent. Smaller producers do not generally have their own in-house attorneys.

Many valuation questions can be resolved by ONRR informally thus benefitting both lessees and ONRR. This requirement serves to discourage seeking any assistance from ONRR with a royalty valuation or reporting question. This benefits no one.

The Alliance supports removing this requirement of the 2016 Valuation Rules for the reasons stated in the notice of proposed rulemaking (NOPR). ONRR is familiar with, and commonly a party to, matters that generate precedent.

Implementing Executive Orders and Secretarial Orders

The Alliance believes that the 2020 Targeted Amendments are consistent with the executive orders and secretarial orders cited in the NOPR.

Although the NOPR talks about altering transfer payments between the United States and its lessees, the Alliance stresses that the 2020 Targeted Amendments are not reducing royalties below the royalties that are owed. Instead, the 2020 Targeted Amendments may allow industry to reduce the amount of overpayment of royalties that otherwise occurs.

For example, some companies take no allowances because of the difficulty of applying the marketable condition rule. If such a company is able to elect the index-based option, then it is true the company will be able to take some allowances (i.e., the adjustments built into the index-based formulas) but this will only reduce the overpayment of royalties that was previously occurring under the no allowances situation. As discussed above, the index-based option will still result in more royalties that royalties based on gross proceeds with unbundled transportation and processing allowances.

Finally, the NOPR's analysis of benefits to industry does not present a completely accurate picture. To the extent the 2016 Valuation Rules took away allowances (such as for extraordinary transportation or processing costs) that the 2020 Targeted Amendments propose to restore, the 2020 Targeted Amendments are simply returning royalties to the status quo prior to the 2016 Valuation Rules.

The leasing statutes, language of federal leases, and decades of IBLA and Court decisions have held that value is to be determined at the wellhead, which is why transportation and processing allowances are required. Reinstating allowances that the 2016 Valuation Rule took away is not reducing royalties below what is owed, it is simply removing regulations that resulted in excessive royalties beyond what was owed.[3]

Western Energy Alliance appreciates your consideration of these comments. Please do not hesitate to contact me with any questions.

Sincerely,

Tripp Parks
Vice President of Government Affairs

3 *U.S. v. Gen. Petroleum Corp. of Cal*., 73 F. Supp. 225, 258 (S.D. Cal. 1946) (gas royalty is determined "at the leases, that is, *before it left the field*"), *aff'd sub. nom.*, *Cont'l Oil Co. v. U.S.*, 184 F.2d 802, 820 (9th Cir. 1950) ("royalties were to be calculated at values at the wells, not at the . . . destination"); *Shell Oil Co.*, 70 I.D. 393, 396 (1963); *Arco Oil and Gas Co*., 109 IBLA 34 (1989); *Shell Oil Co.,* 52 IBLA 15 (1981); *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 sub. nom.*, *Indep. Petroleum Ass'n of Am. v. DeWitt*, 279 F.3d 1036 (D.C. Cir. 2002).