Chevron

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Hyla Hurst
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Office of Natural Resources Revenue
P.O. Box 25165
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Re: Docket Number ONRR-2011-0005
RIN 1012-AA01
Comments of Chevron U.S.A. Inc. on Advanced Notice of Proposed Rulemaking on Federal Oil and Gas Valuation

Ladies and Gentlemen:

Chevron U.S.A. Inc. (Chevron) appreciates the opportunity to comment on the Office of Natural Resources Revenue (ONRR) Advance Notice of Proposed Rulemaking on Federal oil and gas valuation that was published in the Federal Register on May 27, 2011 (76 Fed. Reg. at 30878-30881). Chevron is a leading international oil company with major operations and investments in the United States. Chevron is the largest federal leaseholder in the Gulf of Mexico, and also holds a substantial number of onshore federal leases. As a federal leaseholder and operator, Chevron has a strong interest in the scope and content of any revisions to the federal oil and gas valuation regulations. Chevron concurs in ONRR's stated goals that any such revisions should provide clarity and ease of understanding, efficiency, certainty, and consistency in royalty valuation, and we firmly believe that revenue neutrality is critical. We offer the following comments to address the specific questions raised in your May 27, 2011 Advance Notice of Proposed Rulemaking.

A. Use of Index Prices To Value Oil and Gas

The ONRR is seeking comment on the existing use of index pricing to determine the value of production for oil royalty purposes and whether the use of index pricing should be expanded or altered.

We strongly encourage the ONRR to expand the availability of oil index pricing as a valuation option for all arm's-length and non-arm's-length oil dispositions. Because markets evolve, the ONRR should also provide the ability for lessees to propose additional market centers for approval so that the list of approved market centers remains current. For example, SGC at Nederland, Texas has become an active market with a valid index, but is not currently an approved market center. We also suggest that the use of a published differential to adjust value from the market center to Cushing should always be an available alternative even when an actual exchange differential is available, as the published differential affords simplicity in reporting and reduces the audit burden for both the lessee and the ONRR.

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Additionally, the ONRR is considering the use of index pricing in valuing Federal gas for royalty purposes.

We support the use of gas index pricing for royalty valuation, as long as the specific regulations drafted provide administrative simplicity and remain revenue neutral. The current residue gas arm's-length proceeds pricing actually works well. The true benefit to gas indexing is not the price itself, but the opportunity to achieve clarity, transparency and certainty on allowable deductions, thereby reducing the administrative burdens in reporting and auditing for both the lessee and the ONRR. An index-based approach can eliminate pricing adjustments, non-arm's-length transportation and processing calculations and true-ups, unbundling of arm's-length transportation and processing agreements and related true-ups, and special keepwhole accounting reporting requirements. Thus, an index price methodology should not include any safety net calculations, dual accounting, true-up requirements or special keepwhole accounting requirements, all of which increase reporting and auditing burdens.

Please consider the following:
• *We seek input on how well index prices currently represent the value for oil and gas produced in different regions or areas of the country, such as states on the Gulf of Mexico coast (including Texas, Louisiana, Mississippi, and Alabama, as well as onshore areas within those states), the Midwest (including Oklahoma and North Dakota), the Southwest (including New Mexico and the Permian and San Juan Basin areas), the Rocky Mountain area (including Wyoming, Montana, and Colorado and Utah outside the San Juan Basin), the West Coast states (primarily California), and Alaska. Please identify what index publications you believe apply to what parts of these areas and the relative advantages and disadvantages, and strengths and weaknesses, of using each of the identified published index prices.*

For gas, index prices accurately represent market value for all regions except Alaska. A majority of our equity gas sales are index-based, and we have substantial experience comparing gas index prices to our actual netback of arm's-length proceeds. Our experience shows that over time, index-based pricing tracks within 1% of actual netback proceeds. Gas index regulations could be based upon a basket of indices, or the ONRR could approve a single representative index for each area (*e.g.*, Henry Hub for the Gulf of Mexico; EPNG SJ for the San Juan Basin; NWPL WY for the Rockies).

Except for production from the Rocky Mountain Region and California, our experience indicates that oil index prices generally track closely with gross proceeds over time. Dispositions of Cushing oil are typically valued at prices resembling calendar month NYMEX plus the roll. Thus, using NYMEX plus the roll, adjusted for location and quality, should be an accurate and viable alternative. Index prices for the **Gulf Coast, Midwest and Southwest** are accurate. On the other hand, the lack of reliable indexes for the **Rocky Mountain Region** illustrates the need for the regulations to continue to offer alternative valuation options.

Similarly, for **California** our experience shows that the ANS index price methodology does not approximate market value, as we have seen large differences in the adjusted ANS price versus the actual market price in the field for the same lease (*i.e.*, in situations where we have both arm's-length and non-arm's-length sales from the same lease in the same month). One solution to this California concern, which would also provide consistency in the regulations, would be to add to 30 C.F.R. § 1206.103(a) the same mechanism for valuing oil not sold under an arm's-length contract found at 30 C.F.R. § 1206.103(b)(2) (using the arm's-length sales price to value non-arm's-length volumes if over 50% of the production from the field is sold at arm's-length), so that this option is also available for production from leases in California and Alaska.

• *We also seek input on whether value should be based on first-of-month prices, daily spot prices, or some mixture of the two when considering the use of index prices.*

While actual gas sales prices typically incorporate a mixture of first of the month and daily spot prices, with a higher first of the month component and lower daily spot price component, in order to achieve the important goals of efficiency and certainty it would be appropriate to adopt first of the month pricing for federal royalty valuation purposes.

• *In addition, we seek input on how to best value this gas for royalty purposes in situations where gas from Federal leases is produced in areas not covered by index pricing, or where limited reported spot market activity exists.*

Gross proceeds should always remain an option for valuing gas sold under both arm's-length and non-arm's-length agreements, without a two-year election as found in the current regulations, since a two-year sale commitment may not always be practical. Additionally, companies should retain the option to request a value determination for any federal lease production. *See* 30 C.F.R. §§ 1206.107, 1206.152(g) and 1206.153(g).

• *Does the concentration of Federal production in some areas of the country create any potential problems with relying on index prices in those areas, now or in the future?*

We do not believe this creates any potential concerns.

• *Finally, we request comment on whether ONRR should use published index prices to value Federal oil and gas sold under non-arm's-length contracts as well as arm's-length contracts.*

We strongly support index pricing as an option for both non-arm's-length and arm's-length dispositions of oil, gas, NGLs and other products, with proceeds remaining an available alternative.

B. Transportation Allowances

The ONRR is examining possible alternatives to the requirement to track actual costs for determining transportation and to address the bundling issue. Please consider the following:

• *If ONRR were to adopt index-based valuation, the point at which the index prices are compiled and published may or may not be the point of actual sale for particular gas, and the costs of transportation to the actual point of sale may not be relevant. However, the index pricing point would be remote from the lease or unit in virtually all circumstances, and value at the index pricing point may not reflect value at or near the lease or unit. If ONRR employed index prices to value Federal oil and gas for royalty purposes, what methods should be considered that would adjust for location differences between the lease or unit and the index pricing and publication point?*

In order to most accurately reflect value, the adjustment should capture both the transportation fee and the fuel component, and include an escalation factor. The ONRR must also provide a mechanism for review so that the adjustment differentials and/or percentages and the escalation factors are periodically revised to maintain their validity. Provisions for extraordinary transportation allowances, as found in the current regulations at 30 C.F.R. §§ 1206.109(c)(2) and 1206.156(c)(3), should be maintained.

• *In the interest of simplifying the determination and verification of location adjustments, should ONRR consider prescribing either a fixed differential amount per unit volume (thousand cubic feet (Mcf) or million British thermal units (MMBtu)) or a fixed percentage to be deducted from the index value to account for location differences?*

To best achieve revenue neutrality, transparency, efficiency, and certainty, a fixed percentage deducted from the index value of the gas should be used. A percentage of the index value of the gas tracks the commodity value of the fuel component of the transportation cost, and thus is the best means to achieve revenue neutrality. Because a percentage is necessary for the fuel component, in the interest of simplicity it would be acceptable to use a percentage approach to the entire transportation allowance (*i.e.*, a percentage that covers both the transportation fee and the fuel). If a cap is utilized, then a floor would also be appropriate. A differential would also eliminate some aspects of the current unbundling challenges, but to maintain revenue neutrality it would need to separately address the actual value of fuel via a percentage approach. If a differential off of an index price is used, it should be based on Mmbtu, which is the industry standard, and not on Mcf.

• *Should ONRR apply a fixed differential amount per unit volume to all production in a particular area or that is transported through a particular pipeline?*

If a location differential is used, it should be provided for each index point, including offshore.

- **Offshore**: For **Shelf** production it is conceivable that a weighted average differential that approximates the cost of transportation to shore from a particular area could be used. However, **Deepwater** production would likely need to be addressed on a pipeline basis with the differential based on a tariff or transportation contract(s) to shore.

- **Onshore:** The onshore differential would need to be provided on a plant or pipeline basis to maintain revenue neutrality. There are too many varying types of gathering, treating, processing and transportation contracts to establish a valid differential on a broad geographic basis for onshore production.

Would a flat percentage of the index value (perhaps with a cap) be preferable, either on a regional or nationwide basis?

A percentage approach tracks the commodity value of the fuel component of the transportation cost, and thus is the best means to achieve revenue neutrality. Because a percentage is necessary for the fuel component, in the interest of simplicity it would be acceptable to use a percentage for the entire transportation allowance (*i.e.*, a percentage that covers both the transportation fee and fuel). If a cap is utilized, then a floor would also be appropriate.

C. Processed Gas and Processing Allowances

The ONRR is considering accounting for the value of liquid hydrocarbons contained in the gas stream by applying an adjustment or "bump" to the index price, applicable to residue gas when gas is processed, in lieu of valuing residue gas and extracted liquid products separately, calculating the actual processing costs, and deducting those costs from the value of the extracted liquids (the procedure required under 30 CFR 1206.153(a) and 1206.158 through 1206.159). This adjustment could be based on, or could incorporate, a number of components, including the following:

• *Gas quality (either Btu content or gallons per Mcf (GPM)).*

The most efficient methodology would be to utilize Btu content, as long as an exception is provided for cases in which gas is processed under a keepwhole contract that does not have a processing uplift or liquid credit. GPM would more accurately capture value, but would be administratively burdensome and difficult to implement.

• *The differential between the gas price and the oil or natural gas liquids (NGL) price similar to a "frac spread" or a "processing margin."*

For revenue neutrality, the differential between natural gas liquids and gas pricing must be recognized and kept up to date. The ONRR would need to publish these differentials very timely in order for lessees to incorporate them into their federal reporting.

• *Certain plant operation factors, such as shrinkage, producer processing costs, and plant operations costs.*

For purposes of simplicity, we support the use of a component that takes into account plant operations, shrinkage, processing and plant operation costs. This component must take into account both the processing fees and plant fuel charges, and be periodically updated to maintain its validity. It would be desirable for the ONRR to make its method of calculating this component transparent to the industry.

We also seek input regarding whether such an approach could eliminate the burden of accounting for allowable costs to process gas and reduce or eliminate the potential for disputes over unbundling of gas plant charges, without reduction in royalty value. The ONRR could calculate this adjustment on a monthly basis and make it available on our website expressed in the form of a price per unit volume (MMBtu or Mcf).

Having the ONRR calculate and post the adjustments on its website would ensure use of the correct pricing and differentials/adjustments/bumps, but it would be critical that such postings be made timely. Under this approach MMBtu content is preferable. Additionally, we recommend that a process be developed under which any identified corrections and/or adjustments to the ONRR prescribed rates would be rolled forward into the following month or year, as opposed to requiring that prior period adjustments be filed for all of the affected properties.

ONRR could maintain current reporting requirements for processed gas and NGLs but establish a fixed processing allowance. This fixed allowance could be either on a nationwide basis for all Federal gas or on a narrower basis, such as offshore and onshore leases; offshore regions and onshore basins; or gas-plant-specific.

A fixed processing allowance would eliminate some aspects of the current unbundling challenges, provide certainty and efficiency, and reduce the burden of federal reporting and audits. If the ONRR adopts an index-based gas valuation methodology under which NGLs remain a separate royalty-bearing product, then index pricing should also be used to value NGLs, utilizing OPIS published prices for Mt. Belvieu, and various Louisiana locations reported by OPIS (Napoleonville, Geismer/Sorrento). Under a fixed processing allowance approach, the fixed allowance should not be nationwide – a narrower basis is preferred because the narrower the basis, the more revenue-neutral the allowance will be. At a minimum, any fixed allowance should be on an offshore region and onshore basin basis, **and** on a plant type basis. The type of plant (*e.g.*, cryogenic, lean oil, adsorption, absorption) and the plant efficiency should also be considered.

We seek input regarding the advantages and disadvantages of simplifying processed gas royalty reporting and payment by either of the aforementioned methods.

As long as the index-based valuation methodology remains revenue neutral and adequate time is allowed for implementation of a new approach (as discussed below) we forsee no significant disadvantages. An index valuation system could reduce the administrative burden associated with audits and reduce the potential for disputes. However, we find that the current residue gas actual netback proceeds pricing works well. Because we have existing obligations to non-federal royalty owners and severance tax authorities to pay on proceeds, we would continue to have to calculate the actual netback proceeds even if ONRR switches to index pricing, thus an index methodology would not reduce the overall burden of monthly royalty calculation and payment.

We also are interested in other methodologies that would simplify the reporting associated with gas processing allowances or, if possible, eliminate the allowances by substituting a market-based proxy to reflect the value of liquid hydrocarbons contained in the gas stream.

Chevron has no other alternative methodology to propose.

D. Other Alternatives

The ONRR also is interested in receiving comments on any other alternative methodologies. If you propose a methodology different from those discussed above, please explain how the suggested methodology would meet the goals outlined above and why you believe your methodology is the best alternative.

Chevron has no other alternative methodology to propose.

In addition, ONRR requests your input on how the various methodologies would affect your business practices, bookkeeping, etc.

Given the magnitude of the proposed changes to the regulations, industry will need a minimum of 12 months (and perhaps longer depending on the complexity of the changes) from the time the final rule is published to implement the necessary changes to system programming and accounting set-up and to perform all necessary testing.

Thank you for the opportunity to comment on ONRR's Advance Notice of Proposed Rulemaking. If you have any questions regarding our comments, please feel free to contact me.

Sincerely,

Greg C. Morby

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