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Council of Petroleum Accountants Societies

Turning Energy Into Synergy

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Comments on Proposed Rule on the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Report (1012-AA13)

COPAS is a professional organization comprised of the oil and gas industry's most knowledgeable and influential accounting professionals. COPAS has operated as a non-profit entity for 50 years and has over 4,000 members with 24 societies in the United States and Canada. COPAS was established in 1961 by representatives from various independent local societies throughout the U.S. and Western Canada. These societies recognized the need for standardized procedures and guidelines as the oil and gas industry expanded across the country so that common issues and problems could be addressed in a central forum. The societies have developed standardized documents in areas such as joint interest accounting, auditing, production volume and revenue accounting, and financial reporting and tax matters so that companies operating in all parts of the U.S. and Canada can effectively and efficiently use the same standards and guidelines. Additionally, many of our members are responsible for the filing of the Federal royalty reports to the ONRR.

COPAS appreciates the opportunity to comment on the proposed rule on the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Report. With that said, we would like to provide comments for the following areas:

COPAS agrees with ONRR that gross proceeds from arm's-length contracts are the best indication of market value, and we support ONRR's efforts to collect every dollar due, as long as the reporting requirements can be cost justified. We also commend ONRR for proposing the "Index Option" which could simplify and provide certainty in the reporting of Federal royalties, although we believe ONRR's proposal has significant changes that need to be made to be viable to our members. Conversely, COPAS does not support duplicative and burdensome reporting requirements, requirements that are difficult if not impossible to comply with, or valuation changes that do not allow gross proceeds from arms-length contracts or that result in ONRR collecting more royalties than what is actually due. Lastly, COPAS has not, and never will support retroactive valuation or reporting changes.

COPAS also has concerns that the cost to industry is greater than what was identified in the proposed rule. No additional cost was identified for situations where ONRR would invoke the "Default Provision", and no cost was identified for the proposed move of arms-length percentage of proceeds "POP" contracts from the current unprocessed gas regulations to the proposed processed gas regulations. If an estimated cost would have been included for these items, the total estimated cost to industry could exceed $100 million.

Default Provision (Oil – 1206.104 & 1206.105; Gas – 1206.143 &1206.144)

COPAS believes the proposed rule provides too much discretion resulting in additional uncertainty, with some proposed situations being inappropriate for the ONRR to invoke the "Default Provision". COPAS recommends the proposed rule be amended or clarified in the following areas:

- ONRR needs to identify who has the authority to invoke the "Default Provision." Is it Audit & Compliance Management, the Asset Valuation Team, the Office of Enforcement, Delegated states, and/or anyone else? How will ONRR ensure consistency when and how the "Default Provision is applied?"
- Anytime ONRR invokes the "Default Provision", the remitter needs to be notified of the reason/justification as to why it is being invoked, so the remitter could provide additional information or justification as to why it should not be. Additionally, the notice should be sent to the individual/s identified on the ONRR Form 4444 that handles Audit & Compliance correspondence. In ONRR's notice it should also include the lessee's rights to appeal.
- The "Default Provision" should not be invoked for simple or inadvertent reporting errors. Similar to today, the errors should be given to the lessee to correct.
- 1206.104(c)(2) & 1206.143(c)(2) - ONRR should not be able to invoke the "Default Provision" because the value is 10% below the lowest reasonable measure of value in arms-length situations. Current regulations require the value to be reasonable, so adding a discretionary "10% below the lowest reasonable measure" requirement is unnecessary.
- 1206.110(f)(2) & 1206.152(g)(2) - Similarly, ONRR should not be able to invoke the "Default Provision" because the transportation or processing allowance is 10% above the highest reasonable measure of transportation or processing. Current regulations require deductions to be reasonable actual costs, so it is unnecessary to add the discretionary "10% above the highest reasonable measure of transportation or processing" requirements. Additionally, ONRR provides no justification for the change to not allow all reasonable actual transportation or processing costs, resulting in ONRR collecting more royalties than what is due.

Transportation Deductions (1206.20; Oil – 1206.110, 1206.111, 1206.112; Gas 1206.152; 1206.153; 1206.154)

COPAS believes the proposed oil & gas valuation rule eliminates several transportation deductions without appropriate justification:

- The transportation allowance for OCS leases for the movement to first platform (1206.20 Definition of Gathering, Oil 1206.110(a)(2)(ii) and Gas 1206.152(a)(2)(ii)) should be added back because the MMS had previously determined after a significant amount of research and comments, that the current regulations allowed these transportation allowances. In discussions with industry prior to the May 20, 1999 guidance letter on "Determining Transportation Allowances for Production from Leases in Water Depths Greater Than 200 Meters" it was recognized that utilization of subsea completions tied to host platforms was key in the ability to develop leases in water depths greater than 200 meters. It also noted this allowed smaller fields to be developed economically that would not have been if the construction of a platform was required. It was also recognized that the products would be transported/severed off the lease in a commingled stream and then separated on the host platform. ONRR recognized the transportation as an allowed deduction for royalty bearing products. ONRR stated that they felt the current regulations allowed for the transportation allowance and requested industry agree to the use of a guidance letter for industry and ONRR to use instead of going through the process of revising regulations to clarify the application of the subsea producer owned transportation allowance. In all discussions ONRR recognized the cost of this transportation as being an allowed deduction that is supported by the regulations. COPAS strongly disagrees with changing the regulations to disallow these valid transportation costs that ONRR has publically recognized as an allowed transportation deduction. If there are specific situations where a lessee is inappropriately applying the guidance provided by the MMS's Associate Director on May 20, 1999, then those situations should be specifically excluded.

- The ability to request approval to exceed the 50% limit on transportation allowances needs to be added back (Oil 1206.110(d)(1) &(2) and Gas 1206.152(e)(1)&(2)) – There are operational/environmental/current pricing circumstances that result in the regulations appropriately allowing exceptions to exceed the 50% transportation cap. As required by the current regulations, all exceptions have to be requested and the transportation costs must be actual, reasonable and necessary. ONRR has the ability to not approve any request that does not meet these standards. Additionally, ONRR's comments that "the current 50-percent limit on transportation-related costs is adequate in the vast majority of transportation situations" proves there are a small number of transportation situations for which the current 50-percent limit is NOT adequate and having to process the requests for exception cannot be an administrative burden. ONRR cites administrative cost as a reason to do this, but provides no documentation or data that justifies the disallowance of actual, reasonable and necessary transportation costs. If ONRR wants to reduce the administrative costs for processing these requests for exception, they should consider approving the exception for periods of 2-3 years versus requiring they be approved every year.
- As stated in previous comments, COPAS does not support the elimination of netting a "transportation factor" (covered in the section by section analysis for Oil 1206.111 & Gas 1206.153). We support MMS/ONRR's position that was identified in the 1988 Final Oil & Gas Valuation Regulations which stated: "The MMS has determined that the regulations should be revised to provide that transportation factors which reduce arm's-length sales contract or posted prices are to be considered as reductions in value rather than transportation allowances."
- COPAS would also like to point out that "transportation factor" is not defined in the proposed rule, and it is unclear what is or is not a 'transportation factor." If ONRR pursues not allowing the netting of the transportation factor, it needs to be clearly defined (egg. NGL transportation and/or fractionation, location and/or quality differential on oil and/or gas). This may result in unbundling issues where a single factor includes multiple items, some of which may not be considered a transportation factor. It should also be noted that eliminating the netting of a "transportation factor" will result in a major accounting and system effort to split out the identified transportation factors.
- If the "transportation factors" are now to be included in the transportation allowance, then the regulations need to be expanded to include the "transportation factors" as an allowable transportation cost. Additionally, the final regulations need to acknowledge that some

factors are not actually <u>incurred</u> by the lessee, as they are simply netted by the purchaser from their payment.

- In the Proposed Rule under the transportation allowance Section 1206.153(c)(8) - *Other non-allowable costs,* it now requires the lessee to place the gas, residue gas or gas plant products into marketable condition at no costs to the lessor as identified under Section 1206.146 (marketable condition rule) and it disallows the costs of boosting residue gas as identified in 30 CFR 1202.151(b). With ONRR proposing to eliminate the separate marketable condition rules for both unprocessed and processed gas, and replace them with a consolidated marketable condition rule (Section 1206.146), the additional disallowance of boosting residue gas (both in the proposed rule and in 30 CFR 1202.151(b)) is either redundant or may result in the lessee having to incorrectly pay for some marketable condition costs twice for processed gas. The booster compression exclusion was first included in the regulations prior to the advent of modern cryogenic technology. Thus, to add the boosting residue gas language to the requirement to place products into marketable condition is unnecessary and not correct. Eliminating the proposed language on boosting will ensure consistency in product valuation for all natural gas, whether processed, unprocessed, conventional or coalbed methane, and all plants (cryogenic, lean oil absorption, refrigeration, and CO2 removal). It will also ensure the proper treatment involving leases that produce at a pressure above the marketable condition requirement or for offshore leases where the gas leaves the production platform at or above the marketable condition pressure, by requiring the gas be placed into marketable condition only once. Lastly, it should be noted that boosting residue gas is part of plant costs and it is not associated with a transportation system or transportation allowance.

<u>NAL Transportation (Oil 1206.112; Gas 1206.152; 1206.154)</u>

- Gas – Eliminates option to use FERC/State approved rate (1206.154). Because the lessee must file the necessary information to obtain FERC or State approval of their transportation rate, as previously identified by the MMS when the option was added to the current regulations, it would be duplicative and an unnecessary burden to also have to file similar information with the MMS. The MMS further stated "The underlying concept that the current provision is meant to embody is that if a regulatory agency has either adjudicated a particular tariff for a transportation system (to resolve an objection to the tariff as filed) or has analyzed the tariff (if there is no objection filed) and found it to be a just and reasonable rate, the lessee should be able to use it as the basis for its transportation allowance as long as the tariff rate is still consistent with actual market conditions." It should be noted that many of these situations involve affiliated pipelines where obtaining the information to do these calculations would be problematic and burdensome due to the governmental restrictions placed on pipeline companies in sharing information with shippers. For these reasons we believe this option needs to be retained.
- The deduction for line fill for oil was previously justified and added to the oil valuation as a cost of transportation several years ago by the MMS and now it is being eliminated. In the Final Federal Oil Valuation rule in 2004, ONRR identified line fill to include "The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill" as an allowable deduction. Furthermore, they stated "MMS does not modify its long-standing policy of not allowing as a deduction from gross proceeds the costs of placing production in marketable condition or costs of marketing production, including indirect or internal costs, or any other costs that are not necessary for the lessee to incur in order to move its oil. MMS believes that the

costs it lists as transportation costs in the final rule are consistent with the reasoning that it has always followed in determining whether costs are for transportation or for something else." Since it was specifically identified in 2004 by the MMS/ONRR as not being marketing related and being an actual cost of transportation, we disagree with it being eliminated in the proposed rule - (1206.111(c)(9)).

- Eliminates the multiplier of 1.3 times the S&P BBB Bond rate, now allowing only a 1.0 multiplier (Oil 1206.112(i)(3); Gas - 1206.154 (i)(3)). A lot of analysis was done justifying the 1.3 multiplier when it was added to the regulations. When the multiplier was added for oil in 2004 the MMS stated: "MMS, through its Offshore Minerals Management, Economics Division, has studied several years' worth of data for both non-integrated oil transportation companies and larger oil producers, both integrated and independent, that MMS believes are more likely to invest in oil pipelines. After a thorough review of the MMS and API studies, and consideration of the comments submitted by States and industry, we believe that the allowance for the rate of return on capital should be adjusted to 1.3 times the Standard & Poor's BBB bond rate. This number is the mid-point of the range suggested by the MMS study, which concluded that the range of rates of return appropriate for oil pipelines would be in the range of 1.1 to 1.5 times the Standard & Poor's BBB bond rate." In 2005 when the multiplier was added to gas transportation, the MMS said: The MMS believes that the study conducted by its Economics Division, Offshore Minerals Management, used the most relevant data for a reasonable period and, therefore, is the best source to decide on the appropriate rate of return. If ONRR believes the 1.3 multiplier as identified by their study is no longer justified, they should have a similar review done to support their proposed change.
- 1206.152(a) disallows claiming transportation costs for transportation when the production did not incur those costs. Further clarification and examples are needed on what is meant by the term "incurred". Similar to how ONRR calculates their unbundling UCAs, costs of transportation/processing systems are totaled and then divided by the throughput, but not all gas goes through every piece of equipment on the transportation system or plant.

<u>**Processing Deductions (1206.159; 1206.160; 1206.161)**</u>

- The proposed rule eliminates the ability to request approval to exceed the 66.67% processing cap (1206.159(c)(2)&(3). As has been documented in the past, there are extenuating circumstances where there are unique production profiles with little or no liquids to offset all the processing costs or other operational/environmental/current pricing circumstances (eg. keepwhole contracts) that result in exceeding the 66.67% processing cap. The lessee on a case-by-case basis, must submit a request to exceed the 66.67%, and the costs must be actual, reasonable <u>and necessary</u>. ONRR also comments that "the current 66 2/3 percent limit on processing-related costs is adequate in the vast majority of situations" which proves there are a small number of processing situations for which the current 66 2/3 percent limit is NOT adequate and having to process the requests for exception cannot be an administrative burden. ONRR provides no documentation or data that justifies the disallowance of these actual, reasonable, and necessary processing costs. If ONRR wants to reduce the administrative costs for processing these requests for exception, they should consider approving the exception for periods of 2-3 years versus requiring they be approved every year.
- The proposed rule also eliminates the ability to request an extraordinary processing allowance (1206.159(c)(4). As supported by the two fields that have received an extraordinary allowance, there are fields that have unique gas composition, complex plant designs and extremely high unit costs that justify them being extraordinary. ONRR's

explanation that the plants are old is not sufficient justification for them to revoke their existing agreements to allow an extraordinary processing allowance, and ONRR provided no justification for no longer allowing a lessee to request an extraordinary processing allowance.

Gas Index Pricing Option (1206.141(c) and 1206.142(d))

COPAS supports the option to choose index pricing for unprocessed and processed gas, and strongly recommends the option be available to arms-length sales (this was recommended by the 1995/96 Federal Gas Valuation Negotiated Rulemaking Committee) as they too, have the same tracing and unbundling issues as those lessees with non-arms-length sales. Unfortunately, the proposed terms identifying the index price that you must use, results in a value so far above what is reasonable, that it is doubtful many lessees will choose the index option.

- Pay on the highest reported monthly bid week price 1206.141(c)(1)(ii) & 1206.142(d)(1)(ii) is not reasonable or justified, as this price is often $.05-$.20/mmbtu more than the average, and can be $.50-$1.00/mmbtu above the average for a month or two each year.
- If gas "can" flow to multiple index points, you must use the highest index even if your gas did not flow due to pipeline constraint 1206.141(c)(1)(iii) & 1206.142(d)(1)(iii). There are reasons other than pipeline constraint – the lessee may not have a processing contract for that plant; or the transportation rate for that index price may be greater, which results in a lessee not transporting on a specific pipeline. The index price should be based upon which way the lessee's gas flowed.
- The above requirements result in a higher price than the Indian Gas Valuation price that contains a major portion pricing provision.

Index Pricing Option for Gas (Transportation Deduction)(1206.141(c)(iv) and 1206.142(d)(iv))

The proposed transportation deductions and the floor and cap are outdated and do not reflect the current market.

- The 10% of the gas index for all other areas was derived from the Indian Gas Valuation Rule based upon transportation deductions associated with periods prior to 2000 and is not reflective of the transportation rates we are seeing today.
- The 5% of the gas index for OCS GOM needs to be higher and not lower than onshore, as offshore transportation does not have the unbundling issues associated with onshore. Additionally, the OCS GOM has the IBLA 97-120 approved TLP transportation and the subsea transportation allowances, and much higher capital costs making it more expensive than onshore.
- The proposed floor and ceiling for transportation deductions (can never be below $0.10 per mmbtu nor above $0.30/mmbtu) is also based upon the 15 year old Indian Gas Valuation rule and is not reflective of current transportation costs. Both the floor and ceiling needs to be raised to be more reflective of the current market.

Index Pricing Option for NGLs (1206.142(d)(2))

COPAS supports the option to choose index pricing NGLs, and strongly recommends the option be available to arms-length sales as they too, have the same tracing and unbundling issues as those lessees with non-arms-length sales. Unfortunately, the proposed terms identifying the index price that you must use is unclear, and the allowed deductions appear to be not reflective of the current market and do not cover all the transportation costs incurred by the lessee. If the proposed terms are not more in line with the current market, it is doubtful many companies will choose the index option.

- If NGLs are sold with an ONRR-approved commercial price bulletin, you can opt to value NGLs using bulletin's monthly average price (1206.142(d)(2)(i)). The regulations need to specific whether "the monthly average price for that bulletin" means to use the monthly average "average" price or the monthly average "high" price. The index option is more likely to be chosen if it is the monthly average "average" price.
- The proposed rule stipulates that you <u>must reduce this price</u> by the amount ONRR posts on their website for (1206.142(d)(2)(ii);
  - Theoretical processing allowance (Onshore - \$0.15/gal; GOM - \$0.10/gal); and
  - T&F charge (NM - \$0.07/gal; Other Onshore - \$0.12/gal; GOM - \$0.05/gal). Appears low.
- The proposed standard processing deduction is based on the minimum monthly rate over the past 5 years. This is too long of a time period for which the minimum monthly rate should be chosen. To be more market sensitive, the chosen rate should be over the most recent year or two. There is concern with using ONRR 2014 information as some companies are not deducting anything or have already started unbundling, therefore, choosing the minimum monthly rate may not be appropriate.
- The proposed rule says the reductions would be updated periodically, but ONRR needs to update them annually, and they should be prospective only.
- The standard deduction for T & F charges only represents costs after the processing plant and does not include a theoretical transportation allowance to get the NGLs to the plant. The proposed rule allows a theoretical transportation allowance for field transportation for unprocessed and processed gas, but does not provide a similar standard deduction for NGLs. A standard deduction for the transportation of the ngls from the lease to the plant needs to be provided in the final rule.
- The standard T&F charges in the proposed rule appear to be too low and out of sync with the current rates for transportation and fractionation.

<u>Field Fuel Reporting (1206.142(b)(1)&(2)&(3); 1206.142(d); 1206.150(b)(1))</u>

If a company chooses to pay on index, the proposed rule instructs them to apply the index prices to residue and NGL volumes only. If ONRR also expects royalties to be paid on the field fuel/lost or unaccounted for volumes and disallowed plant fuel, then the regulations need to be updated to reflect this requirement with examples. If the final rule does require royalties to be paid and reported for the field fuel and disallowed plant fuel by companies that choose the index option, it will increase the cost to those companies making the index option less likely to be chosen.

<u>No Written Contract (1206.111(d); 1206.141(d); 1206.143(g); 1206.153(d); 1206.160(c)</u>

The proposed regulations need to be revised to recognize unwritten, unsigned, arms-length, legally binding contracts for sales, transportation and/or processing, and they should be acceptable in establishing value. Not having a written or signed contract should not be the sole determining factor in requiring the oil or gas be valued at index or through the "Default Provision."

<u>Miscellaneous Comments</u>

The proposed rule retains accounting for comparison 1206.151. COPAS recommends this requirement be eliminated as it is no longer necessary because companies will now be required to report the first arms-length sale or index, and it requires too much effort and manpower for very little additional money.

The proposed rule also retains keepwhole accounting/reporting as processed gas (1206.142), and COPAS recommends it be eliminated. Although the proposed rule gives an example on how the keepwhole accounting is to be calculated, the plant statement usually does not contain sufficient information (plant efficiencies and NGL values) to perform all the calculations. This requirement needs to be removed or simplified, or the index option to value as unprocessed gas needs to do away with the keepwhole reporting requirement.

Both the "Location Differential" and "Spot price" definitions need to be expanded to cover all relevant products. Also, 1206.116(d) which is on the reporting requirements for non-arms-length contracts for oil, references 1206.112(j) which does not exist in the proposed regulations. ONRR also needs to add a section under the oil valuation regulations similar to proposed gas regulation 1206.147 - When is an ONRR audit, review, reconciliation, monitoring, or other like process considered final?

Opportunities to Further Streamline Valuation Process – ONRR Requests Comments on:

1. The potential for creating standardized ''schedules'' for transportation and processing allowances to reduce the need to rely on case-by-case operator reporting and agency review of actual costs.

COPAS is interested in meeting with ONRR to discuss the possibility of ONRR creating standardized tables that could be used to identify the disallowable component costs for compression, dehydration, CO2 removal, and/or H2S removal. Thus, if your lease required dehydration and compression that would be disallowed under the regulations, the lessee could simply add back the standard components to their transportation or processing deduction. Because of the complexities involved, we would be interested in meeting and discussing how the calculations/schedules would work, the need for them to be updated periodically, and for them to be optional to allow lessees to use actual costs. These schedules would eliminate the need for unbundling and prior period adjustments.

2. Opportunities to more fundamentally reassess how non-arm's length transactions are treated for the purposes of determining royalties owed.

COPAS recommends ONRR allow a company to use the previous year's actual costs/rates for the current year provided they are within a threshold, and not have to do prior period adjustments in the following year when the actual information is available. An additional option would be to take the below threshold adjustment for which no adjustment was made, and to roll it forward into the deduction for the following year.

We also recommend the lessee be allowed the option to deduct the standardized processing or transportation deductions ONRR is going to post for the index pricing option. Thus, they could still use their product price, but they could deduct the standardized processing or transportation charge.

Similar to item 1, due to the complexity of the issues involved, COPAS would like to meet with ONRR to discuss these recommendations to streamline the handling of non-arms-length transactions for determining royalties owed.

Closing Comments

COPAS chose not to comment on all the proposed changes and focused on those areas that need to be clarified or result in costly reporting requirements, unjustified changes that result in ONRR collecting more than "every dollar due," and changes that result in making the COPAS supported index option too costly to be chosen by many companies. COPAS also wants to emphasize that due to the magnitude of the valuation, accounting, and ONRR 2014 reporting changes, at least 12 months will be needed from when the final rule and any 2014 report reporting changes are published to make all the accounting and system changes.

Once again, COPAS appreciates the opportunity to comment on the proposed rule on the Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Report. COPAS also welcomes and encourages additional opportunities for Industry participation in drafting these valuation rules. We believe that Industry can provide valuable insight to ONRR on how the proposed valuation rules will impact royalty reporting and payments. If you have any questions regarding our comments, please contact me at (832) 337-2592.

Sincerely,

Pam Williams

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COPAS Revenue Committee Chairperson