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Re: COMMENT LETTER REGARDING ONRR– 2012–0004

In the request for comments on the above-referenced proposed rulemaking, ONRR noted the following:

> "ONRR recognizes that the costs and benefits of making further changes to its valuation regulations (beyond those specifically proposed in this rule) will depend on the specific commodity at issue (i.e., oil, gas or coal), as well as geographic or other factors. Thus, detailed comments that elaborate on specific situations where further valuation changes should be considered would be particularly useful to ONRR as it proceeds with this rulemaking as well as any future rules that may be considered."

In response to this specific request, this comment letter addresses how a requirement that water vapor be measured in oil and gas production could improve valuation results and achieve a perception throughout the oil and gas supply chain that the proposed rule will result in fairness and transparency for all involved.

Water vapor exists everywhere on this planet. It is measured in countless industries because it is a contaminant and can affect manufacturing processes, chemical processes, cause safety issues, and a whole host of other problems if it is not measured accurately. For example, the natural gas interstate pipeline industry requires water vapor content be measured to ensure the safety of the pipeline from corrosion and from blockage caused by hydrate formation.

Water vapor certainly exists with natural gas in the ground, as many formations have water in them, which suggests that the natural gas being extracted in wells is saturated with water vapor. However, this is not always the case. Sometimes the formation does not have water, or some water vapor is condensed out either on the way up to the surface because of colder temperatures, or through treatment that happens at the wellhead. If the formation is at low pressure and the gas needs to be pumped out, that tends to lower the saturation temperature. The opposite happens if the formation is under higher pressure. The bottom line is that there are many factors that can influence the water-vapor content and thus assuming a certain saturation temperature and calculating a water-vapor-content percentage based upon that assumption is arbitrary and inaccurate. There are technologies that exist that can accurately measure the water-vapor content of natural gas at the wellhead that are commercially available and low cost on a per well basis. Using those technologies to determine the actual amount of water vapor benefits all sides of the equation, the gatherer, the producer, and the royalty holder.

Assuming a BTU content of the gas and then paying for the gas based on an assumed value is truly problematic, which is why some spot sampling is done to try to make the transaction more fair and that at least some quantification steps are taken to try to ensure that the gatherer is not over-paying or under-paying for the gas from the well. But the bottom line is that current practice is that water-vapor content is not being measured and an arbitrary percentage is being taken out of the value of the gas to account for the presence of water vapor.

IM 2009-186 changed how the water-vapor content of natural gas was to be calculated. Originally, it was assumed that the gas was saturated at a specific temperature, which worked out to a reduction of about 1.7% of the royalties paid as that was the amount of water vapor calculated to be in the gas at this specific temperature. IM 2009-186 provided that it would be assumed that the gas was dry unless water-vapor content was measured. A dry measurement would of course increase revenue to the royalty holder as well as the producer of the gas. This would disadvantage the gatherer, as the gatherer would then be paying for water vapor, which has no heating value and thus dilutes the value of what they are paying for. Currently the existing saturated assumption has the potential to disadvantage all parties, certainly over a whole range of wells.

Making a well-thought out measurement using a verifiable measurement technology makes a lot of sense for all parties. It is ultimately fair to all, as no one is paying for water vapor or losing out on royalties because too much of a percentage is taken out based on an invalid assumption about the amount of water vapor in the gas stream.

There are currently oil and gas companies out there that have been collecting water vapor data on their fields in Colorado, Wyoming, Kansas and Utah since 2012 using commercially available, accurate, and low-cost sensors. Typically a sensor is under $10,000 and a tech can use one sensor to measure 100-200 wells a year. Their findings thus far indicate that making the measurement is beneficial as the water vapor content is seldom 1.7% -- sometimes higher, but usually lower. The potential savings from doing this measurement pays for the sensor in a matter of a few months.

Our suggestion is that water vapor be measured for all wells, similar to what is being done to measure BTU content. It is very easy to measure water-vapor content while the GC is determining BTU content when a tech is at a well doing a spot sample. Using a primary standard such as a chilled mirror would be an accurate, verifiable way of making this measurement that would pass the scrutiny of all parties. There are other commercially available technologies as well that are also accurate, such as laser hygrometers . We do not feel that making this change results in a costly over-burdensome regulation, and that it will ensure fairness for all parties in the natural gas transaction. As the government considers raising royalty rates, this sense of being treated fairly and transparently for the true BTU content of the oil and gas produced could go a long to acceptance of new regulation.

Sincerely,
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