BEFORE THE SUBCOMMITTEE ON
ENERGY AND MINERAL RESOURCES
COMMITTEE ON NATURAL RESOURCES
UNITED STATES HOUSE OF REPRESENTATIVES

Oversight Hearing
"Ensuring Certainty for Royalty Payments on Federal Resource Production"

December 8, 2015

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I. Introduction

Chairman Lamborn, Ranking Member Lowenthal, and members of the subcommittee, I am Judith (Judy) Matlock, a partner in the Denver law firm of Davis Graham & Stubbs LLP. Thank you for the invitation to testify today on ensuring certainty for royalty payments on federal resource production.

I am testifying today in my personal capacity and not on behalf of a specific client. I have represented oil and gas producers for over 30 years in connection with the gathering, transportation, processing, fractionation and marketing of natural gas, natural gas liquids and crude oil. My practice includes assisting clients with federal royalty calculations and reporting. This includes helping companies with the "unbundling" of gas transportation and processing fees so that they can comply with the marketable condition rule in the regulations of the Office of Natural Resources Revenue ("ONRR" or the "Agency").

On January 6, 2015, the Federal Register published a Notice of Proposed Rulemaking concerning "Consolidated Federal Oil & Gas and Federal & Indian Coal Valuation Reform." 80 Fed. Reg. 608. The stated goals of the rulemaking are 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 early certainty to industry and ONRR that companies have paid every dollar due of oil, gas, and coal produced from Federal leases and coal produced from Indian leases.

These are very important goals. My observation is that companies want to correctly pay their federal oil and gas royalties and they want to know, at the time they submit their reports and payments, that everything is correct. The goals of the rulemaking are consistent with and required by the due process clause of the United States Constitution in order for a regulation to be constitutional. The United States Supreme Court has held that the void for vagueness doctrine addresses at least two connected but discrete due process concerns: "first, regulated parties should know what is required of them so 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).

On May 8, 2015, I submitted comments on the federal oil and gas portion of the proposed regulations. Again, my comments were my own and not attributable to any of my clients. The purpose of my comments was to identify and explain areas in which the proposed regulations would not achieve the stated goals but would, instead, increase uncertainty and industry's cost of compliance. I also identified certain unintended royalty-reporting consequences of the proposed regulations that would require costly accounting system changes.

<u>Attachment One</u> to my testimony is a copy of my comments on the proposed rulemaking. My testimony today concerns one of the most difficult challenges for federal lessees - "unbundling" – which is topic 5 in my rulemaking comments. However, there are other proposed rule changes covered in my rulemaking comments which, if adopted, will also make it impossible for federal lessees to know, when they submit their royalties, that they have done so correctly. I will be happy to answer questions on any part of my rulemaking comments.

II. Background on Unbundling

What is unbundling?

Unbundling is the process of dividing a bill into its component parts.

People pay bills all the time that include more than one good or service. For example, we used to all pay telephone, gas and electric utility bills that were just a dollar amount with no detail. Those were "bundled" bills. Today, telephone, gas and electric utility bills in most, if not all, states are "unbundled" so that consumers can see how much of the bill is for each component of the bill. These bills could be unbundled because utilities are regulated by state public service or utility commissions and are required to charge cost of service rates. The historical bundled bills were just the result of adding up the individual cost components of the utility rates. The unbundled bills simply list the individual cost components that would have been historically bundled.

Why is unbundling hard?

Unbundling is hard because consumers do not typically have the information necessary to unbundle.

Suppose there was a legal requirement that you unbundle bills that you receive such as your dry cleaning bill, an auto repair bill, or college tuition bill? Suppose, in order to take a child care income tax deduction you had to be able to unbundle the day care bill into its components: building rent or mortgage, telephone, gas and electricity, insurance, labor, bookkeeping, supplies, etc. What if you had to unbundle the bill without any help from the day care provider? Because consumers do not typically have access to this type of information, it would be very difficult to unbundle the day care bill.

What bills do federal oil and gas lessees have to unbundle?

Lessees of federal oil and gas leases (and Indian leases not located in an Index zone) need to unbundle two bills: (1) the bill for transportation of their natural gas production away from the lease to a gas processing plant or to a point of sale off the lease, and (2) the bill for processing of their natural gas production in a gas processing plant. (Gas processing is done to remove ethane, propane, butane and other natural gas liquids from a gas stream by using refrigeration, changes in pressure, or other means.) The costs of transportation and processing will be in a single bill if the same company owns the transportation system and the gas processing plant.

Why is unbundling of gas transportation and processing bills necessary?

The Agency's regulations provide for two allowances (i.e., deductions): transportation and processing. However, the cost to put gas into marketable condition is not deductible. Unbundling of gas transportation and processing bills is necessary because of a change in the interpretation of the term "marketable condition" in the agency's regulations. As a result of the change in interpretation, some components of transportation service and some components of processing service cannot be included in the transportation and processing allowances.

What was the original interpretation of the term "marketable condition?"

The definition of "marketable condition" in the current regulations (adopted in 1988) is "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 CFR 1206.151. On December 8, 1995, the Minerals Management Service (predecessor to the Office of Natural Resources Revenue) issued a Compression Guidance Memorandum which stated:

> A lessee's gross proceeds may not be reduced by the cost of compression, whether incurred directly or indirectly, which is performed to meet the delivery requirement for pressure of the pipeline immediately downstream of the BLM or MMS approved measurement point. Such compression is deemed to be for placing the gas into marketable condition.
>
> The cost of compression, whether incurred directly or indirectly, which is performed **after** meeting the delivery requirement for pressure of the pipeline immediately downstream of the BLM or MMS approved measurement point, is an allowable deduction from royalty as part of the lessee's cost of transportation. [Emphasis added.]

The BLM or MMS point of valuation (a/k/a the royalty measurement point) is a meter located on the lease (or communitization agreements or units in which the lease is included) unless prior approval for off lease measurement has been obtained. Thus, generally speaking, the approved point of valuation is the wellhead meter.

Additionally, on April 22, 1996, the MMS issued a Dear Payor Letter which stated:

> Costs for compression downstream of the royalty measurement point, to the extent necessary for transportation, can be included in the transportation allowance.
>
> Costs of dehydration occurring after metering at the royalty measurement point can be taken in the transportation allowance.

<u>Attachment Two</u> to this testimony is a flowpath schematic illustrating this guidance and showing the point where gas was considered to be in marketable condition. On the schematic, marketable condition services are in red to signify that the costs are disallowed. Compression and dehydration occurring after

metering at the royalty measurement point are in green to signify that the costs were allowed.

What was the change in the interpretation of the term "marketable condition?"

In 2003, the 1995 and 1996 guidance documents were overturned retroactively by the Acting Assistant Secretary for the Department of the Interior in a decision known as the "Devon Decision." The Devon Decision was appealed all the way to the United States Supreme Court which denied certiorari (review) in 2009. The Devon Decision interpreted the term "marketable condition" to mean that, when the market is not in the field, the requisite pressure and quality for gas to be marketable is the pressure and quality necessary "for the gas to enter and pass through the line through which it must pass to be delivered to the purchaser(s)." Elsewhere in the Devon Decision, the Agency refers to the marketable condition requirement as being a requirement of the "receiving pipelines." The term the Agency uses today is "mainline pipeline."

A similar interpretation of the definition of marketable condition occurred in *Amoco Production Co. v. Watson*, 410 F.3d 722 (C.A.D.C. June 10, 2005) which held that gas must be of a quality required for the dominant market for gas from the area. The dominant market for most of the natural gas production in this country is the interstate market. If a portion of a lessee's gas is sold locally and the rest is sold into the interstate market, then the portion sold locally must meet the quality and pressure requirements of the local market but the portion sold into the interstate market must meet the quality and pressure requirements of the interstate market.

<u>Attachment Three</u> to my testimony is a schematic illustrating the Department of the Interior's interpretation of the marketable condition rule under the Devon and Amoco Decisions as requiring that gas be of the quality and at the pressure required for the market into which the gas is sold (in the illustration, the market is the interstate market).

What are the allowed and disallowed costs under the "marketable condition" rule?

Under the current interpretation of the term "marketable condition," any treating, dehydration or compression incurred prior to the point where the gas meets mainline quality and pressure requirements is disallowed.

> Treating involves the removal of impurities from a gas stream such as carbon dioxide or hydrogen sulfide. (If these products are removed but sold, then the removal is considered processing, not treating.) These services can be performed on the transportation system or at a gas plant or split between the two. Not all gas requires treating. Typical mainline quality specifications for carbon dioxide vary (between 1% to 3%) by interstate pipeline tariffs but 2% by volume is common. Typical mainline specs for hydrogen sulfide are no more than 1/4 grain per 100 standard cubic feet.
>
> Dehydration involves removing water vapor from the gas. Typical mainline quality specs for water vapor are not in excess of 7 pounds per million standard cubic feet of gas.
>
> Compression involves increasing the pressure of the gas by pushing the gas molecules closer together. Once gas is under pressure, it will move down a pipeline, from a point of high pressure at the outlet of the compressor toward the lower pressures down the pipeline (just as air inside a pinched balloon will rush out of the balloon when it is no longer held closed).

Compression is used for transportation to cause gas to travel down a pipeline. The pipeline walls cause friction and so gas has to be recompressed as it travels along a pipeline.

Compression is also used in one type of gas processing plant – a cryogenic plant – which removes natural gas liquids (ethane, propane, butane, natural gasoline) from the gas stream by compressing the gas to a high pressure (typically 600 to 800 pounds) and then quickly dropping the pressure which chills the gas stream to approximately a minus 150 degrees, causing the liquids in the gas stream to convert from a gas phase to a liquid phrase (just as cold temperatures will convert water vapor in the air to condensation on a window).

Compression is also used to reboost the gas that remains (the "residue gas") after natural gas liquids are removed from a gas stream by processing at a gas plant. Residue gas must be boosted up to the pressure of the pipelines at the outlet of the gas plant (the "mainline" pipelines for purposes of the marketable condition rule). The cost of residue gas reboosting is always disallowed even if the gas has previously reached the mainline pressure.

What are the transportation and processing fees that producers have to unbundle?

Producers pay for transportation and gas plant services in a variety of ways. Three of the most common types of contracts are:

1) **Percentage of proceeds** ("POP" contract) – under a POP contract, the owner of a transportation system and gas plant purchases the gas at the wellhead (at the BLM approved point of measurement), transports it to the gas plant, processes the gas to remove the liquids, and sells the residue gas and liquids. The owner pays the producer a purchase price based upon a percentage of the revenue from the resale of the residue gas and liquids. The value of the residue gas and liquids retained by the owner under a POP contract is the bundled fee for transportation and processing services.

   The dollar amount of the bundled fee will be different every month because residue gas and liquids prices are different every month. For example, a POP contract for a typical onshore Permian Basin gas stream, at October 2012 residue gas and liquids prices, would have a bundled transportation and processing fee that would be almost double the transportation and processing fee using October 2015 residue gas and liquids prices. The lower fee today is due to the depressed gas and liquids commodity prices.

2) **Keepwhole** – under a keepwhole contract, the owner of a gas plant keeps the producer whole on the quantity of gas, as measured in MMBtus, received into the system. The owner takes out the natural gas liquids (which reduces the MMBtus) but replaces the MMBtus in the liquids with gas that the owner purchases for that purpose. The producer thus receives the same quantity of MMBtus at the outlet of the gas plant as it delivered at the inlet of the gas plant (minus in some cases gas used as plant fuel) and the owner of the plant has to cover its costs from the sale of the liquids. For purposes

of the federal royalty calculation, the processing fee in this situation is the difference between the value of the liquids retained by the plant and the value of the replacement MMBtus delivered by the plant to the producer. Again, the dollar amount of the bundled fee will be different every month because residue gas and liquids prices are different every month.

3) **Fixed fee** – a producer might pay a fixed fee for transportation, processing or both. For example, a fixed fee contract might provide for a combined fee of $0.45 per MMBtu of gas received into the system. This fee will have to be unbundled into the allowed and disallowed costs for transportation and gas plant services.

Contract types can be combined. For example, transportation could be for a fixed fee and processing could be for a percentage of the liquids. Some contracts charge separately for certain services such as treating or dehydration. Services for which there are separate charges are not included in the bundled fees.

How has the agency addressed the unbundling requirement?

The agency has unbundled some transportation systems and gas processing plants by dividing the transportation and processing facilities into two categories: components performing disallowed services and components performing allowed services. The agency obtains the depreciated capital costs (or in some cases replacement cost), operating and maintenance costs, and a return on investment of the equipment and facilities in each category and then calculates two ratios – one for allowed costs (as a percentage of total costs) and one for disallowed costs (as a percentage of total costs). The agency's ratios were initially called "Annual Factors" but these are now called "Unbundling Cost Allocations" or "UCA's."

The agency first announced the development of Annual Factors in an October 6, 2010, guidance document which is posted on its website at http://www.onrr.gov/Unbundling/default.htm. The October 6, 2010, guidance stated that it was being issued "for federal royalty payors in situations where they are assessed a combined contract rate for a variety of services (bundled rate) under their arm's-length contracts with third-party service provides. The guidance document announced that ONRR was publishing "Annual Factors" that represent the percentage of the arm's-length rate that may be deductible as a cost of transportation and/or processing at certain facilities. The guidance document advised that Annual Factors were currently available for the following transportation systems and/or processing plants:

Williams Manzanares Transportation System
Williams Torre Alta Transportation System and the Kutz Plant
Williams Torre Alta Transportation System and the Lybrook Plant
Williams San Juan Conventional Transportation System and the Ignacio Plant
ConocoPhillips San Juan (Blanco) Plant

By way of illustration, Attachment Four to this testimony is a copy of the original Annual Factors for the Kutz plant. These Annual Factors were for the years of 2003 through 2006. When the October 6, 2010, guidance was issued, federal royalty lessees whose production had been processed at the Kutz plant were required to go back and reverse and rebook their federal royalty reports and pay additional royalties for production from 2003 forward based on the Annual Factors. This included using the 2006

Annual Factors as estimates for 2007 and subsequent years until ONRR published Annual Factors for 2007 and subsequent year. In July of 2014, ONRR published the 2007 through 2010 Annual Factors.

How is ONRR able to get capital cost and O&M information from the owners of transportation systems and gas processing plants?

Although I do not know for sure what authority was used to obtain depreciated capital cost and O&M cost information from owners of transportation systems and gas plants, I do know that Section 103(a) of the Federal Oil and Gas Royalty Management Act ("FOGRMA") 30 U.S.C. §1713, gives the Secretary of the Department of the Interior the authority to require the production of records from any person directly involved in developing, producing, transporting, purchasing, or selling oil or gas subject to the Act. This authority has been upheld by the courts in situations in which the agency has requested records from parties other than federal lessees. Shell Oil Company vs. Babbit, 125 F.3d 172 (3rd Cir. 1977).

I have been told that the information provided to ONRR from the service providers was provided on a confidential and proprietary basis. Because of this:

> Federal royalty payors do not have the ability to check ONRR's Annual Factor or UCA calculations because the supporting information cannot be obtained through FOIA requests.
>
> ONRR is not able to provide any details regarding the services that were included in the development of Annual Factors or UCAs. Therefore, a federal royalty payor cannot determine whether using an ONRR UCA is appropriate for its facts. For example, if a gas plant performs treating services, then the ONRR UCA would include the cost of the treating facilities in the Disallowed UCA. However, a particular lessee's gas might already meet maintain quality specifications without treating. In that situation, if the lessee used ONRR's Disallowed UCA, the lessee would be denied more costs than the costs to put the lessee's gas into marketable condition.

How does a federal royalty payor use ONRR's UCA's?

If there is an ONRR UCA for the transportation system or gas plant that a federal lessee is using, the payor multiplies the allowed ONRR UCA's by the bundled fees to determine the portion of the transportation and processing fees that can be deducted in the transportation and processing allowances.

However, because the costs on which ONRR's UCAs are based change every year, the UCAs change every year. Because of the labor involved in calculating the UCAs, it is not possible for ONRR to keep the UCAs current – there is a time lag between a production year and when the UCA for that year is published on the website. The instructions on the website (if you click the "I Understand" button) advise federal royalty payors that:

> If ONRR receives more accurate information, then ONRR will update and modify the UCAs. You may use these UCAs ***as estimates*** for later time periods until such time as ONRR provides updated information. When ONRR updates or modifies information you may be subject to additional royalty obligations, or a credit, and associated interest. .. When ONRR updates the UCAs for a specific year you should adjust previously submitted royalty lines only for that

specific year. Do not change previously reported data until ONRR publishes actual values. You should use the most recent UCAs as estimates for future reporting months.

Lessees reporting 2015 production that is processed at plants that ONRR has unbundled can only report on an estimated unbundled basis because the existing UCAs are anywhere from one to five years old. Additionally, ONRR may revise (and has in some cases revised) UCAs that were previously published based upon more accurate information or for other reasons.

Federal royalty payors using ONRR UCAs are using estimates. They do not know at the time they submit their royalty reports whether they are correct because the UCAs will not be available until after the reports are submitted (in some cases several years after the reports are submitted). They may have to reverse and rebook later.

If ONRR has not unbundled a particular transportation system or gas plant, do federal royalty lessees still have to comply with the marketable condition rule?

Although industry and some auditors concluded from the announcement regarding Annual Factors in the October 6, 2010, guidance document that industry could wait until ONRR published Annual Factors for a particular transportation system or gas plant, that is not ONRR's position. In an ONRR presentation at the Petroleum Accountants Society of Oklahoma – Tulsa workshop on Federal/Indian Royalty Compliance held in February of 2015, attendees were advised that ONRR expects industry to:

Correctly calculate transportation and processing allowances – this means UNBUNDLING

- Calculate your own UCAs using a reasonable method
- Alternative 1 – Use ONRR UCAs if available
- Alternative 2 – Take no allowance

A reasonable effort includes providing ONRR with:

- The applicable transportation systems and processing plants
- Specific marketable condition requirements
- Inlet/outlet conditions for major equipment including (*but not limited to)* compression, dehydration, CO2 removal, and H2S removal
- Allowed and disallowed fee portions through a clearly explained methodology of unbundling (*see ONRR Unbundling website for examples)*
- Supporting documentation

(Slides of Doug Ginley and Linda Shishido-Sheahan of ONRR.)

Additionally, in 2015, the agency started a compliance review process for certain plants that have not been unbundled by ONRR. The process starts with a data request of 22 questions concerning one test federal lease and two test production months in 2011. Lessees receiving the data request have 30 days to provide all of the contracts and accounting information for the test lease and test months and must state whether they have unbundled the transportation system and the processing plant. If the responses to the data request show that unbundling has not been performed, a preliminary determination is issued advising the lessee that it must either submit an unbundling proposal for review or correct its last seven years of royalties to take no allowances for transportation or processing.

Has the agency issued any guidance to producers regarding how to unbundle?

Yes. The agency has four guidance documents on its website that describe an engineering approach to unbundling. http://www.onrr.gov/Unbundling/methodology.htm The documents include lists of the engineering, accounting and cost data information that will be needed from the owners of the transportation system and gas plant to use the engineering approach described in the guidance documents. The data lists include information that can only be obtained from the owners of the transportation systems and gas plants such as GIS data or a list of diameters and lengths of each segment of pipeline; list of all compressors upstream of the specified plant, date placed into service, compressor type (centrifugal, reciprocating); detailed process flow diagram of the plant with a legend including all compressors and processes performed at the plant; list of the major improvements to the plant and the year placed in service; itemized capital costs, operating expenses, maintenance expense and overhead expenses for the transportation system and the plant; list of producers who shipped through each transportation system or whose gas was processed through the plant; sample transportation contracts and associated invoices; sample processing contracts and associated invoices; etc.

Can lessees get the engineering, accounting and cost data information on ONRR's lists?

Unfortunately, no. Lessees who contacted system and gas plant owners to try to get the information on the data lists were not able to do so. The owners of the transportation systems and gas plants will not provide this information on the grounds that it is confidential and proprietary. Lessees have no legal ability to force the owners of transportation systems and gas plants to provide the engineering, accounting and cost data that ONRR lists on its unbundling methodology website and that ONRR is able to obtain under FOGRMA.

May lessees use other methods to unbundle the transportation and processing bills?

Yes. ONRR's unbundling methodology website states that, "these are not the only methods by which the UCAs may be calculated. Other methods may be used provided they are in accordance with appropriate regulations." However, unbundling is very difficult for producers and most are not able to do it. Some producers have been able to submit unbundling proposals based upon their own experience providing the services involved. For example, some producers own and operate pipeline systems with compressors and dehydrators and, therefore, they have information on relative costs for this type of equipment. Unbundling of gas processing plants is much more difficult for producers because they are much less likely to have experience with gas plant facilities. Attachment Five to this testimony is a generic process flow diagram for a cryogenic gas processing plant which illustrates the complexity of the task.

My firm spent over nine months in late 2013 and the first part of 2014 in an intensive effort to obtain as much publicly available information as we could find regarding compression, dehydration, treating, delivery and products extraction services and costs for transportation systems and gas processing plants. We eventually used the information we found to develop a methodology for unbundling based upon the ratios of the estimated stand alone costs for each of the services received by a particular lessee for a particular source of gas. (This methodology estimates stand alone costs as if the producer had performed the service itself.) We have continued to refine this methodology since that time. However, the methodology is not a cookie cutter methodology. Each transportation system, gas plant, contract and source of gas has to be separately evaluated. It is not always possible to obtain sufficient information about a transportation system or gas plant to put together an unbundling proposal. Even if sufficient information can be obtained, it is a labor intensive, time consuming and expensive process.

> ONRR gives lessee submitted unbundling proposals a thorough review which requires the dedication of agency resources. If a lessee is able to submit an unbundling proposal to ONRR for review, the agency will provide feedback. If the methodology is found to be inadequate, no allowances may be taken. If the methodology meets some minimum threshold of reasonableness, a lessee may use its unbundling proposal on a going forward basis and must make retroactive corrections. However, lessee's will not receive any type of final or binding approval for an unbundling proposal. The lessee's unbundling <u>will be subject to future audit and the potential for future reversals and rebookings.</u>

If a lessee does not unbundle and continues to deduct 100% of its transportation and processing costs, the lessee can be severely penalized.

> A lessee that implements an unbundling proposal after ONRR review, does not know at the time it implements the proposal whether its royalties are correct. That will not be known until a future audit. The most that can be accomplished by submittal of a lessee unbundling proposal is to "get out of the penalty box."

What did the agency say about the difficulties of unbundling in its Notice of Proposed Rulemaking?

In the NOPR the agency stated:

> Many pipelines and services providers now charge producers "bundled" fees that include both deductible costs of transportation and non-deductible costs to place production into marketable condition. Both ONRR and lessees with arm's-length transportation contracts have found allocating the costs between placing the gas in marketable condition and transportation is administratively burdensome and time consuming. Similarly, when processing plants charge bundled fees that include non-deducible costs, the cost allocation is administratively burdensome and time consuming. … Litigation also has complicated the application of ONRR's gas valuation regulations. Although litigation has clarified what constitutes marketable condition, its application is fact specific and time consuming. See *Devon* and cases cited therein.

Do you agree with ONRR that unbundling is administratively burdensome, fact specific, and time consuming?

Absolutely.

What has the agency proposed in its NOPR to address the difficulties of unbundling?

The proposed regulations provide for an option to value production on publicly available index prices less a specified deduction to account for transportation and processing. The specified deductions would already take into account marketable condition costs so that no separate unbundling would be required. The agency stated that in the NOPR that it believes this index price option simplifies the current valuation methodology and provides early certainty.

However, the NOPR only proposed this option for lessees who do <u>not</u> sell their production in an arm's length transaction. The majority of federal lessees sell their production in arm's length transactions and, therefore, this option would not be available.

Why didn't the agency propose a formula based royalty valuation methodology for lessees selling their gas in arm's length transactions?

On May 27, 2011, ONRR published an Advance Notices of Proposed Rulemaking (ANPRs) regarding the valuation and received responses from 19 State, industry, industry trade association, and general public commenters. ONRR then conducted 3 public workshops on Federal oil and gas valuation in September and October 2011 in Houston, Texas, Washington, DC, and Denver, Colorado. A t the workshops, ONRR asked attendees to discuss, among other things, the use of index prices to value oil and gas, alternatives to the current requirement to track actual costs to determine transportation allowances, and alternate methods for valuing wellhead gas volumes to eliminate the requirement to trace the value of liquids removed from processed gas. The NOPR reports that an index-based pricing option was not being proposed for lessees who make arm's-length sales because of the comments received to the ANPR. Very large companies generally supported index pricing as an option if it is revenue neutral and there are no required trueups (end-of-year comparison of the index value to actual sales and payment on the higher of the two). Independent gas producers and States generally disagreed with the major companies and did not support index pricing because they believed it would not reflect actual value and might not be revenue neutral.

That was then, this is now.

Federal lessees, small and large, who make arm's length sales are as much in need of an option to provide early certainty and relief from the complexities of unbundling as are lessees who make non-arm's length sales. The complexities of unbundling were not well known at the time comments were made in response to the 2011 ANPR. Those commenters that were opposed to index-based pricing might have a different viewpoint today. Furthermore, ONRR only received comments from 19 commenters and they were split on the question. That is not a sufficient number to conclude that an index-based pricing option for lessees who make arm's-length sales should not be proposed.

Given the existing complexity of valuation and reporting, including the challenges associated with unbundling and the consequences of an inability to unbundle, alternatives should be explored including (i) an index pricing option for lessees who make arm's length sales, (ii) 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 (an option suggested by the agency in the NOPR), or (iii) or solutions that would simplify royalty reporting and valuation so that lessees would know, at the time they submit their royalties, that they are correct and not subject to change.

The agency and stakeholders have been able to negotiate solutions to other complex royalty reporting and valuation requirements. For example, new regulations recently went into effect to establish an index-based method of calculating "major portion" prices for oil production from Indian leases. These new regulations were the result of the work of a negotiated rulemaking committee.

The agency has tried to help with the unbundling challenge by using its authority to obtain information from system and plant owners to estimate allowed and disallowed costs using a cost of service estimation methodology and publishing the resulting UCAs for some transportation systems and gas plants. However, cost-of-service unbundling is a very time consuming and administratively burdensome job for the agency. The agency cannot unbundle every transportation system and gas plant and for the systems and plants the agency has been able to unbundle, it is not possible to provide annual UCAs in real time.

Unbundling is also very difficult for producers who do not have the same ability as ONRR to obtain information from the owners of the systems and plants. Producers want and need to know at the time they submit their royalties, that they are correct. Critical decisions cannot be made regarding oil and gas operations (to drill a well, to recomplete a well, to shut in a well) if all of the company's costs, including royalties, are not known.

Both sides can benefit from decreasing the cost of compliance by industry and the cost to ensure industry compliance by ONRR. Both sides can benefit from early certainty to industry and ONRR that companies have paid every dollar due.

We look forward to working with ONRR to address unbundling and other complexities of the existing and proposed rules to achieve the goals of the proposed rules.

Thank you again for the opportunity to provide testimony. I look forward to your questions.