PUBLIC HEARING ON

MINERALS MANAGEMENT SERVICE'S
SUPPLEMENTARY PROPOSED RULES ON OIL VALUATION

taken on February 18, 1998,
beginning at 9:00 o'clock a.m.,
in the offices of the Mineral's Management Service,
Houston Compliance Division,
4141 North Sam Houston Parkway East,Houston, Texas,
before Amanda L. Smothers, Certified Shorthand Reporter
in and for the State of Texas,
taken pursuant to notice,
under the Texas Rules of Civil Procedure.

I N D E X

A P P E A R A N C E S

MEMBERS OF THE PANEL:

Peter Christnacht, Mineral Economist for M M S

Dave Domagala, Mineral Economist for M M S

Dave Hubbard, Chief of Economic Valuation Branch with M M S

Bob Kronebush, Office of Policy and Management Improvement

Don Sant, Deputy Associate Director for Royalty Management of M M S

Debbie Gibbs Tschudy, Chief of the Royalty Valuation Division of M M S

MS. DEBORAH GIBBS TSCHUDY: Good morning. Can you all hear me loud and clear? Welcome to the first public meeting on The Minerals Management Services Proposed Rule For Valuing Crude Oil Produced From Federal Leases. Let me first introduce the panel members up front to you. To my far left is Dave Domagala, a mineral economist with the Minerals Management Service. Next to him is Bob Kronebush, with the Office of Policy and Management Improvement. Those two gentlemen are the experts on the economic impact analysis that was done along with the supplementary proposed rules. So they can answer any questions you may have on that analysis. Next to Bob is Peter Christnacht, also a mineral economist with the Minerals Management Service. He is our expert on the Form 4415 and the instructions with the form. So any questions you have about that can be directed to Peter. Next to Peter is Dave Hubbard. He's the chief of our Economic Valuation Branch with M M S; he's also one of the primary authors of the Second Supplementary Proposed Rule. I'm Debbie Gibbs Tschudy, chief of the Royalty Valuation

Division of M M S, and to my right is Don Sant, Deputy Associate Director for Royalty Management of M M S.

A few housekeeping items: The restrooms are located right outside the conference room; the vending machines are up on the second floor. Unfortunately, the elevators don't work so you'll need to go down the hall, take the stairs up

to the second floor and then head back down this direction to the vending machines. If you need to leave a phone number for people to reach you, we're taking messages at the following number: (281)987-6800. There are a number of handouts out on the front table that you maybe interested in. We do ask that you sign in so we know who's here with us today; and also ask if you'd like to speak, if you could sign up in advance; and when you do speak, we ask that you come to the podium and state your name. There will be a transcript available from today's meeting. You can obtain that transcript from the court recorder Amanda Smothers. Her phone number is here. She's also got a number of business cards you can take with you to obtain a copy of the transcript.

We'll start with a brief explanation of the supplementary rule, answer any clarifying questions that you may have, and then open up the meeting to any statements by the public. We'll start first with those people who signed up to speak and then after that, open it up to any member of the public who would like to make a statement for the record. So with that we'll give a quick overview of the rule.

For those of you who were at the Rocky Mountain Mineral Law Foundation, Special Institute, I apologize because you saw much of this about a week and a half ago; but we thought it would be useful to walk attendees of this public meeting

through the supplementary rule before we opened it up to questions. So I'll give just a little bit of background and then walk through the rule itself. By way of background, the proposed rule results from changes that have occurred in the crude oil market in the last 20 years, and our objectives to decrease our reliance on posted crisis, develop rules that reflect market value, and reduce the administrative costs of royalty valuation as well as add certainty to that process.

I'm sure all of you are aware that we published a proposed rule in January of last year. It stated where you had a true arm's-length sale value was based on gross proceeds; however, if you had a non-arm's-length sale, an exchange agreement, a crude oil call, or if you had purchased oil from anybody anywhere in the United States for the last two years, value would be based on index; for California/ Alaska, that was Alaska North Slope spot prices; for the rest of the country, it was NYMEX. Due to the comments that we received on that proposed rule, in July we published a supplementary proposed rule that would do three things: It would eliminate the two year purchase provision; it would require pairs that have calls to use NYMEX only if that call is non-competitive and if it's exercised; and it would have allowed pairs with arm's-length exchange agreements to base value on the arm's-length sale that occurs after the exchange, that was a -- in the case of a simple exchange agreement.

So in summary, that supplementary rule would have allowed royalty to be based on gross proceeds unless five things occurred; and the first two are standard and contained in the current 1988 regulations, that is if the contract does not reflect the total consideration for the value of the oil, if the value's not reasonable due to misconduct or breaching the duty to market to the mutual benefit. The third was if the oil was disposed of under an exchange agreement, except again in the case of a simple arm's-length exchange where you could base value on the resale after the exchange. The fourth was if an overall balance was maintained between the buyer and seller, and the final was if a non-competitive crude oil call was actually exercised.

Based on all the comments we got on the proposed rule and the supplementary rule, we reopened the comment period last September and requested comments on five alternatives that arose out of those comments. The first was to value production not sold arm's-length based on outright sales or so called bid-out or tendering programs. The second was a series of benchmarks that was proposed by one of the trade associations. The third was a method proposed by one of the states where M M S would calculate a price based on prices reported to us for geographic regions. The fourth was to use fixed, flat differentials off of the NYMEX price to simplify

the differential process. A bid was once suggested by a state commenter that we use spot prices instead of NYMEX.

The comment period closed on that, reopened comment period in November. We held two public hearings last April, one of them in here; and we held seven workshops, a couple of those in here as well as across the country in October and November; and received written comments on those five alternatives from 28 different parties.

So the second supplementary proposed rule making was published February 6th. It has a 45 day comment period so it closes March 23rd, 1998. We do have additional public meetings planned in addition to this one. We'll be in Washington next week on the 25th, that's in the large buffet room downstairs in the main interior next to the cafeteria. We'll be in Denver on March 2nd in the Veteran's Administration Building where we had our public hearing last April. Then we'll be in Bakersfield, California on March 11th and Casper, Wyoming on March 12th.

Okay, the second supplementary proposed rule is based on five basic principles. The first, that royalty must be based on the value of production at the lease. The second, that for arm's-length contracts royalty obligations should be based on gross proceeds. For other than arm's-length contracts, M M S still believes that index prices are the best nature of value for most areas of the country. The

fourth principle is that the lessee does have a duty to market production at no cost to the lessor; and finally, that customized regulations for unique producing areas are preferable to a one-size fits all approach.

Okay, so the second supplementary proposed rulemaking states that gross proceeds under an arm's-length contract determine value except in four situations, and this is gross proceeds received by the lessee or its affiliate. So if the oil is sold arm's-length by the lessee or its affiliate before it is refined, value is based on the gross proceeds received under that contract unless -- again we have these first two standard exceptions that are in the '88 ranks. They were in the January proposal. The third is oil disposed of under an exchange agreement except if you have one or more exchange agreements, in which case if the oil is sold arm's-length after those exchanges, value can be based on the gross proceeds received under that arm's-length contract; and the fourth exception is oil disposed of under a non-competitive crude oil call; and you'll note that we eliminated the overall balance exception that was contained in the July proposal.

For oil that is not sold by the lessee or its affiliate before it is refined, there are different valuation methods for three distinct parts of the country. For the Rocky

Mountain area, which includes the six state region Wyoming,

Colorado, North Dakota, South Dakota, Montana, and Utah, value would be based on a series of benchmarks and the first applicable would be applied. The first is an M M S approved tendering program. To be approved by M M S, the tendering program must receive at least three bids from others who do not also have tendering programs in the same region. The lessee must tender at least 33 1/3 percent of its federal and nonfederal production from the area, and value must be based on the highest bid received for that production. If that benchmark does not apply, the second benchmark is the weighted average of the lessee's and its affiliates' arm's-length sales and purchases from the field or area provided that those sales and purchases exceed 50 percent of the lessee's or its affiliates' federal and nonfederal production from the field or area. The third benchmark is a NYMEX price adjusted for location and quality back to the lease; and the fourth, if the lessee can demonstrate that these first three methods do not yield a reasonable value M M S will -- the M M S director will establish an alternative method. That's for the Rocky Mountain area. For the other two regions where oil is not sold at arm's-length before it's refined in California and Alaska, value would be based on the spot price for Alaska North Slope crude, again adjusted for location and quality. For the rest of the country, value would be based on the spot price for the

market center that is nearest the lease for oil of like quality, again adjusted for location and quality.

The location and quality adjustments contained in the second supplementary rule are: First, from the market center to the aggregation point, either a lessee's actual rate or if they do not have an actual rate, a rate published by M M S based on information we collect on a much simplified form, 4415; from the aggregation point to the lease, the actual cost of transportation including quality adjustments based on pipeline quality banks; and in the few situations where a lessee may be required to value production on a spot price and actually sells at the lease, M M S will calculate the transportation allowance for that lessee.

We've greatly simplified the Form 4415 from the earlier proposals. The information is required only on exchanges involving Federal oil. It's only on exchanges from aggregation points to market centers. There's much less data required on the new form than the earlier form, and roughly 1/3 less aggregation points than we had identified in the January proposal.

A couple of the other features of the rule. We've changed the timing of the index prices to coincide with production months to the delivery months. Our proposal in January would have tied the production month to the trading month. We're now proposing to tie the production month to the delivery month. We're also eliminating the proposed changes to valuing oil taken in-kind that we make available to eligible refiners. In the January proposal, we had proposed to establish the value of that production that we take in-kind and make available to eligible refiners based on a NYMEX price less a fixed differential. We've decided instead to establish the value in the actual contract with the eligible refiner rather than by regulation. So we've actually eliminated any proposed changes to 30 CFR 208.

A couple of charts we thought you might be interested in that puts the rule in perspective. This chart shows how Federal crude oil production is spread across the country. Seventy-three percent of our oil from Federal leases comes from the Gulf. Another 15 percent comes from onshore and offshore California leases. Wyoming accounts for six percent. New Mexico, four percent; and the Rocky Mountain Region the remainder, not including Wyoming, accounts for only two percent.

This chart demonstrates what percentage of Federal production, we believe under the supplementary rule, will be valued based on index and what percent will be valued based on gross proceeds by area. So you can see that for

California and the Gulf over 70 percent of the production, we believe, will be valued based on index. In the Rocky Mountain Region, nearly 70 percent will be based on gross

proceeds. Same thing in Wyoming and New Mexico. The majority of production will continue to be valued based on gross proceeds as it has been for a number of years.

So that concludes the overview so that the panel is available for any clarifying questions before we take public comment. Okay, we'll open it up to any questions, and we'll need you to come to the podium and identify your name before you ask the question so the court recorder can pick it up. John?

MR. JOHN MUNSCH: Yes, I have a question. My question is can you re-explain your index timing. I was confused as to terminology that -- would someone explain that?

MS. DEBORAH GIBBS TSCHUDY: Okay. So today is

February 18th. So they're trading today for delivery in March, right?

MR. JOHN MUNSCH: Correct.

MS. DEBORAH GIBBS TSCHUDY: So for crude oil produced in February, February production month, delivery is in March. Right? So we're going to tie the production month of February, royalties due and payable in March, to prices reported and Plats and others for delivery in February. We tie the production month to the delivery month. That's different then what we did in January.

MR. TOM WHITE: Are you saying like in today's

Plats --

MR. DON SANT: Identify yourself for the court reporter.

MR. TOM WHITE: Tom White with Walter Oil and Gas. In today's Plats Oil Gram, it quotes prices that were in effect this morning for yesterday's trading; and that indicates a price for March, which is what we're trading. So are you saying that a price in Plats Oil Gram will be used in the calculation of the royalties for the delivery in March?

MS. DEBORAH GIBBS TSCHUDY: Okay, if production is occurring for February -- you've got 30 days of production in February. You'll take the average of the spot prices that correspond with delivery in February. So it would have been the January -- it actually would have been the December 25th through January 25th prices.

MR. TOM WHITE: Okay. We understand what you're saying.

MR. DAVE HUBBARD: In effect, the whole process is moved back one month from the way we had it originally.

MR. TOM WHITE: You were trying to use today's prices for today's production in the original proposal.

MS. DEBORAH GIBBS TSCHUDY: Right, and we heard you at the workshops and made the changes.

MR. TOM WHITE: Well, the way you were coming across, it was kind of -- I misunderstood you. What you were saying is -- what Plats is reporting is, like, March. You would use that to price March for crude oil, is a simpler way to put it.

MS. DEBORAH GIBBS TSCHUDY: Okay, that's a better way to put it.

MR. DAVID SIMPSON: David Simpson with Total. I was wondering if you could explain on the definition of affiliate. You have now said that any person that you own at least 10 percent of would be considered an affiliate. Could you give me some idea as to how that 10 percent was derived, that 10 percent figure, as opposed to maybe some other number or some of the other affiliate definitions that are used to define regulations.

MS. DEBORAH GIBBS TSCHUDY: The current regulations that were promulgated in 1998 state that ownership between 0 and 10 constitutes control, between 10 and 50 is a presumption of control that's rebuttable by the lessee. We've eliminated that 10 to 50 percent for a number of reasons, to add certainty and simplicity; and also the fact that there have been a number of joint ventures that have been formed by our lessee since 1988, and we just wanted to make a clean cut between what's an affiliate transaction and what is not an affiliated transaction.

MR. BEN DILLON: Debbie, Ben Dillon from

I P A A. Could you all explain to us a little further under 206.102 how the math or the methodology is to work in 206.102 (a) or (4) -- no excuse me (b). It's the business about having to do a volume weighted average of the values if you have multiple arm's-length contracts. It sounds simple on the face of it. We're trying to understand, since that obviously attacks most of the membership, how you all envisioned this actually working because obviously there could be multiple contracts for different streams and what you all expect or how you all expect someone coming under this provision to behave.

MS. DEBORAH GIBBS TSCHUDY: Ben, I believe that's very similar to what we do today where if the lessee sells oil from a lease under one contract to an affiliate and perhaps another portion of the oil not to an affiliate or under a different contract, you just take a weighted average of those contracts to determine the value at the lease. Am I not understanding your question?

MR. BEN DILLON: No, what my question is -- I think you've now gone into a more direct question. Is this a lease driven determination; meaning, if I have more than one contract for that lease production, then I take a weighted average of those contracts but it doesn't extent beyond the lease point; meaning, for instance, san in a unit agreement I've got multiple contracts, do I take a weight average for

all those contracts and allocate across those leases? I guess we're trying to ask how wide do you see this calculation ocurring? That's all. We may have -- let's just talk about the unit. I'm just trying to get an understanding of the unit situation. If I'm an arm's-length seller, I've got multiple contracts for that unit.

MR. DON SANT: It expands as far as it has to, to trace the production back to the lease. So if you have sort of two leases that get into an aggregation point before you sell it, then that sales contract will have to apply to the volumes that you allocate back to those two leases.

MR. BEN DILLON: Could be quite a large expansion depending on the situation, is what I'm asking. It's much broader than a lease, probably. Do you agree with that?

MR. DON SANT: That, that's how it is today.

MR. BEN DILLON: I'm not saying it is one way or the other. We're just trying to understand the math.

MS. DEBORAH GIBBS TSCHUDY: Other questions?

MR. DOW CAMPBELL: Dow Campbell with Findlay Oil Company. Under 206.102, could you explain the scenario you envision under the eighth read there, if you sell or transfer to another person under a non-arm's-length contract and under (a)(2) you discuss affiliate, but what's the non-arm's-length contract that you're referring to there?

MS. DEBORAH GIBBS TSCHUDY: The rulemaking defines an arm's-length contract as one between parties who are not affiliated or who have opposing economic interests. So you could have a non-arm's-length contract where the parties are not affiliated, meaning they have less than 10 percent ownership but they do not have opposing economic interests; and the preamble describes the Xeno situation, that is what number (3) was meant to address.

MR. DOW CAMPBELL: So then you look through that party to their arm's-length?

MS. DEBORAH GIBBS TSCHUDY: That's correct.

MR. DOW CAMPBELL: We should have access to that.

MS. DEBORAH GIBBS TSCHUDY: That's correct.

MR. DOW CAMPBELL: Is your determination -- I have one follow up question. On the transportation section, 206.111 (c)(4), I believe, is the option of elected either under your actual costs depreciation or the return on depreciable capital investment. It appears to me you the lessee selects either little i or little (2)i. First, the first phase of the question is if we have already selected one of these, can we change it with the effective date of this ruling that these regulations would be entered into; and secondly, I guess, where did the March 1, 1988 date come from, derived at?

MS. DEBORAH GIBBS TSCHUDY: This portion of the regulation is not a change from the '88 regulations. This is exactly what's in the '88 regulations so there's no proposed change here. So that's where the March 1st, 1988 came from.

MR. DOW CAMPBELL: So if we've selected it under the current rates, we cannot change it? Is that correct?

MS. DEBORAH GIBBS TSCHUDY: That's correct.

MR. DOW CAMPBELL: And the March 1,'88 is just the date of the rates?

MS. DEBORAH GIBBS TSCHUDY: Right. That's the date of -- the effective date of the current regulations.

MR. DOW CAMPBELL: Okay, thank you.

MR. DAVID BLACKMAN: Hi. David Blackman, Burlington Resources. I just wanted to follow-up -- go back to 206.102 (a)(3). This kind of disturbs me a little bit. I want to ask you how this would apply to a situation where a non-operator is selling the oil to the operator of a well or joint operating agreement and the operator is then reselling the oil. Would the J O A sale qualify in your definition as a contract that is not an arm's-length?

MS. DEBORAH GIBBS TSCHUDY: I don't believe so, David. What we're looking for is sales contracts and what we're tracking is the actual disposition of the oil by

the lessee or its affiliate.

MR. DAVID BLACKMAN: Right, the lessee? Well, (a)(3)says that the lessee has got to know what the proceeds are that were received by an unaffiliated company or that unaffiliated company's affiliate; and I don't believe we can do that legally. I don't think I have access to an unaffiliated company's sales information, pricing information. So I don't see any way, even if the situation such as you cite here in the preamble Xeno, in the example, exists. I don't know how we can comply with this particular piece of this regulation. So is it M M S' idea that this is something that, you know, is going to be a rare exception, and where those exceptions exist you're going to end up having to comply with it on an audit?

MR. DON SANT: Well, I think it's a limited exception. You're first argument would it be -- it's an arm's-length contract so you start with the gross proceeds. We would have to go under the (a)(3), you transfer to another person under a non-arm's-length contract.

MR. DAVID BLACKMAN: The reason I ask about J O A sales, Don, is because I have an order from the M M S on gas where we had gas sales being sold under a joint, operated, unaffiliated company selling our market under the J O A. That was determined by M M S to be a non-arm's-length contract. So it concerns me that J O A sales on oil is a very common situation, and I'm concerned that this piece of the rule is not going to be as rare as you may envision.

MR. DON SANT: In the example, in the preamble the Xeno case, it was Xeno that is part owner of this gas gathering system.

MR. DAVID BLACKMAN: Sure, but what I'm saying -- and I understand the Xeno case is not a J O A example, but what I'm saying is that Burlington Resources has received orders from M M S that say that sales under the J O A are not an arm's-length transaction.

MR. DON SANT: I thought I heard you say you sold to the Burlington's marketing agent.

MR. DAVID BLACKMAN: Nonaffiliated companies sold to Burlington Resources' marketing affiliated company.

MR. DON SANT: And we have issued orders to the affiliated companies that that is a non-arm's-length.

MR. DAVID BLACKMAN: Well, the orders -- I'm trying to remember the context here. What the order said was that those sales by third parties to our affiliate did not constitute comparable sales because there was no separate contract. Sales were made under the joint operating agreement and thus were not arm's-length transactions, in the case that met with comparable sales.

MR. DON SANT: Well, that's a different

question. What my initial answer was, in likely, on those third party sales, (a)(3) wouldn't come into play. Their gross proceeds to Burlington marketing would be the value for those third party transactions. The next question under existing rules, from the producing arm to the marketing arm of Burlington, what benchmarks would you use to value that non-arm's-length transaction? What this rule then says though if the producing arm of Burlington transfers it to the marketing arm and then the marketing arm sells it somewhere else, that constitutes -- that second sale constitutes the gross proceeds and then less any allowances, deductions back to the rule. So truly the third party sales under the joint operating agreement, initially, you'd argue that, that's the gross proceeds and it's an arm's-length contract; and then we would have to look at some of those other exceptions before we would go to the benchmarks.

MR. DAVID BLACKMAN: Well, I understand, I guess, what you're saying; but I don't really understand because I don't see how a transaction can be determined by M M S to be an arm's-length contract for one purpose and not an arm's-length contract for another purpose. It's either an arm's-length sale or it's not, it seems to me. Either a J O A sale is an arm's-length transaction or it isn't.

MR. DON SANT: Even if it's an arm's-length transaction, under the '88 rules, we're looking to

comparability. So if the volumes of the transaction between Burlington's producing to the marketing are substantially greater than these transfers from the third parties, arguably, there's an argument that they are comparable sales.

MR. DAVID BLACKMAN: Well, the argument was not made on volumes. The argument was made because the only contract in existence was the J O A, and M M S determined that the J O A sale could not constitute an arm's-length sale in the order that I have.

MR. DON SANT: Directors sometimes overturn subordinates.

MR. DAVID BLACKMAN: Okay, I'll let it drop.

MS. DEBORAH GIBBS TSCHUDY: Other questions?

MR DAVID SIMPSON: In that -- David Simpson with Total. In that same area, if I'm a 100 percent owned affiliate of a company and they have a 10 percent affiliate which is typically, diametrically, opposed and economically to my interests and I sell them the oil and they make then a third party sale, how am I going to know? I have no access to that information. I have no board representation on that company. I'm just a shareholder, through an affiliate, of 10 percent. I have no control; I have no access to that information. How am I supposed to get that third party information or even know what they do with that oil that they buy from me? I'm selling it at the highest price that I can

possibly get particularly in this case because I'm a 100 percent owner. Why would I sell it at anything else to get 10 percent of, you know, something less so I can avoid the rule.

MS. DEBORAH GIBBS TSCHUDY: You sell to your marketing affiliate that you own 100 percent?

MR. DAVID SIMPSON: No, you defined that as a marketing affiliate, I would not. I would say I have 10 percent ownership of this company. I have no control over this company. I'm a shareholder, that's it. It is not an affiliate, in my estimation. Under this rule, it would be. It would go in that 10 to 50 percent where you would say -- presumption of ownership would say that you would have control, where I could demonstrate that I do not have control; and under other aspects of that 10 to 50 percent, I would not be considering that as an affiliate. Under this rule, since there's no exception, my question is how am I to get that information when I have no access to that?

MS. DEBORAH GIBBS TSCHUDY: Let me ask you a question. What are you doing today under the current rules because anything between 10 and 50 is presumed to be control and it would be non-arm's-length unless you come to M M S and rebut the presumptions. So what are you doing today?

MR. DAVID SIMPSON: Well, apparently not selling to this affiliate, but I do not rule that out in the

future. It might preclude us ever doing business with them if we have to get into this sort of administrative nightmare, but presently we're not selling to this affiliate.

MS. DEBORAH GIBBS TSCHUDY: Again, this is not a change from the current rules that under the current rules 10 to 50, you could rebut.

MR. DAVID SIMPSON: I understand. I could rebut and I would be able to rebut. My point is under this rule I would not be able to.

MS. DEBORAH GIBBS TSCHUDY: That's a public comment -- some written comments we'll need on the proposed rule about your ability to get information from an affiliate. Fred?

MR. FRED HOGEMEYER: Can I ask a question about raised overheads? Fred Hogemeyer, Marathon, I had the valuation method by area that you've shown me, the percentages. Could you explain a little bit as your assumption you used in coming up with that concept.

MS. DEBORAH GIBBS TSCHUDY: I'm going to pass it down to Dave.

MR. DAVE DOMAGALA: Sure, what we did is we categorized the companies into five different categories and that ranged from large companies all the way down to small independent companies; and within those categories we identified companies that did have refinery capability. Now we assumed that if a company had refinery capability, then, likely, they would be transferring that oil to the refineries so thus they would be on some kind of index system. The smaller companies that didn't have refinery or the marketing arms that didn't have refineries obviously, they'd be trading that oil; and we assumed they'd be trading it at arm's-length so that they would remain on the gross proceeds methodology like they currently are. So out of the five categories, we had three of the five who we assumed to be transferring the far majority of their oil internally so thus they would use the index pricing. For the other two would be transferring at arm's-length, so then they would use gross proceeds.

MR. FRED HOGEMEYER: So anyone who had a refinery would just assume a hundred percent of it, would that be correct?

MR. DAVE DOMAGALA: That's correct.

MR. FRED HOGEMEYER: Was it -- a follow-up to that. Was there any effort to sort of verify that, find out if that was really a true assumption or not?

MR. DAVE DOMAGALA: We have a lot of internal documents detailing some of the companies and how they operate so we went off some of the work that we've already done.

MR. FRED HOGEMEYER: Thank you. Follow-up if
I could on the rule, I guess, something perhaps you can

explain. It appears that in the Rocky Mountains you have an option what has been proposed in terms of -- one may argue about the methodology you chose on the tendering and then the buy/sell as to number two. Can you explain why you wouldn't have also adopted those two methodologies in other regions, too.

MS. DEBORAH GIBBS TSCHUDY: As the preamble indicates, we believe that there are very reliable indicators of market value available in the other regions. There are actively traded spot markets that are publicly available and allow certainty then for the royalty valuation process. We were told in public comments and from our consultants in the Rocky Mountain Region, the spot market is very thinly traded. There is not a reliable, nearby, indicator of market values so we had to look to other indicators in the Rocky Mountain

Region.

MR. FRED HOGEMEYER: I guess, maybe I'll phrase the question slightly different, Debbie. Was there any reason for you to come to a conclusion that the tendering or the out-right sales were not market values in the other regions?

MS. DEBORAH GIBBS TSCHUDY: Well, it's more of a means of an administrative simplicity and certainty where we have, in those other areas than the Rocky Mountains, reliable spot markets. There's no reason to go through the

administrative burden of a tendering program that has to be approved by M M S verifying weighted average of sales. We can just go straight to a spot price.

MR. FRED HOGEMEYER: But if that were to be shown that, that was a better indicator of production value at the lease, you would consider it?

MS. DEBORAH GIBBS TSCHUDY: Certainly. One of our main objectives is to capture market value but at the same time try to achieve a certainty and simplicity.

MR. FRED HOGEMEYER: Okay, thank you.

MR. JOHN HALEY: John Haley with Conoco. I'm looking at 206.103 on the tendering program in the Rockies, the center column, where you talk about the program and who would qualify and who would not qualify. You first say that you would expect or mandate that the company having the program would pay based on the highest tendered bid. Is that correct?

MS. DEBORAH GIBBS TSCHUDY: Uh-huh.

MR. JOHN HALEY: Now if you bid out crude and Conoco is doing this in the Rockies. We have certain bidders that will only bid on certain volume, which may not be the 33 1/3; it may not be enough equaled to the Federal oil up there, the royalty barrels. We get volume limited bids. So are we now under this required to take that highest bid price, which is volume limited, and apply it to all Federal barrels in that area?

MS. DEBORAH GIBBS TSCHUDY: Yes.

MR. JOHN HALEY: We also have instances where we know other companies have a tendering program in that area and quite often we find their bids to be the highest when they're biding in our program. If our intention is to continue to send out bids to those people, we would have to discount those bids for paying royalty barrels, right? So we don't pay you the highest price that we receive only the highest price of the bidders who do not have a tendering program?

MS. DEBORAH GIBBS TSCHUDY: That's correct, but we asked for specific comments in the preamble about that.

MR. JOHN HALEY: Okay. Also in our notes that we provided, I think it was in August maybe early September, on these, the question of the various benchmarks and so forth, we gave some specific data that showed that our bid-out programs generating in the Gulf Coast a higher price for Federal barrels then your index system. Conoco thinks that, that obviously is a better way to go because it's simpler for us. The index would require a lot more work. Have y'all considered in this the amount of work that's going to be placed on the industry to meet all these various programs and subprograms?

MS. DEBORAH GIBBS TSCHUDY: Yes, we have. As a requirement of publishing a supplementary rule, we had to complete an economic impact analysis and calculate the administrative burden on small entities and on lessees; and so yes, we have completed all that analysis and considered the burden on lessees. If that's the end of the questions, could we go ahead and take public statements?

MR. DOW CAMPBELL: Could I ask one more question? Dow Campbell with Marathon, on the 33 1/3 percent your branching out for that in the preamble lists that, that is the combined Federal royalty rate, state tax, and royalty rate for onshore.

MS. DEBORAH GIBBS TSCHUDY: Plus 10 percent.

MR. DOW CAMPBELL: Plus 10 percent. I'm not sure I get the 33. You're adding federal and state on top of each other.

MS. DEBORAH GIBBS TSCHUDY: Correct.

MR. DOW CAMPBELL: So for any one lease, it seems like it should be on a lease basis. You would only have a Federal royalty rate or you would have a state, and then add tax; and if you want, your 10 percent.

MS. DEBORAH GIBBS TSCHUDY: Dave actually researched with the states their severance tax rates and their royalty rates and can better explain it.

MR. DAVE HUBBARD: And better explain the

approximation of 33 1/3 percent. Since we did, as you already indicated, take the Federal royalty rate and then an approximation of the various rates for states around the country varying quite a bit, so that is simply an approximation added to the Federal rate, plus the state rates, and then roughly 10 percent added on to that. Again it's just a rough approximation.

MR. DOW CAMPBELL: Okay, for any one lease you only have a Federal royalty rate or a state royalty rate, correct?

MS. DEBORAH GIBBS TSCHUDY: But the tendering program applies to all of your federal and nonfederal production in an area. You have to tender at least 33 1/3 percent of your federal and nonfederal production.

MR. DOW CAMPBELL: I realize that. I guess, I'm indicating on a lease basis it's overstated 33 1/3 percent, based on your own rationale. I think there's a flaw there.

MS. DEBORAH GIBBS TSCHUDY: Point that out in your public comments. One more question.

MR. JOHN MUNSCH: Can we have two? John Munsch, Santa Fe Energy. Can someone explain -- I'm reading this as the use of the 4415 by a producer arm's-length sales and does do trading. Does -- in my understanding, we would be filling the 4415 out if we go from aggregation point to market center?

MS. DEBORAH GIBBS TSCHUDY: Correct.

MR. PETER CHRISTNACHT: For all those exchanges that are between aggregation points and market center. Now you may have a number of exchanges which are not between those. Those would not need to be reported.

MR. JOHN MUNSCH: Right, okay. That's good.

MS. DEBORAH GIBBS TSCHUDY: Should we go ahead and take public comment? Just a couple more questions because we really are looking forward to your comments. Who was first?

MR. GEORGE BUTLER: My name is George Butler, Chevron. In 206.107, you state that if one requests a valuation guidance, that we can propose a valuation method to M M S and submit all available data and M M S will promptly review our proposal and provide us with a nonbinding determination with the guidance that we request. By nonbinding, do you say that you reserve the right to come back and determine that your own value, valuation guidance, is not the correct value and you're reserving the right to

assess additional value against the lessee? Is that what you
mean by nonbinding?
MS. DEBORAH GIBBS TSCHUDY: What it means is
yes, essentially, that you would not be granted appeal rights
and that it does not bind the agency.

MR. GEORGE BUTLER: This is a rewrite of a
former provision that required the agency to promptly issue a
value determination to a lessee who required one so that a
lessee could achieve certainty and valuation and be protected
in the event M M S changed its minds about valuation. Do you
believe that 206.107 adds certainty? I mean, if one of your
objectives was to add certainty to royalty valuation, why
would you have a specific provision which would provide that
we could only receive a nonbinding determination of value
prior to audit?
MS. DEBORAH GIBBS TSCHUDY: George, I would
suggest that you submit written comments on that particular

proposal. I can't speak for the assistant secretary on this particular issue.

MS. DEBBIE HAGLAND: Debbie Hagland with Mobil. Can you give us some idea of the time that you have in mind when you say prompt? What does that mean to the authors?

MS. DEBORAH GIBBS TSCHUDY: We don't have any definition for that provided in the preamble or the rule.

MS. DEBBIE HAGLAND: Can you just give us a feel for what you would intend?

UNIDENTIFIED SPEAKER: Could you repeat the question?

MS. DEBORAH GIBBS TSCHUDY: The question was

what did we intend by the term promptly under 206.107. As soon as we can, as soon as resources allow. Obviously, if it involves a new policy that has not been determined before, it takes a little bit longer time.

MR. GEORGE BUTLER: My last question was do you have a proposed time line for publication of a final rule?

MS. DEBORAH GIBBS TSCHUDY: It depends on the comments we receive on this second supplementary proposed rule, but the semiannual regulatory agenda that the agency publishes in the Federal register twice a year indicates that the target date for a final rule is May '98. Okay, I think we will conclude the questions and start with public testimony. The first person who signed up to speak was Ben Dillon with I P A A.

MR. BEN DILLON: Can I do it from here?

MS. DEBORAH GIBBS TSCHUDY: Why don't you come up here so everyone can hear you.

MR. DAVID BLACKMAN: Can I ask one question? Why are we cutting off questions? It's not even 10:00 o'clock, we're going to be out of here by 11:00. I don't understand why we're cutting this so short.

MS. DEBORAH GIBBS TSCHUDY: I didn't know whether we are going to have a lot of public comment or not. I just wanted to allow plenty of time during the day for public comment. That's our goal in being here today.

MR. DAVID BLACKMAN: Could we have questions after we do public comment?

MS. DEBORAH GIBBS TSCHUDY: That's a good idea. Let's do that.

MR. BEN DILLON: I will -- Ben Dillon with Independent Petrolman Association of America. Debbie, my comments will be brief today but we've taken a look at this and I've got some additional questions; but if you would allow us to ask them, then I'll save those for when we return to the floor for opening it up.

Where to start? We were allowed to hear the announcement and in your press release from Cynthia Quarterman that you've returned to a methodology of honoring arm's-length contracts and gross proceeds; but we want to comment that we believe that the definitions have been changed in such a way that we no longer have a level playing field, that things are different; and we're not so sure at this point. We're going to have to continue to examine, that in fact, independent producers who sell arm's-length that the wells of an affiliate have any more certainty then maybe they had at the initial proposal about a year or so ago; and you might say, "Well, how could that be?" Well, we need to look at these definitions and exceptions and we're compiling a list of what all the exceptions to gross proceeds involve; and it seems

that the list is long and you need to kind of compile it all together, you know, gross proceeds maybe, and all the what-ifs are growing.

So let me just highlight what some of our concerns are that we're going to be looking into. We first need to look at the definition of gross proceeds; and of course, there we see that it's changed and it's changed significantly. Words have been inserted like "marketing", and of course, in the buy-down issue as two examples. When you include that, we believe we would broaden its definition; and you compound that with now the "brightline", as you put it, test on affiliate, as David Simpson exemplified. We may now be -- changed the rule to quite dramatically; and I understand that you made it clear that people could petition, but now they can't; and obviously, we'll be commenting on that area because you may have included a lot more companies then we originally thought.

Now given -- take the given that the rules have changed, the definitions have changed, we're starting from a new perspective. Let's look at the exceptions that we're concerned about; and, obviously, again the membership was delighted to hear they were back on gross proceeds. So we've basically, at this point, have only looked at 206.102. That's our focus. Those two paragraphs or paragraph and a half seem to apply to most of the membership; but you come in

there and you say, okay, I get to pan out my arm's-length contract except one. There's this issue of burden to prove up there in (a), something that was discussed earlier in question, opposing economic interests. When you look in the preamble, what does that mean J O A? How many times are we going to be kicked out; and it seems that, that burden is not a matter of M M S looking for comparables on arm's-length. It seems that, that burden has been shifted right on to the producer to determine that in fact they have to demonstrate somehow that their arm's-length contract is in fact valid. In fact, when is it valid? And that just seems to add to all the uncertainty; and given that it may not be valid, then I better start worrying about 206.103 and the formula. I'm not sure an independent can rest assured at night that they're not going to have to understand how those methodologies work.

But now we go past that, we jump down to (c) and I understand that some of this is in the current rags; but when you combine it with some of the other stuff, it becomes confusing; and of course, let's -- the first one you have is determines that an arm's-length contract does not reflect total consideration, and I understand that's the current rule; but there's an exception. The second, of course, is does not reflect a reasonable value. What is that? And what's the comparable, what's the benchmark, and am I going to be served, especially as we start moving through affiliated transactions. Then comes misconduct, exception three. Then comes, of course, the one that probably upsets the membership the most, breach of your duty to market. You know our comments, I don't need to repeat those. We've stated them clearly in the record a number of times.

As to our objection, you've stated in the preamble why you reject our comments, and obviously, we're going to disagree on this point; but quite frankly, no one understands what it is. It's not really defined. It's discussed but do I again -- and we've had this discussion many, many times. Is this going to be used to second guess gross proceeds? We're told no, no, no. It's not intended by Lucy and others, but then when you see it inserted here, when you see it inserted in transportation in 206.110, why is it there? Why? Why is it shown as an exception to gross proceeds when you've not fulfilled your duty. It seems to us to be a clear indication that the Bureau plans to use it to say to the gross proceeds producer maybe you should have marketed it or if you would have done different types of marketing arrangements, you could have done a better deal; and therefore, you should be paying us additional royalties.

And then of course, you come into the exchange piece and there's some language there about, again, the exchange has to be reasonable, has to have a reasonable location, or quality differential. Those are royalty attorney's dreams come true

words as far as we're concerned. I think the royalty attorney crowd should be quite happy to see some of this. Again, my members wonder how one complies with those kinds of words in place.

Then of course, the nonexercised, non-competitive call. We think that the way you've defined it now brings in additional contracts. You know, we comment a lot on this, and it seems that our interpretation, which would maybe be a follow up question, is that unless your competitive call contains a specific language reflected in your definition, you will be going to the the methodology which will basically be some sort of index netback. Again as you note, Debbie, in our surveys, we're not sure how many of these exist but we tried to make it clear that if the producer could demonstrate that they tried in their best effort to get the best price, even though they had a noncompetitive crude oil call, that should satisfy. We don't think that this definition accommodates that. Therefore, again these independents will have to be looking to figure out how to index NYMEX in Wyoming back or market center in the Gulf of Mexico back; and therefore, the independents need to understand and embrace those rules, which we're not going to provide comment on today. We'll be looking at that further as the process progresses. So again we're concerned about the noncompetitive crude oil call, how it's defined. It seems

too tight. I'm sure you're, again, trying to go for a brightline test, certainty and simplicity; but, again, what happens when you do that is you throw more lessees on to the alternative system, which is going to cause great confusion. It seems to drive your need for the 4415.

Then you get into data that says, "Well, whatelse must I do if I value under Paragraph A?" So it's not over after you think through everything I just said as a producer. You've got to look at these other conditions. You must be able to demonstrate and then two, you must certify and three -- but you've got the highest price. So there's a lot to this whole thing of arm's-length contracts, a lot of burdens that we think were placed on the producer. It looks like three, which maybe some restatement of past policy, expands a little to have the government intervene on contract enforcement in some instances.

So to sum up. Do we have certainty and simplicity? We're not sure, with all those exceptions that are in place and what that means to each individual producer and how they're going to be enforced by the M M S; and I think when you try to quantify your $66 million as to how many people are under this gained revenue, this alleged gained revenue, maybe that number is not correct because it assumes that all these parties that are arm's-length are going to pay in arm's-length; and when you map that against the exceptions,

there maybe more paying on the index system then you assumed in that calculation.

Let's go to the proposal for those that have to look to the alternative. We'll just use the example of an exercised noncompetitive call. What do we do? Well, as you know -- use my little prop today. We put this proposal together on what we call royalty valuation procedures. The membership worked hard to provide you all, the M M S, the states, what we thought was a reasonable plan. Unfortunately, I think we're discouraged by the fact that it seemed that M M S kind of picked and choosed, based on some logic, and then kind of just blasted out pieces in different parts of the rule and missed the primary message; and that was we wanted a consistent valuation methodology, realizing that when you apply that methodology in certain areas that it may, you know, certain conditions may not apply; but let's come up with a common methodology and I know there's been confusion about that, especially with regard to the letter that was sent in by the trade associations in December. Yes, we said the characteristics are different in Wyoming then in the Gulf of Mexico; but we thought we still could come up with an overall valuation methodology that was consistent with lease term and based it on value. What am I talking about? Well, as you know, we suggested tendering and weighted volume averaging for the entire country, and felt that if you

defined significant quantities and criteria appropriately in certain geographic areas, they may not be available. We are not happy to see that these options were only limited to the Rockies; and in fact, not available at all to independents who don't take their production to their refinery. We ask, why? It's a follow-up question maybe from what Fred Hogemeyer asked or the membership saying that these in fact are indicators of lease market value. Why can't I choose to use them, just because I don't refine my oil. That was our whole rationale in this proposal, was to provide options and to provide ways to lock in and to be able to select and all that has been taken away. Well, you might respond by saying, "But we've given you your arm's-length contracts," and we're going to respond by saying, as you know, "But you didn't give us marketing costs;" and so therefore, we're not going to be at a well head value; and even if you would have given us marketing costs, I think there were many members that still might have wanted to look to other alternatives; and you might say, why? Well, because tracing might be a big issue for different sized companies. We have some companies that want to trace some that don't. It's more of a quantity question then anything else, but yet because a few members seemed to step forward and say we can trace, we've got added cost to risks; and that was used to say, well, then everybody can trace and you're not going to be allowed to take a look at these other options.

We would ask you to reconsider the opportunities to give the membership a choice or some benchmarking. We tried to get off of benchmarking scenario, a menu system to say, hey, you may not have to always trace back. What if you wanted to -- even say there may be an independent who wants to go on index. I'm not sure about that, but say, theoretically, that there is, why can't they choose to do that?

And you further slammed the door shut on the membership by saying there's not even an opportunity to go plead my case to set the accordment to the director. I don't get that opportunity because I don't refine my oil. We're not sure. We don't understand the logic on that one as well. So, again, our approach has been selected and dissected into what we think is an unworkable approach.

Let's go back to the Rockies. If I'm a producer up there and have an exercised noncompetitive call, one, can I tender? No, at 33 1/3 percent and you've heard questions about that. We would greatly want to discuss that a lot more. So we think -- I'm talking about the small producer. They're going to skip one, going to go to two, 50 percent, no; and three, I'm at NYMEX, and how does that all work; and I thought we all agreed that NYMEX didn't work for the Rockies and, guess what, we see that is what in fact is going to be used. So that's where you end up. We don't understand the difference

between 33 and 50, and then we don't further understand the logic to get to the 33.

Now let's go to the offshore, same independent has an exercised non-competitive call. Where are they, market center, period. None of these other options are even available and if they represent fair market value, then they should apply everywhere; and that is the consistency rationale that we tried to clarify in the association letter. That's why I P A A signed off on it so just to clarify anything there. I've talked about competitive calls. I think I pretty much had hit everything.

I want to maybe end by talking about the 4415. Yes, it's been simplified. That's good news and yes, it's only applied to Federal; but I know you reserve the right to ask for other exchanges off of nonfederal in the preamble. We still advocate it. You asked the question, and is there a way to get rid of it? We hope that the answer is, yes, and maybe I would close with a question of how do you plan to use this information; and certainly, you're going to have to apply it, the theoreticals, to those parties that have the -- I sound like a broken record -- exercised, noncompetitive call. If this is such a minor issue, the tail wagging the dog, maybe there's a way to, as we advocate, to deal with this in a way that those parties aren't on the formula; and you're having to collect all the data. Now maybe, Debbie, I think through

it. For some refined barrels, you may be having to use some theoreticals that are also collected by the 4415; and you can answer that when I close here.

Basically, that's what we've done so far in our analysis. We'll be providing a lot of comment. We'll also be looking -- not providing, participating in the Washington workshop;

and once again, I have to end by saying that certainty and simplicity could be achieved through, guess what, R I K. Debbie, could you or someone answer my question about the 4415 and how the data might be used for parties other than the non -- or the exercised non-competitive calls.

MS. DEBORAH GIBBS TSCHUDY: You're right. In the preamble, we asked the question whether we needed the form, meaning those people that would be required to go to index would either physically move the oil to the market center, in which case they would know their actual cost, or they would exchange it to the market center so they'd have a rate contained in the exchange agreement. If that's the case, we don't need the form; and if, as you say, there are just very few companies that have non-competitive crude oil calls that are exercised, perhaps we don't need the form and we could deal with those on a case by case basis and calculate a rate for them. That is feedback that we would very much like to have in your written comments.

MR. BEN DILLON: And if I could ask a second question. There's someone after me, I'm sure, so I want to be quick. Could someone again, and I know it's in the preamble, maybe after the statements, explain the $66 million analysis so that -- we could do that now or later. I think that would be helpful, before we leave again, and I know it's in the preamble. Peter and Bob, I think, if you talked through it with us we might understand it a little better.

MS. DEBORAH GIBBS TSCHUDY: Dave, do you want to go ahead and do that now?

MR. DAVE DOMAGALA: Okay. As far as coming up with the 66 million, what we did is we -- the analysis was broken up the same way the rule was broken up. We looked at California onshore/offshore, we looked at the Gulf, New Mexico, and we looked at the Rocky Mountain Region. Now as I said earlier, we identified the companies for each one of these regions for the year of 1996 and how those companies, depending on their size -- we made assumptions on how they transferred their oil; and this is all contained in the 12-8-66, which is also part of the record that you can request; but the categories went in one to five, one being the large major companies with refinery characteristics, primary capabilities. All right, number two would be the large independent producers, marketers with refinery capacity. Number three would be the large independent producers, marketers without refinery capacity. Number four

would be small independent producers with refinery capacity; and number five were small independent producers without refinery capacity. So for the year of 1996, we looked at production and broke that into the five categories by company. As I said, we did this by region, California, Gulf, and the Rockies; and for each of those areas, we made specific adjustments to index prices to reported prices to, as close as we could get, approximate the additional revenue that we would receive through the rule.

Now the specifics for each area -- if you'd like me to go into that, I could. It's in the analysis. Do you want me to go through the specific adjustments that we made for each particular area? Okay. For offshore California, in adjusting to Alaska North Slope 27 degree oil, we had to make transportation adjustments. We base those adjustments on some Four Corners Pipeline data that we had and other sources of data. We made sulfur adjustments based on some consultant report data that we had; and we also made, like I said, the gravity adjustments for the 27 degree oil making a comparison for A N S. So that sums up, essentially, what we did offshore California.

For the Gulf of Mexico, we grouped or rather we had the production by area; for instance, Green Canyon, High Islands. For that particular area, we made a weighted average gravity for the entire area and then adjusted that to the applicable

spot price. We used all three spot prices, the Eugene Island, spot price at St. James, the light Louisiana sweep at St. James, and the heavy Louisiana sweep at Empire. We determined what oil was going to those particular areas, and then we made an assumption as to what type of oil that was. We also allowed for the first onshore delivery point to that spot price; we also allowed anywhere from $.15 to $.20 transportation adjustment so that when it reported a value of the oil delivered to the first onshore point, we also allowed an additional $.20 to get that to either Empire or St. James; and then we made a gravity adjustment from that point and made the comparison there. For onshore, Bob did some of the work onshore. Would you like to explain?

MR. BOB KRONEBUSH: I've got a prepared written statement of what I did here. For onshore California, we arrived at a monthly price at the lease by taking the A N S spot price less a gravity deduction from a posted price adjustment scale, effective to the production, to Midway Sunset specifications. A N S is at 27; Midway Sunset is at 13 degrees; A P I, the range within that year, went from anywhere from $.10 to $.25 per degree; therefore, in any given month, the deduction would have been a $1.40 to $3.50 a month. In addition to that, we deducted a 75 percent transportation charge from the Midway Sunset Field to L A area refineries. That was the average tariff rate for the

Four Corners Pipeline, the $.75. We used -- the Midway Sunset production is roughly 80 percent of all Federal onshore production in California, and another 10 percent is right in the areas so that's why we, basically, used the Midway Sunset for the whole California production. We then compared that monthly A N S price which was adjusted down to the unit prices in the category, excuse me, the three refinery categories. We assumed that the other two categories, the independent producers with no affiliates or refiners, would be on gross proceeds; and it was just a arithmetic, it was weighted average, arithmetic average of over and under, the price that we determined per month; and with that, we came up with our overall impact and it was plus and minus. We took into effect some pairs were height, you know. It was weighted average all the way across so we took that into effect, and that's, basically, what we came up with there.

I might as well go with the rest of the onshore, too. For onshore New Mexico, we arrived at a monthly price for the lease by taking the West Texas Intermediate at Midland less a $.19 charge for transportation and quality. That $.19 was made up of $.10 was a basic pipeline charge and the weighted average gravity adjustment for about 90 percent of the New Mexico production was about $.09 so that came up to $.19 deduction there and a $.25 charge from the aggregation point

to Midland, Texas; therefore, it was $.44 deduction per month from the W T I price. Once again, we just -- for the three refinery categories, we just did again the arithmetic average across and came up with our bottom line adjustments. For New Mexico, it came out to be about, say, an $800,000 addition. For onshore California, it was roughly $550,000.

For the rest of the onshore area, the Rocky Mountain area, this is different, again, because now we're under the benchmark situation, but that was also the problem. We determined that calculating monthly values by state, for the three valuation criteria, could not be done due to lack of information. It is difficult to estimate what unit value or tendering program would have yielded nor is it easy to estimate how much production would be offered for sale. It's also difficult to determine the volume weighted average price of a lessee's arm's-length sales and purchases from a field or area or whether that volume met the 50 percent threshold since we cannot determine what sales or purchases were arm's-length. We could also not determine the location, quality location/quality differential for Cushing, Oklahoma, to each of these fields and areas of each state due to lack of information.

So you're saying how can we do anything then. Well, in order to arrive at a fair market value that approximated arm's-length sales -- i.e., we attempted to mirror the

proposed valuation criteria -- we utilized the monthly weighted average unit price per barrel for the large and small independent producer marketers with no refining capacity. Therefore, basically, bottom line is, we used what the independent producers got as our floor. We brought the refiners that were below that floor up. If the refiners unit pricing that month was higher than the average arm's-length price, we assumed they would keep paying on that because due to their large volumes, marketing capabilities, exchange agreements, whatever, they were getting that price; and again, we did the numbers across for all the states and it came up to about a $2 1/2 million increase for the people -- for certain payers in the refiner categories. That's all. Any questions?

MS. DEBORAH GIBBS TSCHUDY: Hold on. We have to change tape.

(The court reporter changed paper at this point.)

MS. DEBORAH GIBBS TSCHUDY: Okay.

MR. JOHN HALEY: Just a question. Conoco's not involved in any A N S or offshore California production or anything like that anymore, but you said you used an A N S at 27 gravity, is that correct? You might want to check that because A N S at Valdez is 31 gravity.

MR. BOB KRONEBUSH: We were using the

specifications from Plats, and they were at 27.

MR. JOHN HALEY: It's wrong. Believe me, it's wrong.

MR. DAVE DOMAGALA: If you could put that in the comments.

MR. JOHN HALEY: Sure.

MR. TOM WHITE: I have a question of Dave. On the offshore Gulf of Mexico incremental income to be received estimated of approximately 50 million, how did that break down by your categories? I'm curious.

MR. DAVE DOMAGALA: I've got it right here. As long as I'm looking, California broke down category one, almost 12 million; category two, 500 thousand; category four, 270 thousand. Gulf category one, 43 1/2 million; category two, almost 5 million; category four, 1 1/2 million.

MR. TOM WHITE: I'm sorry, category one was 43 1/2?

MR. DAVE DOMAGALA: Right.

MR. TOM WHITE: Category two was five.

MR. DAVE DOMAGALA: Roughly five.

MR. TOM WHITE: And what about category three?

MR. DAVE DOMAGALA: Three and five were not used.

MR. TOM WHITE: Three and five were not used?

MR. DAVE DOMAGALA: Right, because they had no

refinery capacity.

MR. TOM WHITE: So you've assumed that you're not going to get any more, then they're already paying you. Is that correct?

MR. DAVE DOMAGALA: That's correct.

MR. TOM WHITE: You've already maxed out on that, right? Those were non-refiner entities, is that correct?

MR. DAVE DOMAGALA: That's correct.

MS. DEBORAH GIBBS TSCHUDY: The next public statement -- other questions?

MR. TERRY KYLE: Terry Kyle, Kerr-McGee. What were the total Federal royalty barrels in 1996, total Federal royalty barrels in 1996 in your study?

MS. DEBORAH GIBBS TSCHUDY: I know the total Federal royalties from oil in 1996 was about $1.5 billion. I don't know how it breaks out by barrels.

MR. BOB KRONEBUSH: I think the royalty barrels were close to a hundred million. Cause it was -- in 1995 when I did, it was 85 million. It'd be close to a hundred because of the added production, I mean, that's been going on in the Gulf.

MR. PETER CHRISTNACHT: At a break we can run upstairs. We can find that out very quickly.

MR. TERRY KYLE: And does that relate to the

$66 million economic impact? Is that a direct correlation?

MR. DAVE DOMAGALA: We took revenue that we received and barrels that we received in '96 and then we applied the closest approximation of what the proposed rule would net us; and so we just sort of overlaid the proposed rule on royalty receipts for '96. Does that answer your question?

MR. TERRY KYLE: You're talking about $66 million additional royalty on approximately a 100 million Federal royalty barrels.

MS. DEBORAH GIBBS TSCHUDY: Or another way to look at it is $66 million additional royalties out of 1.5 billion. It's about a four percent increase.

MR TERRY KYLE: I'm trying to relate a dollar per barrel impact.

MR. BOB KRONEBUSH: I think that $66 million is more related to Debbie's graph that she put up there, the 70 some percent that would be paying on the index or the, well see, the 30 percent across the board was on my gross proceeds. So, like, 30 percent, somewhere there, would be -- it wouldn't be effected because they are the independent gross proceeds payers, but it would be the other 2/3 that it would really effect. So it might come down to a dollar barrel, I mean, roughly a dollar barrel.

MR. TERRY KYLE: That's what I was trying to

understand.

MR. BOB KRONEBUSH: Roughly, roughly estimated.

MR. TERRY KYLE: So we were paying an additional dollar a barrel, in essence.

MS. DEBORAH GIBBS TSCHUDY: If you refine your oil before selling it at arm's-length.

MR. GEORGE BUTLER: George Butler, Chevron. Did you take into account by saying that if you or your affiliate disposes of production in an arm's-length contract, prior to refining of the production, did your analysis take into account the fact that there would be a lot more, if that were the case, that there would be a lot more people paying on gross proceeds then on indexes?

MR. DAVE DOMAGALA: That may be the case, and this is the nearest approximation that we could come to by overlaying the rules that we're proposing in place now. There maybe some things that are different than what actually happened in '96 that maybe the case, but this is as close as we could approximate.

MR. BOB KRONEBUSH: I would say, George, onshore, yes, it's possible because how we did it there was that if the refiners' unit price was higher than the average gross proceeds unit price, we assumed they would be staying the same so we didn't adjust that one. So there was a lot of

refiners in the onshore categories, refiner companies, that we didn't adjust up or down. Since their unit price for a given month was higher than the gross proceeds prices, we assumed they would keep paying on that. So to a certain extent, yes, that might have been taken into consideration; but for the time and the amount of information that we had to do these things, this is the best that we could come up with.

MR. GEORGE BUTLER: I just have a follow-up question. It's not really related to your analysis; it's more related to how the rule is supposed to work. Assuming that someone has an affiliate and that affiliate enters -- is not only -- perhaps that affiliate is some sort of a midstream type of marketer, who is in the marketing business. There maybe some production that goes to eventually ends up in a refinery. Assuming that that affiliate has arm's-length transactions, how are you proposing that the gross proceeds be traced back to leases, to the lessees, to the individual leases? How are you proposing that a gross proceeds that are realized by a marketing affiliate or just an affiliate, how those would be allocated or sourced back to Federal leases?

MS. DEBORAH GIBBS TSCHUDY: Well, essentially, in the same manner they are today, taking the affiliate's resale price less actual cost of transportation. So basically, the same manner they're done today.

MR. GEORGE BUTLER: But my question is if I have one Federal lease and all of my production from my Federal lease is sold to my affiliate and my affiliate rather than moving that production to a refinery decides, for whatever reason, to sell all of that production, then I think that it's easy to do what you're saying to do; but if I have hundreds and hundreds of Federal leases around the country and my affiliate is in the marketing business and they're doing any number of things, some of my production may move directly to a refinery. Some of my production, you know, -- there was any number of ways that my affiliate may be able to dispose of that production through any number of series of transactions. How do you propose that the totality of the affiliate's dispositions, some of which may be non-arm's-length to the refinery, you know, to an affiliated refinery, some of which may be arm's-length, some of which may be purchases of other production, how do you propose that the affiliate's gross proceeds as defined in the proposed rule be allocated back to individual Federal leases?

MS. DEBORAH GIBBS TSCHUDY: Again, George, in the same manner that it's done today, taking the resale price with a reasonable allocation method to allocate it less transportation costs to arrive at value back at the lease;

but it is the department's policy today that in no case can royalty be less than gross proceeds; and so today the department asks that you trace your affiliate's resale back

to determine value at the lease.

MR. DON SANT: Can you be more specific and give an example. I mean, your California production's never going to get commingled with Gulf of Mexico production or Rocky Mountain is not going to get commingled --

MR. GEORGE BUTLER: Are you saying that none of Chevron's California production ends up anywhere except California? Is that what you're thinking?

MR. DON SANT: Yes.

MR. GEORGE BUTLER: That's incorrect.

MR. DON SANT: You could exchange some oil from California. The oil itself is going to stay in California.

MR. GEORGE BUTLER: I think you should go and look up the All America Pipeline. I assume that what you're suggesting is that some sort of a weighted average in the same manner is -- several years ago, there was a request for guidance or value determination that Marathon made with respect to pool sales of gas, arm's-length pool sales of gas, and M M S issued some guidance directly to Marathon. I don't know if it was a value determination or just a response to a request, but it more or less said that if you have production that is not contractually and physically traceable, that you're supposed to calculate some sort of a weighted average. Is that what you're advocating?

MR. DON SANT: Well, yeah. I remember it was April of '88 we made a presentation at the annual Copus meeting and showed all the examples in gas of how you would do the weighted average and allocate the transportation components on the weighted average to get it back to the lease.

MR. GEORGE BUTLER: So my question -- if that's the case, in gas more or less being a fungible commodity, are we supposed to make adjustments for all of the differences in quality as well, and we're supposed to somehow weight average all of that?

MS. DEBORAH GIBBS TSCHUDY: Right.

MR. GEORGE BUTLER: Okay, thank you.

MS. DEBORAH GIBBS TSCHUDY: Okay, the next speaker that signed up is John Haley with Conoco.

MR. JOHN HALEY: Good morning. My name is John Haley. I am Director of Upstream Affairs and Special Projects for Conoco's crude oil supply and trading group. During my 24 years employment with Conoco, I've been assigned to the crude oil supply and trading function for approximately 19 of those years. Conoco intends to provide comments to the M M S regarding supplementary proposed rule on or before the requested due date. However, in this forum Conoco wants M M S to know that we are displeased with the supplementary proposed rule.

Conoco believes the current proposal is both unfair and unreasonable for the following major reasons. Conoco does not have the accounting nor the recordkeeping systems in place to comply with the proposed rule. We are currently working to try to determine how much it will cost to comply with these proposed regulations. Two, the M M S essentially ignores that a market exists at the lease other than in the Rockies or when oil is sold out-right at the lease.

Conoco's proposed competitive bid program was offered as a fair and reasonable method for all lessees, including integrated oil companies, to fairly establish market value at the lease. The M M S has chosen to ignore Conoco's program that Harvard professor Dr. Joel P. Cault, a leading petroleum economist, has found to be quote, "clearly meet the economic criteria of achieving third market value", end quote. Conoco is very disappointed that, even though we offered, the M M S would not accept Conoco's offer for a detailed review of our program.

Finally, the requirement to quote "offer and sell" 33 1/3 percent of our production, including nonfederal production and a given area in the Rockies, is clearly arbitrary and capricious. If one stops and thinks about this sensibly, this percentage far exceeds the royalty share on Federal leases. The consequences of this requirement is that the lessee would be obligated to sell a significant portion of

its own nonfederal related oil to generate an acceptable M M S allowed market value for Federal royalty oil. Thus, the Federal government will get the benefit of investments that the lessee has made separate and apart from its investments and Federal leases. How can this be fair and reasonable? Conoco does not believe that the M M S is entitled to ride the backs of the lessees to potentially higher prices in this manner.

Three, the tendering program designed for the Rockies is so restrictive in nature that we expect only a few lessees would choose to use this system, this method. Four, Conoco recognizes that it has a contractual duty to place M M S crude oil and marketable condition but we do not agree that we also have a duty to market M M S oil free of cost. Five, the reporting requirements incorporated in M M S' proposed Form 4415 would be a significant burden on Conoco. Conoco does not have the systems nor staff in place to perform the data collection as required under this new M M S form. We do know that it would be an extreme financial and administrative burden.

In summary, since the M M S will not propose a rule that is both fair and reasonable to all lessees, including major integrated oil companies, Conoco's position is the M M S should take their oil in-kind and market it themselves. Conoco strongly encourages the M M S to do so today, which

you have every right to do. If you are truly concerned about being gained by the lessees, you should choose this alternative, which has always been available to you. Your paranoia of being gained probably comes from a lack of understanding of what makes a market and how markets work in an unregulated environment in the oil business. Thank you.

MS. DEBORAH GIBBS TSCHUDY: The next commenter is Tom White with Walter Oil and Gas.

MR. DON SANT: I'd actually like to ask John a comment or question. Where you have an exchange, I mean, where you eventually have an arm's-length -- well, let's see what is it. I guess it's when you would be on the index. Would you always have an exchange that you could use your own information to get from the, I guess, the market center to the aggregation point? The question is could we get rid of the 4415 in your case where you're going to be using the index. Are you going to have an exchange so you could have your own actual value to get between the market center and the aggregation point?

MR. JOHN HALEY: Well, we do have trades exchanges from location points. That's the major purposes of our buy/sells is to relocate oil. Do we have them for all aggregation points where we have oil? I can't answer that question. You've got some two hundred, I'm guessing, two hundred aggregation points listed and I just don't have the answer to that. We have not focused on all that.

The burden of trying to implement systems to keep up with that will clearly run us in excess of a million dollars because we're going to have multiple systems in place. We're going to be, essentially, required to do different things in different locations. Fortunately, we're not on the west coast so we don't have to worry about that, but we're active in the Rockies. We have Federal oil in the Rockies; we're active in New Mexico, offshore Gulf of Mexico is where most of our Federal royalty barrels are. Conoco has about two thousand barrels a day of Federal oil that we pay royalties on. We actually have about four thousand barrels a day in which half of it you already take in-kind, which we're happy with that. A million dollars for new systems divided by two thousand barrels a day in one year equals a $1.37 a barrel penalty for the systems; and we think that our program right now is generating higher revenues to the M M S then what you're going to get through this system. We don't mind paying you a higher price or a fair price at the lease as long as we don't have to incorporate a whole new info-structure of accounting systems and accounting people and administrative systems to put in place; and then I've had very little chance to go through all this. I was out of the country last week, but what I read over the last two days there's no certainty left in here for us. We don't know

whether we'll ever be in compliance.

MR. DON SANT: Well, it is an important question on the 4415. Can we eliminate it; and that goes back to whether companies that are going to be using the index have an exchange so they could have an actual value to move from the aggregation point to the market center.

MR. GEORGE BUTLER: Could I answer the question?

MR. DON SANT: Yes.

MR GEORGE BUTLER: George Butler, Chevron. I do believe that in some instances oil moves directly to refineries; and in those cases, it may not move from an aggregation point via a market center.

MR. DON SANT: That is covered in, I guess, I think, (e) of the proposed rule.

MS. DEBORAH GIBBS TSCHUDY: In that case, you would use your actual costs of transportation, but in all other cases, George --

MR. GEORGE BUTLER: No, what about well-head sales to what -- no, there could be some sort of a well-head sale that was somehow deemed non-arm's-length.

MS. DEBORAH GIBBS TSCHUDY: Only in the case of a non-competitive crude oil call, which I P A A provided testimony that there could be. They've not been able to get a clear answer from surveys, but they believe there's very

few actual non-competitive crude oil calls. If there are just few, we could deal with those on a case by case basis rather than having a form; but for everybody else who's going to be required to go on spot, you either physically move it to a market center or a refinery, in which case you have actual costs, or do you exchange it to a market center?

MR. GEORGE BUTLER: Oh, I'm sorry. I don't know. I'd have to go check but you're saying that if I move it to a a refinery, then you're going to charge me the value at a market center adjusted by my transportation costs to the refinery. So you're going to charge me the value of production at another location, at location A, for production that I've moved to location B, and you're going to take my transportation costs from the lease to location B; and you want -- and your suggesting that you deduct that from the value.

MS. DEBORAH GIBBS TSCHUDY: From the spot price.

MR. GEORGE BUTLER: From the spot price?

MS. DEBORAH GIBBS TSCHUDY: Right, but we provide a provision in the proposed rule that if you think that that's not reasonable, you can come to M M S and just demonstrate the market value at the refinery and then deduct from that your actual cost. John, can I ask another question since we're asking you questions now?

MR. JOHN HALEY: Yes.

MS. DEBORAH GIBBS TSCHUDY: What do you think about the definition for the Rocky Mountain Area, that includes the six states. Should a portion of New Mexico also be included in the Rocky Mountains?

MR. JOHN HALEY: I don't know that it makes any difference. You only have really, essentially, one market in the Four Corners Area so if you include it in the Rockies definition, you haven't gained anything. It's a separate area.

MS. DEBORAH GIBBS TSCHUDY: The whole state?

MR. JOHN HALEY: No, just the Four Corners.

MS. DEBORAH GIBBS TSCHUDY: Okay, just the Four Corners so you'd keep it as its own region?

MR. JOHN HALEY: Yeah. Conoco today is, under our competitive bid program, we evaluate it every month. What should we be doing there to get the best reasonable, fair value we can at the lease; and we keep trying to figure out bigger and better ways of doing it, but there's really only one market in the area.

MS. DEBORAH GIBBS TSCHUDY: With regard to the benchmarks in the Rocky Mountain Area, do you think we should have tendering as a second benchmark and the weighted average of sales and purchases as a first? Would you reorder the benchmarks in any manner?

MR. JOHN HALEY: No, I would have it a menu and I would still have tendering there and I would change the perimeters of the tendering. I looked in the dictionary yesterday about what constituted a competitive market and it says two or more. It doesn't say three or more. I don't have any influence over dictionaries, and it says two or more. In some cases, Conoco's lucky to find two people willing to bid on crude oil. We have areas where there's, luckily, no Federal oil that we're biding out, and we're lucky to get two people to bid on it, two different companies, because it's not on the beaten path. It's somewhere out in the middle of nowhere and there's requirements for trucks and gates and all kinds of different considerations that a potential bidder has to concern themselves with, and not everybody wants to go through all that for oil. The world is not short of oil today.

MS. DEBORAH GIBBS TSCHUDY: Any other questions for John? Tom White with Walter Oil and Gas.

MR. TOM WHITE: Good morning. My name is Tom White and I'm with Walter Oil and Gas Corporation, which is an independent oil and gas producer operating almost exclusively in the Gulf of Mexico. I'm not sure which category we are, number three or number five, but I will go back to our accounting people and tell them that the M M S is certainly not expecting any more money from us since we seem

to be doing a pretty good job as it is, for what solace that brings us.

I want to say that my comments are going to be focused, very narrowly, on one issue that is to the heart of the matter for us; but in beginning, I want to say that after reading the new proposed rule our feeling is that we strongly believe that the rule further establishes the need and the requirement for an R I K program, which we believe will be the only truly program within which the M M S will be satisfied in knowing a fixed and determinable price. We think the proposed rule will continue to add a great deal of uncertainty; and in fact, we estimate that the audit requirement is going to increase by a multiple from where it is today.

What I wish to talk about, however, is the changing oil marketing environment which you so eloquently discussed in your opening remarks, which we agree with. We think oil marketing has changed. It's changing today. It's going to change in the next few years. To what, I don't know. The industry is responding to that change. We do things differently today then we did five years ago or ten years ago.

Without belaboring it, let me just mention that, historically, for the independent sector of the oil and gas business, it was traditional that we would sell our oil at or

near the lease and not entertain downstream or midstream marketing opportunities. For a period of time, for a great many years I should say, we felt that given the requirements of staffing, financial requirements, that the independent sector was probably better suited just to sell their oil at a location as close to the lease and be off with it. When we began venturing into the offshore arena, that assumption didn't necessarily carry forward. Initially, in the offshore arena, the principal markets were ones offered to us at or near the lease that we didn't feel adequately gave us the price that we wanted. So you were faced with a situation of what do you do. Do you sell at a posted price offshore or do you undertake other marketing activities, recognizing that this was a change from what you historically have done.

Well, for a great many of us, not all obviously, but a great many of us, we chose to undertake a more direct

marketing role and that was a change. We had to employ
additional people. We had to undertake activities and
operations that, historically, were in the midstream market
trading operation, which we now became a member of; and it
required not only the additional personnel and equipment to
do this job, but it also required additional financial
requirements above and beyond what we would have been
expected to do if we had remained in what I would call a more
passive role in just being a seller at the lease. We have to

provide linefill now in a great many of the pipelines. We
have to provide inventories on onshore terminal locations,
and for the few unfortunate of us who are privately owned
companies, we have to post letters of credit in a great many
locations to move our oil and your oil from the offshore
arena to the market locations where we trade it.
What is disturbing to us and troubling to us, as we have
indicated in prior hearings such as this one, is that we

don't think the M M S truly understands the change in this environment. Your adamant position that marketing costs are the requirement of the lessee producer, I think is a position that goes back historically and doesn't recognize the change in the environment which we are confronted with. Granted we think the other changing environments are perhaps ones that we need to be moving into in terms of how you look at pricing and how you get value because the M M S appears to me and to our company to be adamantly set in its position to not change with the times and recognize that what we are doing today to get you and us higher value requires an entirely different kind of marketing organization. We can go back to the passive days. We can, basically, get rid of our affiliate marketing company and employ one or two people to do nothing but sell this oil at the lease. We do not think that, that is in your interest or our interests; although, that is the historical way that it has been done; and to this day, I would think a great many of the independents, particularly onshore, continue to sell their oil that way. We feel that it's necessary for us, and we think a way to maximize the revenue stream is to go beyond that; but in so doing, we have undertaken an entirely different set of business risks and activities, and we think that the M M S does not recognize that change. I think you are still looking at the old definition of marketing where it was done at or near the lease, and you have not accepted the changing conditions and we are deeply troubled by that position. We think it is incorrect.

The other thing that I think is somewhat inconsistent, perhaps you all could help me here, is that in your opening remarks you indicate that the value of royalty should be placed on production at or near the lease, but yet you're imposing on me this requirement that if we have an affiliate, that the oil be priced on a basis at a trading location, whether it be at St. James or Cushing or Midland or wherever. So that position, at least from our perspective, appears to be somewhat inconsistent with where you're wanting to go. As you know, we are a member of the I P A A and will be providing comments to you regarding the entire proposed rule. I really believe that this rule continues to not get to the point where we need to in the business to be truly equitable.

What troubles me also is that the relationship between

the M M S and those of us who are independent producers continues to be of an adversarial nature. I'm troubled by that. It appears that we have opposing economic interests when in reality we really shouldn't. You really should be supportive of what we're trying to do on your behalf, but there's always this feeling of the Big Brother leaning over looking at us, challenging and questioning everything that we're doing; and it's very troubling, very concerning to us.

I might also mention that we reviewed -- our company, by the way, we not only market our affiliate's production, our affiliate producing production; we also purchase and resell a greater volume of third party oil in the Gulf of Mexico from other producers primarily independents but in some cases, larger companies, but the larger volumes are from independents; and recently, we were with one of our large independent customers and we were reviewing the effects of this proposed rule on their activities. I indicated to them that it appeared, at this time, that they would continue to be allowed to use the gross proceeds method. However, in all candor, I mentioned to them that given some of the particular wording of the exceptions in the law that provides for the director or the M M S to come back and challenge some of those bona fide third party arrangements, that in fact, they should be considering down the road that they may be, I don't want to say the word forced, but may be induced to have to

market their oil in a method similar to us where they would have to go out and hire additional people and additional requirements like I have to meet now. I got to tell you they're really concerned about it. They really don't want to get into the marketing business on a full stream basis, but they're very concerned.

In conclusion, I just want to say that the single issue that continues to bother the independents with affiliates more than any single issue is the fact that the M M S refuses to update and modify its position on marketing costs, and those are marketing costs that have been incurred above and beyond what we normally used to do, and those, what I want to say, are to enhance your value. Sure they're to enhance our value, too; but I got to tell you it's an entirely different kind of business. We're all -- those of us who are in the business out here today, we're all going through some gutwrenching times right now in the market place because of it which our producer affiliate does not get involved in. Obviously, they're unhappy with the price but they don't get involved in their negative business like we do. Thank you very much.

MR. DON SANT: Question on, I guess, the benchmarks in the Rocky Mountains and the argument that they ought to be moved to the Gulf of Mexico, Tom.

MR. TOM WHITE: You're asking me. I'm sorry, could you repeat that. John whispered something in my ear and I didn't hear you.

MR. DON SANT: That's why I stopped. I'd like you to comment on the benchmarks in the Rocky Mountain and M M S' decision or conclusion not to move them to the, say the Gulf of Mexico; and we argue that there's good benchmarks in the Gulf of Mexico; but I would read from your statement that you would agree with us if we gave marketing costs.

MR. TOM WHITE: Let me just say this, I have no activity in the Rocky Mountains whatsoever. In fact, we have very limited onshore activity, our affiliate has none. In our marketing company we do have some. I really haven't focused in on what you do in the Rocky Mountains or what you proposed my interest has been in the Gulf of Mexico. I think that I can echo many of the comments here that I find it very difficult to value oil in the Rocky Mountains on an index kind of basis because I just don't see how you get there to do it. Okay. I think there are some real problems, as John pointed out, when you're in some areas when there is only one market and that's the only bid that you get on a tender. I think if I was an independent producer in the Rocky

Mountains, I would be trying to see how to get my oil out of that market place, if I could; but what you may be confronted with is that the sheer economic cost of doing that where you could get the oil valued on a different basis just may not be

possible. I think maybe others are probably more qualified to talk about the Rocky Mountains then myself.

My concern is when you're looking at marketing costs, Don, is that, and I know the case that you all cite in your defense here, really goes back to a time when a great many of us in the independent sector simply were very passive in our roles and really did not undertake the additional marketing requirements beyond the lease. Those days are over with, particularly for those of us in the Gulf of Mexico and we've had to change our operation, which is incurred additional costs and activities and we just think that for you to share in those benefits, which we are perfectly willing to share with you we want you to share in those benefits, you should pay your proportionate share of the cost in getting the benefit, and we don't think that's an unreasonable request. We think that your position, these will be the marketing costs, really goes back to an era when it was passing; and I would tell you that if we undertook a program where we sold all of our oil at or near the lease, we wouldn't be asking for any marketing costs. We would assume all of that responsibility. We'd do it in house and we would assume all of that responsibility, but when we go beyond that, when we undertake these other activities and these other risks, we think that we have changed the definition of what I think the M M S views marketing costs as, and I'm just saying I think

that in all fairness for you to get what we think is this upgraded value, given this additional business risk, you should share in your proportionate cost. That's all we're asking. I just don't think we're being unreasonable.

I think you all have been adamant in your position and I just think that -- and I know Corpus, I believe, is the one particularly adamant in it, and I just think that your definition and your position on marketing costs predates the change of the environment; and as you've asked us to change things, I think we're saying to you, hey, I think it's time for you all to take a look at changing some of your positions on things. Let's get with the program. It's in your benefit.

MR. DON SANT: Well, the point I was trying to have you make is that the sales at the lease probably aren't the best benchmarks anymore.

MR. TOM WHITE: Well, I don't know about in the Rocky Mountains, as I said I'm not active up there.

MR. DON SANT: Right, but we didn't move those benchmarks to the Gulf because we really didn't think those were the best indicators and you had a lot of indicators that were already available in the Gulf of Mexico.

MR. TOM WHITE: As I indicated in my comments, I buy oil on a third party basis, right now, on bona fide sales and I think if you brought my customers in here and asked them how they felt about those transactions whether they were indicative of fair market value, I think they'd be pretty adamant, yes, they are; and to say that that wouldn't be a benchmark value got --

MR DON SANT: -- and we left those in the rule but Debbie's chart up here said 75 percent, approximately, of the Gulf of Mexico production was transferred non-arm's-length.

MR. TOM WHITE: I don't dispute that. I'm obviously --

MR. BEN DILLON: How did you leave what Tom just described in the rule as a fair indicator of fair market value of G O N?

MR. DON SANT: Not for the non-arm's-length but for the producers that he's purchasing in third party, those are the gross proceeds.

MR. TOM WHITE: But you're, in essence, saying that sale would not be an applicable benchmark sale.

MR. DON SANT: Right, even though 20 percent of the production shouldn't necessarily be the value for 80 percent of the production.

MR. BEN DILLON: Tom can't use those values under your current proposal, correct? Tom cannot use those third party transactions as an indicator of fair market value at M M S.

MR. DON SANT: That's correct.

MR. BEN DILLON: And why? You just agreed they were fair market value indicators.

MR. DON SANT: We said -- the rule says they're value for the seller, but he says he wants us to go with him.

MR. TOM WHITE: I didn't say I want you to go with me. I said, I want you to give me my marketing costs. I mean, I'll be candid with you, Don.

MR. DON SANT: If we go with you, then just give you marketing costs is what you said.

MR. TOM WHITE: We really have to take a hard look, if this goes in, a hard look at whether the affiliate should continue to market the oil from our producer affiliate, or we just enter into bona fide third party sales for the -- and let the the market, the producer affiliate, just sell it outright. I mean, I think that is what is at the top of our list as the alternatives. If we are not successful in getting marketing deduction for marketing costs, we go back to what we were doing. Okay? You come out behind; I think we may come out behind. I'm unhappy with it.

I got to ask one other question, too, since you kind of broached this issue. What was the M M S' position, I guess as to when the I P A A -- obviously, we presented a number of benchmarks and one of those was a tendering program offshore.

Why did you all elect not to include that in this new language in the new rule, the revised rule?

MS. DEBORAH GIBBS TSCHUDY: I think I answered that question earlier. We believe that in the Gulf there are readily available reliable indicators of market value, that is spot prices in the Gulf and there's no need to look to other means of valuing the production.

MR. JOHN HALEY: Conoco disagrees with that. That spot price is not a price at the lease and our competitive bid program is proving that out. Let me try to answer a question that Don just had a minute ago. I want to quote what Dr. Cault said about our program. Okay, quote, "offering for bid 10 percent of Conoco's volume in any given producing area is, in general, more than adequate for the market forces to reveal fair market value of their crude. There is no need for the percentage to bear any relation to Conoco's royalty or working interest obligations in the area. The design of the program provides the opportunity for market forces as expressed in arm's-length bids to operate, and if you're using a competitive bid program at the lease, that is the fair market value at the lease not some distant trade center." If you value crude at the lease under maybe some other means to value crude other than a competitive bid program, I can't answer that question today; but I'm convinced that our program does value the crude at the lease at the appropriate fair market value at the lease.

Now, the fact that we do not take all that oil and sell it, we're valuing every barrel at that lease on the competitive bid program. Conoco is not placing a value that we generate internally on those barrels. The price that we place on those barrels are generated from third party bids, every barrel. We may choose to match that, but every lease holder in those properties gets paid that competitive bid price. It's a volume weighted average of the bids. We don't think that one interest owner has a right to the highest bid price. We think they have a right to a volume weighted average of the bids, and that's how we designed our program; and we think that, that is the best indicator that can be generated today, in today's market, to come up with a fair market value at the lease; and we think that, that applies anywhere where you can get two or more people to start to bid on leases.

MS. DEBORAH GIBBS TSCHUDY: Was there another question in the back?

MR. DAVID BLACKMAN: Yes, David Blackman, Burlington Resources. Getting back to the discussion that you were having with Tom for a second. One of I P A A's big concerns here is that this rule will result in a transfer of crude from refinery companies to non-refinery companies in midstream market activities. If you look at 206.102 as has

been pointed out, there are nine exceptions that we can see to gross proceeds in 206.102; and I'm sure you know when a company engages in tracing activities. The tracing of the ultimate disposition of that oil can be incredibly high proportion, which we believe M M S will choose to focus much of its audit efforts on. Doing that is going to be encouraged, as Tom said, to change its marketing practices to avoid the audit scrutiny, to avoid six years of second guessing its marketing decisions and it's marketing operations. Given that and given M M S' stated desire to have increased certainty and simplicity as a result of this rule, I have to ask why it is that midstream marketing companies who do not have refiners are not allowed an option to choose the spot price methodology offered to refinery companies in the Gulf of Mexico and elsewhere in the country.

MS. DEBORAH GIBBS TSCHUDY: As you know, we had that option available in the January 24th proposal. This supplementary rule just makes a clean cut between oil that is sold arm's-length before it's refined and oil that is not. So we just decided to make a clean cut that arm's-length gross proceeds represents value. Where we don't have arm's-length gross proceeds, we have to look to other indicators of value. David, could you review with me the nine exceptions to arm's-length, and I would just like to point out before you do so that all of the exceptions here,

except two of them, are verbatim exactly out of the 1988 rule. So to my knowledge, the only two new exceptions to paying on an arm's-length contract is one, an exchange agreement. However, we have an exception to that exception, that is after multiple exchanges you can pay an arm's-length; and then the other is a noncompetitive crude oil call, which we've been told by your association is very infrequent.

MR. DAVID BLACKMAN: I believe the breach, the duty to market the oil for mutual benefit for self or lessor, is a new language.

MS. DEBORAH GIBBS TSCHUDY: Not at all. That's verbatim right out of the '88 regulations.

MR. DAVID BLACKMAN: Duty to market?

MS. DEBORAH GIBBS TSCHUDY: The breaching of the duty to market is right out of the '88 rates.

MR. DAVID BLACKMAN: You have those. You have (a)(2), sell or transfer to an affiliate and that affiliate or other affiliate then sells the oil under an arm's-length contract. It's not an exception. That is an audit. Okay, that's going to be the focus of an audit.

MS. DEBORAH GIBBS TSCHUDY: I'm just interested in the nine exceptions to being able to pay --

MR. DAVID BLACKMAN: I'm sorry I misstated that. Nine areas of increased audit in 206.102. The point is this, in the '88 rates you had a set of benchmarks that you had to go through valuation purposes that provided you options for valuation to qualify you for benchmarks just prior to having to trace. This rule eliminates those. You have to trace through your affiliate. That's automatically increased, increased complexity, likely to increase the scrutiny, particularly, when companies or refiners are paying such a large portion to your royalties are now going to be paying these spot prices less these public indication differentials that are going to be requiring very little audit scrutiny.

MS. DEBORAH GIBBS TSCHUDY: Now the current regulations require, essentially, a duel accounting. It's the benchmark value and then the current rules contain the gross proceeds minimum. This supplementary rule eliminates that gross proceeds minimum. If you're in to 206.103, you do not also have a requirement to pay on no less than your gross proceeds, whereas the current rule you have the benchmarks and then you also have the tracing requirement under the gross proceeds minimum.

MR. DAVID BLACKMAN: I guess that's true. The point is that we're concerned there's going to be a shift in audit scrutiny under this rule.

MS. DEBORAH GIBBS TSCHUDY: What's the basis for that concern?

MR. DAVID BLACKMAN: Are you saying that this

rule is going to continue to require people under 206.103 to trace gross proceeds? Is that what you're saying?

MS. DEBORAH GIBBS TSCHUDY: No, I'm saying that the current 1988 regulations require value under the benchmarks as well as a comparison to your gross proceeds, a tracing. This supplementary rule eliminates that gross proceeds tracing requirement. If you're under 206.103, index is value. There is not the gross proceeds minimum. So could you please explain the basis for your concern about an increased audit burden of this rule compared to the current regulations.

MR. DAVID BLACKMAN: An increased audit burden for companies who have the value under 206.102, you have to trace through their affiliate rather than pay on a spot price less the public indication differentials.

MS. DEBORAH GIBBS TSCHUDY: How is that an increase over the current regulations?

MR. DAVID BLACKMAN: It's not an increase under the current regulations. What we're saying is that our concern is there's going to be a shift from companies who currently audit to death if you have resident auditors on staff in all these refinery companies. Now they're going to be paying you under 206.103 because they never have their arm's-length sale. What I'm saying is -- well, they don't never have arm's-length sale, but in those instances where

they move the oil from the lease through their refineries, they're going to be paying under 206.103, which is in our opinion going to require far less audit scrutiny then the current regulations.

MS. DEBORAH GIBBS TSCHUDY: So, David, are you saying that for about 75 percent of the production we should have decreased audit burden by going to index?

MR. DAVID BLACKMAN: Possibly, yeah. I think that's possibly right. Our concern is that those audit resources will be shifted to companies who are paying you under 206.102 because it is more complex to trace through an affiliate than to pay on spot.

MR. BEN DILLON: Debbie, before we leave this, George, let me if I can; and I'm not going to debate this, I just want to understand it. It seems that what we see is a third new exception on duty to market. You would dispute that that in fact is under current rule. Do we not need to look as to the definitions that drive the exception? You're telling me -- we haven't had time to do a comparison -- that double little i is verbatim to little i, double i is verbatim under '88 rates; but do we not have to go to 206.106 and see if in fact you have expanded your terminology as to what duty market to market is; and I thought you all were clear that,

that in fact has changed, in many, many discussions.

MS. DEBORAH GIBBS TSCHUDY: But that's not an

exception to paying on arm's-length contracts. It just clarifies the responsibility of all lessees to place production in marketable conditions into market production at no cost to the lessor.

MR. BEN DILLON: So you would say it's a clarification.

MS. DEBORAH GIBBS TSCHUDY: Of existing policy.

MR. BEN DILLON: But you're saying that is now codified in regulation, which changes the definition, which creates a new exception so there is in our minds three.

MS. DEBORAH GIBBS TSCHUDY: But it's not an exception to paying on arm's-length gross proceeds. You'd still pay royalties based on proceeds under your arm's-length contract; but should you incur any marketing costs, you cannot deduct those from your arm's-length gross proceeds.

MR. BEN DILLON: Should you breach your newly meanted duty to market, you are not allowed to use gross proceeds; and I'm just trying to clarify that definition.

MS. DEBORAH GIBBS TSCHUDY: That has not changed. The breach to duty to market contained in the exception is verbatim out of the '88 rules and to my knowledge has not been applied in the 10 years of this rule's existence.

MR. BEN DILLON: So you have concluded, right

-- am I wrong -- in the market in the definition of gross proceeds that is a change.

MS. DEBORAH GIBBS TSCHUDY: Yes, but it's not an exception to paying on arm's-length gross proceeds. You still pay on your arm's-length gross proceeds.

MR. BEN DILLON: We're going to disagree on that obviously.

MS. DEBORAH GIBBS TSCHUDY: George?

MR. GEORGE BUTLER: George Butler, Chevron. I would like to take issue with what I heard to be M M S' interpretation of David's statement. I think I heard, Debbie, I think I heard you ask David if he was saying that the audit burden would be simpler for 70 percent of those of us who are on index, and I would like to really, really take issue with that at this point on the record.

First of all, what the new rules do is they say that if oil is sold prior to being refined by the lessee or the lessee's affiliate, you have to trace it back. Okay. Unless you think that our affiliate's only business is to move oil to refineries, which is not the case, then there is going to be a tremendous amount of production that has been valued previously under the non-arm's-length benchmarks. That will be valued based on tracing under your new rule. So what is going to happen is when you come in there and audit, you're going to want to audit the affiliate's records; and you're going to want to separate the sheep from the goats, the dispositions arm's-length versus the M M S version of non-arm's-length dispositions of the affiliate. Okay, this could either be the affiliate or the downstream division of the company that does some sort of dispositions and either markets the production arm's-length or transfers it, ultimately, to a refinery; and what the effect of your rule by saying that you have to use gross proceeds for any arm's-length sales is, you're going to be finding a situation where the marketing affiliate or the downstream division of the company is engaged in all sorts of downstream activities with production from Federal leases, private leases, and state leases, which cannot be sourced, logically, back to individual Federal leases, and which must be, therefore, allocated back through some sort of a weighted average pool pricing mechanism; and, therefore, what is going to happen is, basically, every sale by an affiliate will have to be somehow allocated back to every lease and that is going to entail an extremely complex, an enormous burden, on lessees to try to implement the gross proceeds rule the way it's being expressed now; and it is going to be an absolutely crushing audit burden and to me it's almost like a Federal

Employee Job Security Act of 1998. Thank you.

MS. DEBORAH GIBBS TSCHUDY: George, how is that any different than the current regulations?

MR. GEORGE BUTLER: Because the current regulations say that if you have an M M S marketing affiliate if you have a marketing affiliate that purchases only the lessee's production, you're required to trace back from the lessee, from the marketing affiliate a quote, "marketing affiliate's resale price".

It was M M S' policy and valuation determinations following it's 1988 regulation not to trace through by sales and exchange agreements unless they were considered to be transportation by sales. You're FOYA documents that you have produced have showed that it was not your policy when you promulgated the 1988 regulations to consider sales by an affiliate that was not a quote, "M M S marketing affiliate" to be gross proceeds to the lessee, and we all know that your view of the world of what gross proceeds are has changed since 1988 in the sense that the department now takes the position that under the 1988 rules gross proceeds to a lessee's affiliate, even if it's not a quote "marketing affiliate" as defined in the '88 rules, are, in essence, gross proceeds to the lessee. So you have evolved, clarified, whatever you want to call it, I would say changed your position and only with your change in position can you say that, that is not a change of position in the new rules; but we all know that there was an internal debate within the department for years about auditing affiliate's proceeds.

Some people thought well, proceeds to the affiliate are proceeds to the lessee. Other people within the department thought no, we just need to audit the sales to the affiliate and all that to make sure that there were no services provided at no cost to the lessee by the affiliate for which the lessee's non-arm's-length gross proceeds should be jacked up to reflect the value of those.

So I do believe that there is a tremendous change, a C change, in what's going on because I just have to disagree with you, David, and say that there is going to be a tremendous audit burden resulting from tracing back from gross proceeds in every case that is not a situation where you know there's only one disposition by an affiliate. They're going to be millions of them. They're going to change from month to month. There's going to be spot sales, term sales, every kind of disposition that you can imagine because these affiliates are not out there with a single goal of taking lease production to a refinery and so there's going to be any number of dispositions, and it's going to be very, very difficult to audit, you know.

I suppose, intellectually, you can look at this and say well, gross proceeds to the affiliate are gross proceeds to the lessee; but it's much more difficult to implement this type of regulation. There certainly is no simplicity, no certainty. We're going to have more audits; we're going to have more disputes, but it seems to be that the only thing that you're really going for here is, with the new regulation, is trying to get more money, you know. That seems to be the basis of the regulation. This belief that you're being underpaid today and trying to come up with a regulation that would provide you more money in the future; but certainly no simplicity, you know, no certainty for us. We certainly see a lot more disputes about how to actually implement this regulation down the road.

MS. DEBORAH GIBBS TSCHUDY: So would you advocate then having all payers on index rather than having the arm's-length payers pay on their arm's-length resale, for simplicity purposes?

MR. GEORGE BUTLER: No, ma'am. No, ma'am. I would advocate that you take your production and market it yourself.

MS. DEBORAH GIBBS TSCHUDY: Wait, before you go away.

MR. GEORGE BUTLER: She's using the syncretic method, I'm shaking in my shoes. It's been awhile since I was in law school.

MS. DEBORAH GIBBS TSCHUDY: You would have to say though that there would not be increased burden under this rule compared to the department's current policy regarding gross proceeds.

MR. GEORGE BUTLER: The department's current policy. Well, I don't know. It seems like the jury's out on that. I mean, you do have some court decisions in your favor on the right to audit affiliate's books. I don't think you have court decisions in your favor on your position that -- I think your position that proceeds to an affiliate equal proceeds to a lessee, I think that's currently -- I don't even know if we have a final decision in the department on that. I know we have a final decision in the department in the Shell I B L A decision. We know what the department's position is. I don't think we have a final department decision on proceeds to the affiliate equals proceeds to the lessee under the 1988 rules. Do you think that there's a final decision in the department on that? I don't know of one so I can't agree with you is what I'm saying. I'm really nervous here. You're trying to get me to say something I don't want to say because I don't believe it.

MS. DEBORAH GIBBS TSCHUDY: Okay, let me ask you some other questions while you're up here. I only have two pages worth of questions so it won't take long.

MR. GEORGE BUTLER: Okay, I probably won't be able to answer them, but I'll try.

MS. DEBORAH GIBBS TSCHUDY: What do you think about the definition of the Rocky Mountain Area, six states.

MR. GEORGE BUTLER: I think your tender

program is far too restrictive. Is that the question? Was that the question that you asked me?

MS. DEBORAH GIBBS TSCHUDY: No, it wasn't. Let me try it again.

MR. GEORGE BUTLER: Okay, let me say this. I agree with Conoco's position that going through and having different methodologies, requiring different systems for different geographical locations based on different marketing characteristics is unworkable and overly burdensome for lessees.

MS. DEBORAH GIBBS TSCHUDY: Let me restate my question. We defined the Rocky Mountain Region as including six states. Should there be other states that are part of the Rocky Mountains or should there be some states that shouldn't be included in the definition of Rocky Mountain?

MR. GEORGE BUTLER: I don't know, which is going to show how dumb I am.

MS. DEBORAH GIBBS TSCHUDY: Do you have any comments on the new definitions contained in the new revised rules?

MR. GEORGE BUTLER: Yes, ma'am, I do have some comments on that. I don't like the way marketing affiliate and control -- it was bad enough before but we did have the ability to to come in and try to rebut the presumptions; that's been taken out, I think. From what I've heard today, that's been removed, the ability to rebut a presumption of control.

MR. DON SANT: Have you ever come in to rebut a presumption of control?

MR. GEORGE BUTLER: Have I?

MR. DON SANT: Has Chevron?

MR. GEORGE BUTLER: Well, we never had that problem before, did we? We didn't have the problem until 19 -- we didn't have an affiliate until 1996 so we have not come in and rebutted that. I don't know if anyone else has, but I don't like it nevertheless.

MS. DEBORAH GIBBS TSCHUDY: Do you have any specific comments on the tendering program, the percentage? Should it be a second benchmark instead of a first benchmark or anything related?

MR. GEORGE BUTLER: Not at this time.

MS. DEBORAH GIBBS TSCHUDY: Regarding the Form 4415, is it -- any ideas you have on ways we could enhance the quality of that information we collect or less information we need, more information we need. Could we eliminate the form?

MR. GEORGE BUTLER: I can't really answer at this time. I'm sorry, Debbie, I really didn't come here prepared to make a statement. When I heard what David said and I heard you concluding on the record that the industry

was agreeing that somehow 70 percent of the transactions were going to be easier to audit in the future, I could not let it lie without protesting. That was my only reason for speaking.

MR. DAVID BLACKMAN: And for the record, David Blackman stands fully chastised and corrected.

MR. GEORGE BUTLER: But we will try to get you some comments on this and answering those questions.

MR. DON SANT: We made some assumptions and provided what we thought would be the production in various areas valued under arm's-length and valued under the index.

I guess your statement is that you think we understated the volume of production that would be valued under arm's-length under gross proceeds. Is that true?

MR. GEORGE BUTLER: When I look at that graph and the gentlemen told us how they kind of came up with those numbers, their methodology, I think I heard them say that they assumed certain things; and that was that certain companies were going to be paying on index and certain companies, certain types of companies, were going to be paying on gross proceeds; and what I am telling you is that, I believe, that based upon my knowledge of the marketing, the oil marketing business, you are going to be having a tremendous amount of -- when you go up there and audit, I believe, that you will be determining that there are

arm's-length sales which occur by a lessee or a lessee's affiliate prior to -- if you're throwing out this whole overall balancing and all this kind of stuff, whatever that means to you. I mean, what I'm saying is that there are interrupting dispositions all along the way and what I hear you saying is even if a lessee is using all of its production whether it be in by sales, exchange agreements, arm's-length sales, whatever to obtain, to eventually obtain, feed stock for their refineries; notwithstanding that fact, I believe that the way your regulations are proposed those lessees who are really, you know, because they are engaging in the marketing business, you know, that I believe that the effect of your regulation is to require many, many more instances of much greater amount of Federal production to be valued under a gross proceeds to affiliate netback type methodology then the indexes. That is my belief as an individual citizen and taxpayer and not necessarily as Chevron's representative, but based on my practice of law in this area and understanding of this rule, my cursory understanding, you know, I believe that there would be a lot more arm's-length dispositions then you currently -- then we all currently believe there are under the existing regulations, you know, as we would say there are.

MR. DON SANT: Can you as Chevron or you as a member of a trade association try to do some analysis like that and provide to us for comments on the proposed rule?

MR. GEORGE BUTLER: I don't know, I mean, it would seem to me -- I don't know, perhaps. I think that you get into issues where, I mean, it's one thing for lessees to talk to each other. It's another thing for us to talk to each other and say can you get your affiliates to, you know, to talk about how much, what percentage of the oil they control. I mean, first of all, these guys are going to say, I think, I get oil from a lot of places besides you Mr. Producing Affiliate; and it all goes into a big pot and I do all this other stuff with it and I have no idea how much of it comes from a Federal lease versus a private lease or a state lease. They maybe able to. I mean, I think that's part of the controversy that we have right now with affiliates throwing their records over; and the fact that you have to just kind of make some assumptions about what's happening to the Federal production, but it's certainly something that I'll, you know, -- if that's what you want it's on the record. Mr. Ben Dillon has something to say.

MR. BEN DILLON: I do. I would like to help you on that analysis -- what?

MR. DON SANT: Stop.

MR. GEORGE BUTLER: She has to do the tape.

(The court reporter changed paper at this point.)

MR. GEORGE BUTLER: Okay Ben, you're on.

MR. BEN DILLON: Don, we'd like to help you in that analysis but to do so could we -- I know you all have stuff posted up on the home page, I guess, about the analysis; and we'd like to look at that if we could get some of the spreadsheets and things that they've been talking about at the beginning point. So would you make those available to us so we could assist?

MR. DON SANT: I'll ask them if there's any.

Is it aggregated enough so there's no proprietary problems here?

MR. BOB KRONEBUSH: No.

MR. DAVE DOMAGALA: There's a total proprietary problem. There's production data for every company for 1996.

MR. BEN DILLON: But there are spreadsheets that are aggregated on some level, obviously.

MR. BOB KRONEBUSH: Yes, at the five category level.

MR. BEN DILLON: That would be a great place to start. I mean, I just got to figure out a way to get it explained.

MS. DEBORAH GIBBS TSCHUDY: The 12-8-66 is part of the rule making record and we could clearly give you -- I think that might give you much of the information you're

looking for.

MR. BEN DILLON: As much as you think you could give us. That would be great and if you could send it to my office, I'll take a look at it.

MS. DEBORAH GIBBS TSCHUDY: I have a question of George. You said that with the elimination of the overall balance you think there are more payers who are going to pay on arm's-length.

MR. GEORGE BUTLER: No, that's not what I'm saying. I'm saying that you have -- something about this thing you took out overall balance as an exception to gross proceeds or something, and so I may have misspoke there. All I'm saying is I don't know anything about that. I mean, I'm not telling you one thing or another about that. I was just saying that I do believe that there's going to be -- that the result of what you're saying -- if what -- if the cutoff between gross proceeds, Rule 102 versus 103, is the ultimate disposition of a barrel of oil from a Federal lease, if the cutoff is whether or not there was an arm's-length disposition prior to the refining of that barrel and changing the chemical composition, my personal opinion is that you have thrown the royalty payment valuation rules into greater chaos then I can describe to you because we don't know -- we can't tell you where it goes barrel for barrel, and so you're setting a standard that is such that you're going to have to

use this kind of a pooled weighted average kind of thing. How much of your sales went to -- how much did you sell to a refinery Mr. Affiliate? How much did you purchase from your lessee, your producing affiliate? How much of the producing affiliate's production did you buy versus production that you bought from somebody that wasn't a producing affiliate? How much of the producing affiliate -- how much of the production that you bought was Federal? How much was state; how much was private? They're going to have to be so many factors that will go into trying to separate what of the affiliate's dispositions should be traced back through some sort of an allocation or a weighted average back to your Federal leases versus what portions of the affiliate's dispositions may have gone to the refinery should be used in order to get those back through your very complex methodology to employ indices.

I believe that there will be tremendous uncertainty and a tremendous burden on audit and what we found with the existing rules is that all of the assumptions that everyone made when the existing rules were published are being, you know, are not holding true to us. We seem to be -- we're very surprised today by at once we're being audited on valuation rules. What we're being asked -- what we're being told is the value of production and how those rules are applied. It's coming as a complete utter shock and surprise, and that is going to be increased by many orders of magnitude

under this type of a proposed rule. That would be, you know, what my problem is, you know. I'm sorry what I said about overall balancing. I don't know how that really fits into it.

I guess what I'm saying is that there are many situations where an affiliate may take a certain portion of the production they control at some location and sell it. They may buy other production from some other place. You don't know with what they're moving to refineries whether it came from Federal leases, whether it's part of the production that they purchased. I mean, you just don't really know so you have to make all these assumptions, and it's going to be very difficult for us on audit. We're going to have a lot of disputes.

MS. DEBORAH GIBBS TSCHUDY: Sara?

MS. SARA TAYS: I have a question that I'd like to get answered. Sara Tays, Exxon. One of my questions was about the estimate, the $66 million estimate, and 208 where it talks about small refiners. In your introduction you talked about the small refiners' piece was pulled out but it still says in 208 that it's going to be paid according to 206, so is part of the volumes that were calculated for the $66 million, does that include the small refiners' increase in their payments?

MR. DAVE DOMAGALA: Yes, it does.

MS. SARA TAYS: It does. So like if they're saying -- you said there was like $43 1/2 million offshore Gulf of Mexico. So if they are taking 30 percent of that, so 30 percent of that increase would come from small refiners?

MR. DAVE DOMAGALA: That's correct.

MS. SARA TAYS: And then on the estimate that y'all did about paperwork reduction, it appears that you looked at paper costs and that kind of costs. What about systems costs, did y'all pay? It doesn't look like you put any estimates in for how much systems costs would be if you're trying to generate a lot of 4415 work.

MR. DAVE DOMAGALA: We assumed that existing systems would be used that there would not be an additional cost or --

MS. SARA TAYS: Okay and so you didn't like for -- even if you set aside the 4415, there wasn't an estimate for what existing systems costs would be to try to pay it in a different way, right?

MR. PETER CHRISTNACHT: To get back to your question on systems costs. We estimated that the first go around would probably be -- a first go around would not include a computer changeover, but that we kept that annual burden to be the same, realizing that adjustments would be made and that there would be a learning curve, if you will. That would hopefully reduce those costs in subsequent years

so to say that we didn't really, I mean, I don't know how sophisticated a system you're going to need to aggregate those forms that you're going to need to report on; but we anticipated that it will be less in subsequent years.

MS. SARA TAYS: Okay. Which is -- (speaker was inaudible.)

MR. PETER CHRISTNACHT: I'm sorry, I didn't catch the second part of your question there before that.

MS. SARA TAYS: I was just wondering if for just the overall change of value royalty in a different manner or tracking different information or the different regions, if y'all had included any systems cost for that or any work effort for making that change?

MR. PETER CHRISTNACHT: I think until we

understand the changes that will be required, it will be difficult for us to come up with a real concrete number on that.

MS. SARA TAYS: Then we can evaluate some of that and make a comment on it.

MR. PETER CHRISTNACHT: If you have any suggestions that might help us define that cost, we certainly would like to hear that.

MS. SARA TAYS: Thank you.

MS. DEBORAH GIBBS TSCHUDY: Is there anyone else that would like to make a statement for the record? We

had a number of questions, specific questions, in the preamble we were hoping to get answers to today, and we've asked some of the folks that came to the podium to answer some of those questions; but are there other members of the audience that would be willing to give us some feedback on some of these questions?

The first one was comments on the Rocky Mountain Area
definition. Are there other states that should be included,
are there states that should be deleted, and specifically,
we'd asked about New Mexico, about including northwest New
Mexico, not including the Permian Basin, but including
northwest New Mexico into the Rocky Mountain definition. Any
thoughts on that?
MR. DAVID BLACKMAN: Do I remember correctly
from our round table meetings back in September wasn't the
state actively opposed to that?
MS. DEBORAH GIBBS TSCHUDY: Yeah, the Valdeen
Servanson did recommend that the whole state remain out of
the Rocky Mountain Region, but we've also gotten some
comments from others that, particularly, the northwest part
of New Mexico might be better a part of the Rocky Mountain
Region; and then Conoco has suggested that the Four Corners
Area itself shouldn't be a part of any region. It should be
its own region. Anyone else have ideas on that?
Okay, hearing none, the next question is whether there

were any comments on the proposed new or revised definitions? Yes?

MR. DAVID SIMPSON: David Simpson, with Total. To reiterate what I had mentioned earlier, that we think that it's not fair to remove the possibility of being able to demonstrate that there's not a presumption of control when ownership is between 10 and 50 percent.

MS. DEBORAH GIBBS TSCHUDY: Thank you. Anyone else? Are there any additional comments on the geographical breakdown by different areas having different valuation methods for three different parts of the country? Fred?

MR. FRED HOGEMEYER: Fred Hogemeyer, with Marathon. I guess I just wanted to follow-up on what was actually asked. I think Don and others may be trying to elude to probing this issue about the tendering and the arm's sales purchases that, at least in some form, was included in the Rocky Mountains. I guess I would like to make a comment or respond to that by suggesting that it just doesn't seem that there's material differences with the Gulf Coast Region or in New Mexico of why those valuation tools would not be of particular value. I realize your response to that question earlier was you felt the spot price was a valid indicator, and I guess one can respond to that by suggesting that first of all there are a lot of term contracts at leases trying to value production at the lease spot may or may not reflect

that term so there maybe certain circumstances where that could be a valid indicator; but many cases where it may not be, it would seem logical that you would allow those two possibilities in those regions, and for those who fit into those categories would use them appropriately and then if the facts don't fit that, then they would slide to the next one. However, it was sorted out.

So I would like to comment as we saw it, and I think we tried to articulate to you in past discussions that it seems to make sense to look at somewhat of a system that had some logical processes. Now each region may have particular facts that are different and you may look for different things, and it seems to me, anyway, that you sort of took that a little bit differently in looking for an index that was unique to an area versus to when it's unique all over. It really wasn't the point at all. It was about the valuation system that will it be tendering or using arm's-length sales or purchases, which could very well give an extreme indication of market value lease.

MS. DEBORAH GIBBS TSCHUDY: Other comments on the geographic breakdown? How about on the tendering program? We've heard quite a bit but others may have comments about the 33 1/3 percent requirement, minimum of three bids. Should tendering be a second benchmark instead of a first benchmark or any related comments you have on

tendering.

MR. DAVID SIMPSON: David Simpson, with Total and just a couple of comments. It seems to me that the 33 1/3 percent is too high first of all, that requiring three bids in all cases is too many, and lastly, excluding companies that have tendering programs themselves, I think is unreasonable to exclude those because in some areas you might eliminate all of the competition there. Those three I would have a problem with.

MS. DEBORAH GIBBS TSCHUDY: So what percentage would you propose?

MR. DAVID SIMPSON: Well, I think personally that, certainly, something above the royalty percentage plus an equity portion of the producer. We talked, what did we say 15 to 20 percent or something in that range would seem to be not be unreasonable.

MS. DEBORAH GIBBS TSCHUDY: And how many bids?

MR. DAVID SIMPSON: Two, if available and not excluding any companies. No, exclusions.

MS. DEBORAH GIBBS TSCHUDY: If we didn't have that exclusion of any company, how do we prevent companies from tendering to each other and basically gaming the system?

MS. PATTY PATTEN: Patty Patten, Oxy. That's antitrust. They've got bigger problems then gaming your system if they're committing antitrust.

MS. DEBORAH GIBBS TSCHUDY: Any other comments on tendering? Fred?

MR. FRED HOGEMEYER: Yeah Debbie, just to follow-up on your question there. I guess, if I may respond just a little bit to not allowing the tendering. I haven't had a chance to study through this kind of detail that you understand at this point, but I didn't quite understand the logic that if I -- and we sell a lot of ours outright. We do not if -- the model that Dave and others have used that refiner takes everything that is refined, that's not necessarily true; but the point being is that we sell a lot of barrels outright, and the fact that I sell it outright in arm's-length transaction to, if it happens to be Conoco, that's a valid arm's-length transaction for paying royalties; but it turns out that if I bid those out in something called a tendering to Conoco, then it's not allowed. It seems a little illogical why one is an arm's-length transaction, perfectly valid, the other one is not an arm's-length transaction, it's not valid. So we didn't quite understand what was the difference between the two, which kind of led you to believe that why would you exclude others just because they're also tendering. Being a tendering is nothing more than a bid out program and they're biding out barrels. If in an open market, great for them. If I happen to buy those barrels, there's no connection between me purchasing those

barrels and me selling my own barrels. So anyway that's a comment on that. That restriction didn't seem quite logical to me.

I guess just a comment on the percentage. We had talked about this in previous discussions to a certain extent. I think the key here was that there needed to be a certain minimum, but as John pointed out earlier in his discussion, you know, there are those in the economic community who feel that a 10 percent number is more than adequate to be representative and that's the key element, representative of the market; and there's been discussion of taking that up even to the royalty percentage or even more, but whenever you quantify any of those discussions, you're talking that 10 to 20 percent range so we didn't quite see where they made the leap to 33. We may argue about that but the point being is that we felt we got pretty good representation about that quantity in the crude area. Thank you.

MS. DEBORAH GIBBS TSCHUDY: Any other comments on tendering? The next question we had in the preamble related to the overall location, quality transportation adjustments that would apply when you go to index pricing. Specifically, we had comments on having a separate adjustment for quality differences between the oil produced and the oil at either the aggregation point in the market center. One change, you know, we made was to allow the use of quality

bank adjustments. Could we get your specific comments on whether that's a good idea or not a good idea?

MR. JOHN HALEY: Well, since nobody else is going to say anything, I think you got to do it. I mean, that's what is being paid is going into a quality bank. It's representing a difference in a quality. What goes in the pipeline is what you get out of it. If you put in a 25 gravity and you get out a 30, you get the value of that. You pay into the quality bank; and the way they run -- the way they work it's a zero sum game so, you know, it should be balanced from the front to the end of the pipeline.

MS. DEBORAH GIBBS TSCHUDY: Any other comments on the adjustments off of index?

MS. PATSY BRAGG: May I ask you a question? Would you briefly explain for us when you're in the 103 section how those adjustments are intended to work and do they work simply in each of the three areas?

MS. DEBORAH GIBBS TSCHUDY: The question is to explain how when you're in 206.103 how the adjustments work off of index pricing.

MS. PATSY BRAGG: Quality location differential adjustments and I know you say you must take those. You may take transportation so if you could give us a brief explanation that would help.

MR. DAVE HUBBARD: Well, starting with the spot price, you know, the adjustments for -- I think you're probably aware of what we discussed earlier on the exchange agreement location differentials. If you have the exchange agreement the actual differential from your own contract, you'd use that. If we have -- if you don't have the actual contract information, M M S would calculate one based on the form, assuming that form is still in place, you'd use that. That would bring you up to the aggregation point. From that point, you get actual transportation costs and the way they're structured right now, you get a quality adjustment based on any quality banks that might apply for that particular lease to aggregation point or market center combination. If there were not a specific quality bank between those two points the way the regulation is structured, there would be no such adjustment.

MS. DEBORAH GIBBS TSCHUDY: Patsy, let me respond to your question about the must and the may. On the location quality adjustment, that adjustment can sometimes be a positive differential. That's why you must. On a transportation allowance, it's always your actual costs of transportation. It's always a deduct so you may take that if you wish. That's the distinction.

MS. PATSY BRAGG: Would the production of either non-arm's-length or arm's-length exchange come into play on the first deduction?

MS. DEBORAH GIBBS TSCHUDY: Absolutely. It's only differentials contained in arm's-length exchange agreements that we would allow as an adjustment.

MS. PATSY BRAGG: So if you've got a non-arm's-length exchange under 103, then what's the scenario?

MS. DEBORAH GIBBS TSCHUDY: You're going to probably have to use the M M S published rate or you, actually, have ownership in the pipeline and you're transferring the oil, actually transporting the oil, from the aggregation point to the market center, you get your actual cost of transportation.

MS. PATSY BRAGG: Then if you wouldn't mind running through the difference between an arm's-length and a non-arm's-length exchange.

MS. DEBORAH GIBBS TSCHUDY: Same as the difference between an arm's-length sales contract and a non-arm's-length. It's defined by affiliation and opposing economic interests. So it would have the 10 percent threshold.

MR. GEORGE BUTLER: So does that answer Don's question before about situations where one would not be able to use their own differential to get from the lease to the market center if they have a non-arm's-length exchange as opposed to an arm's-length exchange?

MS. DEBORAH GIBBS TSCHUDY: Let me ask you a question. I hate to turn this around on you. How often do you have non-arm's-length exchange agreements? How often do you enter into exchange agreements with your affiliate?

MR. GEORGE BUTLER: You have to have an affiliate to do that.

MS. DEBORAH GIBBS TSCHUDY: Okay, assuming you have an affiliate. I should quit looking at you. Assuming you have an affiliate, do you enter into exchange agreements with your affiliate?

UNIDENTIFIED SPEAKER: Are you talking about a marketing or refining affiliate?

MS. DEBORAH GIBBS TSCHUDY: Doesn't matter. A company that you own more than 10 percent of. Do you ever enter into exchange agreements with them?

UNIDENTIFIED SPEAKER: Oh, yeah, you will with a joint venture.

MS. DEBORAH GIBBS TSCHUDY: With the joint ventures. So rather than selling to that joint venture or to that affiliate, you'll exchange and you, the producer, will get oil back on the other side of the exchange and then do what with it?

MR. GEORGE BUTLER: Well, the lessee or the lessee's affiliate will get oil back on the other side of that exchange.

MS. DEBORAH GIBBS TSCHUDY: Right, but you really are going to exchange. You, the producer, are going to exchange and you, the producer, with your affiliate then are going to get oil back from your affiliate at some point and then do something with it.

UNIDENTIFIED SPEAKER: Yeah, because you've got multiple affiliates.

MS. DEBORAH GIBBS TSCHUDY: But you would exchange with them rather than sell to them.

MR. TOM WHITE: Well, it's a buy/sell exchange. It's a buy/sell exchange. In a proprietary line, they've got to own it.

MS. DEBORAH GIBBS TSCHUDY: Right.

MR. TOM WHITE: Okay, so you're going to have to sell it to them even if they're an affiliate. If you're an affiliate, you've got to sell it to them, particularly, in these new joint ventures.

MS. DEBORAH GIBBS TSCHUDY: But your going to buy it back.

MR. TOM WHITE: They're going to sell it back to you at some other location, right.

MR. GEORGE BUTLER: Oh, that brings up something, a question. Assuming that lessee owns 50 percent of its affiliate of its marketing affiliate, 50 percent. Okay, and then the marketing affiliate somehow is in some

sort of joint venture on transportation line or something, and the marketing affiliate owns a 10 percent interest in that. Okay, so that the lessees, the lessee, I mean -- I guess what I'm asking you, what is the lessee's ownership in the line is it 50 percent or 50 percent times 10 percent or only 5 percent? So that the transportation costs the lessee incurs is calculated by taking the percentage of the lessee's ownership in the affiliate times the affiliate's ownership in the affiliated pipeline.

MR. DON SANT: I think you would look at each transaction there, so you would look at the transportation. It would just be a 10 percent that you're looking at so it would still be controlled in an affiliate.

MR. GEORGE BUTLER: But would you think that the lessee would control the pipeline? You're saying because the affiliate is the lessee if the affiliate controls the pipeline, then the lessee controls the pipeline.

MR. DON SANT: The way the regs are structured, whether they're correctly that way, you're looking at the contract between this entity and that entity and you're looking to see whether it's an arm's-length or a non-arm's-length contract; and the first one, is it a non-arm's-length contract then the affiliate with the pipeline is a non-arm's-length contract.

MR. GEORGE BUTLER: Okay, and I had another question. Can you elaborate on why you excluded the exception for Furk approved tariffs? In situations where there was jurisdiction, Furk jurisdiction, why you excluded those in the calculation of transportation?

MS. DEBORAH GIBBS TSCHUDY: Well, again for most of our oil in the offshore there is not -- Furk has not asserted its jurisdiction over the pipeline. So you're talking about the onshore interstate pipelines. Basically, it's our belief and based on the feeling we got from the workshops, that people want their actual cost of transportation. We do not believe that Furk Tariffs accurately reflect actual cost of transportation.

MR. GEORGE BUTLER: You got the impression that the lessees wanted their actual cost of transportation.

MS. DEBORAH GIBBS TSCHUDY: Everything we heard from the workshops is that producers prefer to pay, deduct from the price the actual cost of transportation; and so retaining that philosophy, we did not believe that Furk Tariffs accurately reflect actual costs of transportation.

MR. GEORGE BUTLER: Is it possible for us to get the transcripts of those?

MS. DEBORAH GIBBS TSCHUDY: Yeah, we have minutes from those. Those are on the internet.

MR. BEN DILLON: I think for I P A A, Debbie, our record of such was in actual costs as compared to your

theoretical formulas is quite a different discussion.

MR. GEORGE BUTLER: Well, that's not the same for tariffs.

MS. DEBORAH GIBBS TSCHUDY: No, it's not. It's not related to the Furk Tariff question. I was just trying to lay the foundation. Our goal is to retain or to allow a deduction to the actual cost of transportation, and we don't believe that Furk Tariffs capture the actual cost of transportation.

MR. GEORGE BUTLER: And that's the reason you've eliminated that?

MS. DEBORAH GIBBS TSCHUDY: Well, for offshore. For most of the oil, we've eliminated it because Furk does not have jurisdiction over this pipeline.

MR. TOM WHITE: Well, they still call them

Furk tariffs. They still file them.

MS. DEBORAH GIBBS TSCHUDY: But that's all they do.

MR. TOM WHITE: I don't care. I'm not sure I would be speaking for the Federal Energy Regulatory Commission but there's a body of thought that says that they're going to reinstitute authority over that. Some people are pressing for it.

UNIDENTIFIED SPEAKER: What about when it gets onshore and moves from the onshore point to the market

center?

MS. DEBORAH GIBBS TSCHUDY: Are you asking is that then jurisdictional?

UNIDENTIFIED SPEAKER: Those are Furk lines.

MS. DEBORAH GIBBS TSCHUDY: But Furk has ruled in three different decisions that it's only then if the oil physically moves into another state did they assert jurisdiction. So as long as the movement is from offshore to an adjacent state and it remains in that state where it's refined, then they ruled that that's nonjurisdictional.

UNIDENTIFIED SPEAKER: Then it's going to be reset passed the state line.

MS. DEBORAH GIBBS TSCHUDY: Under the current regulations if you can demonstrate that the oil moves into interstate commerce, moves beyond the adjacent state, then we would accept the Furk Tariff; but under this proposed rule, in no case would we accept Furk tariffs. Good point. Don points out unless that is your actual out of pocket cost of transportation, unless you're a third party shipper through the line and that's what you're paying. It's only for non-arm's-length transportation that we don't allow tariffs.

Another question we have in the preamble was whether there are any comments regarding your ability to request an alternative location or quality differential if you can show that the one we calculate is unreasonable. Is that a good idea or not a good idea?

MR. GEORGE BUTLER: Have we got a snowball's chance?

MS. DEBORAH GIBBS TSCHUDY: Okay, we asked a lot of questions about whether or not we need the form. Is there anyone else that would comment on whether we need the 4415 or whether we can calculate on a case by case the differentials that those companies may need that don't have their own differentials?

MR. BOB TEETER: Bob Teeter with Coastal. I'm not a trader so I'm not speaking as an expert in this area but, I mean, the spot market prices are compiled by a private company who simply sits at a telephone and calls up some brokers and say, you know, what are your deals. Seems to me rather than burden the entire industry with filling out a form that most of us aren't going to use anyway, that somebody from the M M S could just make a few phone calls and find out what those differentials are.

MR. GEORGE BUTLER: Well, I have a comment on that. The purpose for a differential for location and quality should be to adjust whatever value you start with to market value at the lease. I think we all agree that that's the purpose to the extent that information available to the lessee does not capture all of that or to the extent that information that M M S has or to the extent that M M S'

methodology for calculating that differential does not reflect all of the elements which comprise the difference between where you start with value under your methodology, you know, to the extent that whatever that differential is does not arrive at a value at the lease. Then the major objective of the rule, which is to arrive at a royalty value at the lease, is not met; but it is completely inappropriate to eliminate trying to determine what that differential should be.

So we have problems with -- I would say that you are going to encounter problems with the form whether it actually captures that differential. You're going to encounter administrative burden associated with the form because of the way that you want to try to capture that information. You're going to have problems with your methodology for capturing that differential. So I just don't want you to get the impression that life would be great if you just eliminated the form because it's not. You know, there's problems with the form; there's huge problems with the form. You know that there's problems with your form, but you still have to arrive at a value at the lease; and throwing out the form and coming up with a higher value at the lease then the market value at the lease is inappropriate.

MS. DEBORAH GIBBS TSCHUDY: A few more questions about the form. What improvements could we make to

the form? Is there a way we could lessen the burden on the form and still get the information we need to these differentials for those companies that don't have them?

MS. PATSY BRAGG: 4415 is to capture aggregation point to market center location and quality differentials, is that correct?

MS. DEBORAH GIBBS TSCHUDY: Yes.

MS. PATSY BRAGG: Then would you look up for me 212(e), which is this quality adjustment. Is that also aggregation point to market center or lease to market center?

MS. DEBORAH GIBBS TSCHUDY: It's lease to aggregation point or market center, I believe.

MS. PATSY BRAGG: It says or market center.

MS. DEBORAH GIBBS TSCHUDY: Or market center because there maybe situations where companies actually transport their production to the market center; and there's a quality bank from the lease to the market center or the quality bank may only be from the lease to the aggregation point.

MS. PATSY BRAGG: So that you could use whatever your exchange amount is plus this quality differential under 212(b) or, alternatively, just 4415, or 4415 and 212(e).

MS. DEBORAH GIBBS TSCHUDY: You can't use both. In fact, there's language in the preamble that you cannot use both. You couldn't double dip the quality adjustment and get it one side of your differential and another time out of your quality bank. You have to use one or the other.

MS. PATSY BRAGG: So it would be either 4415 or your exchange agreement plus 212(e)?

MS. DEBORAH GIBBS TSCHUDY: You got it. Any other comments or questions on the form?

MR. LIN SMITH: Lin Smith, Barents Group. How are you going to address the issue of providing the kind of disaggregation you need for the quality and the location adjustments? If you get, let's say, just one 4415 for a particular segment or a small number of 4415 so you would have to classify it in ways that could end proposed differentials for individual transporters or shippers, how are you actually going to publish the data from the 4415?

MS. DEBORAH GIBBS TSCHUDY: Lin, the intent was to publish the information either annually through a Federal register notice or through a due payer letter, and then your question is what do we do if there's just one company that reports one exchange agreement between an aggregation point and a market center. What do we do about that being proprietary?

MR. LIN SMITH: Yes, but more specifically though, if you're going to disaggregate this for location and

quality differential, let's say, you're going to have a by sulfur content or by gravity, how are you going to do that? What would you envision actually being published?

MS. DEBORAH GIBBS TSCHUDY: Well, a rate per barrel for different ranges of quality or different ranges of sulfur content, if necessary.

MR. LIN SMITH: You would have a table that would have location and gravity for a market center to an aggregation point. You would be filling in all those cells in that table.

MS. DEBORAH GIBBS TSCHUDY: If they are separate differentials. Sometimes the exchange agreements don't break them out and the location and quality is one rate per barrel.

MR. DAVE HUBBARD: I just wanted to add, I don't think there would be a whole lot of cells to table. I say, I don't think there would be a table with a lot of cells in it. The extent that we can differentiate between general ranges of gravity, general levels of sulfur, we would do that. Hopefully, we wouldn't have a table that would have 10 or 12 different elements between a given market center and aggregation point.

MR. LIN SMITH: Okay, so I guess I'm trying to visualize what you would publish. Could you give, let's say, just a simple example of what might actually be displaced in

the Federal register for one market center to one aggregation point. What would go there? Let's say, just in a typical scenario, what would you publish?

MR. DAVE HUBBARD: Well, at the simplest level if you had a sweet oil at the index pricing point, a sweet oil that you're using as to compare it to that's being produced, you'd have one location differential and if the sweet was to sour, you'd have a second. Beyond that, I don't think we've thought about the levels of detail that would be in between.

MR. LIN SMITH: That's what is a little confusing to me, I'd say, about the 4415. As you start thinking about all the different market center to aggregation points, the combinations that you would have, how are you going to actually use this data to publish something in the Federal register and what would that look like? I'm confused when I think about how you're actually going to mix and match the data to come up with something that each user of the 4415 will take and apply.

MR. DAVE HUBBARD: And frankly, part of the answer to your question has to depend on the type of information we get in, the level and type of it. Until we see how much of a spread there might be in different exchanges, in terms of quality differences for the oil being traded at both ends of the exchange, you know. That's necessarily going to drive the results of our -- how many different differentials we have for different levels of quality.

MR. LIN SMITH: Right now you haven't tried to do audit data or anything else to try to come up with a prototype for this at all. You're just going to wait to see the data to figure out what you're going to do.

MR. DAVE HUBBARD: That's correct.

MS. DEBORAH GIBBS TSCHUDY: Other questions or comments on the form? Is there anyone else that would like to make a statement for the record? If not, we'll close at this point and thank you.

MR. DAVID SIMPSON: One other question if I may. David Simpson with Total. Earlier when we were talking about 206.102 and number two and number three, the cells are transferred to your affiliate or that affiliate of another affiliate, or under three you sell or transfer to another person under a non-arm's-length contract and that person or an affiliate of that person sells the oil under an arm's-length contract, you come back and say, no, that wasn't a non-arm's-length contract. I thought Don said that the burden of proof would be on the M M S to say, no, that's not a non-arm's-length contract; but then I go over to Section or Paragraph D and number one it says you must be able to demonstrate that a contract or exchange agreement is an

arm's-length contract. So I was a little bit confused as to where that burden may lay, or did I misinterpret what you said earlier, Don?

MR. DON SANT: Well, I mean, I think the burden that you have to provide for an arm's-length contract is first of all, that you're not an affiliate. So if your ownership is less than 10 percent --

MR. DAVID SIMPSON: Or to the other person.

MR. DON SANT: I'm not sure I understand.

MR. DAVID SIMPSON: Well, it says in there or another person. You sell or transfer to another person under a non-arm's-length contract. I'm not talking about an affiliate really. The question arose that if we said it was a non-arm's-length contract and you came back around and said no, that is not an arm's-length contract, I thought I heard you say that the burden would be on the M M S to prove that it wasn't a non-arm's-length contract; but I read later that the burden is, if I value oil under Paragraph A, which subpart three would be under there, that burden is on me if I'm selling to another person under what you deem to be a non-arm's-length contract.

MR. DON SANT: Well, we're going to ask you, give me the documentation that you don't own more than 10 percent of this company. I think that places, I mean -- we can't just come in and say that isn't a non-arm's-length

contract but certainly can ask you for the information of ownership in that; but if you can demonstrate that you're less than 10 percent, than it goes back on us, at least, to provide some other information why it is not an non-arm's-length contract.

MR. DAVID SIMPSON: It just seemed that, that language was kind of flipped on that. That the burden is on us to prove that it's a arm's-length contract not that it's up to you to show us that it's a non-arm's-length contract.

MR. DON SANT: Well, I read that your burden starts with giving us the data that shows what the ownership is.

MS. DEBORAH GIBBS TSCHUDY: Thank you very much for your comments and time.

(The hearing was then concluded.)

STATE OF TEXAS)
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COUNTY OF HARRIS)

I, Amanda L. Smothers, Certified Shorthand Reporter in and for the State of Texas, being neither related to nor employed by any persons present, and having no financial interest in the matter, hereby certify pursuant to the Texas Rules of Civil Procedure and/or agreement of persons present, to the following:

That the transcript taken on February 18, 1998, is a true record of the statements and comments made by the panel and the public;

That I was present at the time said record was made, and that I have transcribed same into typewritten form.

WITNESS MY SIGNATURE this day of , A.D., 1998.

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