PUBLIC COMMENTS ON PROPOSED FEDERAL CRUDE OIL VALUATION REGULATIONS

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I N D E X

WEDNESDAY, MARCH 11, 1998
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MR. CHRISTNACHT: My name is Peter Christnacht. I work with the Minerals Management Service in the Royalty Management Program, the economic valuation branch. I am an economist.

To my right is another economist in that same branch, David Domagala. I welcome all of you here today to Bakersfield.

This is the fourth in a series of five public meetings that is to be held on the Federal Crude Oil Valuation Proposal that came out in February of this last year. I think it was the 6th of February.

A couple of housekeeping items, for those of you who have not signed in yet, I think there are at least two of you, there is a sign-in sheet.

We have a court reporter here today as well. So I would ask you to whenever you speak, please identify your name and speak loudly enough that the court reporter can hear you.

I also told Tim, our court reporter, if he has difficulty hearing you, to please interrupt so that we can get this recorded for the record. It's important that we hear everyone's comments and get them clearly.

I have handouts up here which I'm going to go over briefly, which kind of talk about the evolution of the rule as well as some of the highlights of the current proposal and how it's changed since earlier additions.

Then I would like to ask people to ask for comments on the rule or for clarification, points of clarification on the rule. Dave and I will certainly be able to address those. And then we would get into the public comments that people might have.

So, at this point, if you do not have a handout, please make sure you get one. Does everybody have one that wants one? Please pass that back.

And rather that go over everything in detail, I'm just going to canvass the audience to see if everybody here would want me to go through the history of the details of how this thing evolved; if not, I'm going to do somewhat of an abbreviated rendition of this.

Since I have no one here who's intimately interested in the gory details, I'm just going to talk about how it started and where we are today.

We started this process back in 1995, the end of the year, and we asked for public comments on whether or not a revised crude oil valuation rule would be something that is needed in the industry. We asked for comments from states, from industry, and from the Indian tribes. At one point, this was also commingled with the Indian rule. That has since been bifurcated, and there's separate rulemaking going on for that, as you're probably aware.

We got comments back from the state saying that yes, they believe that posted prices were an obsolete method for valuing crude oil, and that we would be best served by moving beyond posted prices to some other system which incorporated or recognized premiums over postings, which seem to be operating in marketing for crude oil in much more pronounced, or much more voluminous types of sales than there had been previously.

So the majors who were embroiled, who are still, I think, embroiled in much litigation, requested that we delay the rule until the litigation that they are embroiled in was over. But we did not feel we could do that; so we decided to go ahead with the process, and invited industry, states, and everyone else's participation.

We published the first proposal about a year ago in January of last year. And some of the highlights of that rule we had -- we still retained arm's-length sales for true arm's-length sales. Those proceeds would be used to value that oil. For non-arm's-length sales, we changed that from going to an index pricing system. We initially started with NYMEX for the rest of the country, but here in California and Alaska, we rely on ANS -- Alaskan North Slope -- spot prices.

We then published a supplementary rule after the comment period. We received about 2600 pages of comments on that initial proposal. And then we made some revisions to that proposal in July of last year.

We then had some workshops in September after we got some more comments on that. But some of the changes, we took away a two-year purchase revision from the earlier January proposal, and that would have required all states -- excuse me -- would have required all purchasers who bought oil anywhere in the United States to go immediately to index.

The independents told us that that was too severe because there was a number of instances where they would have to purchase oil to run their leases, and they didn't feel they should be bumped up to index prices if they had no marketing capacity beyond the lease or selling to -- in the case of captive sellers, to be able to gain the types of proceeds that sophisticated marketing entities could garner for that oil.

Most of the requirements regarding misconduct for and marketing the oil are not changed from the earlier or from the 1988 rules, but the biggest change is that we move away from posted prices to index pricing, and that we do not have comparable sales in the early version. The most current version does return to some of those, and I'll get to those in a minute.

I'm going to skip ahead here and save a little time. Again, if you have any questions, you'll have ample opportunity to ask.

We did have workshops, as I mentioned. We also had two public meetings for the first rendition in Houston, and one in Denver; they were well attended. We then had workshops in Denver, Houston, Washington, here in Bakersfield, and Casper last fall, where we asked for comments on a supplementary rule, which asked for comments on several other proposals that industry had given us through the initial comment period, and we published those in the Federal Register, and then came out here and several other places asking for those comments. Twenty-eight entities commented on those five alternatives.

Again, this year, we published the second supplementary proposal, which is now the proposal we're talking about today. If you need a copy of that, there's one up here. Hopefully, all of you have had a chance to look at that, at least enough to be able to talk about it today.

Again, there are five different meetings. This is the fourth meeting, public meeting, on that, where we are asking for comments. Tomorrow will be the last one in Casper. We had one in Houston, Denver, and Washington earlier in the month, late last month.

The major principles of this rule that we were trying to implement are as follows: Royalty must be based on perceived value of production at the lease. We tried to retain arm's-length contracts; royalties should be based on gross proceeds. For other than arm's-length contracts, index pricing would be the best measure of value. Lessee, we believe, continues to have a duty to market at no cost to the lessor. And customized regulations for unique producing areas are preferable to "one size fits all."

You'll notice in this proposal, we have a separate Rocky Mountain states valuation system from the Gulf region and from ANS for California, whereas, before, we only had the two, one for the rest of the country versus California and Alaska.

Gross proceeds are arm's-length, under an arm's-length contract to determine value unless the contract doesn't reflect total consideration.

This is not a change from the '88 rule. Value is not reasonable due to misconduct, again no change there. Oil disposed under an exchange agreement accept one or more arm's-length exchange agreements, then value would be based on arm's-length sale after exchanges.

One of the reasons we made a change from the earlier proposal on that is, we heard from a number of producers from the Gulf who said they needed to enter into multiple changes to get their oil to shore if they are going over several different pipeline systems.

Oil disposed under noncompetitive crude oil calls would not be a value under arm's-length contract sales.

And the reason we did is that we were told by a number of producers and states who looked at some of these contracts that initially we had a proposal where any crude oil call would send you to index pricing, but a number of these contracts are not exercised, or the calls are not exercised; so we did not necessarily want to throw those payers to index pricing if they were actually getting an arm's-length contract, and the crude oil call was not exercised.

I won't spend much time on the Rocky Mountain lease unless anybody wants me to, but we have a separate series of benchmarks for the Rocky Mountains. The State of Wyoming as well as some of the other states, North Dakota, expressed some reservation to going to an index pricing situation because the Guernsey spot price, they believe, was very thinly traded. They felt that we could come up with benchmarks that could work there. So we tried to accommodate that desire.

The first benchmark in the Rocky Mountains would be ANS-approved tendering programs. Several companies such as Conoco, Texaco, have a tendering program. If it would meet the criteria we lay out in the rule, that would be the first acceptable benchmark that would be used for valuing oil in the Rocky Mountains.

The weighted average of the lessee/affiliate's arm's-length sales and purchases in the field area would be the second benchmark if the first one did not qualify.

And then, third, we would go to non-index pricing, if neither of those worked for valuing non-arm's-length production in the Rocky Mountains.

Fourth, if the company could establish that NYMEX wouldn't work, then we would enter into a negotiation with that company to value oil in the Rocky Mountains. That would be acceptable under the rest of our criteria.

Oil not sold at arm's-length in California and Alaska, ANS continues to be -- has been from the beginning -- the spot price that we feel would be appropriate for that production. It would be adjusted for location and quality.

For the rest of the country, spot prices that are nearest the market center, Midland, Empire, Saint James, the Gulf area, the Continent area, and that would be adjusted for location and quality, again.

Okay. Location and quality adjustments for market centers to aggregation points, this is a major change from the first addition of the rule. Before, we were asking for all exchange agreements to be submitted to MMS, and we would come up with a series of notes to come together and publish a data base that people could use to value their oil.

We believe that actual rates that the companies use to transport that oil would be a better way to go; it would save administratively for both MMS and industry. We have reduced the number of aggregation points significantly by at least a third. And we also have qualified that the only types of exchanges that you would need to submit would be from aggregation points to market center exchanges. So all the other exchanges that might be from the lease to market center, or lease to aggregation point, are no longer required to be filed. We feel that would save significantly on everyone burdenwise, as well.

Actual cost of transportation and quality adjustments based on pipeline quality banks. We tried to utilize what industry uses to the best of our ability so that, again, we would minimize the amount of burden on everyone.

Allowances from lease to aggregation points to actual cost are not available to lessee. That is something we need to talk about before we leave, hopefully. Whether or not there's some belief on the part of some people that we might not need to publish the 4415 or require that form would be used if the people that are going to need to use it actually have their own costs, and we can talk about that a little bit later.

As I already said, the 4415 form will be required to be filed, I think, by less people. It's been simplified. We feel like we've improved the instructions. And there is certainly less data elements than the earlier form.

One other thing I would like to get some comments on if I could, is the timing of index prices.

We heard from a number of people that though industry practices are different than what we had had in the initial January 24th proposal, i.e., that the amount of time that lagged, if you will, from when prices were reported in either spot or the NYMEX publications would coincide better if we went to the actual month of production as listed in the approved MMS publications, though the publications would be things like Platt's, Argus, Bloomberg's, there's a number of pricing services which I believe will qualify.

We don't want to unnecessarily burden any of those or put any of them out of business because we don't accept those. But we can talk about that a little bit later when we get to that part of the discussion.

And also it would eliminate proposed changes for valuing oil taken in-kind. We separated the RIK part of this rule from what was initially in the January 24th, '97 proposal. That's a separate initiative.

Again, we're here to hear your comments on concerns, clarify what's in the rule today. We're really not going to address our efforts on RIK. We do have a separate program which is looking into the feasibility of taking oil and gas in-kind. There are two pilot programs starting up; one will be in Wyoming this fall and the other one in the Gulf sometime next year.

Today we're talking about assuming that we're going to continue to take our oil in value, what would be the best way to ensure that the public gets a fair market pricing, and that the industry pays a fair market price.

The last two charts here are just for your clarification, edification, on where our Federal production arm is and how the rule we believe will affect the various parties involved. It isn't -- the pie chart, the second-to-the-last page -- difficult to read. The Gulf OCS is the large part of that pie chart; about three-quarters of the chart comes from OCS Gulf.

California, 15 percent, includes onshore and offshore. I think there is a significant portion, higher portion from offshore. Unfortunately, I don't have those numbers with me. Wyoming, New Mexico, and the rest of the Rocky Mountains account for the rest of that, other than what might be two-tenths of a percent, the little bit of oil we get from some other, very small, Federal production.

When we did this study, or when we undertook the rule, we had to do an economic impact study. And the last page kind of summarizes where we feel who the affected players are in this.

What we did is we looked at who owns a refinery, which companies have marketing arms that market their oil, and which companies we believe would be paying on a gross proceeds based on the fact they do not have a marketing arm, or they do have a marketing arm but don't have a refinery; therefore, they would be selling outright under this rule. That's kind of a breakdown by region of who would be paying where and in what region by percentages. That's a rough cut at it, I guess is a good way to characterize that.

At this time, I would be happy to answer any questions or clarifications about major provisions in the rule, and then we can move into public comments after that, if you like.

Suzanne?

SUZANNE NOBLE: Suzanne Noble with WSPA, which stands for Western States Petroleum Association.

As we stated last time, we're pleased with MMS's willingness to bring the rulemaking to California into Bakersfield, more specifically MMS's willingness to include California and our industry in the rulemaking process as you did in October with the previous workshop. But prior to that, the workshops, California wasn't included; so we would like to see that continue, not only with this issue, but issues in the future.

Basically, the comments I'm going to make for WSPA are going to be basically confronting the West Coast Federal issues and, of course, ANS spot prices.

As we all know, MMS has retained their previous proposal, which includes the Alaska North Slope prices for California and Alaska. And WSPA has submitted extensive comments, and gone to great lengths to explain why ANS is flawed and unsatisfactory for using as a valuation method for California oil product.

At this time, we're really not pleased with MMS's response to our comments and to your lack of consideration for our concerns.

We do believe or have believed that MMS did have a willingness, does have a willingness to work with the California stakeholders, and really evaluate our concerns, and look for solutions. And we don't believe that's been accomplished.

But we are here today to, once again, listen. I'm not going to go through all the comments that we've made two or three times already. I might pull two or three out. But basically, we didn't see much change in your rule specific to California. Therefore, our concerns are still relevant.

If I can add to that, I noticed in your handout here that this comment period, unlike the others, was only a forty-five-day period, and usually the requirement is a sixty-day period. I understand you got an executive order to make it a forty-five-day period as opposed to a sixty.

I'm a little curious. I think you stated in the rule that you went with the forty-five days because you had already reopened and basically extended and reopened in previous rulings with this issue. At this time, because that had already been done, you weren't going to go for the whole sixty days in this round.

Does that mean that this supplementary portion of the rule is any less important than the others, or is it that because certain concerns and comments when incorporated, there's really not as much to review as there has been in the past?

MR. CHRISTNACHT: I can only comment on what my understanding of what the requirements are.

Initially, we are required to have a sixty-day comment period for the first initial proposal, and then after that, customarily, we are required to have a thirty-day comment period for supplemental or further proposed rulemaking. We decided to have a forty-five-day period because we believe that it was significant enough that we would increase over the requirement to forty-five days; however, we believe that this issue has been going on, it's been going on for over two years. We also believe that we owe it to the public to come with a -- try to speed up the process as much as is prudent to do.

SUZANNE NOBLE: Hasn't it been in the past proposals that you have given sixty days as opposed to thirty? I'm just a little curious why that changed.

MR. CHRISTNACHT: If you remember from the January 24th proposal, we initially put out a sixty-day proposal. We extended that twice to at least 120 days because of industry's comments.

If you look at the comments that we've gotten, they have commensurately gotten less. I think people understand the issue better now. It seems to us, at least, to be appropriate to not wait sixty days in this case.

SUZANNE NOBLE: Okay. I know that, I think, DOI, it's fair to say that DOI has received a record number of comments on this proposed rule, probably more than they have in the past, like 3,000 or 2600 comments that you have received.

I think it would be a fair bet to say that more than half of these comments have been in concern to what has been proposed so far. And due to not much change in this particular supplementary proposal, I just -- we just see that these comments are being ignored in large volumes. To have that many people concerned with this issue, and to make no changes, it just seems a little odd.

MR. CHRISTNACHT: Well, if I might comment on that. Many of the comments that we received were repetitive. In other words, many of the respondents said the same thing. I will also testify that in that 3,000 pages, we had at least seven versions of the Barents' report, which was in and of itself, sixty-some pages or so.

So it's not as if all those comments were different. And we were able to categorize a lot of those comments.

We have looked at all the comments. We will in the final version of the rulemaking go through that process. We have been advised by our solicitor's department that for the entirety -- rather than go through each time summarizing all the comments, that we will address comments that in their entirety we can do that with the final version of the rule. And we relied on our solicitor's department for that.

DAVID GILBERT: David Gilbert, California Independent Petroleum Association.

I'm curious as to why you did not -- you said you believed that the public's interest would not be well-served by delaying this implementation or moving forward on proposing this rule for various reasons. And you haven't really explained what those reasons were. Because Carolyn Maloney and Barbara Boxer got up on their soapbox and said the oil companies are screwing us? Or exactly what was your reason for not delaying this proposed rule until the lawsuits were settled?

MR. CHRISTNACHT: I can't comment on what impact Carolyn Maloney or Barbara Boxer had on the rule.

What I will comment on is, we have been, as I say, involved in this process for over two years; for us to wait until industry, one, gets out of litigation, I think would be irresponsible. Because we certainly have all the way along invited industry to participate in this rulemaking. And it really wasn't until after the first proposal was published that we got very much participation at all.

We also have clients in the states that get 50 percent of our revenues for onshore oil. We have their interests to look out for as well. So I don't know if you need to say we are in the middle. We feel a responsibility to all the public on this, not just to industry or to the people who are against the rule. It certainly --

DAVID GILBERT: Has anyone from the public complained that they feel like they are not getting an adequate amount of royalty payment to the Federal government?

MR. CHRISTNACHT: I'm sorry. What was the question, David?

DAVID GILBERT: Has anyone from the public raised the issue --

MR. CHRISTNACHT: Yes, they have.

DAVID GILBERT: -- that they are getting an underpayment OF royalties.

MR. CHRISTNACHT: There have been public interest groups that --

DAVID GILBERT: Public interest groups?

MR. CHRISTNACHT: That's correct.

DAVID GILBERT: But not the public in general? Like Ralph Nader has nothing to say. I don't necessarily say that Ralph Nader speaks for the public.

MR. CHRISTNACHT: I'm not going to comment on what Ralph Nader speaks for.

DAVID GILBERT: You say "the public"; I'm just curious, in whose interest is it? I mean, what public are you protecting?

MR. CHRISTNACHT: The taxpayers of the United States.

DAVID GILBERT: What taxpayers have raised this issue? This is based on the purported belief that there has been some type of price manipulation. I think, if anything, right now, with the downturn in prices, it demonstrates that no company can manipulate the market in this country. If any manipulation is occurring, it's not by individual companies, it's by companies that belong to OPEC.

And before you move forward on trying to make operators pay some indexed royalty payment based upon what they don't receive, it, to me, just is incredible that you believe that somehow you can set a price based on ANS, and that you can adjust it, and all of a sudden, that's going to be the market value for Kern River crude. Why don't you use WTI? You can pick anything out of the air, and you're not going to get what the market value for that crude is unless you are getting it right at that field. That's the only way to establish market value.

If you can't establish market value that way, then you should take it in-kind.

MR. CHRISTNACHT: We have found through a number of our audits, through our experience in the -- well, the California interagency task force has looked at a number of documents that suggest that there are oil exchanges between the field and with forced spot prices.

So, in our view, we see where a number of companies are able to realize higher revenues by making exchanges, which we are not getting reported as the market value for that oil.

And posted prices, the fact that you have a T-plus market, you have a number of exchanges, where because under our rules, they are paying under-posted prices, we do not believe that the full value for royalty purposes is being realized in all cases.

Now, if you have suggestions about what the adjustments to the index prices are, those would be things that we would like to hear about in your written comments as well as today.

DAVID GILBERT: I think our suggestion is to look at where it comes from, and base it on what the person gets, regardless whether they have a marketing arm or not. Whatever they sell their crude for is what you should be paying a royalty on.

MR. CHRISTNACHT: Well, we found that most of our crude oil is not disposed through arm's-length sales. And that through those exchanges companies are able to move that oil away from the lease, either sell it outright, or there's no actual arm's-length sale that we can pin a value to.

So what we are trying to do is come up with a method of valuing that oil, which realizes what the true market value for that oil is.

Suzanne.

SUZANNE NOBLE: Suzanne Noble with WSPA.

I saw here in your handout, I can't find it now, it said the reason this has all started was because of "misconduct," quote, unquote.

So would you say this rulemaking is a response to this misconduct? If so, can you give me a little more of a definition as to misconduct?

MR. CHRISTNACHT: Well, I would not characterize everybody in the oil industry as operating under misconduct. No, I would not say that. There has been some instances in the past where certainly when the task force looked at the instance in California where we did not believe that the true market value of oil was necessarily being realized because of the mechanism of exchange agreements, and there was no record of a true arm's-length sale.

Since we saw a number of exchanges, outright exchanges, for crude such as ANS for California indigenous crude, we believe that in that case, that would be -- a better mechanism for realizing that would be to get the value of that ANS price for the oil that was exchanged. That would be one example.

Any other comments?

DAVID GILBERT: David Gilbert with CIPA.

If you're having an exchange on some leases, why don't you base the exchange price for what you believe develops rules that reflect market value? I don't know how you can do that. That really amazes me that you can say that.

If you can base it on that general area, don't base it on ANS. If you have stuff from Midway Sunset that's being exchanged for other crude, figure out the prices for Midway Sunset crude and assess it that way. Don't have ANS come in and have some crazy index that's going to make companies pay more than what they actually received for that crude.

MR. CHRISTNACHT: If the companies exchange oil under the current iteration of this rule, that oil is sold arm's-length outright, that would be the market value of that oil that we would recognize the gross proceeds for that oil.

DAVID GILBERT: You just said your concerns with respect to exchanges, that people are exchanging California heavy for ANS.

MR. CHRISTNACHT: In not all cases are they doing that. That's certainly one of the possibilities.

But when oil is not sold arm's-length outright when it is moved to a refinery, we need to find a mechanism which -- we believe we would like to look at a transparent price, which spot prices provide.

If the field -- if there was a mechanism in the field which provided price transparency, I don't believe that we would be where we are today. But there does not, in our view, seem to be that type of a situation in very many fields where different payers can see what other payers are paying for their oil, or purchasing, or selling their oil for.

Suzanne.

SUZANNE NOBLE: Suzanne Noble with WSPA.

The one change that I did see in your revised -- your supplementary proposal was that you did convert plain English, which we appreciate, and you also renumbered a few sections. But we didn't find much more for California's ANS proposal that much had changed.

I'm not exactly sure what you want us to comment on, but I have a few points I just want to bring up that have probably been brought up, again; I want to make sure are on record.

The first one is, I couldn't find it in the rule. Maybe you could point it out to me. We mentioned in the past that we are concerned that this proposed rulemaking is going to affect some of the recent DOI incentives for royalty reduction, especially here in California. For example, the heavy-oil royalty relief and the strip-oil royalty relief.

Just two weeks ago, Dave and I were invited by Armstrong and Senator -- in New Mexico to participate in giving speeches at a press conference in which strip oil would be reissued.

I couldn't find any language within the proposed rule that addresses the royalty rate reductions, and how this rulemaking might affect that. If it's in there, perhaps you could point it out to me.

MR. CHRISTNACHT: There is nothing in this version of the rule which would address royalty rate reduction. However, the royalty rate reduction would be the mechanism, in my understanding, as to how relief would be accomplished.

So I know with stripper wells we have reduced the actual rate percentage that we would require you to pay under these rules. That would be where I think the reduction would be made.

SUZANNE NOBLE: Well, I would like to request that we would feel much more comfortable if a statement or some type of language, just a simple statement, you've told us in the past that this isn't going to affect the royalty rate reductions, those two in particular. I would like to see something in writing. If it could be put into the rule, I would like to request that.

MR. CHRISTNACHT: I'm a little confused as to what it is you would like.

SUZANNE NOBLE: Well, you say it is not going to affect the royalty rate reduction initiatives, using Alaskan North Slope for California. I'm happy to hear that, but I would like to see it.

MR. DOMAGALA: You can put that in your written comments as well.

SUZANNE NOBLE: We have put that in our written comments as well.

MR. DOMAGALA: Thanks.

SUZANNE NOBLE: And also verbally suggested it, or requested it, at the other workshops. I just -- you seem to agree that it's not going to affect, and we're happy to hear that, but I just wanted to ask for a sentence or two within the rule.

BRIAN McMAHON: Brian McMahon, City of Long Beach, State of California.

As you are probably aware, since you looked at the documents which were produced to us by the oil companies in California, heavy crude oil in California tends to be more depressed, more underpriced historically than light crude oils. And the oil company documents explicitly state that. All of the major oil companies explicitly state that.

To my mind, it would be shocking to somehow give a further reduction for the heavy production in California as if somehow it was required in order to make a fair price for heavy crude. In fact, heavy crude is the most underpriced crude in California, and it's precisely to address that concern I think the ANS pricing mechanism does so with appropriate transportation, and with appropriate quality adjustments.

And I would like to make a couple other comments about what's been said.

In fact, I know CIPA members who have had to move their crude to Utah by all sorts of means, including trucks, in order to get a fair price for their crude.

CIPA members have historically -- and this goes back to the early 1970s, to the present, complained about underpricing of crude oil in California, that they are locked into selling their crude at the lease to pipeline owners.

And so it seems to me CIPA should be in favor of a mechanism which would attempt to raise the price of California indigenous crude oil.

DAVID GILBERT: David Gilbert, CIPA.

For one, CIPA wasn't even around in the early '70s; so they haven't complained since the early '70s.

Number two, there have been a number of issues with respect to why the heavy crude has been devalued. There was the ANS oil being forced onto the market. Heavy crude, yes, it was. We have a DOI study that shows ANS crude was being forced to the West Coast. That's why they lifted the ban on it, so they could export ANS crude.

Also, heavy crude costs more to produce. It cannot be refined into the highly-profitable product as easily as the light crude can. So there is a big price differential. The price differential of WTI has been closing lately; now it's huge.

So there is nothing that -- and the fact that most places outside the West Coast don't have the refining capabilities to handle the amount of heavy crude that's been produced.

That in no way means that there's some suppression of the price. That is the market for that crude in this area.

MR. McMAHON: I suppose if you haven't seen the oil company documents, it's possible to come to that conclusion. Once you do, the oil companies say that the most valuable crude in the United States is California heavy crude oil. Without question, each one of them does.

The cost of refining the heavy crude in California with the modern refineries does not account for the low pricing in California. The profit margin is bigger here than it is anywhere else in the country.

GREG MEISINGER: Greg Meisinger with Air Energy.

I would like to go back and maybe augment some of the -- or one of the comments that Suzanne Noble made, and that's regarding the royalty reduction.

Not only are we concerned about the stripper-well royalty reductions and the heavy oil reduction, but also another thing that had been brought up in our previous workshops in Bakersfield was for those royalty reductions where there are existing royalty reduction agreements that are based on net proceeds. And we are very concerned about how net proceeds fit into this proposed rulemaking.

The issue being that in those negotiations, as I'm sure you're well aware, the operator basically opens up the books with the MMS. The MMS has ample opportunity to question and probe and push, and then the two parties enter into a contractual arrangement which represents the value that is required by the operator to continue to produce that oil with a reasonable rate of return. If that reasonable rate of return, based on net proceeds, is not sufficient, the operator then has no alternative but to surrender the lease, which then does no good or has no benefit to the people of the United States or to that operator. I mean, it's lost revenue.

In addition to that, I know that the MMS has been working on start-of-life royalty relief for some of those properties, especially offshore, that would not be economical to even initially invest capital until -- at the current royalty rates.

Again, the same situation presents itself where the MMS has ample opportunity to investigate the true value of crude and the reasonableness of net proceeds before they enter into that contractual agreement between the two parties.

And our issue here is that that level of scrutiny when you enter into specific contractual agreements with an operator, provided they have ample opportunity for the MMS to protect the interests of the people of the United States, that we're very concerned about how this blanket type of indexing scheme fits into net proceeds.

MR. CHRISTNACHT: Suzanne.

SUZANNE NOBLE: Suzanne Noble of WSPA.

Another point or question I have from your handout is, you talk about MMS has approved tendering programs basically in the Rocky Mountain Area. I don't recall the information in the proposed rule when I went through it, which was rather quickly. But is it being proposed just for the Rocky Mountain Area? And if so, why is it restricted just to that area?

MR. CHRISTNACHT: The reason why it was proposed only for the Rocky Mountain Area was that the comments in that area's states, and mainly the states who are the ones who came to the table in the workshop, and the IPAA, also for industry, really believe that there was agreement with both the states and with industry there that in that circumstance or in that area, the spot price was very thinly traded at Guernsey, and that they would feel more comfortable with this system that we came up with where we had benchmarks such as tendering and arm's-length sales and purchases in the field by the operator.

We had a number of different proposals that came up that ultimately were withdrawn by the IPAA and others within the industry because they were unworkable; they saw that they would not work there.

But it was felt that in both the Gulf market and in California, you did have a transparent price indicator, i.e., ANS and California and the other spot prices in the Gulf area where you did have a market-determined price with a good amount of liquidity that could be used as an indicator to start. And that's why in the Rocky Mountains it was not felt that the Guernsey spot price gave you that.

SUZANNE NOBLE: Also, in your handout on the next page, back to California and Alaska and ANS spot pricing, and I also do recall this in the rule, you talked about that you want to propose ANS for California, of course, with adjustments for location and quality.

I would like you to elaborate a little bit on how you're going to make adjustments for quality. I didn't think that was explained within the rule. And if you can explain it here today, maybe consider adding some more specifics to that within the rule.

MR. CHRISTNACHT: What we proposed to do for quality adjustments would be to use market determined -- to the best of our ability, market-determined quality adjustments such as pipeline gravity banks, quality banks, in the case of sulfur, to come up with rates that would adjust off of ANS as the benchmark crude, arm's-length prices. And we would also allow for the cost of transporting, the actual cost of transporting from the lease to the refining center in that case as well.

So that's the methodology we were proposing. And whatever the actual costs of the company are to move that oil, if they are moving it from the Midway Sunset field down to Los Angeles, whatever the actual rates that they are charged or paying, those would be deductible off of the ANS price as well as any quality adjustments that are recognized. We will come up with a system based on the pipelines in the area.

GREG MEISINGER: Greg Meisinger with AERA.

Again, just going on Suzanne's comment, in this supplemental rulemaking, there is enough language in there that you could start to get an idea of where the MMS was coming from with regard to transportation. However, there was no detail whatsoever on the quality adjustment methodology.

And I know that WSPA has brought this issue up before; it's very difficult to provide any substantive comments on the ANS index without some type of detailed discussion on the actual methodology that would be used, would be proposed to be used, for quality adjustments.

A fear is -- well, a fear and a question -- is that after this supplemental rulemaking, the fear is that there would have to be another rulemaking simply to develop the methodology for quality adjustments.

And I guess what I would like to know is, is MMS proposing that an additional rulemaking for quality adjustments to implement this program is going to occur in the public forum, or is it MMS's intent to have a public forum for the index methodology, and then internal type of policy directive on how to develop quality adjustments?

MR. CHRISTNACHT: I don't believe I can answer that question today, as to what the intended --

GREG MEISINGER: I guess on behalf of WSPA, that is a question we would like to have addressed --

SUZANNE NOBLE: Absolutely.

GREG MEISINGER: -- prior to the close of this rulemaking. We don't know what we're commenting on.

MR. CHRISTNACHT: Okay.

SAM VAN VACTOR: Yes, I'm Sam Van Vactor from Economic Insight. I just have a series of questions about the quality and adjustments, assuming you already use ANS as an index price. I'll just throw out each question. If you have an answer today, I would like to hear it.

The first is, that North Slope oil is going to be declining over the next few years, as we all know, and there's already some concern that the number of spot transactions aren't adequate to get a reliable base for spot pricing.

Do you have a comment on that?

MR. CHRISTNACHT: The rule allows for an adjustment to be made if it's determined by MMS and industry that ANS becomes a thinly-traded commodity. And there are provisions in the rule which will allow us to come back to the table and determine a methodology that would be workable. So for the foreseeable future, we would anticipate it would be ANS.

SAM VAN VACTOR: The second question, the quality of ANS itself, which in the last five or six years has changed somewhat as more and more natural gas liquids have been added to the mix up there; so that what you're getting is an increase in gravity, and as NGL's are added in and mixed with the crude oil, you don't necessarily get an increase in quality, you get an increase in gravity.

So that using anti-price gravity differentials from pipelines, or whatever, may be wholly inappropriate for whatever the mix of crude oil coming off of the North Slope is. And it's a dynamic thing because we don't know what proportion of heavy crude oils would be mixed in with the NGL's; so you don't really know what kind of stream mix you're going to get.

Clearly, it will be changing. So what would you propose to do about that?

MR. CHRISTNACHT: Again, I think we would rely on the market to take care of that difference.

If it's determined that ANS becomes less desirable for whatever reason, we would expect that the spot price would reflect that change in demand or desirability, and that the difference between ANS would -- the margin, if you will, would narrow.

SAM VAN VACTOR: In other words, the quality differential between California crude oils and ANS would be changing as different qualities of the crude oils being compared by change, and that quality comparison could be something other than just a gravity differential.

MR. CHRISTNACHT: Well, certainly the spot price of

ANS, one would in a competitive market expect that it would fluctuate if it backs less desirable relative to California crudes, then I believe that the price adjustment, there would be a narrowing that of gap.

SAM VAN VACTOR: Yeah, but how are you going to tell if you're only indexing against ANS and you're using gravity differentials off of the pipelines, how are you going to tell whether or not how you got this quality?

MR. CHRISTNACHT: Are you suggesting there would be no adjustments made between the pipeline companies?

SAM VAN VACTOR: Well, the pipeline gravity differentials will be based on California crude oils, which presumably will not be changing, and not on ANS.

MR. CHRISTNACHT: But relative to ANS, one might expect that if California crude becomes more desirable, that you would have -- the pipeline companies will see a need to make those adjustments.

SAM VAN VACTOR: Let me back up and make sure I'm clear.

You got a crude oil pipeline, so the All America Pipeline is shipping California crude oil, and it decides for whatever reason the gravity differential should be twenty cents. But that's for California crude oils.

Now, if the MMS is going to be using that twenty cents per degree to do a differential off of ANS indexes in order to get a California proxy or index, but the value of ANS is changing relative to California crude oils, you're not going to pick that up in using the All America Pipeline gravity differential.

MR. CHRISTNACHT: I would encourage you to write this out in detail, what your concerns are, so we can address it.

SAM VAN VACTOR: Okay.

MR. CHRISTNACHT: I'm not prepared to really get into that analysis right now.

SAM VAN VACTOR: The other point I have is that at least with regard to Reuters and Dow Jones, which are the two sources for spot price information that BP used to determine its contract price for ANS.

Those prices are collected across the whole pad five, could be the Y, could be Puget Sound, probably a preponderance of California refinery centers also. The bulk of the transactions may be in California, but sometimes they may not be, depends upon, of course, what's going on in the spot market.

Do you expect that collecting price information, for example, basing what refiners are willing to pay for ANS and Puget Sound, how does that relate to what refiners are willing to pay for California crude oils in California? Is that a reliable indicator of value?

MR. CHRISTNACHT: I think -- I'm not exactly sure what it is you're asking regarding the -- you're talking about Alaska's royalty program, or --

SAM VAN VACTOR: Right. No. You're using an ANS base price in which to value California crude oils; that's your proposal. And the ANS price you're using is one that reflects not only what California refiners are willing to pay for it, because it's a mix of all these transactions, it also reflects what Puget Sound refiners are willing to pay for it, and all the rest.

But those are submarkets within the pad five market, price differences, there are price differences there. Circumstances vary, as you well know; you have a refinery by Puget Sound that doesn't reflect California prices, all kinds of things that can happen. So you may get an index base that is not reflective of two market values of crude oil as a whole for California. It may reflect Puget Sound and not California for that particular period of time, a week, or two weeks, or a month.

Do you -- and my question is: Do you plan to take account of those kinds?

MR. CHRISTNACHT: We certainly would invite you to detail those concerns.

SAM VAN VACTOR: Okay.

Another question I have has to do with -- this relates in part to the analogy that I used about the fact that ANS -- the quality of ANS may be changing, but there's also -- it's generally thought throughout the world, this is not the U.S. industry -- that you can do gravity differentials in terms of price valuations, value differentials for a family of crude oils, for an adjacent group of crude oils. But when you go across families of crude oils, it's not a valid comparison.

I think most refinery engineers believe that ANS is distinctly different from California. So if you have an ANS 27-degree crude oil, and the California 27-degree crude oil in the same place at the same point in time, both going to the same refiner or groups of refiners, they may go for very different market values in an objective, competitive circumstance. One may be of better quality than the other.

Is that going to be a part of your procedure in doing the quality valuation, the quality difference?

MR. CHRISTNACHT: I'll have to ask you to detail those concerns --

SAM VAN VACTOR: Okay.

MR. CHRISTNACHT: -- in written comments.

MR. McMAHON: Can I make a comment on the last one?

MR. CHRISTNACHT: Uh-huh.

MR. McMAHON: The oil company documents that compare Ventura Avenue with ANS explicitly say they are equal refinery value over time, and Ventura Avenue is 28 degrees, 29 degrees.

MR. CHRISTNACHT: Very close in gravity and sulfur contents.

MR. McMAHON: And I don't know what the basis of saying most refiners agree, the documents don't agree that they are different.

SAM VAN VACTOR: Just to further comment. I think the refining quality of the two crude oils are different. And you know, the extent to which that is reflected in value is a determination that is individual to the refinery.

And, I mean, I think that my experience has been that you do observe, you certainly observe in spot price data a significant premium being paid for ANS consistent over the years over, say, Line 63. With respect to Ventura crude oils, I don't have an objective source to do a price comparison, so I don't know.

But you can take two spot price series, Telerate or from Reuters, either one, and what you do tend to see over time, you see a lot of fluctuation, and Line 63 itself is a complicated crude oil screening because it has a bunch of crude oils in it. But you do tend to see, generally speaking, North Slope oil commands a premium thirty, forty, fifty cents on average. I think you would agree with that. That's an established fact, and it's a fairly objective one.

MR. McMAHON: Two comments on that.

One is, that is the reason why we need ANS because of the problems with getting a competitive price for California crude oils.

Number two, I think everyone would agree that Line 63 spot sales are very thin, and to determine a market value of California crude based on ANS spot prices just doesn't work. I should say Line 63 spot prices doesn't work.

MR. CHRISTNACHT: Suzanne.

SUZANNE NOBLE: Suzanne Noble with WSPA.

I kind of have more a "just for my own personal knowledge" question.

In the rule in the supplementary proposal on the second page, last go-around you had offered five alternatives, and we commented on those. And just for my own understanding on the rule procedure here, it states, I guess it's the third paragraph on the second page, and I'll read it aloud.

It states, "However, because we are still in deliberative process in this rulemaking, MMS is not responding to the individual comments made on the five alternatives or on the previous proposals. Once MMS decides on its framework for a final rule, we intend to thoroughly respond to all comments received. For this reason, it is not necessary for commenters to resubmit earlier comments."

Can you elaborate on that? What exactly does that mean in the process in how we're going to proceed in this?

MR. CHRISTNACHT: Okay. I will defer to our solicitor's department. We consulted with them in terms of how to best handle that workload. They advised us that it would be appropriate for us to do it in the manner which we have done.

SUZANNE NOBLE: I'm not questioning what you've done so far. I'm just asking, within here you don't have responses to our comments on the five alternatives you proposed last time, necessarily.

So it states that possibly in your final rulemaking, you'll talk more about our comments on these five alternatives.

Am I to assume that you don't want to use any of our comments, or you don't want to incorporate any of these alternatives in the proposal, and you'll discuss that in the final rulemaking? Because I wouldn't think you would throw something if you're going to use one of these alternatives or use one of those comments that we have on these alternatives in final, quote, unquote, "rulemaking"; that you would do it at that time.

MR. CHRISTNACHT: We have used a number of comments from the workshop. If you look at the evolution of this rule, you'll see that, for instance, the Rocky Mountain idea came out of the workshop. Several of the other ideas such as changing from using primarily NYMEX in Mid-continent regions to using spot prices to try to simplify that. The index pricing system came out of the workshop.

I don't know that it's fair to say that we haven't --

MR. DOMAGALA: If you would continue to read down there, you'll see the alternatives and general statements of the comments that we received.

SUZANNE NOBLE: Yeah, I see the summary of public comments.

MR. DOMAGALA: Right. Those are the five.

SUZANNE NOBLE: I thought from this paragraph you were going to comment more specifically on individual comments on these five alternatives in the future. Is that what that statement says, what I just read?

MR. CHRISTNACHT: It is our intention in the final rulemaking to go through a lengthy discourse of replying to each of the comments that were submitted through the process. We did not feel at this time, according to our solicitors, that it was necessary for us to do it at this particular stage in the rulemaking.

SUZANNE NOBLE: I assumed when I just recently got this in February, that that's what a lot of this would be on. But that was excluded; so I just was kind of curious how that was going to be handled in the future.

MR. CHRISTNACHT: Any other comments?

MR. McMAHON: I have a comment.

You wanted to move from a question to a comment period. And I do have comments.

MR. CHRISTNACHT: Okay. Does anybody have any further questions of clarification at this time, or shall we move on to the public comments?

All right, Brian, you have the floor.

MR. McMAHON: Okay. We are, as you know, in general agreement with using ANS. We're against royalty in-kind in California, we think, for a number of reasons. One of which is the posters in California have publicly stated on numerous occasions they are not going to pay more than posted price. So we would expect that any royalty in-kind sales posters would take themselves out of the bidding process.

Second, the heated pipelines are still private pipelines. And at least some of the Midway Sunset crude and Federal royalty crudes is tied into the mobile-heated pipeline. So that would restrict bids on that crude.

Generally, the market is very concentrated in California, a few major oil companies. The independents keep going out of business.

So we do think the ANS is an appropriate measure, and we're glad to see it. We're glad that generally that no one seems to be defending posted prices anymore.

When we looked at the new rules, there were -- I'll call them questions, I can either call them questions or objections. And I would say either one because maybe I misunderstood what the rule is about. And I'll list five of them, and then I'll go in detail as to what the problems are.

First of all, I'll call it the problem with tracing through successive Buy/Sells or exchanges. I'll use the word "exchange" as a shorthand way of saying exchange or Buy/Sells. And this is Section 206.102 (b).

A second problem has to deal with the transportation cost deduction of Section 206.113 (b).

Three, what appears to be a double deduction for transportation and quality adjustments in Section 206.113 (a).

Four, what I'll call a back-door rule, which allows evidence of purchases at posted prices, Section 206.103 (e) (i).

And five, the problem of balancing agreements, generally.

I've given you a three-page handout which I will use to try and illustrate what I think the problems are with some of these rules.

First of all, the tracing problem, I call it, and that breaks down when we have multiple exchanges, one of which is tied to Federal lease oil, that breaks down into four sub-problems. I'll call it the accounting problem, the commingling problem, the lease value of crude problem, and the transportation cost problem.

First, the accounting problem. As the task force recognized in its published report, oil company accounting records, at least in California, don't allow tracing through successive Buy/Sells.

Second is the commingling problem that -- I think the conceptual model for allowing in the new rule successive exchanges is a model of successive, what I'll call, In/Out exchanges, where someone puts crude oil in a pipeline at a given volume, and at some point down the stream, takes out the same volume out of the pipeline and, perhaps, puts the same volume on another pipeline and puts it on the second pipeline and takes it out. But all the time it's the same volume of crude being delivered to some ultimate point.

But the rule, as stated, doesn't restrict itself to that situation. And often we find that when crudes are exchanged into some central location, that the crudes received on exchange are commingled with lots of other crudes. So you end up with a common strain.

And the problem, then, is trying to trace the hydrocarbon molecules that were produced at the Federal lease through the successive exchanges.

In fact, it's conceptually meaningless to talk about where those hydrocarbon molecules ultimately go.

Now, the next problem I'll try to explain, and maybe it will help to use the first of these handouts here. Assuming you could trace it through successive exchanges when they are not in, but all over the place, if there are multiple sales at the end of this chain, then the producer can use a lowest sale to value his Federal production.

And I'll illustrate it. Let me go to this example here, which is one that is not unrealistic in California, and I'll give another example that might apply to the Gulf Coast area, too.

Suppose production is in Midway Sunset by a Federal lessee, and that company exchanges it for Kern River crude. And my example is the exchange is ten thousand barrels. So now the company that produced has crude at Kern River. Then the company trades Kern River crude for SJVH, San Joaquin Valley Heavy crude coming out the Texaco pipeline up in the Bay area. That could be a different volume, maybe 50,000 barrels.

Then, in turn, there's another trade, another exchange of SJVH at that point for ANS crude, and for Wilmington crude, both of which delivered in Los Angeles.

And at that point in time, let's suppose the company then sells both ANS and Wilmington crude.

The question is: To which of those sales do you attribute the Federal lease valuation?

And in my example here, I wouldn't go through all the details here, but my example of on the ANS sale, you can get a $15.05 valuation, and on the Wilmington sale, you can get a $15.85 valuation.

I think what the rules envision here was that you would have one sale at the end, which would be the same volume as the sale you started with, but there is a no reason in principle why that should happen.

So as you go along all these differentials that the company would have to pay are added on under the rule, and therefore, added on and subtracted from the ultimate value.

To further complicate this, let's suppose that there are spot sales from time to time of Kern River crude or spots sales of SJVH crude up in the Bay area. The royalty owner can use any of those to value the crude. So he's getting different, you know, crudes at different places being sold.

Again, going back to the model, I think it was the feeling that prospectively the producer is thinking of getting his crude down to the Bay area. In fact, the way the oil companies operate, they have lots of evergreen contracts going on constantly, all over the place. And this methodology, using this tracing problem, permits them to use any one of the points along the line to value the crude, if there are outright sales at those points. And, therefore, it allows them to pick the cheapest, the cheapest sale price and attribute that back to the lease.

A similar kind of thing can happen in the Gulf area if you have Permian Basin crude, which is exchanged at Midland, and then Midland crude is commingled and exchanged for Cushing, and then maybe Cushing crude is exchanged for either Arabian crude down in the Gulf or some other crude down in the Houston area. Again, you have that tracing problem. These are not In/Out exchanges; these are discrete swaps in different places.

So it seems to me what I find, then, is that this rule is just unworkable in theory even; it just can't work. So that's my first problem.

The second problem is, the rule that allows the full transportation cost from lease to refinery, and my problem is illustrated in my second example here.

Again, unless I read the rule incorrectly, it would permit some of the producers of OCS crude in California to ship the crude to the Gulf Coast, and deduct the full transportation cost of that crude. And again, I don't know whether that was intended or whether I'm misunderstanding it, but that certainly is possible under your rule.

And I'm sure you're aware of the fact that historically the OCS producers valued OCS production in reference to the L. A. market. So they have agreed since they leased, the early '80s, that the appropriate market center would be Los Angeles, no matter where they ship the crude. So again, what I think this does is allow too great a deduction for transportation.

A similar kind of thing might happen in the Gulf area. I'm frankly not familiar. Permian Basin crude, to my understanding, some of that goes to the Midwest and some of it bypasses Midland, doesn't go through Midland.

So, again, under this rule, as I understand it, it would permit full transportation deduction to go up to some of the refineries in the Chicago area. And I don't think that was what was intended.

I would agree, we agree that the valuation of crude in the field must take into account the cost to move that crude to the nearest market center. So that in case of OCS crude, for example, in California, the value of crude offshore in the Santa Barbara area is less value than that same crude in Los Angeles. And appropriate adjustment would have to be made for the transportation or the location differential.

So we agree with that. Just the question here is:

What's the appropriate market?

So what we think is the rule should be clear in -- I'll qualify it -- almost all cases, you would use the nearest market center even if crude is shipped to the refinery, and then figure the transportation cost from the lease to the nearest market center.

And, you know, two further points, one of them is that the lessee might, in fact, not ship any crude to the market center. And then the question is: Well, then, what transportation deduction should that company use?

In California, I think the answer is readily available. There are enough common-carrier pipelines coming down the coast, Unocal, the Shell one, the Texaco one that goes across valley and connects with the M-70.

So I think in California at least, and in most other areas, at the minimum, you have common carriers that use the common-carrier rates. More likely, your forms will show you through the information you get what the common transportation cost is to get it to a nearby market center.

So you can use information from other companies, other sources, even if the Federal lessee itself doesn't know the cost to move it to the nearest market center.

I would, I think, have to allow an exception in a case where no production from an area moves to a market center but moves directly to a refinery. I don't know if such situations exist; they may. In that case, I think the market center would be the refinery. So in that case, yeah, you would allow the rule as it is, but in that very limited circumstance.

MR. CHRISTNACHT: Would you say, for instance, something like taking crude to Santa Maria -- to cite an example -- would taking crude from Point Pedernales OCS lease, West Coast, to the Santa Maria refinery, be an example of such a case where you're not taking it directly to a market center?

MR. McMAHON: No, it wouldn't. It wouldn't be one of those rare-exception cases, if that's the question, because Point Ped also goes to major market centers as well. And so you can figure the transportation cost to Point Ped to crude production to Los Angeles via common carriers.

I would be thinking that if there was a refinery in Wisconsin, and an oil company somewhere, crude production in Wisconsin, and it only goes to that refinery, there may be no other way of figuring realistically what a market center would be in that circumstance.

The third example I had was what appears to be a double deduction under 1206.113 (a), which tells you that if you dispose of lease production under an arm's-length exchange agreement, you deduct transportation cost under 206.112 (a), (c) and (e).

And then I put together this third handout.

Again, this maybe just misreading of what you intended to do, though, if I'm unclear about it, at the minimum, you need to clarify.

It looks like you're saying you can deduct all these costs. First, you deduct under (a), the cost to move it from the lease to the market center, and the quality deduction.

(c) says you deduct the cost to move it from the lease to the aggregation point, which presumably is somewhere along the line towards the market center. So there's a double costs there.

And the third one says you deduct per the quality deduction, which appears to duplicate the quality deduction in (a). So it looks like you're double counting here to deduct. And something needs to be either clarified or removed.

In this case here, this is a pure hypothetical, under the rules you would allow a $3 deduction; under what we think would be a rational way of doing it, you deduct only a $1.75, the cost of getting it from the lease to the nearest market center.

Do you have a question on that?

MR. CHRISTNACHT: Without looking at this in more detail, I think it would be premature to comment on it.

MR. McMAHON: Okay. Our further concern -- this is the fourth one now -- is that in the case of a company that moves crude to its refinery, directly to the refinery, then the rules permit that company to go to MMS and argue that the valuation rules don't properly account for the true value of the oil. And they are allowed to show the sales -- the purchase price of crudes that are used at the refinery -- of other crudes.

And our deep concern here is that at least in California what that would amount to, say for Bakersfield refineries, what that would amount to would be sales posted price, purchases posted price; so it would be a back-door way of getting into posted prices again.

MR. CHRISTNACHT: Are you talking about for the Rocky Mountains?

MR. McMAHON: No. I'm concerned about California.

MR. CHRISTNACHT: So specifically what provision are you --

MR. McMAHON: 206.103 (e) 21.

It looked like -- I know there is a provision in the Rocky Mountain Area. It looked like for all refiners that take the crude from the lease and bring it to their refinery, they have the right to go to MMS and say, "We are still paying too much."

MR. CHRISTNACHT: Okay.

MR. McMAHON: And they are allowed to bring in considerations of purchases, which in California would, for the most part, be posted price.

My final point really is not so much -- well, it looked like under the previous versions of the rules, on an over-all balancing agreement, when they existed, would be automatic that a company could not use these post-proceeds methodology.

Our concern is that it looks like under the new proposal 206.102 (c) 1 and (c) 2, it seems to place the burden on MMS to find out whether or not there's an over-all balancing agreement. And frankly, we think that's beyond the ability of MMS to discover without an extensive amount of work.

Over-all balancing agreements, we found, are sometimes verbal understandings rather than something that's actually written. And the normal audit work of MMS is not going to turn these things up.

So rather than have MMS just state if you have an over-all balancing agreement, you can't use the gross-proceeds methodology with the company you purported to sell crude to, rather than leaving it to MMS to discover whether such things exist.

Those are my comments.

SAM VAN VACTOR: Sam Van Vactor, Economic Insights.

A quick comment and a question, perhaps, about the example of the offshore crude oil and using the nearest market center, Los Angeles, as the point of valuation on that.

Speaking as an economist, I don't think it's ever necessarily the nearest market-setter that sets market value in the field; it's really an indeterminate. It depends on the circumstances.

And this particular example is a really good one, because right now the OCS crude oil can go across the All America Pipeline and then down to L. A. It's a pretty expensive operation. It used to be quite cheap. You could take it by tanker along the coast. I don't believe they're allowed to do that anymore.

One of the consequences of that is it's over $4 to ship it to L. A. Well, it's not a lot more to ship it all way over to the Gulf Coast. It might have a higher value in the Gulf Coast, which would give it a higher net value at the well. Whether or not it's going to be the Gulf Coast price that ultimately sets market value at the lease, or whether it's going to be the Los Angeles price, depends upon the constraints on transportation, fluctuations in the markets, and a whole lot of variables. You can't say in advance that one specific market location and one specific market valuation at a refinery center less costs represents the lease value.

MR. McMAHON: Can I make one final comment on that last point?

I think you would agree that if the crude at a minimum, if the crude is shipped to the Gulf, if you're going to use index pricing, you're going to use the index price at the Gulf to figure out what the cost is, rather than the price is in Los Angeles. So you would subtract the transportation from that price and not from the Los Angeles price.

SAM VAN VACTOR: Well, I think I wouldn't get into the specifics of how it would be done. That would depend absolutely on the particular transaction and the particular point in time.

My point is just much more general, that when you have crude oil in a field, and it can be shipped to multiple refinery centers, you cannot predict in advance which of those refinery centers are going to set a value which would determine the value of the lease. It's a very complex process, a dynamics of demand and supply that works itself out.

And frankly, it changes all the time. In effect, you may have Los Angeles valuations that are setting value at one time, and have Gulf Coast setting it in another.

MR. CHRISTNACHT: Any other formal comments to be made at this time?

If you don't mind, then, I'm going to go through a number of questions that we have in the preamble that we would like to comment upon. Don't feel if you don't want to comment on them, you have to. I just would like to raise them in case they would stimulate some comments.

Again, I know we have been focusing here on California, understandably so, since we are on the West Coast. But we did ask in the preamble to talk about the definition of the Rocky Mountain region. We did not include New Mexico in that mix for a number of reasons. The State of New Mexico suggested that they would more appropriately be tied into Midland than -- at least for Federal production, because most of our production is near the southeast part of the state or in the southeast part of the state.

Any ideas about changing or amending what the current proposal for the Rocky Mountain states which would use that different valuation system? Right now it includes Utah, Colorado, Wyoming, Montana, North Dakota and South Dakota.

Any bites?

Okay. How about the definitions that we provide? There are several that we changed. I think if you look at the end of the preamble, the first part we talked about, definitions, are there any comments?

SUZANNE NOBLE: Suzanne Noble with WSPA.

On your definition section, I didn't go back and check your other proposals, but it's the same? I mean, as far as you're just adding onto it? Did you add everything in? Or did you just show the new ones that you added? I think you just carried it on and included what you amended.

MR. CHRISTNACHT: I think the preamble addresses some changes to that. To be quite honest with you, I'm not immersed enough in this rule to know exactly what those iterations and changes are.

I know the definition of sales has changed. There are a few others in there. I know there are some additional ones; the Rocky Mountain Area would obviously be a new one.

MR. McMAHON: Did you the change arm's-length contract, Peter?

MR. CHRISTNACHT: Yes, we did change the arm's-length rule.

MR. McMAHON: May I make a comment on that?

MR. CHRISTNACHT: Yes.

MR. McMAHON: The problem that I have with it, it seems to be kind of an off-on switch. It either is arm's-length or it's not. And that might be misleading, especially to people outside the industry, like politicians.

I mean, it could be arm's-length with regard to, say, transportation, or quality differences between the two crudes being exchanged, but not as to the -- you know -- the absolute price of the crudes in the contract.

So it says, "We have opposing economic interests regarding that contract," is ambiguous. It may be with regard -- I think you recognized that there are going to be some contracts for which you won't look at the price of the contract, but you will still regard it for purposes of tracing downstream, so to speak, where there is an ultimate sale.

So I think you need to clarify that. It could be arm's-length with regard to certain things that would still make it usable for certain purposes, but not for others.

MR. CHRISTNACHT: Again, I would invite you to put that in written comments and detail that --

MR. McMAHON: Sure.

MR. CHRISTNACHT: -- so we're clear on what your concerns are.

I guess my point on that is, if you've looked at these, certainly there are some new terms in there as well as some that have changed. If you look, and if there are questions of clarification or concerns about the definitions that are in here, that's certainly what we would being asking for at this time.

Again, if you have more detailed questions or concerns about them, you can also submit those in writing.

GREG MEISINGER: Greg Meisinger, Aera.

Just a question as to MMS's philosophy for changing the presumption of control. In the last proposed rule, there was a presumption of control between the two entities, 50 percent -- or greater than 50 percent, there is a presumption of control if a parent company owned 40 percent. And then also a rebuttal presumption of independence if a company owned -- I think it was less than 10 percent.

In this rule, to define independence, it was a flat 10 percent ownership or control.

I was just wondering what was MMS's rationale for making that change from the last version of the rule and this version.

MR. CHRISTNACHT: I really can't comment on that, not having been one of the primary authors. I know, if I'm correct, the '88 rules did include a 10 percent clause. I'm not exactly sure. I think "affiliate" did change from the '88 rules.

GREG MEISINGER: Yeah, it happened in this version, yeah. It changed. Because we had actually talked about that with you when you were out in Bakersfield last year. At that point in time, it was still the '88 rule without really any comment by MMS. It just changed to this 10 percent issue.

MR. CHRISTNACHT: And you're talking about the "affiliate" definition?

GREG MEISINGER: Yes.

MR. CHRISTNACHT: Any comments on the breakdown of, now, three different regions of the country as opposed to the prior two?

Obviously, California, Alaska has not changed. The Rocky Mountain is now a separate region.

Does anybody want to talk about the Rocky Mountain? A lot of these questions are geared toward that. I certainly will go on if nobody wants to comment on those changes.

SUZANNE NOBLE: Suzanne Noble, WSPA.

I think it would be safe to say most of us here are interested in the ANS and not the Rocky Mountain region.

MR. CHRISTNACHT: Okay.

Brian has already provided some comments on the location of quality transportation adjustments. Any other further comments on those, this version of the rule? Okay.

Any comments on lessee's ability to request an alternate location of quality differential if it can show MMS calculated differentials unreasonably under lessee's circumstances? I know you commented on that already, Brian.

Okay. One of the main things we would like to hear comments on today is the need to continue or to continue with the process of the 4415.

In our view, probably the most likely instance where that would be needed is if you had a crude oil call that was exercised, a noncompetitive crude oil call, so that if it was a company that was an independent, did not market their oil or have actual transportation charges to a market center that they could rely on, they would need MMS to come up with a number for them to deduct.

There's been some talk in the past about if 98 percent of the companies that would use this had actual transportation information at their disposal, then this collection effort may be a lot of time for very little gain. And those few cases where there was no transportation number for those companies, that they might be able to come to MMS and negotiate an agreement as to what that charge should be. That might be more burden than it would be worth for everyone involved.

Are there any comments on that particular need or lack thereof to continue with the 4415?

Jim.

JAMES McCABE: Jim McCabe, City of Long Beach, State of California.

I can't comment in detail because I haven't looked personally at that closely. I would wonder whether the information you collect on the forms could, however, serve as a reality check on the numbers that were, in fact, deposited to you by individual companies that did have their own figures.

MR. CHRISTNACHT: Okay. Any comments on the form itself submitted, on the collection of the information, whether or not it would indeed allow MMS to obtain the information that it needs? Other comments, perhaps, on the clarity of the instructions or the form itself?

SAM VAN VACTOR: Sam Van Vactor, Economic Insight.

I haven't had a chance to really study the form. And I would just comment that the variables that go into crude oil exchanges are very complex, and that there's a lot of noneconomic -- a lot of economic impacts that may or may not be picked up.

So my guess what you're going to get from these forms is a great variability in the values. It would be a very difficult job to actually valuate any type of transportation costs. I suspect it would not be worth the effort. You might consider a pilot program or something like that if you're uncertain.

MR. CHRISTNACHT: One last thing I would like to bring up is MMS's movement toward an index price that is tied to the month reported in the publications versus the way that we previously had it.

What we did was change from using prices that were determined during the same month of production, i.e., the problem with that was, in effect, the day the oil came out of the ground to going back a month prior, which if it was February's production, it would be the month when February's pump month was reported, which in actuality, would be the period prior to when the price was determined, prior to when the oil is coming out of the ground. We got a number of comments come from industry preferring that approach. We would certainly like to open that up for discussion if anyone would like to comment on that. Probably in the long run it would be a wash, but there may be some concerns.

I have quarter of 11:00.

Suzanne.

SUZANNE NOBLE: Were you closing?

MR. CHRISTNACHT: Soon. Looks that way.

SUZANNE NOBLE: I still kind of have maybe two questions --

MR. CHRISTNACHT: Sure.

SUZANNE NOBLE: -- and a couple of closing comments. I know I'm not following along with the specific categories, but if you would allow me to -- go ahead. I'll wait.

MR. CHRISTNACHT: All I was going to say was if anybody has any further questions or comments, now would be a good time to raise them.

Suzanne first.

SUZANNE NOBLE: Suzanne Noble with WSPA.

One question that came to mind was, has this proposal been evaluated through any of its stages, been evaluated through a

NEPA process? Certainly it would have effects on industry.

MR. CHRISTNACHT: Help me out with the acronym there.

SUZANNE NOBLE: NEPA, National Environmental Policy Act.

I guess this is more something that BLM deals with, everything they do. So I was wondering. I just saw that.

MR. DOMAGALA: If you look at the procedural matters section, you'll see all the requirements that need to be met as far as putting a rule out, includes the Paperwork Reduction Act. When you ask for a form such as the 4415, it talks about the economic impact which is under Executive Order 12866. It detailed several requirements that need to be met in order for the rules to be published. And in that section, that will detail what we have done to meet these requirements.

DAVID GILBERT: David Gilbert, CIPA.

Does that also include like the red flags for the SBREFA, the Small Business Regulatory --

MR. DOMAGALA: Yeah, right.

DAVID GILBERT: Okay.

MR. DOMAGALA: That's under procedural matters. You see that in the preamble, toward the end of the preamble.

DAVID GILBERT: There will be a small business analysis done?

MR. DOMAGALA: There was an impact -- an economic impact analysis was done in terms of the actual impact on small businesses.

We did an analysis that detailed the very minimal impact on small businesses.

MR. CHRISTNACHT: For reporting purposes, it was felt that small businesses would not need to --

MR. DOMAGALA: Right, from a reporting standpoint, the small business impact, we felt was small. So there was not a separate small business impact study performed.

We feel that the rule primarily impacting small business is not going to change the way that they do business to comply with the new rule because we feel that most of the small businesses will continue to value based on gross proceeds.

DAVID GILBERT: But if a small business were to be part of a marketing cooperative, would this not then have an impact to the way they conduct their business?

MR. CHRISTNACHT: Could you elaborate on that, David, how that scenario would unfold?

DAVID GILBERT: Well, there are marketing cooperatives in California that producers belong to that they aggregate their production so it can be marketed, and those producers who may not have the capability of transportation or marketing themselves because of their small quantities, but in total they can get a better value for their crude. But they are still small businesses. Would that not somehow impact the way they do their business?

MR. CHRISTNACHT: Are you in a position to tell us how much oil is moved that way, or what the impact would be?

DAVID GILBERT: I could guesstimate. I'm not sure of the exact numbers that they market. But it would -- I would safely say it's about 10,000 barrels a day.

MR. DOMAGALA: We're assuming that even if they are in that type of arrangement that you're describing, the majority of the crude is going to be sold arm's-length, so they are going to use gross proceeds. In that case, there's really no difference under this rule than what they are doing now. So that's our assumption.

If you have specific examples, if you can detail that.

DAVID GILBERT: We heard a lot of hypotheticals today. If a company were to belong to a marketing cooperative, and then as they turn their crude over to that cooperative, and then that cooperative goes out and markets that, is that an arm's-length transaction to give it to that marketing cooperative?

MR. DOMAGALA: If it meets the terms of an arm's-length definition, which we described. If, indeed, there are opposing economic interests there by the parties that are unaffiliated, then it may be arm's-length.

DAVID GILBERT: All right. But if you haven't done the SBREFA, in this particular instance, wouldn't that be subject to some type of congressional review of the regulation under the conditions of SBREFA?

MR. DOMAGALA: Right. We've actual gone above and beyond some of the requirements for this rule. It does not -- under our analysis, it does not have an impact over one hundred million dollars. So technically by definition the rule would not be considered significant by OMB's definitions.

However, because of the amount of industry feedback we got, we decided that the rule was, indeed, significant. So we went ahead and did the full-blown Executive Order 12866. If you look at that, which is available on the internet, it has a lot of details in terms of what we feel the impact would be on some of the larger companies, the smaller companies, and the general business-operating changes that we would foresee under the new rule.

DAVID GILBERT: Refresh my memory. Is that hundred million dollar threshold, is that total impact the rule, or is that only what the effect of the rule would have on those individual businesses that would qualify as small business, or is it total effect?

MR. DOMAGALA: It's the total effect.

DAVID GILBERT: Okay. Okay.

SUZANNE NOBLE: Has this proposal been scored by OMB?

MR. CHRISTNACHT: Yes, it's been looked at and reviewed by them.

SUZANNE NOBLE: Which version? I guess they are all the same.

MR. DOMAGALA: OMB has copies of everything you find in the procedural matters section, has been sent to OMB.

SUZANNE NOBLE: What's the score for budget analysis and so forth?

MR. DOMAGALA: We haven't got any feedback from OMB yet.

SUZANNE NOBLE: It's probably premature.

MR. CHRISTNACHT: They certainly haven't given us feedback on the form, the earlier versions. We followed their recommendations to try to simplify the form, but they are still under the sixty-day review and will be sending comments specifically about the rule to us.

DAVE GILBERT: Aren't gas royalties the third largest contributor to the Federal?

MR. CHRISTNACHT: They are second or third.

SUZANNE NOBLE: They are second.

DAVID GILBERT: Isn't it like between $4- and $6 billion per year?

MR. DOMAGALA: 4.1, yeah.

DAVID GILBERT: What do you expect to increase your royalty collections to with this rule?

MR. CHRISTNACHT: I'm sorry, David. What?

DAVID GILBERT: What do you expect your royalty collections to increase to under this rule?

MR. CHRISTNACHT: Currently, right now, oil, currently about one billion a year for oil.

MR. DOMAGALA: At least in '96.

MR. CHRISTNACHT: Yeah. So --

DAVID GILBERT: With the bonus bids and all the other things that are involved in the leasing, you guys collected about 4 in '96, right?

MR. DOMAGALA: With 4.1, that's oil and gas.

DAVID GILBERT: Okay.

MR. DOMAGALA: I'm talking oil only is about 1 billion.

MR. CHRISTNACHT: Gas is higher than oil.

DAVID GILBERT: So, what do you expect to increase your revenues to from -- I mean --

MR. DOMAGALA: According from the analysis, 66 million.

DAVID GILBERT: 66 million additional dollars?

MR. DOMAGALA: Yeah, based on '96 data.

MR. CHRISTNACHT: Prices.

MR. DOMAGALA: Right.

DAVID GILBERT: The average price in '96 was what?

MR. CHRISTNACHT: 18.

DAVID GILBERT: 18?

MR. CHRISTNACHT: Roughly.

MR. DOMAGALA: I don't have that in front of me.

If you want to look at the details of where we came up with the 66 million, that's available.

DAVID GILBERT: No. I'm just curious. Because, again, I'm kind of going back to the whole problem. I think we have a problem with the fact that there is -- I mean, I don't know who in the public is clamoring for this rule to move forward.

MR. DOMAGALA: Well --

DAVID GILBERT: Royalty owners --

MR. DOMAGALA: As Peter said, MMS has a lot of customers that we need to be accountable to. That includes industry, public, states, the Indians. We have a lot of customer base that we need to account for.

So there are groups, and they are represented here today, that are in favor of making some changes to move away from posted prices.

DAVID GILBERT: Yeah, but it's in their own self-interest to be supportive of this. Then they can say, "Look, the Federal government is doing it; so this is how we have to manage our business."

MR. DOMAGALA: If you want to put that in a written comment, that would be great.

MR. CHRISTNACHT: Suzanne.

SUZANNE NOBLE: To comment on your response, Dave, and also to ask a question. Congresswoman Maloney, Democrat of New York, has been a driving force on this valuation ruling politically. And she introduced two pieces of legislation last year; more significant was 1107, HR-1107, which was called the Royalty Collection Format." And this basically, in one sentence, would be the transfer of royalty collection taken from DOI and given to the Department of Treasury.

MR. CHRISTNACHT: That's right.

SUZANNE NOBLE: Do you have a status of if she's still proposing that? I know they had a few hearings on the Hill regarding it. And I know this is one of the forces that encouraged the Interior to move forward as quickly as possible with the rulemaking. Can you guys give me a status if that's still her initiative?

MR. CHRISTNACHT: I don't know of --

MR. DOMAGALA: I couldn't give you any information.

MR. CHRISTNACHT: I don't know of any updates on that other than, yes, that legislation has been introduced.

But in fairness, before even Congresswoman Maloney took up the cause of royalty collection, the task force investigating crude oil under valuation in California recommended as part of their recommendations to the Assistant Secretary that we look at revising the crude oil rules. So that that was certainly independent of any of the congressional pressure on us, well before this issue surfaced publicly.

SUZANNE NOBLE: Yeah, that should be stated. And I'm well aware of the task-force efforts at that time and the congressional pressure that followed thereafter.

You know, we just want to say on behalf of WSPA, once again, that we are very displeased to continue to see Alaska North Slope spot prices to remain in the rule. We feel that the only place that this leads is to more litigation.

And with that said, you know, we want to urge you once again to abandon this approach. And I've got to put in a plug here for royalty in-kind. Your goal, MMS has always stated their goal is to eliminate posted prices for California to add a more certainty, if you will, to valuating oil.

RIK would eliminate this uncertainty about the value of oil production. It would eliminate the cost of litigation. And in our minds, it seems to be the only revenue-neutral proposal that's been put on the table so far, of course, by us.

Isn't it -- I don't know, we feel this is a little more reasonable and logical than a document, an unprudent, unworkable index approach such as the Alaskan North Slope.

Once again, someone once told me that "new" and "change" isn't synonymous necessarily with "better." And it appears to us that this seems to be the problem with this issue.

Politically, we realize that DOI has to prove to the Hill that they have made a change, quote, unquote, "to solve this perceived problem with valuation." It just seems they are going to make this change even though it's not necessarily for the better.

To change something just to improve it is one thing, but to have change just for the sake of change politically is another.

MR. CHRISTNACHT: Sam, you had another question, did you not?

SAM VAN VACTOR: I did have maybe a brief comment, and then on your issue of prompt versus current month. As you probably know, posted prices are based on a different timing structure than the spot prices reported by the press services or by NYMEX.

I think the crucial point here is exactly what you said, is consistency, and that you don't put the company or yourself in a position where you're collecting the higher of either March or April's price; that's what you want to avoid.

MR. CHRISTNACHT: Right.

I'll invite anybody else to make a comment or raise a question while we're still here.

DAVID GILBERT: If we have a statement, can we just submit it for the record?

MR. CHRISTNACHT: You certainly can.

Brian?

MR. McMAHON: One final comment: No one defends posted prices.

MR. CHRISTNACHT: Suzanne?

SUZANNE NOBLE: I don't know if that's a statement that should be made for all of us here; perhaps a few, but not all.

MR. CHRISTNACHT: Okay. Well, if there are no further comments or questions, I would certainly thank all of you for coming today. We appreciate your turnout and input into the rule. And we certainly have enjoyed this meeting.

Thank you very much for coming.

(Public Hearing concluded at 11:00 a.m.)

STATE OF CALIFORNIA)
) ss.
COUNTY OF KERN)

I, Timothy Scott, a California Certified Shorthand Reporter, holding Certificate No. 8517, do hereby certify that I was present and took down correctly in stenotypy all the proceedings in the foregoing-entitled matter on the 11th day of March, 1998; and I further certify that the annexed and foregoing is a full, true and correct transcript of such proceedings, and a full, true and correct transcript of my stenotype notes thereof.

IN WITNESS WHEREOF, I have hereunto set my hand at my office in Bakersfield, California, this 23rd day of March, 1998.

Timothy Scott,
California CSR No. 8517