2008 AAPL OCS Workshop
January 16, 2008

Anadarko Building, Allison Hall
The Woodlands, Texas

Regulatory and Judicial Update

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Land and Legal Issues in the Outer Continental Shelf

1. **Notices To Lessees/Letters To Lessees**

   a. Purpose behind NTL/LTL

   b. Particular NTLs pertinent to landmen:

   - **NTL No. 2007-G24: Changes to the Designation of Operator of an OCS Oil and Gas or Sulphur Lease**
   - **NTL No. 2007-G22: Suspension of Operations for Subsalt and Ultradeep Geophysical Work**
   - **NTL No. 2007-G21: Conservation Information Documents**
   - **NTL No. 2007-G05: Well Producibility Determinations**
   - **NTL No. 2007-G11: Guidance for Submitting Exploration Plans and Development Operations Coordination Documents.**
   - **NTL No. 2007-G06: Drilling Windows, Eastern Gulf of Mexico.**
   - **NTL 99-N01 Addendum No. 1: Guidance for Oil Spill Financial Responsibility for Covered Facilities.**
   - **NTL No. 2006-N05: Payment Method for New and Existing Cost Recovery Fees.**
   - **NTL No. 2006-G02: Suspension of Operations Based on Rig Delays, Lack of Rig Availability and Procurement of Long Lead Equipment.**

2. **Recent Case Law**

   a. **Texas Cases**

   - ***Long Trusts v. Griffin*, 222 S.W.3d 412, 50 Tex. Sup. Ct. J. 209 (Tex. Dec. 8, 2006).**
   - ***Boldrick v. BTA Oil Producers*, 222 S.W.3d 672 (Tex. App – Eastland Mar. 22, 2007, no pet. h.).**
   - ***Cummings v. Williams*, 2007 WL 172536 (E.D. Tex. Jan. 18, 2007).**

- ***El Paso Production Co. v. GeoMet, Inc.*, 228 S.W.3d 178 (Tex. App.—Dallas 2007, pet. filed).**

- ***Dominion Oklahoma Texas Exploration & Production, Inc. v. Houston American Energy Corp.*, No. H-06-12, 2007 WL 1004353 (S.D. Tex. March 30, 2007).**

- ***Coral Production Corp v. Central Resources, Inc.*, 273 Neb. 379, 730 N.W.2d 357 (Neb. 2007).**

- ***Edge Petroleum Operating Co. v. GPR Holdings, L.L.C.*, 483 F.3d 292 (5th Cir. 2007).**

b. Louisiana Cases

- ***Gulf Explorer, LLC v. Clayton Williams Energy, Inc.*, 964 So.2d 1042 (La.App. 1 Cir. June 08, 2007).**

- ***Burlington Resources, Inc. v. United National Ins. Co.*, 481 F.Supp.2d 567 (E.D. La. 2007).**

- ***Mayne & Mertz, Inc. v. Quest Exploration, LLC, et al.*, 2007 WL 2900510 (W.D. La. Oct. 4, 2007).**

- ***U.S. v. Burlington Resources Oil and Gas Co. L.P.*, 2007 WL 773716 (W.D. La. March 9, 2007).**

- ***Kerr-McGee Oil & Gas Corp. v. Allred*, 2007 WL 3231634 (W.D. La. Oct. 30, 2007).**

    (i) Reaction to the case

    (ii) Proposed Rules Dealing with Royalty Relief

c. Oklahoma cases

- ***McCall v. Chesapeake Energy Corp.*, 164 P.3d 1120 (Okla. Civ. App. Div. 2, 2007).**

1. *Notices To Lessees/Letters to Lessees*

The MMS periodically issues information (ITL), letters (LTL) and notices (NTL) to lessees and operators of oil and gas leases in the Outer Continental Shelf (OCS). The NTLs may either be specific to a certain region or issued by the National Office. The different regions are the Alaska OCS Region, the Gulf of Mexico OCS Region and the Pacific OCS Region.

NTLs are formal documents that provide clarification, description, or interpretation of a regulation or OCS standard; provide guidelines on the implementation of a special lease stipulation or regional requirement; provide a better understanding of the scope and meaning of a regulation by explaining MMS interpretation of a requirement; or transmit administrative information such as current telephone listings and a change in MMS personnel.

ITLs and LTLs are formal documents that provide additional information and clarification, or interpretation of a regulation, OCS standard, or regional requirement, or provide a better understanding of the scope and meaning of a regulation explaining MMS interpretation of a requirement. The MMS intends to either rescind the existing LTLs or revise the existing LTLs and reissue them as NTLs. The LTLs are to remain in effect until they are either rescinded or superseded.

Summarized below are certain NTLs which we believe would be of interest to landmen and attorneys involved with the OCS.

- **NTL No. 2007-G24: Changes to the Designation of Operator of an OCS Oil and Gas or Sulphur Lease [Effective September 24, 2007]**

  This NTL was issued pursuant to 30 CFR 250.103 and provides guidance for, and more detail about, the requirements for submitting a change of the designated operator of an OCS lease.

  Under 30 CFR 250.143(a), you must submit a Designation of Operator (using Form MMS-1123) unless you are the only lessee and are the only person conducting lease operations. When there is more than one lessee, each lessee must execute and submit Form MMS-1123 along with the required service fee, and the MMS GOMR must approve the designation before the designated operator may begin operations on the leasehold. You do not need to provide the service fee if the designation is to establish the initial operator for a newly-issued lease.

  Under 30 CFR 250.143(d), when you wish to change a Designation of Operator, the lessee must submit a new executed Form MMS-1123 to the MMS GOMR for approval. When there are multiple lessees, all Designation of Operator forms must be submitted to MMS GOMR in a single submittal, which is subject to one service fee.

Under 30 CFR 250.144(a), when a Designation of Operator terminates, the MMS GOMR must approve a new designated operator before operations can continue. Each lessee must submit a new executed Form MMS-1123 along with the service fee required by 30 CFR 250.143(d).

The following guidance applies to all changes to Designations of Operator in the MMS GOMR:

1. The MMS GOMR will no longer approve requests that designate an operator of individual wells or multiple wells. When the MMS GOMR approves a designation change, the new designated operator becomes responsible for all wells, platforms, and lease term pipelines within the described lease or aliquot part(s).

2. Under 30 CFR 250.144, each affected lessee must submit Form MMS-1123 naming the new designated operator. The affected lessees are (1) all record title owners and (2) the applicable operating rights owners who own an interest in the area affected by the change in operator. Make sure that any company name on Form MMS-1123 match exactly the company name shown on the documents used to qualify such company, including case and punctuation. Further, ensure that the forms are executed by a company official authorized to sign Designations of Operator, as indicated in the company qualification file on record with the MMS GOMR. Type or print the name and title of each signatory under each signature. For each submittal, provide a cover letter requesting approval for the change in Designation of Operator, two originally signed Form MMS-1123, and the service fee required by 30 CFR 250.125.

3. An operating rights owner does not need to submit a Form MMS-1123 for a designation change, unless the new designated operator will be designated to operate a portion of the lease where its operating rights are owned.

4. If the designation change applies to the entire leased premises, make sure that the description of the lease on Form MMS-1123 is identical to the description contained in the lease. If you choose to use the official map description, make sure that it is correct. If a partial relinquishment changed the area covered by the lease after the lease was issued, provide the up-to-date description on the Form MMS-1123.

5. If the designation change applies to a portion of the lease, describe the portion in aliquot parts using ½ and ¼ only. Do not specify other parts such as ¾ or $^{1}/_{3}$. The smallest aliquot part that you can designate is a ¼ ¼ ¼ of the lease block, e.g., NW ¼ NW ¼ NE ¼.

6. The designation change may contain a depth limitation applicable either to the entire lease or to an aliquot part. If you specify a depth limitation, make sure that the depth description covers only the depth, e.g., surface to 15,000 feet SSTVD. Do not make reference to stratigraphic equivalent or information recited from a well log.

7. When multiple co-lessees are involved, each must designate an operator. The MMS GOMR will not approve the designation change until all required designations are properly executed and filed. When a designated operator is being changed, one of the lessees should collect all of the signed Forms MMS-1123 from all of the co-lessees (as described above) and submit them to the MMS GOMR as one package with one service fee. This will ensure that the change of designated operator will be processed in a timely fashion. The MMS GOMR does not accept partial filings from multiple parties.

In 2001, the MMS published OCS Study MMS 2001-076, "Oil and Gas Leasing Procedures Guidelines, Outer Continental Shelf." Please note that the guidance in that document regarding Designations of Operator and changes that involve designating particular wells is no longer applicable.

- **NTL No. 2007-G22: Suspension of Operations for Subsalt and Ultradeep Geophysical Work [Effective June 25, 2007]**

This NTL provides guidance for submitting requests for a Subsalt and for Ultradeep Suspension of Operations (SOO) under 30 CFR 250.175(b) and 30 CFR 250.175(c) for leases issued with 5-year or 8-year primary terms. This NTL describes the meaning of potential hydrocarbon-bearing formations and identifies ways in which operators may demonstrate that such a formation lies or may lie beneath their leases.

A potential hydrocarbon-bearing formation means that there is a distinctive and mappable subsurface layer that can be identified by the 3-D depth migrated data. This layer is likely to consist of reservoir-quality rock that may contain hydrocarbons.

Subsalt SOO

As required by 30 CFR 250.175(b), you must demonstrate that you acquired and interpreted 3-D depth migrated data by the end of the third year of the primary term of the relevant lease. You must show that this data indicates the presence of a salt sheet, that all or a portion of a potential hydrocarbon-bearing formation may lie beneath or adjacent to the salt sheet, and that the salt sheet interferes with identification of the potential hydrocarbon-bearing formation. You must also demonstrate that additional time is needed for geophysical work with the objective of identifying a potential hydrocarbon-bearing formation which may lead to the drilling of a subsalt well on your lease.

You may demonstrate that these conditions are met by presenting 3-D depth migrated seismic data with clear, continuous seismic reflectors away from the salt sheet that can be tied to reservoir-quality rock in an analog well. The seismic reflectors may be poorly imaged beneath the salt sheet, but the clear, continuous reflectors adjacent to the salt sheet should indicate that the analog horizon would logically extend under the salt and onto your lease.

Ultradeep SOO

As required by 30 CFR 250.175(c), you must demonstrate that you acquired and interpreted 3-D depth migrated data by the end of the fifth year of the primary term of the relevant lease. You must show that your 3-D depth migrated data over the entire lease area indicates that all or a portion of a potential hydrocarbon-bearing formation lies below 25,000 feet TVD SS. You must demonstrate that additional time is needed for geophysical work to determine whether there is a stratigraphic or structural trap on you lease, which may lead to the drilling of a well below 25,000 feet TVD SS.

You may demonstrate that these conditions are met by presenting 3-D depth migrated seismic data with minimal processing artifacts and clear, continuous seismic reflectors at the target horizon that can be tied to reservoir-quality rock in an analog well.

❑ **NTL No. 2007-G21: Conservation Information Documents [Effective June 1, 2007]**

This NTL provides guidance for submitting Conservation Information Documents (CID) for certain deepwater development projects as required in 30 CFR 250 Subpart B, specifically 30 CFR 250.296 through 250.299.

The MMS will evaluate the CID with the objective of preventing waste and maximizing ultimate recovery of all economically producible reservoirs. In particular, the MMS will evaluate all penetrated reservoirs in water depths greater than 400 meters, and ensure that those deemed economic by the MMS will be produced. For water depths less than 400 meters, CIDs are no longer required.

As required by 30 CFR 250.296(a), your CID shall be submitted at the same time that you submit your Development Operations Coordination Document (DOCD) or Development and Production Plan (DPP) to the Office of Field Operations. However, the CID is submitted to the Office of Production and Development (PD), Reservoir Analysis Unit. You must also submit a CID when a Supplementary DOCD or DPP is submitted but only if requested by the Regional Supervisor of PD. Also, you may request a departure under 30 CFR 250.142 to the timing of the CID submittal and such request must occur before submittal of the DOCD or DPP. The Regional Supervisor will approve the departure request in writing in cases where it is demonstrated that a later submittal is in the best interest of MMS. Failure to submit the CID as required, may result in the issuance of a Notification of Incidents of Noncompliance (INC).

As specified in 30 CFR 250.125, you must pay a cost-recovery fee in the amount of $24,200 with the submittal of the CID. You are not required to submit a fee for a revision to an approved CID.

The information you submit under 30 CFR 250.297 should be based on all wells drilled at the time of your CID submittal. In addition, the MMS should be notified of any wells drilled to total depth during the CID evaluation period. The data gathered from wells drilled during the evaluation period will be reviewed by the MMS and may result in a requirement that you update your CID.

The MMS may take up to 150 calendar days to review your CID and if it does not act within 150 days, your CID is considered approved. The 150 day period may be suspended if the MMS determines there is missing, inaccurate or incomplete data, or if a well is drilled to total depth during the evaluation period. Approval of the CID does not constitute approval of any other plan, application or permit.

Production may not begin before your CID is approved per 30 CFR 250.299. Production prior to approval will result in issuance of an INC and possible civil penalties.

❑ **NTL No. 2007-G05: Well Producibility Determinations [Effective March 1, 2007]**

The purpose of this NTL is to provide information concerning new filing procedures to obtain a determination of well producibility (effective with the date of the determination). This NTL replaces NTL No. 2000-G04 (Effective Date January 28, 2000). Changes in the lease addendums beginning with lease OCS G-22500 (Lease Sale 178) no longer transfer a lease into minimum royalty status when a well qualifies in accordance with 30 CFR 250.115 or 30 CFR 250.116. These leases remain in rental status and the annual rental payments for future lease years becomes payable at the end of the lease year, until the start of royalty bearing production. In the lease year that royalty bearing production begins, royalties become payable in accordance with the lease instrument which specifies the royalty rate and minimum royalty requirements.

Once the GOMR makes a determination of well producibility, no further determination of well producibility will be made on the lease, which will eliminate the necessity for you to resubmit open-hole petrophysical data. The requirements for demonstrating well producibility are found in 30 CFR 250.115 or 250.116. You can obtain a determination of well producibility by sending a written request or an email to the Supervisor of the Petrophysical Analysis Unit (SPAU).

Determination of Well Producibility Based on a Well Test

A. According to 30 CFR 250.115(b)(1), you must give the appropriate MMS GOMR District Supervisor an opportunity to witness each well test that you conduct. Instead of witnessing a test, the GOMR will accept test data with your affidavit, or third-party test data (with affidavit), but the SPAU must approve this arrangement prior to the tests. Submit test data with your affidavit or third-party test data (with their affidavit) from wireline formation tests and/or drill stem tests to the SPAU.

B. You can submit your test data for approval by postal mail, email, or telefax.

C. If the well is an oil well, conduct a production test that lasts at least two hours after flow stabilizes.

D. If the well is a gas well, conduct either a deliverability test that lasts at least two hours after flow stabilizes or a four-point back pressure test.

Determination of Well Producibility Based on Petrophysical Data

A. You no longer have to submit any open-hole petrophysical data with your request for a determination of well producibility since 30 CFR 250.468 and 30 CFR 250.469 ensures that the MMS already has all open-hole data needed to determine the producibility of the well. You need only specify the well and the qualifying zone in your application; however, you can submit any supplemental and supporting documentation for the requested well qualification.

B. The criteria of 30 CFR 250.116(b), (c), and (d) determines whether a well is producible. The Petrophysical Analysis Unit will use established petrophysical software to assist in their determination.

The GOMR realizes that not all formations in the Gulf of Mexico possess the same properties and may accept sound well log interpretation techniques that demonstrate that a well would produce hydrocarbons in a particular area, even though the well may not otherwise qualify as producible under 30 CFR 250.116(b), (c), and (d).

Well Producibility Requests

The following information must be in your request for a determination of well producibility:

1. Active lease number

2. Area and block number

3. Well name and number (and lease number if different from active lease number)

4. Operator name

5. Date total depth (TD) was reached or date of final log run for the well

6. TD of well in feet, i.e., measured depth (MD) and true vertical depth subsea (TVDSS)

7. Expiration date of primary lease term

8. API number of well

9. Requested qualification type (wireline test or petrophysical)

10. Hydrocarbon type: oil, gas, or condensate

11. Depth to top of pay in feet (MD and TVDSS)

12. Depth to base of pay in feet (MD and TVDSS)

13. Net thickness of continuous pay section in feet (MD and TVDSS)

14. For a qualification based on a wireline well test and/or drill stem test, the depth of the tested interval (MD and TVDSS), date of test, test number (if more than one test in the well), and results

The GOMR may place the lease in minimum royalty status or the lease may remain in rental status beginning with lease OCS G-22500 (Lease Sale 178) if it makes a positive well producibility determination.

❑ **NTL No. 2007-G11: Guidance for Submitting Exploration Plans and Development Operations Coordination Documents. [Effective April 4, 2007]**

This NTL provides guidance on cost recovery fees and State Coastal Zone Management review fees, and updates on regulatory citation. It is issued pursuant to 30 CFR 250.103 and supersedes NTL No. 2006-G15, effective July 12, 2006.

Changing Approved and Pending EP and DOCD

Under 30 CFR part 250, subpart B, you must submit Exploration Plans (EP) and Development Operations Coordination Documents (DOCD) to the MMS. In addition to the Initial EP and DOCD, there are four types of changes that can be made to an approved and pending EP and DOCD. These changes are referred to as a supplemental, revised, modified, and amended EP and DOCD (see § 250.200(b) for definitions of these types of EPs and DOCDs).

Each supplemental and revised, modified, or amended EP or DOCD need only contain that information related to or affected by the proposed changes to the EP or DOCD, as approved or pending. Make sure that the descriptions of the proposed changes are complete and includes the rationale for the proposed changes. Also it is advised that you reference the approval date or MMS control number of the approved EP or DOCD you are changing.

Pursuant to § 250.283(b), supplement your approved EP or DOCD when you propose to conduct lease or unit activities that require applications or permits and which are not described in your approved EP or DOCD.

Pursuant to § 250.283(a), revise your approved EP or DOCD when you:

1. Change the type of drilling rig to one with a different impact on the seafloor, production facility, or transportation mode you will use;

2. Change the surface location of a well by more than 30 meters (100 feet) in water depths less than 400 meters (1,312 feet), or by more than 152 meters (500 feet) in water depths 400 meters (1,312 feet) or greater;

3. For DOCD that propose activities that affect the State of Florida, change the type of production from natural gas to oil;

4. Increase the emissions of an air pollutant to an amount that exceeds the amount specified in your approved EP or DOCD;

5. Request a new hydrogen sulfide (H_2S) area classification, or encounter a concentration of H_2S greater than 500 parts per million (ppm);

6. Change the location of your onshore support base from one State to another or to a new base requiring expansion; or

7. Change the approved anchor array pattern associated with your activities, or increase the anchor radius by more than 152 meters (500 feet) if the MMS GOMR did not approve a specific anchor pattern.

Copies of EP and DOCD

Pursuant to § 205.206, submit the following number of copies for Initial and Supplemental EP and DOCD to the MMS GOMR.

Initial and Supplemental EP and DOCD that describe activities on leases and unit areas on the OCS that affect the:	**No. of Proprietary Copies**	**No of Public Information Copies**	**Total No. of Copies**
A. State of Florida	5	17	22
B. State of Alabama	5	5	10
C. Both the States of Mississippi and Louisiana	5	6	11

D. Both the States of Mississippi and Louisiana, with such activities being exempted from CZM certification requirements	5	4	9
E. Only the state of Louisiana	5	4	9
F. Only the State of Louisiana, with such activities being exempted from CZM certification requirements	5	3	8
G. State of Texas	5	4	9
H. State of Texas, with such activities being exempted from CZM certification requirements	5	3	8

Pursuant to § 250.206, submit the following number of copies for Revised, Modified, and Amended EP and DOCD GOMR:

7 copes (5 proprietary and 2 public information)

Electronic Submissions

You can also submit copies of any EP or DOCD electronically in accordance with § 250.186(a)(3). If this is done you must submit it as a single file on a separate CD-ROM and ensure that all electronic files are in portable document format (PDF) or other acceptable format. If you submit your EP or DOCD electronically, provide:

1. In lieu of the five proprietary copies specified above, one proprietary copy on paper and one proprietary copy on CD-ROM; and

2. For EP and DOCD that propose activities that do not affect the State of Florida, one public information copy on paper, and one less than the specified number of public information copies on separate CD-ROM; or

3. For EP and DOCD that propose activities that do affect the State of Florida, provide 8 public information copies on separate CD-ROMS.

Cost Recovery and State Coastal Zone Management Review Fees

Cost Recovery Fees. Effective September 1, 2006, cost recovery fees must accompany the submission of all Initial and Supplemental EP and DOCD to the MMS GOMR. Refer to 30 CFR 250.125-126 and NTL No. 2006-N05 for information on fee amounts and payment methods.

Coastal Zone Management Review Fees. The State of Louisiana and Alabama require a fee in order to process a consistency certificate for an EP or DOCD that affects their respective State.

❑ **NTL No. 2007-G06: Drilling Windows, Eastern Gulf of Mexico. [Effective April 1, 2007; Expires June 1, 2008]**

This NTL supersedes NTL No. 2006-G05 (effective March 1, 2006) which expired on March 1, 2007, and provides a new schedule for the drilling window program.

The GOMR, after consultation with the U.S. Air Force, established a drilling window program in 1991 for exploratory activities on oil and gas leases that were obtained through Lease Sale Nos. 79, 94, and 116 and that contain Lease Stipulation No. 5.

The program divides the subject leases into five groups as follows:

> Group "A" – A rectangle in the Pensacola Area with Block 768 as the northwest corner, Block 988 as the southwest corner, Block 996 as the southeast corner, and Block 776 as the northeast corner.
>
> Group "B" – A group that includes blocks in the Pensacola Area to the east of a line that extends north from the southwest corner of Block 997 to the State-Federal boundary offshore Florida and north of a line that extends east from the southwest corner of Block 997 to the State-Federal boundary offshore Florida.
>
> Group "C" – A rectangle in the Destin Dome Area with Block 20 as the northwest corner, Block 460 as the southwest corner, Block 468 as the southeast corner, and Block 28 as the northeast corner.
>
> Group "D" – A rectangle in the Destin Dome and Apalachicola Areas with Destin Dome Block 29 as the northwest corner, Destin Dome Block 469 as the southwest corner, Apalachicola Block 443 as the southeast corner, and Apalachicola Block 3 as the northeast corner.

Group “E” – A group that includes a rectangle in the Destin Dome Area with Block 507 as the northwest corner, Block 771 as the southwest corner, Block 776 as the southeast corner, and Block 512 as the northeast corner; Destin Dome Blocks 969 and 973; and all the leased blocks in the DeSoto Canyon, Florida Middle Ground, Elbow, and Lloyd Ridge Areas.

The Seventy-fourth Drilling Window closed on February 28, 2007 and the GOMR, in consultation with the Air Force, established the following schedule:

Group “E” opens as the Seventy-fifth Drilling Window effective April 1, 2007.

Group “A” will open as the Seventy-sixth Drilling Window effective June 1, 2007.

Group “B” will open as the Seventy-seventh Drilling Window effective September 1, 2007.

Group “C” will open as the Seventy-eighth Drilling Window effective December 1, 2007.

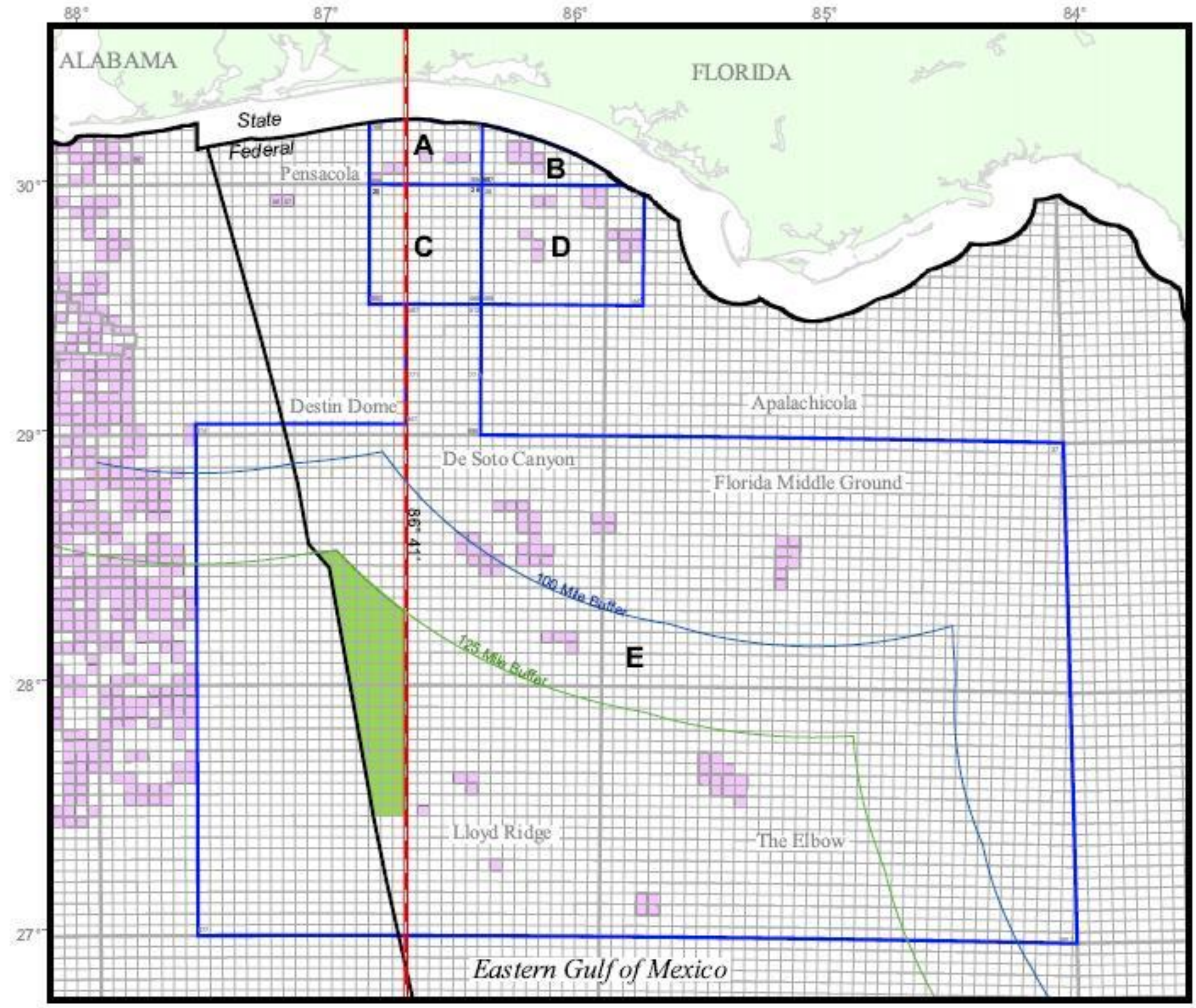
Group “D” will open as the Seventy-ninth Drilling Window effective March 1, 2008.

Pursuant to 30 CFR 250.173(b), the GOMR will direct a suspension of operations (SOO) and it will be in effect for all oil and gas leases that were obtained through Lease Sales Nos. 79, 94, and 116, contain Lease Stipulation No. 5, are east of 87.5 degrees W longitude, and are not located within an open drilling window. Similar suspensions will likewise be directed by separate letters of notification for all such leases not included in a future drilling window and will be effective as of the date of the opening of the drilling window. Any such SOO will terminate when the lease is included in an open drilling window pursuant to 30 CFR 250.170(e).

According to 30 CFR 250.169(a), the term of any affected lease will be extended for a period of time equal to the period that the SOO is in effect.

According to 30 CFR 218.154(b), no payment of rental or minimum royalty will be required during the period of the SOO.

According to 30 CFR 218.154(c), if the lease anniversary date occurs within a period that an SOO is in effect for which no rental or minimum royalty payments are required, the prorated rentals or minimum royalties are due and payable as of the date the SOO terminates. The anniversary date of the lease will not change by reason of any period of lease suspension or rental or royalty relief resulting therefrom.



❑ **NTL 99-N01 Addendum No. 1: Guidelines for Oil Spill Financial Responsibility for Covered Facilities [Effective June 1, 2006]**

This addendum provides further clarification and guidance to NTL 99-01, effective January 6, 1999, which provided for Oil Spill Financial Responsibility (OSFR) for Covered Offshore Facilities (COF) on the basis of 30 CFR 253. It explains to operators and owners of facilities and leases of MMS policies for submitting OSFR documents.

Original Documents Required for OSFR Submittals

The MMS no longer processes or approves an OSFR submittal unless it contains all originally executed MMS forms and financial documentation specified in 30 CFR 253. If the application does not contain these original forms, the MMS will either return the incomplete application or hold it pending the submittal of the remainder of the required documents.

Exception for Form MMS-1019 Fax Binders

The MMS will accept an e-mail, facsimile, or other type of copy as a temporary insurance confirmation (fax binder) for each insurance certificate used as OSFR evidence. This fax binder is a copy of Form MMS-1019, Insurance Certificate, completed to show the full insurance slip, i.e. listing of all underwriters with their individual quota shares, and at least one insurance underwriter's signature, and submitted to the MMS as a fax copy of evidence of OSFR. According to 30 CFR 253.29(d), a fax binder may be used as temporary insurance evidence of OSFR for up to 90 days while the remaining signatures are obtained. Form MMS-1019 will <u>not</u> be accepted as a fax binder when it requires only one underwriter's signature.

Amendment to List of COFs in Current OSFR Demonstration

Form MMS-1022, COF Changes, is used to add or drop COF coverage from your OSFR demonstration. 30 CFR 253.42(b) states that you must continue to demonstrate OSFR for a COF until the MMS approves OSFR evidence for the COF from another designated applicant or OSFR is no longer required. If you want to drop COF coverage or OSFR is no longer required you must include on Form MMS-1022 a statement with the reasons why OSFR is no longer required, i.e. you assigned your interest in the COF.

- ❑ **NTL No. 2006-N05: Payment Method for New and Existing Cost Recovery Fees [Effective September 1, 2006]**

This NTL was issued pursuant to 30 CFR 250.103, 30 CFR 251.3, 30 CFR 280.3(c), and supersedes NTL No. 2006-N04 and applies to all MMS OCS Regions. According to 30 CFR 250.125, 251.5, 256.63, and 280.12 you must pay non-refundable service fees to the MMS. MMS applications and documents that require cost recovery fees must include either fee payments or proof of fee payment through the Pay.gov system.

Payment of new cost recovery fees is required for specified applications or other documents received by MMS on or after September 1, 2006. Pay.gov allows the non-refundable fees to be paid electronically with either a credit card or through Automated Clearing House (ACH) payments. The MMS Regional Offices will no longer handle credit card or ACH payments.

Payment of fees must accompany the submission of the application or document. It is strongly urged to pay these payments through the Pay.gov website which can be found through links on the MMS website. If you pay by credit card or ACH, you must include a copy of the Pay.gov confirmation receipt with your application or document, otherwise it will be returned to you without further processing.

- ❑ **NTL No. 2006-G02: Suspensions of Operations Based on Rig Delays, Lack of Rig Availability and Procurement of Long Lead Equipment [Effective February 10, 2006, Expires February 28, 2008]**

This NTL is issued pursuant to 30 CFR 250.103 and 250.175(a) for the purpose of providing guidance to the existing authority for approving requests for lease or unit Suspension of Operations (SOO) based on rig delays, to implement a temporary policy for granting SOO based on lack of rig availability and for unanticipated time frames needed to secure long lead equipment such as high pressure/temperature tubular and wellheads.

An SOO may be granted when necessary to allow time to begin drilling or other operations when the lessees are prevented for reasons beyond their control such as unexpected weather, unavoidable accidents, or drilling rig delays. SOO typically are short in duration.

Pursuant to 30 CFR 250.175(a), an SOO may be granted to extend the term of a lease when a drilling rig was contracted and scheduled to begin leaseholding operations <u>prior</u> to the lease expiration but due to reasons beyond the lessees control, the rig was delayed. Any delay in a rig release date should be short in term and it is expected that the lessee should have an approved plan and approved APD. The MMS may also approve an SOO when long lead equipment was contracted for and scheduled to arrive in time to commence a lease holding operation prior to expiration of the lease, but was delayed for reasons beyond the control of the lessee.

SOO requests must include:

1. Verification that a rig or long lead equipment contract has been executed,

2. The original date before lease expiration the rig or lead equipment was expected to arrive on the lease,

3. Full details explaining the delay,

4. The new anticipated date for the rig or long lead equipment to arrive on location, and

5. The expected date operations will commence.

This NTL also provides that an SOO may be approved under a temporary policy when the lessee can demonstrate to the MMS's satisfaction that a <u>timely</u> search has resulted in a total lack of rigs capable of drilling prior to lease expiration. In this case the SOO will be considered to allow time for the first available rig to commence operations, provided a drilling contract has been executed prior to lease expiration.

This SOO request must include:

1. Full details, with supporting documentation, demonstrating that a timely rig search was performed,

2. Verification that a rig contract has been executed prior to lease expiration, and

3. The anticipated date for the rig to arrive on location and commence operations.

Also under this temporary policy, the MMS may approve an SOO when timely attempts to secure long lead equipment needed for the commencement of leaseholding operations prior to lease expiration were unsuccessful. Late attempts to secure a drilling rig contract or long lead equipment will not be justification for an SOO approval. All SOO requests must be received by the MMS prior to lease expiration and late permit filings are not justifications for an SOO approval.

2. Recent Case Law

a. Texas Cases

1. *Long Trusts v. Griffin*, 222 S.W.3d 412 (Tex. Dec. 8, 2006).

In this suit the court was asked to decide whether the Statute of Frauds was applicable to certain exploration agreements that provided for the transfer of working interests in oil and gas leases.

The Long Trusts, respondents, in 1978 and 1982 agreed to “pay part of drilling and operating costs in exchange for an assignment of part of the working interest in producing wells.” 222 S.W.3d at 416. After many years of successful production a dispute arose between the parties, where the Griffins, petitioners, claimed the agreements made in 1978 and 1982 were unenforceable under the Statute of Frauds because the properties were not sufficiently identified in the agreements.

In the 1978 agreements the lease was described as being located “in the Northeast portion of Rusk County, Texas and consist[ed] of 50+ leases covering approximately 2100+ net mineral acres in the Dirgin and Oak Hill Fields area” as “described in the attached Exhibit A.” *Id*. The description in Exhibit A gave the lessors name, the survey name, the term, and the new acreage for each lease at issue. The court found this description to be insufficient because it could not be used to identify the exact location of a lease with reasonable certainty. The court noted “a deed purporting to convey land, which describes it only by quantity and as being part of a larger tract, with nothing whereby to identify what specific portion of the larger tract is intended to be conveyed, is void for uncertainty of description.” *Id*.

The 1982 agreements also contained a general description of the subject leases and was supposed to have an attached Exhibit A, which is where the general description was to be given. The 1982 agreements, however, were missing the Exhibit A but had other instruments/exhibits attached. The court found that these attached instruments did not sufficiently describe the subject leases and were too confusing to determine which lease each was intending to refer. The 1982 agreements were also found unenforceable under the Statute of Frauds.

The court noted that oil and gas interests are real property and thus contracts for transfers of interests are subject to the Statute of Frauds. Under the Statute of Frauds a contract "must furnish within itself, or by reference to some other existing writing, the means or data by which the property to be conveyed may be identified with reasonable certainty." *Id*. at 416. "Extrinsic evidence may be used only for the purpose of identifying the property with reasonable certainty from the data contained in the contract, not for the purpose of supplying the location or description of the property." *Id*.

2. *Boldrick v. BTA Oil Producers*, 222 S.W.3d 672 (Tex. App – Eastland Mar. 22, 2007, no pet. h.).

This case concerned a conflict between the payment of overriding royalty interests under a Joint Operating Agreement ("JOA") and a non-consent penalty provision in the same JOA.

On September 15, 1973, Texaco, as Operator, and Ben J. Fortson and Exxon, as Non-Operators, entered into a JOA on February 4, 1977, Texaco entered into a sublease agreement with Sabine Production Company ("Sabine") on the same property subject to the JOA. The sublease was subject to the JOA and Sabine and BTA Oil Producers ("BTA") shared the sublease interest.

After the test well was drilled and subsequently paid out, BTA executed an assignment of overriding royalty interest of which Boldrick acquired an interest. Boldrick's assignment provided that "said overriding royalty interests shall be free and clear of all costs of development and operation and this assignment shall not imply any leasehold preservation, drilling or development obligation on the part of Assignor." *Id*. at 673.

Later there was a proposal by Chevron, the operator under the 1973 JOA, to drill an additional well called the Stallings Gas Unit 2H Well ("Stalling Gas Well"), but BTA elected to go "non-consent." Initially Chevron was paying Boldrick an overriding royalty interest from production from the Stallings Gas Well; however, later it stopped the payments claiming there was a mistake in the division order and asked Boldrick to return the funds previously paid. Boldrick then sued BTA and Texaco/Chevron for money damages, alleging breach of contract, conversion, and unjust enrichment because its share of the overriding royalty interest was being used for the benefit of the defendants, when it was supposed to be free and clear of all costs of development and operation.

Paragraph 31(b) of the joint operating agreement provided that "any subsequently created interest shall be specifically made subject to all terms and provisions of the operating agreement." *Id.* It defined a subsequently created interest so as to include the creation, subsequent to the joint operating agreement, of an overriding royalty created by a working interest owner out of its working interest. Where such a working interest owner elects to go nonconsent under Paragraph 12 of the JOA, "the subsequently created interest shall be chargeable with a pro rata portion of all costs and expenses under the operating agreement in the same manner as if it were a working interest." *Id*. at 674.

Boldrick's overriding royalty interest was created out of BTA's working interest after the execution of the 1973 JOA and, therefore, the court determined the overriding royalty interest was subject to all the terms and provisions of the JOA. Because BTA chose to go non-consent, Boldrick's overriding royalty interest became chargeable with a pro rata portion of all the costs and expenses under the JOA in the same manner as if it was a working interest. The question of whether BTA should reimburse Boldrick for any of the costs and expenses was not addressed in the case.

3. ***Cummings v. Williams*, 2007 WL 172536 (E.D. Tex. Jan. 18, 2007).**

This case asked whether a Facility Site Agreement ("FSA") was acquired by Williams Production-Gulf Coast Company, L.P. ("Williams") in a Purchase and Sale Agreement ("PSA") between Williams and Llano Royalty Limited ("Llano"), a Texas Limited Partnership.

Prior to the execution of the PSA, Llano's predecessor entered into a FSA with Charlie Cummings ("Cummings"). In the FSA the Gas Gatherer, Llano, agreed that for any oil or gas well drilled by the Gas Gatherer on the land and within a ten mile radius of the land, Llano shall install a pipeline system and transport all gas produced from the wells to a site to be located on the land. In the FSA, Llano also agreed to process all the gas produced from the wells at a processing facility which Llano agreed to build. Llano was required to give Cummings notice of any selling, conveying, etc. of any facility constructed on the land; however, no facility was ever constructed.

The PSA stated that Llano owns and desires to sell certain real and personal property interests more fully described in section 1.2 of the agreement. *Id*. at *2. Part of the assets were noted in section 1.2f of the PSA, which stated: "The rights and obligations, to the extent transferable, in and to…purchase, gather, transportation and processing contracts…and other contracts, agreements, and instruments relating to the interest described in section 1.2a, 1.2b, 1.2c, 1.2d, and 1.2e (the "Material Agreements") including without limitation the agreements described on Exhibit B." *Id*. "Section 1.2a indentifies oil and gas rights and lists the Cummings property, which is the subject of the FSA, as an interest that is transferred (Exhibit A to the agreement)." *Id*. Any contract relating to assets acquired as land, oil and gas rights, wells, unitization or pooling agreements and farmout agreements are defined as a "material agreement." *Id*.

Section 4.9 of the PSA is titled "Contracts" and provides that "Material Agreements are described in Exhibit B," in which the FSA is not listed. *Id*. The court then was asked whether the language "including without limitation the agreements described on Exhibit B" expands the agreements which Williams acquired beyond the material agreements described in Exhibit B. *Id*. The court found that the FSA was not a material agreement which Williams acquired for many reasons. First the PSA stated that certain property interests are being sold, not all property interests, which means this is not a total asset sale and purchase. Also there is no mention of a FSA on Exhibit B, which the language of 4.9 stated that all material agreements referenced in subsection f are listed on Exhibit B. Even though the PSA mentions agreements such as the gathering, purchase, transportation, and processing contracts, there was no mention of the FSA.

The court noted that Williams had the right to rely on Llano's representation and warranty that all the material agreements were listed on Exhibit B and that nowhere in the PSA is Williams directed to examine the lease files to determine the interests which he is purchasing. The court also noted that Cummings can still hold Llano liable because of the general rule that a party who assigns its contractual rights and duties to a third party remains liable unless expressly or impliedly released by the other party to the contract.

Cummings second argument was that the FSA is a covenant which runs with the land or alternatively an equitable servitude on the land. "A real covenant runs with the land if: (1) it touches and concerns the land; (2) it relates to a thing in existence or specifically binds the parties and their assigns; (3) it is intended by the original parties to run with the land; and (4) when the successor to the burden has notice." *Id*. Personal covenants are different in that they only bind the actual parties to the covenant and those who purchase the land with notice of the covenant. Also the restrictions in the covenant must concern the land or its uses. "The doctrine of equitable obligation or servitude operates when a landowner's promise binds a subsequent purchaser or possessor who acquires the land with the notice of the promise. A contract to purchase gas imposes a servitude on the property onto the subsequent purchaser who has full notice of such servitude." *Id*. at *4. In this case the FSA specifically stated that it was to be binding on the successors and assigns of the Gas Gatherer. The court found that the FSA was an equitable servitude and that there was a fact issue as to whether Williams had notice of the contract. Williams's motion for summary judgment was granted in part and denied in part, while Cummings motion for summary judgment was denied.

4. *El Paso Production Co. v. GeoMet, Inc.,* 228 S.W.3d 178 (Tex. App.—Dallas 2007, pet. filed).

This case looked at whether a preferential right to purchase extended to the sale of overriding royalty interests. El Paso Production Company, CMZ Join Venture, and CDX Minerals, LLC (collectively "El Paso") and GeoMet, Inc. ("GeoMet") entered into a Farmin Agreement in which GeoMet assigned to El Paso its oil and gas leases in the White Oak Creek Prospect located in Alabama, reserving an overriding royalty interest. The parties also signed a Joint Operating Agreement ("JOA") that contained a preferential right to purchase provision which provided that a party desiring to sell "its rights and interest in the Contract Area and has a proposed purchaser must first offer the rights and interest to the other parties under the agreement on the same terms as to the proposed purchaser." *Id.* at 179,180. The JOA was to be governed under Alabama law.

Subsequently, CDX and GeoMet agreed that CDX would buy GeoMet's interests, including the overriding royalty interest referenced above. GeoMet then notified El Paso of the proposed sale. El Paso agreed to purchase the interests from GeoMet by exercising their preferential rights; however, GeoMet refused to sell to El Paso its overriding royalty interest. El Paso then brought this lawsuit claiming the preferential right to purchase provision set forth in the JOA applied to the overriding royalty interest.

The Texas court stated that overriding royalty interests are interests in real estate. The JOA stated that "should any party desire to sell all or any part of its interest under this agreement, or its rights and interest in the Contract Area, it shall promptly give written notice to the other parties, with full information concerning the sale…" *Id*. at 181. The court then sought to determine whether the overriding royalty interest constituted "interests under this agreement" or "rights and interest in the Contract Area." *Id*. at 182. If it does, then it would be subject to the preferential right to purchase. As defined under the JOA "Contract Area" meant "all of the lands, oil and gas leasehold interest and oil and gas interest intended to be developed and operated for oil and gas purposes under this agreement." *Id*.

The court determined that because the reserved overriding royalty interests were from the production which GeoMet would receive from the leases that constitute the "Contract Area" under the JOA, GeoMet's overriding royalty interest is a "right and interest in the Contract Area." *Id*. GeoMet argued that its overriding royalty interest was not subject to the preferential right to purchase provision because the overriding royalty interest is not part of the Contract Area. The court, however said that the issue is not whether the overriding royalty interest is part of the Contract Area, but rather whether the overriding royalty interest constitutes "rights and interest in the Contract Area." *Id*. "The overriding royalty interest as a right to payment from production in the land and leases constituting the Contract Area, is clearly rights and interests in that land and those leases." *Id*. The court determined that because it is a right to payment from production in the Contract Area, the overriding royalty interest was subject to the preferential right to purchase.

5. *Dominion Oklahoma Texas Exploration & Production, Inc. v. Houston American Energy Corp.,* No. H-06-12, 2007 WL 1004353 (S.D. Tex. March 30, 2007).

The issue in this case was whether the express terms of a Joint Operating Agreement (JOA) created an agency relationship between the parties in the case. Two sentences in the JOA were at issue in the case.

Moose Oil and Gas Company ("Moose Oil") and several individual corporate investors agreed to form an investment group in order to develop certain mineral rights held or to be acquired by Moose Oil. The investment group and Moose Oil entered into a contract called the Working Interest Unit Agreement ("Unit Agreement") with Dominion and another company. The Unit Agreement pooled the interests held by Moose Oil and the investors with that of Dominion, naming Dominion as Operator and was governed by a JOA appended to the Unit Agreement.

The Unit Agreement referred to Moose Oil by name and referred to the investment group comprising Moose Oil and the individual investors as "Moose." The two sentences of the JOA at issue in the case stated, "Moose Oil & Gas Company shall be the liable party to the Operator for the entire 27.5% working interest within the Working Interest Unit for the parties hereinabove referred to as Moose. Moose Oil & Gas Company shall be the responsible party, for each of said parties, to the Operator for obtaining and delivering any and all elections, notices, invoices payments and billings." *Id*.

Unlike the Unit Agreement which was signed by all of the parties including the individual investors, the JOA was signed by Moose Oil only. Once Moose Oil filed for bankruptcy, Dominion attempted to get drilling costs from the individual investors arguing the JOA created an agency relationship between Moose Oil and the individual investors.

The court determined that the two sentences at issue were unambiguous and clear. The court said the Unit Agreement indicated that an assignment of sole liability to Moose Oil, not the creation of an agency relationship, was intended by the parties. The court stated: "The liable party sentence afforded Dominion the convenience of looking to only one party-Moose Oil-for reimbursements; and the responsible party sentence added additional gloss to the liable party sentence by making clear that Moose Oil could not rely on Dominion-or anyone else, to secure payments from the other investors for which Moose Oil was solely liable." *Id*. at 2. Dominion bore the risk that Moose Oil may not be able to pay when it entered into the arms length transaction and therefore could not recover from Moose Oil's investors.

6. *Coral Production Corp v. Central Resources, Inc.*, 273 Neb. 379, 730 N.W.2d 357 (Neb. 2007).

This case was decided in Nebraska under Texas law pursuant to express language in the Joint Operating Agreement ("JOA"). This case interpreted a preferential right provision in a JOA and arose out of a dispute between oil and gas companies that were fractional working interest owners of oil and gas assets in Nebraska subject to the JOA.

Central Resources, Inc. ("Central"), who was the operator under the JOA, offered for sale all of its oil and gas assets in Nebraska. Coral Production Company ("Coral"), the non-operator, claimed it had a preferential right to purchase the assets from Central; however Central disputed this claim and sold 70% of its total assets to EXCO Resources, Inc. ("EXCO"), without first offering them to Coral. The other 30% of Central's assets had been sold two weeks earlier. EXCO later transferred an overriding royalty interest from these assets to Paul Zecchi, Central's chief executive officer. Coral and another party filed a lawsuit against Central, Zecchi, and EXCO claiming breach of contract, fraud, and tortuous interference with contract.

The JOA used by the parties was the 1977 version of the Model Form 610 Operating Agreement developed by the American Association of Petroleum Landmen. The JOA contained standard preferential right to purchase language along with an exception which stated: "Should any party desire to sell all or any part of its interests under this agreement, or its rights and interest in the Contract Area, it shall promptly give written notice to the other parties, with full information concerning its proposed sale………The parties shall then have an optional prior right, for a period of ten day after receipt of the notice, to purchase …..However, there shall be no preferential right to purchase in those cases where *substantially all of the assets and/or stock of the selling party is sold to a non-affiliated third party*." *Id*. at 364. The italicized language was added to the model form by the parties and is the primary issue in the case.

In May 2000, Central issued a property sale memorandum which Coral received a copy of and later responded asserting its preferential right to purchase. Prior to Central making the sale to EXCO the two parties discussed whether Coral had a preferential right to purchase and determined that it did not because Central was selling substantially all of its assets in its sale agreement with EXCO.

Coral argued that the sale did not fall under the exception to the JOA preferential right language because the plain language of the exception shows that a sale of a parties assets or stock to a non-affiliated third party does not include a sale to more than one non-affiliated third party. The court disagreed and said that language added by the parties showed that the parties intended to narrow the preferential right to purchase provision and did not want the right to be triggered if one of them decided to exit the oil and gas business by selling its assets to a nonaffiliated third party. Nothing in the language added by the parties precluded interpreting the phrase "a non-affiliated third party" to include its plural form. Central had offered all of its oil and gas assets in one sale and had no remaining assets after the two sale agreements.

The court also looked at the overriding royalty interest assigned by EXCO to determine whether the preferential right to purchase applied to that transfer as well. The JOA expressly stated that the agreement was to be binding upon the party's successors and assigns and that any sales or transfers were to be subject to the JOA. EXCO argued the overriding royalty interest was not subject to the preferential rights provision of the JOA. The court stated that "Under Texas law, an overriding royalty interest is carved out of, and constitutes a part of, the working interest created by an oil and gas lease." *Id*. at 398.

"The preferential right to purchase provision in the JOA broadly applies to a party's sale of its rights and interest in the Contract Area and overriding royalty interests are interests in the contract area and that a preferential right to purchase applies to a sale of these interests." *Id*. The court remanded the case on the sole issue of whether a sale of an overriding royalty interest had occurred.

7. *Edge Petroleum Operating Co. v. GPR Holdings, L.L.C.*, 483 F.3d 292 (5th Cir. 2007).

The issue in this case was whether a natural gas producer who sold gas to companies, who were now in debt, could recover under the Texas Mineral Lien Act in a conversion action from the downstream purchaser who had bought the gas from the debtors.

Edge Petroleum Operating Company, Inc. ("Edge"), a producer of natural gas, sold gas to GPR Holdings, L.L.C., Aurora Natural Gas L.L.C., and Golden Prairie Supply Services, L.L.C. (collectively the "debtors") who all have filed for bankruptcy. The debtors then sold the gas to Duke Energy Trade and Marketing, L.L.C. ("Duke") who resold it to third parties where it was comingled with gas from other producers. Edge was not paid for the gas and instead of suing the debtors in their bankruptcy proceedings, it sued Duke in state court under a theory of conversion of Edge's security interest under the Texas Mineral Lien Act. Both the debtors and Edge claimed Duke did not pay for the gas. Duke claimed it paid for the gas based on a theory that it had overpaid the debtors in the previous months and was now offsetting the overpayments.

Before trial in state court the case was removed to a bankruptcy court. The debtors intervened in the proceedings claiming that they were the real parties in interest because Edge was trying to enforce a lien against property owned by them in the form of an accounts receivable. The bankruptcy court granted the motion for summary judgment in favor of Duke and the debtors saying that "even accepting, *arguendo*, that Edge possessed a valid lien, Edge sought to enforce that lien against the debtors' accounts receivable." *Id*. at 297. The bankruptcy court held that the action was automatically stayed. The court then stated: "Texas state law did not permit Edge to enforce its possible security interest via a conversion action against Duke." *Id*. The court also found there was a disputed issue of material fact as to whether Edge even had a security interest. The district court affirmed the holding of the bankruptcy court and Edge appealed in regard to its conversion action to enforce its lien.

On appeal Edge contested the bankruptcy court's ruling that the action was automatically stayed. Under U.S.C. § 362(a) only actions against bankruptcy petitioners and their property may be stayed. The court held that "because Edge's claim for conversion against Duke lies against a non-debtor and does not implicate the property of the debtors, the bankruptcy court erred by staying it." *Id*. at 301.

Next the court agreed with the district court that Edge had demonstrated that there is a disputed issue of material fact as to whether it has a gas producer's lien on the proceeds of Duke's sale of the gas, but found that Edge may not recover from Duke via an action for conversion. "The issue of whether Edge has a gas producer's lien on the proceeds raises two subsidiary questions: (1) Does Texas law, under any circumstances, provide Edge with a lien that could be enforced against the proceeds of a sale of its gas to a third party by a downstream purchaser such as Duke; and (2) assuming Texas law provides for a lien against a downstream purchaser, do the facts of this case arguably support the conclusion that Edge has one against Duke." *Id*. at 302. Only the second question was addressed by the court because it had already determined that the legal nature of the lien makes it unenforceable via a conversion action, therefore it was not determined whether there was a lien created in favor of Edge.

According to the court, under Texas law a gas producer may pursue a lien on the gas it produced, and also has a lien on the proceeds from the resale of that gas by the downstream purchaser who resells the gas. In other words the downstream purchaser does not cut off the lien. The court agreed with the bankruptcy court that "a party that benefits from proceeds subject to a statutory lien may be liable for conversion of such proceeds only if it has notice of the lien, then accepts and benefits from the proceeds." *Id*. at 308. Edge could not produce any evidence to show that Duke had notice that Edge held the lien or that Edge had not been paid by the debtors. Edge claimed that knowledge of the statute providing a lien that follows the gas or proceeds from sale thereof until cut off by a sale in the ordinary course of business or payment to the lien holder, is enough to put Duke on notice. The court said that this notice is not even close to other Texas cases dealing with the same issue because even if Duke knew the law, it did not know that Edge was owed the money. The court then affirmed the holdings of the bankruptcy court.

b. Louisiana Cases

1. ***Gulf Explorer, LLC v. Clayton Williams Energy, Inc.*, 964 So.2d 1042, (La.App. 1 Cir. June 08, 2007).**

The issue in this case was whether an operator of an oil and gas lease could recoup well costs from royalty owners, by retaining funds from production attributable to an owner who chose not to participate in the well.

Clayton Williams Energy, Inc., ("Williams") was the operator of an oil and gas producing unit, known as the 8300 RA SUA (the "Unit") that was formed by an order of the State Commissioner of Conservation, effective June 18, 2002. The plaintiff, Gulf Explorer, LLC ("Gulf"), owned certain mineral leases within the confines of the Unit. In September 2002, Williams sent a notice to Gulf of its intention to drill the SL 16901 No.1 ("Well"), as the Unit Well, and offered Gulf the opportunity to participate. Gulf never responded and pursuant to LSA-R.S. 30:10, Gulf was deemed to have chosen not to participate.

The well was completed in January 2003, with Williams paying the entire cost. In September 2003, Gulf released all of its leasehold interests in the Unit. In August 2004, the well was plugged and abandoned when it was approximately $1.3 million short of reaching payout.

Gulf filed suit in October 2003 seeking a declaratory judgment that Gulf's royalty and overriding royalty owners were entitled to their share of production from the Unit and further that Williams should either forward the proceeds directly to the royalty owners or to Gulf. Williams responded that pursuant to LSA-R.S. 30:10, "it was entitled to recover out of production from the Unit Well allocable to the tract belonging to Gulf, the nonparticipating owner, the tract's allocated share of the actual reasonable expenditures incurred in drilling, testing, completing, equipping, and operating the Unit Well, including a charge for supervision, together with a risk charge." *Id*. at 1043.

Section 10A(2)(b)(i) of the statute provides that an "operator is entitled to recover out of production from……the tract….belonging to the nonparticipating owner such tract's allocated share of….expenditure. Tract is defined as a continuous expanse of land." *Id*. at 1044. Williams the court ruled is "entitled to recover its costs of production attributable to Gulf's tract and not merely the amounts attributable to that tract minus the royalties and overriding royalties. Gulf is obligated to pay pursuant to its contracts with third parties." *Id*.

The court said that Williams had no contractual relationship with Gulf's lessors and that it was Gulf, the lessee, who was obligated to pay its lessors their royalties and overriding royalties. Williams had no obligation to pay Gulf's royalty and overriding royalty owners before it recouped its expenses from production pursuant to LSA-R.S.

30:10A(2)(b)(i). Williams had no legal or contractual obligation to pay Gulf's former royalty and overriding royalty owners any amounts due from Gulf under Gulf's leases.

2. *Burlington Resources, Inc. v. United National Ins. Co.*, 481 F.Supp.2d 567 (E.D. La. 2007)

The issue in this case is whether partial liability assumed under a contract is covered by an insurance policy. The policy at issue is with United National Insurance Company ("United") and provides first layer excess coverage to Burlington Resources, Inc. ("Burlington") for certain liabilities associated with Burlington's Joint Operating Agreement ("JOA") with Meridian Resources & Exploration Company ("Meridian"). The JOA covers three units and the Thibodaux Well No. 2 ("Well").

Burlington holds a 26% Non-operating interest and Meridian possesses a 74% Operating interest. According to the JOA Burlington does not have any operational or supervisory control over the Wells and it contains a provision requiring Burlington to reimburse Meridian for damages arising from the Well operations.

After a blowout in June 1999, claimants, alleging to be mineral interest owners and landowners ("Singleton Plaintiffs") sought recovery on claims of negligence, property damage, including environmental property damage, loss of earnings, loss of hydrocarbon reserves, and damage to sub-surface mineral formations. The allegations made by the Singleton Plaintiffs against Burlington concerned a claim that Burlington negligently failed to devise appropriate procedures to prevent further loss of minerals in the underground formations after Burlington, as Non-operator, attended meetings with Meridian regarding plans to shut-in and plug the Well.

After settlement, according to the JOA, Burlington was obligated to pay $2,565,000 or 26% of the remaining amount which was not paid by Meridian's insurance company. Burlington's primary insurance company paid $2,000,000 and as to the remaining amount United denied coverage.

United claimed that it was only to be liable if Burlington assumed total liability from Meridian or was bound as Meridian was bound. United argued that Burlington's agreement to pay a percentage of the JOA obligations in accordance with its respective interest does not constitute an assumption of Meridian's liability.

The court found that "absent the JOA provision requiring Burlington to pay 26% of Meridian's liability for any settlement amount, Burlington would not be liable for any of Meridian's actions by operation of law or contract." *Id*. at 574. United was supposed to cover any liability imposed or assumed by Burlington under any agreement or contract. The JOA contained a provision which makes Burlington partly responsible for the costs of any third party claim or any suit arising from operations, including situations where Meridian was at fault or negligent. Thus, by the express terms of the JOA, Burlington agreed to assume the tort liability of Meridian to the extent of 26%. United had to reimburse Burlington because under the JOA Burlington assumed liability and that fell under the policy limits.

3. ***Mayne & Mertz, Inc. v. Quest Exploration, LLC, et al.*, 2007 WL 2900510 (W.D. La. Oct. 4, 2007).**

This case involved whether a jury could reward damages for loss of a lease opportunity or whether those damages would be too speculative. This case involved 3-D seismic data related to oil and gas exploration. Mayne & Mertz, Inc. ("M&M") contacted Excalibur Land Company, Inc. ("Excalibur") and Texas Tea, L.L.C. to do seismic operations on Excalibur's lands in Calcasieu Parish, Louisiana in order to find optimum well sites. M&M entered into a contract with Excalibur which gave it the right to acquire mineral leases on such lands for eighteen months, with the right to extend the leases for an additional six months. As a part of the contract M&M had to provide the seismic survey data to Excalibur, subject to certain confidentiality provisions.

Using the data, M&M drilled a successful well ("Well") prior to the time the contract was to expire. Later the two parties signed a letter agreement, in anticipation of additional drilling, which gave M&M the right to "acquire an oil, gas, and mineral lease on lands owned by Excalibur." *Id*. at *1. M&M then requested a mineral lease on 409 acres which Excalibur refused to grant. A few months later Excalibur and Quest Exploration, LLC ("Quest") entered into a Non-Disclosure and Confidentiality Agreement wherein Quest would review the seismic data as a consultant. After reviewing the data Quest requested a lease on the same area M&M had previously requested and was leased the land ("Straight Line Prospect") for drilling by Excalibur.

M&M filed a complaint claiming amongst other things that Excalibur misappropriated its trade secrets by giving the seismic data to Quest and that Quest misappropriated its trade secrets by using the seismic data. Excalibur asserted that "if M&M is able to prove a breach of contract between itself and Excalibur, M&M has the burden of proving with full legal certainty, that Excalibur's breach has caused it to sustain damage….[which] it cannot do." *Id*. at *2. Quest filed a similar motion and both motions essentially contend that M&M could not meet its burden under either state or federal law to establish damages because the evidence relied upon was too speculative.

M&M hired qualified experts to testify, who provided reports regarding the success of and revenue anticipated by completing a well on the Straight Line Prospect. All the experts agreed that the probability of success of the well which M&M planned to drill was 70-80 percent. Both the defendants contended that in order for M&M to meet its burden of proof it had to have completed a successful well and because no well was ever drilled on the Straight Line Prospect their motions to dismiss should be granted.

The court compared the case to *Huggs, Inc. v. LPC Energy, Inc.*, 889, F.2d 649 (5th Cir 1989), where the trial court granted plaintiffs damages for lost profits and lost royalties where the defendant operator allowed a lease to expire by failing to recommence drilling or reworking operations within ninety days after the cessation of production from a well. *Huggs* involved a closed well which was no longer producing and the defendants objected that the damages were too difficult to determine to the legal degree of certainty required. The Fifth Circuit in that case noted that "the trial court correctly relied on plaintiffs' expert testimony which included data evaluated from the previously producing well" and that "Louisiana courts allow awards of damages for lost profits in oil and gas cases if the plaintiff can prove such damages by preponderance of the evidence." *Id*. at *4.

The court stated that "while this case does not involve test data from a formerly producing well, it does provide the seismic data which M&M has successfully relied on in completing 70-80 percent of the wells drilled in the prospect area." *Id*. The court also noted that the Well drilled by M&M was drilled based on the same seismic data findings and is located immediately adjacent to the Straight Line Prospect. Based on the expert's testimony, the court held that a jury could conclude that M&M was entitled to damages for the value of the undrilled mineral lease and therefore Quests and Excalibur's motions for summary judgment were denied.

4. *U.S. v. Burlington Resources Oil and Gas Co. L.P.*, 2007 WL 773716 (W.D. La. March 9, 2007).

This issue in this case was whether Burlington Resources Oil and Gas Co., L.P. ("Burlington") was the "responsible party" under the Oil Pollution Act of 1990 ("OPA"). The United States filed a claim under the OPA to recover removal costs related to the cleanup of an oil production pit and the surrounding area. At the time of the cleanup Burlington owned an interest in the mineral servitude on the property which included the pit.

OPA states that for a person to be liable they must be a "responsible party" for a "facility." 33 U.S.C. § 2702(a). "Responsible party" includes "any person owning or operating the facility…" 33 U.S.C. § 2701(32)(B). The statute is not clear as to who an owner or operator is because it defines "owner or operator" as "any person owning or operating such facility." 33 U.S.C. § 2701 (26)(A)(ii).

The oil production pit was created in connection with oil and gas exploration and production in the 1930s and was last used in 1971. In 1986 Union Texas sold a 56.82% property interest, which included the pit, to William D. Blake ("Blake") reserving "all of the oil, gas, and other minerals in, under or that maybe produced from said land." *Id*. In 1991 Burlington's predecessor acquired the mineral interest in the property and at that time an order had been issued by the Louisiana Department of Conservation prohibiting use of the pit.

The court stated that "a mineral servitude is the right of enjoyment of land belonging to another for the purpose of exploring for and producing minerals and reducing them to possession and ownership. Plaintiff has offered no statute, case law, or evidence of customary usage that would suggest that the mineral reservation clause at issue could reasonably be interpreted as also reserving physical assets associated with mineral production." *Id*. at *2. The court went on to state that the oil production pit was permanently attached to the ground and that unless the act of sale to Blake can be evidenced to show that there is separate ownership of the pit, the pit belongs to Blake.

As a mineral servitude owner, Defendants had a limited right to use the property and that right was limited to serving the purpose of exploring for and producing minerals and it was limited to only so much land as was reasonably necessary to serve that purpose. The plaintiff conceded that the pit could no longer be used in connection with the exploration and production of minerals and therefore does not translate into any actual right to use the pit. The court stated that even if there was an obligation to clean up and restore the pit it could in no way be considered the substantial equivalent of ownership of the pit and Blake was therefore still the owner and the Defendant's motion for summary judgment was granted.

5. *Kerr-McGee Oil & Gas Corp. v. Allred*, 2007 WL 3231634 (W.D. La. Oct. 30, 2007)

The Outer Continental Shelf Deepwater Royalty Relief Act of 1995 ("DWRRA"), codified at 43 U.S.C. § 1337, was enacted by Congress to encourage exploration of oil and gas in the Gulf of Mexico's deepwater. The DWRAA replaced the Secretary's discretion to set the volume of royalty suspension for leases issued between November 28, 1995 and November 28, 2000 ("Mandatory Royalty Relief Leases"). *See* 43 U.S.C § 1337(a)(3)(C)(i).

On January 6, 2006, Kerr-McGee Oil & Gas Corp. ("Kerr-McGee") was ordered to pay royalties on eight deepwater leases by Acting Assistant Secretary Burton, on natural gas it produced in 2003, and on both oil and natural gas it produced in 2004 ("Burton Decision"). The eight deepwater leases were issued as Mandatory Royalty Relief Leases pursuant to the DWRRA and contained language that made the statutory royalty relief subject to specified price thresholds. Under the terms of such leases, Kerr-McGee was obligated to make royalty payments if the commodity price of oil or gas exceeded a prescribed price threshold level ("Price Threshold") . Kerr-McGee challenged the Burton Decision stating that its eight deepwater leases were not subject to the specified Price Thresholds.

The Outer Continental Shelf Lands Act ("OCSLA") gives the Secretary of the Interior ("Secretary") the authority to issue and administer oil and gas leases on the Outer Continental Shelf and to promulgate implementing regulations. 43 U.S.C. § 1334(a). The DWRRA amended OCSLA and gave the Secretary the authority to suspend royalties on certain volumes of initial production from the deepest areas of the Gulf of Mexico. 43 U.S.C § 1337(a)(3)(C)(i) & (ii). Three specific schemes were established for royalties from deepwater leases. 43 U.S.C § 1337(a)(3)(C)(v)-(vii).

First, under Section 302 of the DWRRA, leases existing as of November 28, 1995 were permitted to apply for royalty relief, which the Secretary would award if the lease would otherwise not be economic. In addition, Section 302 provided that no royalty relief was allowed if the price of oil or gas meets a certain price threshold, as statutorily defined by Congress. Second, under Section 304 of the DWRRA, Congress provided for royalty relief to leases enacted between November 28, 1995 and November 28, 2000. Third, under Section 303 of the DWRRA, the Secretary was authorized to provide royalty relief and impose price thresholds on leases issued after the five-year period ended on November 28, 2000.

Interpreting Section 304, the Burton Decision found that Kerr-McGee owed royalties from the eight leases because price thresholds were satisfied. The Burton Decision rejected Kerr-McGee's interpretation that the Mandatory Relief Leases are not subject to price thresholds and found that the royalty relief available to the eight Kerr-McGee leases was limited by price thresholds contained in the terms of the leases, imposed pursuant to Congressional authority.

Kerr-McGee argued that it was Congress' intent to establish mandatory royalty relief for specified volumes in the DWRRA and that the mandatory royalty relief provision, Section 304, prevented the Secretary from enacting price thresholds. The Secretary argued that the DWRRA clearly established the authority to establish price thresholds on Mandatory Royalty Relief Leases and Section 304 did not deprive the agency of its ability to establish price thresholds because Section 304 specified the use of the Section 303 bidding system.

In summarizing the dispute, the court stated "the crux of this case is whether Section 304, which requires mandatory royalty relief for specified volumes, also stripped the Interior of its discretion to set price thresholds that would apply before a Mandatory Relief Lease produced the minimum volume of royalty free production."

The court began its analysis by reviewing the Fifth Circuit's decision of *Santa Fe Snyder Corp. v. Norton.* In this decision, the Fifth Circuit found that Section 304 of the DWRRA clearly articulated Congress' unambiguous intent that the royalty relief for Mandatory Royalty Relief leases was automatic and unconditional. Thus, under *Santa Fe Snyder*, the Fifth Circuit found that the Interior's addition of new production requirements was contrary to law.

The court found that the price threshold requirement in Kerr-McGee's Mandatory Royalty Relief leases was similarly unlawful under the plain text of the DWRRA because the DWRRA's Section 304 applying to new leases, clearly require minimum royalty relief. The Interior had no discretion to enact a price threshold requirement that applied to volumes below the minimum volume of royalty free-production. The court held that the Secretary exceeded its Congressional authority by imposing price threshold requirements on Kerr-McGee's eight deepwater leases.

The Secretary raised several contractual affirmative defenses, however because contractual defenses are not available when the Government makes a contract contrary to law, the Interior's affirmative defenses were unavailing and were dismissed as a matter of law.

Reaction to the Case

In an article written by David Ivanovich for the Houston Chronicle, Mr. Ivanovich reports that Democrats in Washington are pushing Bush to appeal the ruling. House Natural Resources Committee member, Nick Rahall, D-W.Va, wrote a letter to President Bush saying "This ruling could result in an unconscionable giveaway to the oil and gas companies on behalf of the American taxpayer." According to the article, the issue of appeal is under review according to a White House spokesman.

Mr. Ivanovich also reports that as many as nine other energy companies plan to move forward with similar lawsuits. Originally the Interior's Mineral Management Service estimated the federal government could now lose more than $60 billion in royalties; however that number is believed to be overstated. If the ruling stands the MMS would have to return about $1.2 billion in royalties which has already been collected. The article also states that lawmakers have acknowledged that it may be difficult to win the case on appeal.

Proposed Rules Dealing with Royalty Relief

Federal Register/Vol. 72, No. 245/Friday, December 21, 2007/Proposed Rules

30 CFR Parts 203 and 260
RIN 1010-AD29

Royalty Relief for Deepwater Outer Continental Shelf (OCS) Oil and Gas Leases – Conforming Regulations to Court Decision

This proposed rule would amend 30 CFR parts 260 and 203 to conform the regulations to the decision of the United States Court of Appeals for the Fifth Circuit in *Santa Fe Snyder Corp., et al. v. Norton*, which found that certain provisions of the MMS regulations interpreting section 304 of the Deep Water Royalty Relief Act are contrary to the requirements of the statute. The proposed revisions would conform the regulations to the court ruling in order to treat leases issued under Section 304 (referred to as "Eligible Leases") in a manner consistent with the *Santa Fe Snyder* ruling.

The revisions to the regulations in part 260 would modify § 260.3 relating to MMS's authority to collect information and remove references in § 260.113(a) to prior production on the field to which a lease is assigned. Deletions in § 260.114 would remove paragraphs on procedures for notification, determination of royalty suspension volumes (RSVs), and having more than one RSV on a lease because they would no longer be required. Section 260.114(b) would also be revised to change the reference to "fields" to a reference to "each eligible lease." Section 260.124 would be revised to remove a reference to eligible leases establishing an RSV for a field, which is not valid under section 304 of the Act, as interpreted in *Santa Fe Snyder*. Finally, all of § 260.117 would be eliminated because provisions for allocation of RSV among multiple leases on a field would no longer be needed.

Changes in 30 CFR part 203, would delete references to "eligible leases" in § 203.69 and would change the sharing rule in § 203.71 for purposes of consistency. It would remove the Eligible Leases from the section that discusses how to allocate RSVs on a field. Those changes mean that regardless of the outcome of an application for royalty relief for leases issued either before or after the 5-year period covered by section 304, which may affect the field to which they are assigned, both Eligible Leases and leases issued in sales held after November 25, 2000 (referred to in the regulation as "Royalty Suspension" (RS) leases), would get the full RSVs stated in the lease instrument. Further, as with an RS lease, production from an eligible lease would count against any RSVs available to pre-Act leases on a field to which eligible leases or a RS lease has been assigned. However, unlike RS leases, lessees of eligible leases may not initiate an application seeking, or requesting a share in, an additional RSV granted to an RS lease. This is because there would now be more than enough financial incentive for any single lease.

The proposed rule would be effective immediately upon being published as a Final Rule with retroactive effect to April 24, 1996.

c. Oklahoma Cases

1. *McCall v. Chesapeake Energy Corp.*, 164 P.3d 1120 (Okla. Civ. App. Div. 2, 2007).

This case was brought by a working interest owner in natural gas wells seeking a determination of the rights and responsibilities under a joint operating agreement ("JOA") with the operator of the wells, and seeking a finding that the JOA was not a marketing agreement, and that she was entitled to market her proportionate share of production from the wells under the Natural Gas Market Sharing Act ("NGMSA"). The operator claimed that it had no obligation to market the owner's share of production under the NGMSA.

Mary McCall ("McCall") owns a Non-operating interest in four wells located within a unit. Chesapeake Operating, Inc. ("Chesapeake") is the Operator of the unit which includes all four wells. Three of the four wells in which McCall owned an interest in were subject to JOA's which were based on a standard industry model form.

In July 2004, Chesapeake notified McCall of its plans to market the production from the four wells. McCall, through her attorney, notified Chesapeake by letter of her objection to the plans and stated that she was electing to exercise her rights under the provisions of the NGMSA to market her share of production. According to the NGMSA "an owner in a well may compel the well operator or other designated marketer to either sell the gas on the owner's behalf or find a market for that owner's gas. The operator or other designated marketer shall find an independent, non-affiliated purchaser for the electing owner's gas, or the designated marketer shall produce and sell gas for the account of the electing owner." *Id*. at 1122.

In response to the letter, Chesapeake refused to market McCall's share of the gas from the three wells subject to the JOA's claiming that according to the JOA each party was required to market its own production. Chesapeake did offer to market McCall's gas under its standard marketing agreement, but McCall declined to sign the agreement and brought this lawsuit.

The court stated that the purpose of the NGMSA is to "protect the rights and correlative rights of all owners in wells producing natural gas…and to afford all such owners an equal opportunity to produce and market their share of gas and to receive the proceeds derived there from..[and] further..to protect such owners against discrimination in purchases in favor of one owner as against another." *Id*. at 1124, 1125. However, there are several provisions to the NGMSA that make certain owners ineligible to elect to market their share of gas. One of those provisions states that owners may not elect to market their share of gas who are "subject to a balancing agreement or other written agreement which expressly provides for the taking, marketing or balancing of gas in a manner other than is provided for in this Act." *Id*.

The JOA which governed three of the wells specifically had in it, provisions governing the "taking, sharing, marketing, or balancing of gas" therefore, McCall cannot market her share of the production from these three wells under the NGMSA. *Id*. "The JOA between McCall and Chesapeake are preprinted industry model forms, under the terms of which each working interest owner is obligated to take in-kind or separately dispose of its proportionate share of the oil and gas produced from the unit." *Id*. As to the fourth well not governed by a JOA McCall must bear her proportionate share of the 3% marketing fee deducted by Chesapeake. The court affirmed Chesapeake's motion for summary judgment.