INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

Comments on BOEM's Risk Management, Financial Assurance, and Loss Prevention ANPR

November 17, 2014

Via e-filing on www.regulations.gov

Janice M. Schneider
Assistant Secretary – Land and Minerals Management
1849 C Street, N.W.
Washington, DC 20240

Re: RIN 1010-AD83. *Risk Management, Financial Assurance and Loss Prevention*, Advance Notice of Proposed Rulemaking published in the Federal Register on August 19, 2014 (79 Fed. Reg. 49,027).

Dear Assistant Secretary Schneider:

On behalf of our members, the Independent Petroleum Association of America ("IPAA") appreciates the opportunity to provide comments to the Bureau of Ocean Energy Management ("BOEM") in response to the Advance Notice of Proposed Rulemaking ("ANPR") regarding financial assurance requirements for the Outer Continental Shelf ("OCS"). In particular, we applaud your decision to initiate a rulemaking to update BOEM's regulations, rather than imposing changes through a Notice to Lessees.

By way of background, the IPAA represents nearly 10,000 independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts. Independent producers drill about 95 percent of American oil and natural gas wells, and produce about 54 percent of American oil and more than 85 percent of American natural gas.

Independents also serve a unique and critical function in the OCS. They increase the range of reserves that can be commercialized.[1] For example, they are able to find and develop smaller fields that the majors would not consider for development, and they are more likely to drill marginally producing wells in mature fields.[2] Throughout the past decade independents have made significant contributions to both drilling and exploration, and several times in recent years have drilled more than 50% of all wells and more than 50% of exploration wells in the deepwater Gulf of Mexico.[3] They also continue to be the dominant presence in shallow waters.[4]

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1 IHS Global Insight (USA), Inc., "The Economic Impact of the Gulf of Mexico Offshore Oil and Natural Gas Industry and the Role of the Independents," pg. 5 (July 21, 2010).
2 *Id*. at 15.
3 *Id*. at 15-16.

Should BOEM impose unduly burdensome regulations which would work to exclude independents from the Gulf of Mexico, the resulting financial impact would be vast and regrettable. In 2010, independents were the largest shareholder in 66% of the 7,521 leases in the Gulf of Mexico, including holding a 52% interest in all of the Gulf of Mexico's deepwater leases.[5] That same year they also operated over half of the developing and producing deepwater fields.[6] Based on these figures the economic forecasting firm IHS Global Insight calculated that independents would contribute an estimated $147 billion in federal, state and local revenues between 2010 and 2020, including $42 billion in federal royalty payments.[7] BOEM's ANPR comes at a time in America's energy revolution when the presence of independent oil and natural gas explorers and producers in the Gulf of Mexico is as important as ever and should be supported and encouraged.

This ANPR also follows BOEM Regional Director, John Rodi's 2013 presentation regarding "Supplemental Bond Issues Related to Decommissioning Liability," which solicited feedback on 10 specific questions related to bonding. At the outset of these comments we reiterate the concerns the OCS Advisory Board voiced in response to that presentation. Requiring excessive bond coverage is a "waste of capital" that would otherwise be productively used in offshore operations, and "unnecessarily uses industry bonding capacity."[8] It is imperative that BOEM give scrutiny to its current system to rationalize its approach to security, and avoid the disincentives to investment in the OCS caused by requiring unnecessary levels of security.

IPAA firmly believes that only through continued dialogue with operators can BOEM create a viable regulatory structure. We look forward to working with BOEM to prepare smart and effective financial security requirements.

EXECUTIVE SUMMARY

BOEM's current system for assuring that companies have adequate capital to remove offshore production facilities is broken. The federal government (and therefore the American taxpayer) has never yet had to spend a penny to plug old offshore wells or remove production facilities. But BOEM and its sister agency, the Bureau of Safety and Environmental Enforcement ("BSEE"), have acted in the last four years to tie up more and more company capital in bonds the government does not need or use. The current bonding requirements are not merely *duplicative*; they are *multiplicative* – requiring, for example, that companies provide $80 million in assurance to cover the same $20 million removal operation. The effect of this action has fallen disproportionately on independent producers.

While IPAA members agree that there is a role for government-required bonds to assure production facilities are removed, they also agree that the era of overbonding must end. To bring that era to a close, IPAA recommends eight steps to assure that bonds cover actual and imminent removal costs, not multiplicative and speculative removal costs.

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4 *Id*. at 5.
5 *Id*. at 6 (defining deepwater for purposes of the study to mean 650 feet).
6 *Id*.
7 *Id*. at 12.
8 *See* "OCS Advisory Board Response to BOEM/BSEE (Bureau) Bonding Questions" at page 6.

1. When determining whether a company is financially strong enough not to have to post a supplemental bond for production facility removal, BOEM should not treat the company as if it owes 100% of the cost to clear a site when it owns only 20% of the lease.

2. When determining whether a company is exempt from bonding or in determining the amount needed for a supplemental bond, BOEM must give credit for money already held in escrow – whether it is a privately-managed or federally-managed escrow. Requiring a $10 million bond to cover a $10 million removal operation is pointless when an escrow account already holds $10 million for that very purpose.

3. When determining a company's "net worth," BOEM must recognize that general accounting principles already subtract from a company's net worth the cost of abandoning wells and removing production facilities. The "asset retirement obligations" ("AROs") are ignored by BOEM, and BOEM effectively double counts the costs of removal by subtracting its own estimates of removal liability from a net worth already reduced by AROs.

4. When determining whether a company is exempt from bonding, BOEM should use modified criteria of financial strength – criteria used by financial institutions in lending – to assure it does not have to deal with another bankruptcy like that of ATP Oil and Gas Corporation. IPAA proposes modified criteria below.

5. Currently, BOEM might exempt from bonding a company with a net worth of $100 million. But if the same company has a net worth of only $95 million, BOEM will require the company to provide supplemental bonds to cover production facility removal liabilities. If the company's removal liability is $25 million, it posts no bonds if its net worth is $100 million, but $25 million in bonds if its net worth is $95 million. BOEM should more rationally limit the supplemental bond to the $5 million difference between the two net worth calculations.

6. Currently, if a current lease operator fails to plug wells and remove production facilities on a lease, BOEM and BSEE order co-lessees and prior lessees to bear the burden. But the agencies do not make the bonds available to cover the costs of the "decommissioning" work (the plugging and removing of wells and equipment). BOEM must alter its policy to let those willing to decommission have access to the funds of those who fail to fulfill their obligations.

7. Currently, BOEM requires supplemental bonds prematurely. A lessee may, for example, file an exploration plan to drill up to seven wells. At the time the plan is approved, but years before many of the wells might be drilled, BOEM requires bonds to cover the cost of abandoning all seven wells. If the first well is a dry hole, however, the company may abandon the rest of the plan. Yet BOEM, already sitting on too much of a bond, is notoriously slow to release the bond – keeping company capital tied up needlessly. BOEM should instead require a bond only when the lessee is ready to drill the given well, limit the bond to the cost of plugging that well, and release the bond within an agreed timeframe when the lessee shows the well has been properly plugged.

8. BOEM's method of determining bond amounts utterly disregards accounting standards of the Financial Accounting Standards Board. If a lessee proposes to install production facilities which are expected to produce for 15 years, BOEM will calculate the full cost of the removal 15 years in the future, without discounting that cost to its present value. That approach takes away capital that could be spent more productively, either in producing additional oil and gas or in conducting currently-due decommissioning operations. Instead, BOEM should bond only the

present value of the future cost, and meet with the lessee annually to adjust bond amounts for all the lessee's removal liabilities, eliminating the cost of those already performed and increasing the amounts as future removals become more imminent.

With these changes, BOEM can provide sufficient and rational assurance that wells will be plugged, production facilities removed, and lease sites abandoned in the manner required by law. But it can also free up capital for the equally important task of prompt, safe, and environmentally-sensitive development of our still untapped offshore oil and gas resources.

OVERVIEW OF DECOMMISSIONING AND FINANCIAL RESPONSIBILITY

The OCS contains significant quantities of oil and gas supplies – including substantial amounts in undiscovered and undeveloped fields which BOEM has estimated account for 69 percent of the oil and 26 percent of the natural gas resources estimated to be contained in the OCS, State waters, and onshore areas of the continental United States and Alaska.[9] Periodically the BOEM leases the right to explore for and develop these minerals at sealed bid auctions.[10] Operators buy the right to extract oil or gas subject to royalty and rental payments, a commitment to operate in an environmentally sound manner, and to remove facilities at the end of the useful life of the lease.[11]

The Interior Department oversees decommissioning to assure that operations conform to federal regulations and do not create future residual liability. To this end, the current regulations treat all lessees, operators, and operating rights interest owners as jointly and severally liable for all lease obligations.[12] Even when a company sells or assigns its interests in the OCS, the BOEM can look back through the chain of title and hold that company liable for decommissioning obligations should the current interest holder fail to meet its obligations. The government has also adopted the position that liabilities accrue when wells are drilled, platforms or other facilities built, and pipelines laid.[13] If, for example, the original lessee obtained a lease and drilled a well in 2008, and the lease was assigned each year for the next six years, then seven companies would be liable for the permanent plugging and abandonment of that well.[14]

A. The Physical Decommissioning Process

Decommissioning means "ending oil, gas, or sulphur operations; and returning the lease or pipeline right-of-way to a condition that meets the requirements of the regulations of BSEE and other agencies that have jurisdiction over decommissioning activities."[15] It is the physical process of "shutting down operations, closing the wells, cleaning and making the platform safe,

[9] *See* BOEM Oil & Gas Energy Program webpage at http://www.boem.gov/Oil-and-Gas-Energy-Program/.
[10] *See*, *e.g.*, United States Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region Sale No. 238 Sale Day Statistics (August 20, 2014).
[11] Mark J. Kaiser & Allan G. Pulsipher, *A Review and Update of Supplemental Bonding Requirements in the Gulf of Mexico* 3 (October 2008), prepared under MMS Contract M07AC12448.
[12] 30 C.F.R. § 250.1701.
[13] 30 C.F.R. § 250.1702.
[14] *Id*.
[15] 30 C.F.R. § 250.1700(a).

and moving, disposing of, or relocating facilities."[16] Although each decommissioning project is different, they usually include a combination of the following activities:

- Planning;
- Regulatory compliance;
- Well plugging and abandoning;
- Platform preparation;
- Pipeline abandonment;
- Conductor removal;
- Topsides (deck structure and equipment) removal and disposal;
- Substructure (jacket and piling) removal and disposal; and
- Site clearance and remediation.[17]

The most common projects involve flushing and cleaning the facility topsides offshore, and transporting the structure to shore for sale as scrap with waste material going to a landfill.[18] Then the substructure is removed and transported to shore for scrap.

1. Platform Removal

The platforms themselves come in various configurations:

- Free-standing caissons with well(s);
- Well-protector jackets;
- Braced caissons with wells;
- Conventionally piled platforms with wells;
- Conventionally piled platforms without wells;
- Skirt-piled platforms; and
- Special application platforms (*e.g.*, mud slide resistant, wells in legs, and buoyant deep-water structures).[19]

Conventional platforms are secured to the seafloor by steel pipes called piles (or pilings) driven through the legs of tubular frames called jackets.[20] Only the upper portions of the jacket are visible above the water surface.[21] The deck portion of the platform rests on top of the jacket.[22] Most decks are multilevel structures that support drilling rigs, production equipment, crew quarters, and serve various other functions.[23]

Platform components are often large and heavy. Jackets in 100 feet of water can weigh as much as 600 tons and in 300 feet of water more than 2,000 tons.[24] Decks can weigh from 100

[16] Dr. Robert C. Byrd, Donald J. Miller & Steven M. Wiese, 2014 AACE International Technical Paper, EST.1648 Cost Estimating for Offshore Oil & Gas Facility Decommissioning, 1648.6 (2014).
[17] Kaiser & Pulsipher, *supra* note 11, 10-12, 17; Byrd, *et al.*, *supra* note 16, 1648.6.
[18] Byrd, *et al.*, *supra* note 16, 1648.7.
[19] MMS, *An Assessment of Techniques for Removing Offshore Structures*, Washington, DC: The National Academies Press, 7 (1996).
[20] *Id*. at 5.
[21] *Id*.
[22] *Id*.
[23] *Id*.
[24] *Id*. at 10.

tons to more than 3,000 tons.[25] Conductor weight varies with the number and size of casing strings and water depth; conductors usually weigh from 20 tons to more than 150 tons.[26] Soil shear resistance on the pipe, depending on the depth of the cut, can add several tons to removal forces.[27]

In general, platforms (at least those not toppled by a hurricane) are removed in the reverse order of installation: first the deck is removed, then the conductors, the piling, and the jacket.[28] Regulations require piling and conductors to be severed at least 15 feet below the mudline.[29] Severing these sections at a designated elevation is done by mechanical cutters, abrasive water jets, or explosives.[30] The topside facilities, deck, conductors, piles, and jacket are removed and placed on a materials barge.[31] Derrick barges are large, floating, ocean-going vessels which either have ship-shaped or rectangular hulls, or are semisubmersible.[32] They are equipped with revolving cranes that are built into the hull of the vessel. Crane capacity on a small derrick barge (240 feet by 70 feet) ranges from 150 to 300 tons. Larger hull vessels (350 feet by 100 feet) have crane lift capacities of 600 to 800 tons. A few large derrick barges in the Gulf of Mexico have 1,600- to 7,000-ton lift capabilities.

The size and capacity of a derrick barge stands in contrast with those of a lift-boat. Lift-boats, which are limited to water 200 feet deep or less, are self-propelled self-elevating vessels with three or four legs connecting a lower mat to the upper hull.[33] The mat is lowered to the seafloor, where it serves as a shallow foundation supporting the upper hull, which is jacked up above the water surface. The hull dimensions are generally 70 feet by 120 feet or less. Lift-boats can house from 10 to 25 people. When outfitted with cranes, lift-boats have a capacity of 10 to 200 tons. They can be used to plug and abandon ("P&A") wells, set cement plugs, and remove production tubing.

The agency's own studies indicate that certain platform abandonment methods – such as leaving them in place, toppling them in place, or using them for artificial reefs – may be preferred over complete removal and would not require the same level of bonding.[34]

2. <u>Pipeline Abandonment</u>

The BOEM allows pipelines to be decommissioned in place when the pipeline does not constitute a hazard to navigation or commercial fishing operations, unduly interfere with other uses of the sea bottom, or have adverse environmental effects.[35] Decommissioning includes "pigging, flushing, filling the pipeline with seawater, cutting and plugging each end, burying

[25] *Id*.
[26] *Id*.
[27] *Id*.
[28] *Id*.
[29] 30 C.F.R. § 250.1716; Byrd, *et al.*, *supra* note 16, 1648.13.
[30] Byrd, *et al.*, *supra* note 16, 1648.13.
[31] *Id*. at 1648.15.
[32] *Assessment of Techniques*, *supra* note 19, at 10; also based on IPAA member input.
[33] *Id*.
[34] *Id.* at 3 ("Leaving platforms in place, partially removing them, toppling them in place, or using them for artificial reefs are options that are economically and environmentally attractive to many ocean users groups. Transport costs, concerns about liability, and regulatory issues now limit their use.")
[35] 30 C.F.R. § 250.1751-1754; Byrd, *et al.*, *supra* note 16, 1648.10.

eacend at least 3 feet below the seafloor or covering each end with concrete mats, and removal of all pipeline valves and other fittings that may interfere with other uses of the OCS."[36]

3. Site Clearance

The final step in the decommissioning process is to clear the site of all debris that has accumulated on the seafloor. In water depths less than 300 feet, all decommissioned locations must be cleared of all obstructions created by oil and gas activities.[37] For a platform or other facility site in water depths less than 300 feet, a trawl with heavy nets must be dragged over the site.[38] For a platform or other facility site in water depths 300 feet or more, operators must either drag a trawl over the site, scan across the site using sonar equipment, or use another approved method.[39]

The options for disposing of offshore structures include complete removal with disposal ashore, placement in an approved ocean disposal site, conversion to a fishing reef, or removal for refurbishing and replacement elsewhere. In approved cases, maintenance in place is an alternative to removal.[40]

4. Timing, Cost, and Trends

Decommissioning times vary, depending on the size of the platform and the amount of equipment on it.[41] Deck weight and jacket weight serve as a proxy for the topsides equipment preparation costs that increase as deck or jacket weight increases.[42]

Cost of material disposal post-decommissioning also varies depending on location. For example, the Gulf of Mexico has an established infrastructure for material disposal; whereas that is not the case along the West Coast.[43] The primary cost driver in offshore structure removal is the cost of derrick barge services.[44]

Studies have noted two trends: refurbishing and reusing platforms is becoming less common; and operators are opting to use rigless methods to P&A wells, in place of a drilling or work-over rig.[45] Companies increasingly identify rigless decommissioning as a significant cost-saving opportunity. Costs for a rigless P&A operation in the Gulf of Mexico average $60,000 per day while the cost to bring a rig to the site ranges from $200,000 - $1.2 million per day.[46]

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36 30 C.F.R. § 250.1751; Byrd, *et al.*, *supra* note 16, 1648.10.
37 Byrd, *et al.*, *supra* note 16, 1648.21.
38 *Id*.
39 30 C.F.R. § 250.1741; Byrd, *et al.*, *supra* note 16, 1648.21.
40 *Assessment of Techniques*, *supra* note 19, R5.
41 Byrd, *et al.*, *supra* note 16, 1648.14.
42 *Id*.
43 *Id*. at 1648.18.
44 *Id*. at 1648.15.
45 *Id*. at 1648.7-8.
46 *See* Donnie Miller, Rigless P&A Cost Expectations, Oil Pro blog at http://oilpro.com/post/6025/rigless-pa-cost-expectations.

5. Costs of Decommissioning in the Pacific OCS Region

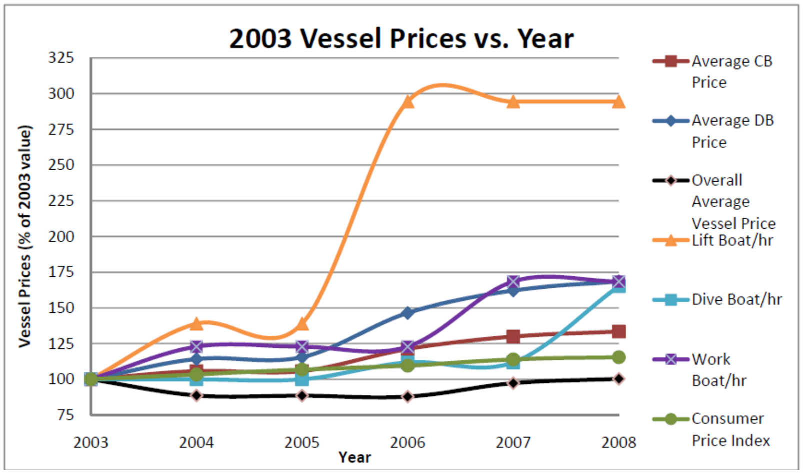
The agency's most recent pronouncement from the Pacific OCS Region is Notice to Lessees No. 2010-P05 effective February 19, 2010.[47] It announced the 2010 updated report on decommissioning costs off the coast of California. The Pacific OCS Region issued a prior report in 2004 and expects to prepare another updated decommissioning cost report in 2015. This report is "one of the inputs" used in supplemental bonding decisions.[48]

The 2010 Report estimated that $1.2 billion (2009 dollars) would be needed to remove the 23 OCS platforms in that Region.[49] The 2010 report assumed that all 23 platforms would be completely removed, but pipelines outside state waters would be abandoned in place.[50] Removal was projected to occur between 2015 and 2030.[51] At the time of the report, only four platforms had been removed – all from state waters, all by Chevron, all in 1996.[52]

All Pacific OCS Region platforms are fixed structures. So, there is a direct relationship between water depth, weight, and removal costs.[53] For example, Platforms Harmony and Heritage are in more than 1,000 feet of water. Both have more than 55,000 tons of steel. Each is projected to cost $150 million to remove. At the other end of the spectrum, nine platforms are in water shallower than 200 feet. They have less than 5,000 tons of steel. Removal costs per platform range from a low of $12 million to a high of $35 million. Finally, in the middle range is Platform Harvest in the Pt. Arguello unit. It is in 675 feet of water, and weighs 29,000 tons. Its removal cost is estimated to be $88 million.

The report estimates 15% of total cost is simply mobilizing and demobilizing derrick barges brought from the Gulf of Mexico or Asia.[54] That is about $180,000,000 of the $1.2 billion. Figures like this, however, highlight that the agency's idle iron program has artificially inflated decommissioning costs. For example, as the chart below from MMS's study demonstrates, as demand increased for various vessels used in decommissioning without a similar increase is supply, the prices charged by vessel operators increased significantly.[55]

[47] United Stated Department of the Interior, Minerals Management Service, Pacific OCS Region, Notice to Lessees and Operators of Federal Oil and Gas Leases in the Pacific Outer Continental Shelf Region, "Decommissioning Cost Report Update," NTL No. 2010-P05 (February 19, 2010).
[48] *Id*.
[49] Proserv Offshore, Decommissioning Cost Update for Removing Pacific OCS Region Offshore Oil and Gas Facilities, USDOI Contract M09PC00024 (January 2010) at iii.
[50] *Id*. at 3-1.
[51] *Id*. at 3-1.
[52] *Id*. at 1-1.
[53] *Id*. at A-4, A-5 (*cf*. Appendix 2 *with* Appendix 3).
[54] *Id*. at iv.
[55] *Id*. at A-21.



This increase does not reflect normal market conditions.

No similar cost report has been prepared for the Gulf of Mexico OCS Region.

6. Floating Production Systems

Agency-commissioned studies tend to focus on abandonment of fixed platforms, and provide only a cursory overview of the decommissioning of Floating Production Systems ("FPS"). Floating Production Storage and Offloading vessels, or FPSOs, are offshore production facilities that house both processing equipment and storage for produced hydrocarbons. Besides FPSOs, similar floating systems include Floating Storage and Offloading systems (FSOs), Floating Production Systems (FPSs) and Floating Storage Units (FSUs). There are also Floating Drilling Production Storage and Offloading vessels (FDPSO) but they have not yet made an appearance in the Gulf of Mexico. Under the decommissioning regulations the term "Facility" includes:

> Installations permanently or temporarily attached to the seabed on the OCS (including manmade islands and bottom-sitting structures). They include mobile offshore drilling units (MODUs) or other vessels engaged in drilling or downhole operations, used for oil, gas or sulphur drilling, production, or related activities. They include all floating production systems (FPSs), variously described as column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc.[56]

The decommissioning process for a spar, FPS, and FPSO is regulated in a manner similar to conventional platforms. Wells must still be P&A'd in accordance with federal regulations, and pipelines must also be decommissioned as previously described. Mooring and anchor piles may be retrieved or abandoned in place. The hull may be removed from the field for salvage or reuse. However, removal of a spar hull is complicated by its large draft (600+ feet in the water column) and so several spar-based projects have proposed onsite abandonment.[57]

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[56] 30 C.F.R. § 250.105.
[57] James B. Regg, *et al.*, Deepwater Development: A Reference Document for the Deepwater Environmental Assessment Gulf of Mexico OCS (1998 through 2007), OCS Report MMS 200-015, 89 (May 2000).

7. Rigs-to-Reefs Program

Current regulations allow the appropriate conversion of retired platforms for reefs when such platforms are permitted and designated for use by a state artificial reef program and within areas established for receipt of platforms for the enhancement of habitat for fish and other aquatic life. Under the Rigs-to-Reefs program BSEE has the authority to “grant a departure from the requirement to remove a platform or other facility and allow partial structure removal or toppling in place so that the structure can be converted to an artificial reef.”[58] In order to qualify for a departure, the lessee/operator must demonstrate that:

- The structure becomes part of a State reef program that complies with the National Artificial Reef Plan;[59]

- The State agency acquires a permit from the U.S. Army Corps of Engineers and accepts title and liability for the reefed structure once removal/reefing operations are concluded; and

- The operator satisfies any U.S. Coast Guard navigational requirements for the structure.[60]

The reefing proposal must also comply with BSEE’s engineering and environmental standards, including that it must not endanger nearby infrastructure, avoid space-use conflicts with other users of the OCS, and must not hinder future oil and gas or energy development.[61] BSEE has stated that “departures from removal requirements associated with platforms toppled due to structure failure will not be granted.”[62]

B. Bonding

All operators are required to post a general bond to ensure compliance with rent, royalties, abandonment, site-clearance, and environmental damage and clean-up activities not related to oil spills. Additional security will also be required when the cost to meet all potential present and future lease abandonment obligations exceeds the amount of the general bond unless one of the current lessees can demonstrate the financial capability to meet these obligations.

1. General Bond

Before BOEM will issue a new lease or approve the assignment of an existing lease, the regulations provide that the lessee or another record title owner for the lease must maintain a bond with the Regional Director that guarantees compliance with all lease terms and conditions.[63]

[58] 30 C.F.R. § 250.1730.
[59] All five Gulf of Mexico coastal states have approved artificial reef plans.
[60] *See* Bureau of Safety and Environmental Enforcement Interim Policy Document, “Rigs-to-Reefs” Policy, IPD No. 203-07, ¶ 5.A.
[61] *Id*. at ¶ 5.D.
[62] *Id*. at ¶ 5.D(6).
[63] 30 C.F.R. § 556.52(a).

A bond review will also be conducted prior to the request for any changes to a lease assignment or an operational activity such as an Exploration Plan (EP), Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD).[64] This includes any changes to the Record Title owner, or Designated Operator of a lease or a holder of Right of Use and Easement (RUE) or Right of Way (ROW).

General Lease Surety Bonds can be lease specific, or they can be areawide. The bond amount is determined by the level of activity on the lease:

	Lease or Lease Assignment **(No Operations, No Activity)**	**Lease Exploration Activities** **(Exploration Plan, Wells)**	**Lease Development and Production Activities** **(Submitting or significant revision of DOCD or DPP)**
Lease specific bond	$50,000	$200,000	$500,000
Company areawide bond	$300,000	$1,000,000	$3,000,000
Timing	Before BOEM issues a new lease or approves the assignment of an existing lease.	(a) The date you submit a proposed EP for approval; or (b) The date you submit a request for approval of the assignment of a lease on which an EP has been approved.	(a) The date you submit a proposed DPP or DOCD for approval; or (b) The date you submit a request for approval of the assignment of a lease on which a DPP or DOCD has been approved.

The Regional Director has the authority (for good cause) to allow submittal of the lease exploration bond after the EP has been submitted but before any drilling activity is approved under the EP, or to allow submittal of the lease development bond after the DPP or DOCD has been submitted, but before the installation of a production facility or the commencement of drilling activities under the DPP or DOCD.[65] The BOEM's public presentations, however, indicate that the EP, DOCD or DPP will not be approved until all bonding has been reviewed and deemed acceptable.[66]

Although the regulations focus on surety bonds, the lessee may also pledge Treasury securities that are negotiable at the time of submission for an amount of cash equal to the value of the required bond[67] or alternative types of security as approved by the Regional Director.[68]

[64] 30 C.F.R. § 556.53.
[65] *See* 30 C.F.R. § 556.53(a)(1)(ii).
[66] *See* BOEM Gulf of Mexico OCS Region, *Rocky Mountain Mineral Law Foundation Bonding and Oil Spill Financial Responsibility*, dated January 23-25, 2013, New Orleans, Louisiana.
[67] 30 C.F.R. § 556.52(f).
[68] 30 C.F.R. § 556.52(g).

Historically, the Gulf of Mexico OCS Region has considered unacceptable such alternatives as letters of credit or production escrow accounts.[69]

2. Supplemental Bond

In addition to general bonding requirements, the Regional Director may determine that additional security, usually in the form of a supplemental bond, is necessary to ensure compliance with lease obligations.[70] The supplemental bond may be required prior to the issuance of an RUE or ROW, and prior to any proposed activity such as exploration or development, as well as prior to the assignment of any lease, RUE or ROW. When the lessee or its guarantor can demonstrate the financial capability to meet these obligations, the BOEM will not require a supplemental bond.

The Regional Director's determination of financial capability will be based on an evaluation of the lessee's ability to carry out present and future financial obligations, including potential decommissioning liability, as demonstrated by a variety of factors. The procedures and criteria used to calculate decommissioning liability and to determine whether to require a supplemental bond are set forth in Notice To Lessees No. 2008-N07 (August 28, 2008). Companies that demonstrate a threshold of financial strength and reliability may receive an exemption or waiver from supplement bonding requirement.

a. Assessing Eligibility for Exemption

At least one record title owner or holder of the RUE or ROW must provide the following evidence of financial capability:[71]

- Independently audited calculation of net worth equal to or greater than $65 million;
- Cumulative decommissioning liability less than or equal to 50% of the most recent and independently audited calculation of net worth; and
- Demonstrated reliability as evidenced by:
  - A track record of successful oil gas production and legal compliance;
  - Credit ratings, trade references and verified published sources; and
  - Other factors as determined by BOEM.

In addition the lessee or holder must demonstrate either:

- Production of fluid hydrocarbons in excess of an average of 20,000 BOE per day from an OCS lease for which the lessee owns a record title interest, based on the most recent 12 months for which data and information are available; or

[69] United States Department of the Interior, Mineral Management Service, Gulf of Mexico OCS Region, Notice to Lessees and Operators of Federal Oil, Gas, and Sulphur Leases in the Outer Continental Shelf, Gulf of Mexico OCS Region, "Guidance for Lease Surety Bonds," NTL No. 2000-G16 (September 7, 2000).
[70] 30 C.F.R. § 556.53(d).
[71] United States Department of the Interior, Minerals Management Service, Notice to Lessees and Operators of Federal Oil, Gas and Sulphur, Leases and Pipeline Right-of-Way Holders in the Outer Continental Shelf, "Supplemental Bond Procedures," NTL No. 2008-N07 (August 28, 2008) at III.

- A Debt to Equity ("DE") Ratio according to independently audited financial statements as follows:
  - ➢ For companies with a minimum net worth of $65 million:
    - o DE ≤ 2.5 & cumulative potential decommissioning liability ≤ 25% of stockholder's equity or net worth; or
    - o DE ≤ 2.0 & cumulative potential decommissioning liability > 25% but ≤ 50% of stockholder's equity or net worth.
  - ➢ For companies with a net worth in excess of $100 Million:
    - o DE ≤ 3.0 & cumulative potential decommissioning liability ≤ 25% of stockholder's equity or net worth; or
    - o DE ≤ 2.5 & cumulative potential decommissioning liability > 25% but ≤ 50% of stockholder's equity or net worth.

In analyzing DE Ratio and net worth a lessee may request BOEM to consider future net revenue associated with the lessee's value of proved producing reserves in the calculation of the lessee's net worth. The lessee may select one of the following two methods of evaluation. The lessee may request BOEM consider the lessee's future net revenues (a) for all OCS leases in which the lessee owns a record title interest equal to the percentage of their interest; or (b) by providing BOEM a reserve report estimating the total proved producing reserves for all OCS leases in which the lessee has a net revenue interest, which report must be verified by an independent third-party and include a certified cash flow spreadsheet.[72] If the request is based on record title ownership with equal percentage interest, then BOEM may include up to 25% of the reserve value in its calculation of the lessee's net worth.[73] If it is based upon a third-party reserve report, then BOEM will determine the value of the proved producing reserves to be included in the lessee's net worth.[74]

For those companies exempt from supplemental bonding, a financial strength determination is valid for up to one year subject to annual reporting and confirmation requirements.[75]

b. Calculating the Supplemental Bond Amount

The written procedure for calculating the amount of a supplemental bond is reflected in NTL No. 2008-N07. BOEM will:

1. Determine the decommissioning liability for all leases, RUEs, and ROWs for which the lessee owns record title interest or is a holder. For lessees that have requested BOEM to include proved producing reserves for the lessee's operating rights interest in its net worth calculation, BOEM will also determine the decommissioning liability associated with such rights.

2. Apply lease-specific bonds to identified leases.

3. Exclude from the calculation the full amount of decommissioning liability for any lease for which BOEM has determined that one or more co-lessee is financially capable. (Less

[72] *Id*. at III.5.
[73] *Id*.
[74] *Id*.
[75] *Id*. at III.

than the full amount may be excluded based upon the "financial or operational history of the companies involved.")

4. Apply the financial strength and reliability analysis set forth above.

BOEM makes two explicit assumptions in determining decommissioning liability. First, all facilities will be removed and transported to shore for recycling and disposal.[76] Second, a rig will be used to P&A all wellbores.[77]

If BOEM determines a supplemental bond is necessary, it will request the security through the designated operator who is responsible for coordinating the submittal with the lessees.[78] In lieu of a supplement bond the Regional Director may also authorize a lessee to establish a lease-specific abandonment account,[79] or accept a third-party guarantee and indemnity.[80]

Unlike the annual review for exempt companies, non-exempt companies may be subject to more frequent reassessment of their supplemental bond amounts. BOEM's will review a company's potential decommissioning liability at multiple stages throughout the exploration and production process, including "periodically," "when the [BOEM] becomes aware of information that indicate a change in financial strength of the company," and "when an Incident of Noncompliance is issued related to safety, environment, non-payment of royalty, or other violations of [agency] regulations."[81] It appears to be common practice that BOEM will increase its decommissioning estimates upon reassessment, and thus will provide notice that it has 30 days to come up with the increased supplemental bond amount.

3. Obtaining Security

In practice, operators overwhelmingly look to the surety market to obtain both general and, when required, supplemental bonds. Surety companies must satisfy the requirements set forth in 31 U.S.C. §§ 9304-9308 in order for the surety bond to be accepted by BOEM.

Although most surety companies are subsidiaries or divisions of insurance companies, regulated by state insurance departments, surety is not the same as insurance. Rather, a surety bond is a credit instrument designed to prevent loss. Surety companies stand behind the commitments undertaken by an operator (called the "principal") through a bonded contract.[82] The principal is primarily responsible to fulfill the contract's obligations and the surety's obligations are secondary to the principal's obligations. Surety companies require a demonstration of commitment through an indemnity agreement.

A surety company underwriter can examine the principal's entire business operations – including the company's finances and financial structure, organizational structure, and track record – in order to ascertain whether the contractor has the wherewithal to comply with its

[76] NTL No. 2008-N07 (August 28, 2008) at IV.1.
[77] *Id*. at IV.2.
[78] *Id*. at IV.3.E.
[79] 30 C.F.R. § 556.56.
[80] 30 C.F.R. § 556.57.
[81] *Id*. at II.
[82] Surety Information Office ("SIO"), a unit of the National Association of Surety Bond Producers and Surety and Fidelity Association of America, "How to Obtain Surety Bonds"1 (2007 Surety Information Office) available at http://suretyinfo.org/?wpfb_dl=57.

lease obligations. Required financial statements may include an accountant's opinion page, balance sheet, income statement, statement of cash flow, accounts receivable and payable schedules, schedules of contracts in progress and contracts completed, schedule of general and administrative expenses, and a CPA management letter. The key data points, however, are usually the balance sheet, income statement, and the company's reserves report. Underwriting standards continue to emphasize the 3Cs – capital, capacity, and character of the principal – but may also consider two more Cs: continuity and contracts.[83] Sureties spend the majority of their time and money underwriting principals to prequalify them in order to minimize the sureties' risk exposure.

Surety bond premiums (an annual fee paid to the surety) vary from one surety to another, but generally range from ½% of the contract amount for companies who are well capitalized to 2½% for companies who are not. The premium may also depend on the size, type, and duration of the project.

Because a surety issues a bond based on the principal's contract promise to indemnify the surety if the bond is called upon, there is no question of whether there is capacity in the surety market to handle heightened bonding requirements: unlike in the case of insurance, it is not a surety's money that is tied up. The issue instead is whether the principals (that is, the lease operators) have the balance sheet to make the sureties willing to accept the indemnity contracts without further collateral from the operators. But the indemnity creates a potential liability on an operator's books, making it more difficult for it to obtain financing if financing is needed. And so a government policy favoring over-security or redundant security makes it much more difficult for smaller operators, who are not exempt from supplemental bonding, to develop oil and gas resources in the OCS. The problem is compounded if a surety feels that it must have collateral for at least part of the bond amount. In current practice, the operator must provide cash or a letter of credit to be held by the surety or a third-party. An operator putting collateralized cash into the account of a surety is basically seeing its capital budget shrink – dollar for dollar – from the level it had hoped it could commit to lease development.

The most troubling aspect about this ANPR lies in the impact higher bonding has on smaller producers. It is obvious that excessive bonding, especially collateralized bonding, impairs smaller operators from achieving the statutory goal of the OCS Lands Act: the expedited exploration and development of the OCS.[84] Yet BOEM, in the ANPR, is unable to point to a single example in which taxpayers were required to pay a penny to plug and abandon a well, remove a production facility, or clear the seabed of the leased property. In contrast, the offshore industry has amassed an impressive record of lease abandonment, as we will now explain.

C. Decommissioning Successes in the Gulf of Mexico to Date

The issuance of Notice To Lessees No. 2010-G05 on September 15, 2010, highlights the BOEM's efforts to reduce the inventory of idle iron and unplugged wells. This Notice gave operators in the Gulf of Mexico a three-year window within which to permanently plug, temporarily abandon, or provide downhole zonal isolation for all wells no longer useful for operations and no longer capable of producing oil or gas in paying quantities. It also mandated

[83] SIO, "Contract Surety Bonds: Understanding Today's Market" (July 2010) available at http://suretyinfo.org/?page_id=81.
[84] 43 U.S.C. § 1802(1).

removal of a platform or other facility that is no longer useful for operations within five years of the Notice's effective date.

Operators have made a significant push to comply with these requirements – a fact which is reflected in the statistics collected as of May 31, 2013, by BSEE showing that 2,086 structures have been removed.

Structures Removed Since 2002 on the GOM OCS As of: May 31, 2013[85]													
Structure Type	Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Caissons	795	43	74	101	41	48	58	59	79	57	111	99	25
Platforms	1037	61	70	64	66	45	82	74	125	145	146	148	11
Mobile Offshore Production Units	3	0	1	0	0	0	1	1	0	0	0	0	0
Mini-Tension Leg Platforms	1	0	0	0	0	1	0	0	0	0	0	0	0
Well Protectors	250	18	24	29	17	16	16	19	25	19	28	38	1
Total	2086	122	169	194	124	110	157	153	229	221	285	285	37

As of January 2010, four structures in the Pacific offshore have been decommissioned (all located in State waters), with 23 platforms remaining on the OCS.

Researchers have also noted that operators are removing more facilities from the Gulf of Mexico than they are installing: [86]

[85] Information published at http://www.bsee.gov/exploration-and-production/decomissioning/idle-iron-statistics/ (last visited November 9, 2014).
[86] Byrd, *et al.*, *supra* note 16, 1648.4, Figure 1.

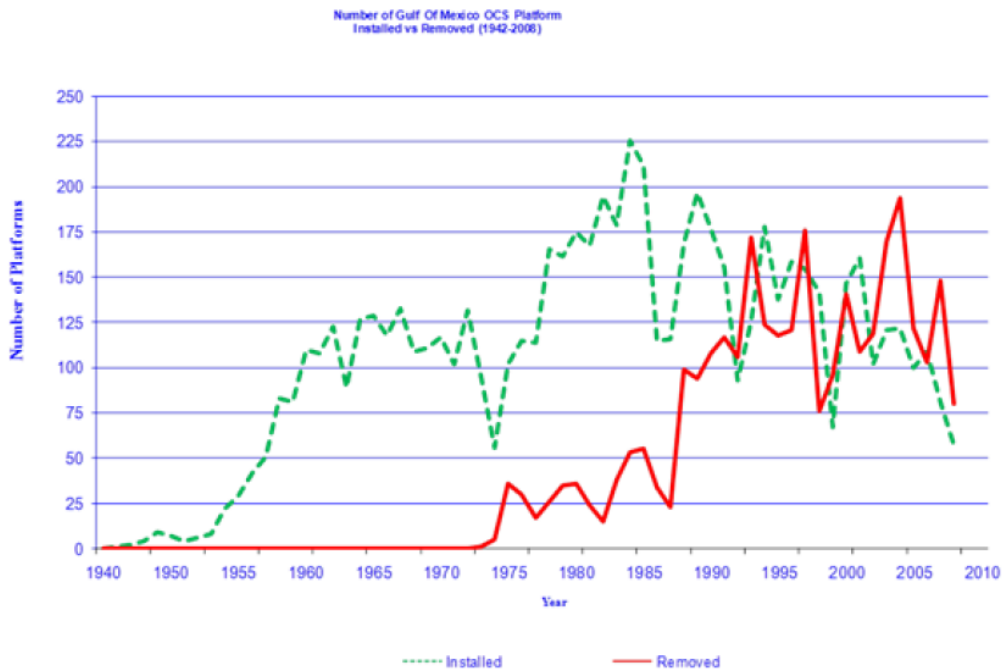

Figure 1 – Platform Removals and Installations (1940 -2008) (BSEE)

Thus, despite concerns that a "comprehensive risk management" program must be accompanied by more stringent bonding requirements, the historical data shows since the issuance of NTL No. 2010-G05 hundreds of platforms have been removed at substantial expense without the government or the taxpayers spending a penny. Private commitments and, in some cases, bankruptcy court outcomes have addressed the issue.

COMMENTS

The ANPR asks 54 questions. Most of them are at such a high level of generality that it is not possible to respond in any useful way. What is missing from the ANPR is an explanation of what the government thinks the problem is with the current system given that they have yet to spend a dime of taxpayer money. We are advised that two events[87] have focused BOEM's concern: (a) the ATP Bankruptcy; and (b) Hurricane Ivan's devastation of Taylor Energy's Mississippi Canyon 20-A ("MC20") production platform.

(a) <u>The ATP Bankruptcy</u>

ATP's position in the bankruptcy has been that the Macondo well blowout and the government's subsequent moratoria on drilling and related activities in the Gulf of Mexico prevented it from achieving 2010 production numbers that would have allowed it

[87] While the Deepwater Horizon explosion is also often cited as a predicate for regulatory reform in the OCS, BOEM expressly excluded costs and damages associated with oil spill financial responsibility as the subject of other proposed rulemakings and outside the scope of this ANPR. *See* 79 Fed. Reg. at 49027. In addition, to the extent it is relevant here, it serves as another example of MC20, *i.e.*, catastrophic failure.

to avoid Chapter 11 Bankruptcy.[88] ATP planned to bring to production in 2010 and in early 2011 six development wells. Had the company been allowed to drill and complete these wells, ATP believes it would have provided a material production change in 2010 continuing to today which would have increased cash flows and allowed the company the ability to withstand normal operational issues experienced by operators in the Gulf of Mexico.

Whether this is the case, BOEM allowed ATP to be approved as an exempt entity under the criteria set forth in NTL No. 2008-N07. However, the criteria that were employed by the agency failed to alert the agency that this was a company from whom supplemental bonds should have been sought.

(b) Hurricane Ivan and MC20

On 15 September 2004, Hurricane Ivan caused a mudslide that toppled Taylor Energy's "A" Platform at Mississippi Canyon Block 20 (approximately 11 miles offshore in federal waters). At the time it had 28 active oil and gas wells. The 555-foot high eight-pile platform slid 400 feet down slope, resting on its side partially buried by more than 100 feet of mud and sediment in 440 feet of water.[89] The structure was submerged nearly 75% below the mud line.[90] In addition, all production piping suffered structural damage and twisted together 150 feet below the original mud line.[91]

Decommissioning has been on-going since 2005, with one structure and 21 wells remaining. In 2008, due to unique and complex technical and geographic issues, the MMS determined that typical P&A efforts would be fruitless and a massive excavation project was unsafe. Taylor has installed a containment dome over the affected area, which would catch the oil rising from the seabed, and the Coast Guard has established a regulated navigation area above the contained dome.[92] *The Oil and Gas Journal* has suggested that decommissioning costs ultimately may total $500 million-$1 billion.[93]

Through these comments IPAA is recommending changes so that the government can be assured it will not have to deal with "another ATP or MC20." And because there is no indication that private parties have failed to properly address abandonment in the face of catastrophic loss, we propose that existing mechanisms are sufficient to address the impacts of hurricanes on production facilities.

BOEM's current system of bonding results in the government demanding too much capital being tied up in supplemental bonds. The government can provide itself with appropriate levels of surety without continuing to impose the burdens it now does. BOEM currently imposes "over-security" in three ways. First is in how it fails to allocate the requirement for surety among

[88] *See* ATP Oil and Gas Corporation Press Release, *ATP Files Voluntary Petition for Chapter 11 Reorganization and Receives Commitment for $617.6 million in DIP Financing; Oil and Gas Operations to Continue in Ordinary Course* (8/17/12) available at http://www.sec.gov/Archives/edgar/data/1123647/000119312512361112/d396167dex991.htm.

[89] U.S. Coast Guard, Section New Orleans, LA, Incident Specific Activation Report: Taylor Energy Gulf of Mexico 2013, Regional Response Team 6 (April 11, 2013).

[90] *Id*.

[91] *Id.*

[92] 78 Fed. Reg. 59234-59237 (September 26, 2013).

[93] Mark J. Kaiser, Oil & Gas Journal, *Gulf Cleanup Continues After Five Major Hurricanes* (July 7, 2014).

lessees on a given lease and among risks posed by a given lessee with multiple leases. Second is in how the agency times its imposition of bonding, routinely requiring bonds prematurely and therefore often unnecessarily. Third is in how the agency estimates the cost of decommissioning. We will address these issues of allocation, timing, and amount in turn. Finally, we will address BOEM's "catastrophic event" concerns.

RECOMMENDATIONS

A. Allocation

Joint and several liability, retained by those lessees and owners of operating rights who were in the lease when the decommissioning obligation accrued, is an accepted proposition written into regulation.[94] That proposition offers the government – even without anything more – substantial assurance that obligations to abandon will be met.[95] Given that the Interior Department has the backstop of joint and several liability going back into chain of title, the agency must be more rational in its approach to bonding. By making changes to the allocation of liability BOEM could mitigate risks of over-securitization. The following scenarios exemplify how allocation could improve risk management without sacrificing development of OCS resources.

First, take the example of Company A, that is seeking an exemption from supplemental bonding. Company A is one of four non-exempt co-lessees. When Company A requests an exemption, BOEM will look to the total abandonment liabilities for each lease Company A holds an interest in, even if the Company's interest is only a fraction of full ownership. So, for example, if Lease 1 has estimated total abandonment liability of $20 million, Company A would be deemed to hold all $20 million in liability, even if Company A owns only a ten percent interest in Lease 1. When reviewing request for exemptions from the other three co-lessees, BOEM repeats this allocation of full liability to each. In other words, the three other co-lessees will also be held accountable for the full cost of abandoning this lease. Rather than assigning proportionate liability to each of the co-lessees, the current government practice is, in its effect, to protect itself against four times the estimated cost of abandonment: the full $20 million attributed to each of the four, effectively $80 million. By inflating each company's abandonment liabilities, BOEM is limiting the ability of financially healthy companies who are on the cusp to be treated as exempt. Compare that with Company B, who is a co-lessee with two other exempt companies. Historically, if there were two exempt parties to the lease, then abandonment liability is not included in the exemption analysis for Company B.

Recommendation: When a company seeks an exemption and BOEM determines a company's "cumulative decommissioning liability," BOEM must limit liability to that company's proportionate share of lease ownership.

94 30 C.F.R. § 250.1701.

95 Although concerns about "risk to the taxpayer" appear frequently in the ANPR, the rhetoric lacks legal substance. First, there is nothing in the OCSLA that permits a citizen to sue the government to force it to undertake decommissioning obligations in any given situation. Second, even if the government were negligent in marking a submerged-below-the-waterline-wreck that one of its lessees failed to properly abandon, the government is immune from a suit for damages. Donna Dixon, BOEM's Program Manager for Office of Risk Management, has confirmed that the United States has "no decommissioning liability." Donna Dixon, OCS Advisory Board 2014 Workshop (2014).

B. Credit for Existing Escrow

Second, in analyzing exemptions from supplemental bonding BOEM does not give any credit for escrow accounts already in existence to securitize decommissioning obligations, including those funds held in escrow by BOEM.

The marketplace has already been responsive to the concerns behind BOEM's proposed rulemaking. Hundreds of millions of dollars in private financial security arrangements have been put in place between buyers and sellers of OCS leases as a result of (i) joint and several liability for all prior owners in the chain of title and (ii) lack of regulations which require BOEM to first call a supplemental bond upon a decommissioning default and make the proceeds available to those required to perform the P&A. For example, as Fieldwood Energy's comments in response to the ANPR point out, pursuant to a Decommissioning Agreement with Apache the company has set up two trust accounts to secure its future decommissioning obligations; one of which is secured with a $500 million letter of credit and which will be funded with additional amounts on a monthly basis until the fund reach a maximum of $800 million. Essentially, in assessing the financial health of a company, BOEM ignores the fact that it can require prior owners to perform the decommissioning obligations and also ignores the millions of dollars of private financial security arrangements which benefit BOEM.

Even more frustrating to lessees is BOEM's refusal to consider escrow accounts held by BOEM itself in calculating potential decommissioning liability.

Recommendation: Give companies credit for security in place for cumulative abandonment obligations when considering exemption from bonding and in setting the bond amount.

C. Credit for Costs Attributed to ARO

Third, BOEM currently double-counts abandonment costs. Companies are required by Generally Accepted Accounting Principles to record decommissioning liabilities as asset retirement obligations ("ARO") on their balance sheets. ARO amounts expected to be expended in the current year are shown as current liabilities and amounts expected to be expended in later years are discounted to present value and carried as long term liability obligations. Assets are offset by liabilities to arrive at owner's equity or net worth. Therefore, the BOEM's calculation of "Shareholders' Equity" already accounts for the ARO balances. Yet, in determining whether a lease owner qualifies for exemption, BOEM does not add back in ARO balances to an owner's equity when comparing an owner's cumulative decommissioning obligations (calculated without discounting to present value) to the equity or net worth of a lease owner. This results in an owner's equity being understated or ARO being double counted for the exemption analysis.

Recommendation: At a minimum, the metric for cumulative decommissioning liability currently set forth in Section III, paragraph 2 of NTL No. 2008-N07 should be modified as follows:

> Cumulative decommissioning liability must be less than or equal to 50% of Adjusted Net Worth (defined as GAAP based Shareholders' Equity + Current and Long-term ARO Liability).

We would also request, however, that BOEM consider the revised equation described next in Part D.

D. Revise Criteria for Financial Strength

Fourth, BOEM's criteria for measuring a company's financial condition are out of alignment with current conservative financial industry practices. Therefore, in addition to the above recommended change, the financial metric for "cumulative decommissioning liability" should be revised to include the following alternative criteria:

- Cumulative decommissioning liability ≤ 100% of Adjusted Net Worth (defined as GAAP based Shareholders' Equity + Current and Long-term ARO Liability); <u>and</u>

- "Adjusted Debt" to "EBITDA(X)" ratio < 4.0x; <u>and</u>

- EBITDA(X) to "Cash Interest Expense" ratio > 3.0x.

OR

- Current Assets to Current Liabilities ratio > 1.5x; <u>and</u>

- Current Assets – Current Liabilities > Cumulative decommissioning liability

In these calculations:

  - "<u>Adjusted Debt</u>" means bank revolver debt, other long-term debt, current maturities of long-term debt, other long-term liabilities in which the company is contractually obligated to pay a third party.[96]

  - "<u>EBITDA(X)</u>" means net income, adjusted to add back interest expense, income tax, depreciation, depletion and amortization, accretion, and impairment. For successful efforts companies, also add back exploration expense.

  - "<u>Cash Interest Expense</u>" means interest expense before the effects of capitalized interest, adjusted to add back noncash interest expense, if any.

  - "<u>Current Assets</u>" means a balance sheet account that represents the value of all assets that are reasonably expected to be converted into cash within one year in the normal course of business. Current assets include cash, accounts receivable, inventory, marketable securities, prepaid expenses and other liquid assets that can be readily converted to cash.

  - "<u>Current Liabilities</u>" means a company's debts or obligations that are due within one year. Current liabilities appear on the company's balance sheet and include short term debt, accounts payable, accrued liabilities and other debts.

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[96] To demonstrate compliance with this criteria lessees would provide a certified statement of all company debts that would fall under the "Adjusted Debt" category, *i.e.*, any long-term debts and liabilities (and current maturities of long-term debts and liabilities) in which company is contractually obligated to pay a third party.

"Net Worth" and "Adjusted Net Worth" are driven by values of oil and gas properties which have been discounted at 10%. This is because the asset item that is generally the largest component of Total Assets – *i.e.*, total oil and gas property and equipment, net of DD&A and impairment – faces impairments on a quarterly basis if it is greater than the PV-10 of reserves using prevailing oil and gas prices.[97] Since BOEM's assessments of decommissioning liability is undiscounted (and therefore not reflective of what will actually occur) and includes abandonment liability at implied 100% ownership percentage even for properties in which companies have smaller working interests, 100% of the Adjusted Net Worth should adequately cover the decommissioning liability.

The addition of the Debt-to-EBITDA(X) and EBITDA(X)-to-Interest Expense ratios to the equation compensates for relaxing "Adjusted Net Worth" from 50% to 100% of cumulative decommissioning liability. They also represent ratios widely accepted and better understood in the financial services industry to gauge financial strength. These metrics are more meaningful than the currently used Total Liabilities to Net Worth ratio for the following reasons:

(1) The debt to trailing twelve months EBITDA(X) ratio (which implies how many years it may take a company to pay off its long-term debt based on the last twelve months of EBITDA(X)/cash flows) is one of the primary metrics used by banks in determining whether a company can take on more debt and is used by those who finance and invest in oil and gas companies when assessing a company's ability to handle its debt load. Thus, unlike the current BOEM measure of total liability to equity ratio, it is a debt ratio which has been widely accepted, tested, and deemed by the financial services industry to be a key measure of financial strength. IPAA proposes that 4x be the high limit for the debt/EBITDA(X) ratio because 4x is the level at which a strictly offshore or offshore/onshore company could be deemed to be highly leveraged.

(2) The trailing twelve months EBITDA(X) to interest expense ratio is also a widely known ratio. While it does not appear as commonly on bank covenants or receive as much emphasis by stakeholders in the oil and gas industry compared to the debt to EBITDA ratio, this ratio shows the relationship between the cash flow that the company generates and the interest payments it must make to not default on its debt load. For instance, if the ratio is 1x, it implies that all of the company's cash flow must go to paying the debt holders the interest payments and there is nothing left for anything else. The ratio we recommend as the low limit is 3.0x.

(3) As an alternative to the preceding EBITDA(X)-based ratios, enterprises in the development stage may demonstrate sufficient liquidity to satisfy their abandonment obligations, even in the absence of sufficient cash flow and/or earnings through the demonstration of an acceptable Current Ratio (i.e., Current Assets/Current Liabilities). While Adjusted Debt/EBITDA(X) indicates the approximate amount of time that would be needed to pay off existing debt at current levels of earnings, it does not consider the circumstance whereby current levels of earnings are not representative of future levels of earnings, because the assets to which the decommissioning liabilities relate, are not yet developed and producing. Even if not generating cash flow and EBITDA(X) at the point in time at which an EBITDA(X) test occurs, by definition and absent an unlikely catastrophic event, cash flow from assets, once developed, will precede decomissioning

[97] Other items go into the ceiling test impairment calculation, but generally the largest driving factor is the PV-10 of oil and gas reserves.

liabilities. In that regard, point in time financial metrics based on future debt maturities and current cash flow and/or EBITDA(X), may not adequately reflect a company's financial strength and liquidity. The degree to which Current Assets exceeds Current Liabilities is an alternative measure of financial capacity for the medium-term that allows cash-rich development entities to bridge the gap to Cash Flow and Earnings by demonstration of sufficient liquidity.

Importantly, these new metrics would likely have prevented "another ATP." This is because the primary failure with ATP was the agency's use of ineffective criteria to determine whether ATP should have been treated as exempt from supplemental bonding. Using IPAA's proposed criteria, if BOEM had looked at ATP's annual financial metrics[98] from 2009 to 2011, the following would have been evident:

	2011	**2010**	**2009**
Adjusted Debt/EBITDA(X)	4.7x	15.0x	7.8x
EBITDA(X)/Cash Interest Expense	1.7x	0.7x	1.4x
Current Assets/Current Liabilities	0.35x	0.75x	0.91x

Using this methodology ATP would not have qualified as exempt and would have been subject to a supplemental bond.

Recommendation: Modify the metric for cumulative decommissioning liability currently set forth in Section III, paragraph 2 of NTL No. 2008-N07 to include the following alternative calculation:

i) Cumulative Decommissioning Liability <= 100% of Adjusted Net Worth (defined as GAAP based Shareholders' Equity + Current and Long-term ARO Liability); and

ii) Adjusted Debt* to EBITDA(X)** ratio < 4.0x; and

iii) EBITDA(X) to Cash Interest Expense*** ratio > 3.0x.

OR

i) Current Assets**** to Current Liabilities***** ratio > 1.5x; and

ii) Current Assets – Current Liabilities > Cumulative decommissioning liability

* Adjusted Debt = Bank revolver debt, other long-term debt, current maturities of long-term debt, other long-term liabilities in which the company is contractually obligated to pay a third party.

** EBITDA(X) = Net income, adjusted to add back interest expense, income tax, depreciation, depletion and amortization, accretion, and impairment. For successful efforts companies, also add back exploration expense.

*** Cash Interest Expense = Interest expense before the effects of capitalized interest, adjusted to add back any noncash interest expense, if any.

[98] Excerpts from publicly available documents supporting these calculations are included herewith as **Attachment A**.

**** Current Assets = A balance sheet account that represents the value of all assets that are reasonably expected to be converted into cash within one year in the normal course of business. Current assets include cash, accounts receivable, inventory, marketable securities, prepaid expenses and other liquid assets that can be readily converted to cash.

***** Current Liabilities = A company's debts or obligations that are due within one year. Current liabilities appear on the company's balance sheet and include short term debt, accounts payable, accrued liabilities and other debts.

E. Bonding Only Incremental Value for Exempt Status

Fifth, BOEM requires excess security in how it uses a company's net worth in determining whether the company is exempt from a supplemental bond. Consider, for example, a company with a debt-to-equity ratio of 2.5 and a cumulative potential decommissioning liability of $25 million. That company would need to have a net worth of $100 million to be treated as exempt. Further suppose that the company has a net worth of $90 million. If its net worth were only $10 million more, it would be exempt. However, because it is under the threshold, the company is required to bond the full $25 million. A more rational approach would be to require the company to bond the $10 million difference between its actual net worth and the threshold level. Furthermore, the agency should not limit the $10 million dollar bond to any one lease, but should permit the bond to cover abandonment obligations on all of the company's leases listed on an attachment to the bond. This approach is not only a more efficient use of the company's capital, but also gives the agency greater flexibility to apply the bond to the leases where the bond coverage is needed.

Recommendation: Permit companies to bond the delta between the company's actual net worth and the thresholds set forth in NTL No. 2008-N07, Section III. If exemption requirement hurdles are not met in one period but met in a subsequent period, consider allowing those bonds to be released once the company has attained exempt status again.

F. Access to Bonds and Release of Bonds

Finally, the agency has been reluctant to allow companies access to bonds. Yet, if these funds are being tied up to ensure proper abandonment, they should be accessible to the party who ultimately performs the work. As it stands, current and former lessees who share in joint and several liability but who were not in breach of the obligation do not have right to the bond and have no ability to call for forfeiture of a bond.[99]

Recommendation: Create a mechanism by which BOEM/BSEE will make at least a supplemental bond (since such bond is based on estimated abandonment liability) to those who share in joint and several liability, so that those funds may be used towards proper abandonment.

[99] BOEM is also looking to increase bond amounts without any sort of track record of actually calling such bonds in connection with decommissioning. In fact the only time BOEM has actually called for forfeiture of a bond, of which we are aware, was accomplished through negotiations with parties to the ATP bankruptcy.

Additionally, BOEM has a history of delay in releasing bonds whenever a lessee (1) submits a replacement bond or (2) fulfills the obligation for which the bond provided assurance. By regulation, BOEM should be required to release such bonds in 90 days.

Recommendation: By rule, require prompt release of bonds that are no longer needed.

G. Timing

Problems with over-security also stem from the current bonding timelines – *i.e.*, what event triggers a security requirement.

In the 1970s Congress amended the OCSLA to encourage lessees to submit an exploration plan ("EP") identifying anticipated exploratory wells to be drilled. The amendment was designed to facilitate planning and speed up the approval process since the EP would only be reviewed once, and further review under NEPA and OCSLA would not be needed for each well in the plan. Congress thus expected that there would be multi-well plans. DOCDs raise the same considerations. OEM's approach to bonding, however, undermines Congress's policy for coordinated review and expedited permitting. It does so by requiring bonding for the plugging and abandoning of wells that may never be drilled and for facilities that may never be emplaced. BOEM should avoid forcing companies to collateralize a liability that remains speculative until drilling or emplacement.

Recommendation: Require that leaseholders and operators submit supplemental bonds at the time the operator files for a final Application to Drill immediately prior to drilling the associated well or files for the final authorization before emplacing a facility (production facility, tie-back, or pipeline). BOEM/BSEE would have the power to suspend the operation, issue an Incident of Noncompliance, or impose civil penalties if a bond is not timely posted.

H. Amount

Companies ought to be able to bond based on a methodology like the Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 143 (June 2001) ("FASB 143") under which one looks at when the asset/production facility is likely to be decommissioned. BOEM should estimate the cost of decommissioning at that time, use a discount rate to bring that back to present value, and set that present value as the amount of the bond. Companies should be required to adjust that calculation every year. As the time draws closer to actual abandonment the amount of the bond would go up. This fairly balances the government's risk by the improbability that it would ever actually have to spend taxpayer money to perform decommissioning. In the event the structure must be decommissioned prematurely (*e.g.*, a hurricane topples a platform 4 years before), we address this concern in our comments on rare catastrophic events.

Using this type of methodology[100] also better reflects actual costs of decommissioning. The government's cost estimates inflate decommissioning costs by ignoring economies of scale.

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[100] It is also true that a methodology is only as good as the data used. While BOEM's push has reduced the amount of idle iron, the push also artificially drove up rates for derrick barges (which, as noted above, are a primary decommissioning cost driver). BOEM is now using those inflated costs to drive up bond amounts.

For example in calculating the costs of P&A-ing those wells, the government should not assume that each well would be P&A'd as an independent project which requires mobilization and demobilization of a derrick barge. Many of these wells can be P&A'd at the same time, so it is inaccurate to assume a single well abandonment when estimating costs. The same is also true for rigs. It is inaccurate to assume that a rig will be used. One IPAA member reported savings as high as $8 million per well due to the efficiencies that a rigless spread provides. BOEM's methodology of calculation decommissioning costs based on a stand-alone well creates greater aggregate liability than is necessary. By using an approach similar to FASB 143, the government will get more accurate cost estimates and can shift the burden to the lessee to demonstrate that derrick barges would be utilized in such a way that more than one production facility would be decommissioned.

To implement this recommendation, we suggest that operators meet annually with the agency to discuss the present value of abandonment obligations as determined under FASB 143, similar to meetings currently required to review the "idle iron inventory."

Recommendation: Adopt a methodology for calculating supplemental bonding amount like that set forth in FASB 143 under which BOEM would:

i) Look at when the asset/production facility is likely to be no longer used and need to be decommissioned; and

ii) Estimate the cost of decommissioning at that time using a discount rate to bring that back to present value.

Companies should be required to adjust that calculation every year.

Recommendation: In calculating the amount of the supplemental bond, a leaseholder should only be required to provide a supplemental bond for the leaseholder's aggregate audited P&A liability less the amount of third-party surety in a form (such as escrow accounts) approved by BOEM.

I. The "Catastrophic Event" Concern

Imposing increased bond requirements on all OCS operators to purportedly protect the government from an uncertain future event of speculative magnitude is a significant misallocation of capital. The agency's concern appears to derive entirely from one event: the catastrophic loss of MC 20 Platform A during Hurricane Ivan. Again, we emphasize that addressing the concern through another government mandate is an excessive reaction, given that not one federal dollar has been spent on the P&A for the wells or the removal of that part of the platform above the seabed.

Industry's response to hurricane losses has been exemplary. There have been five significant wind events in the past decade and companies have proven their ability to fund the subsequent decommissioning obligations. The Gulf of Mexico witnessed five devastating hurricanes between 2004 and 2008: Ivan, Katrina, Rita, Gustav, and Ike. Combined, these wind events damaged 181 structures and 1,673 wells.[101] Currently, only 40 structures and 130 wells remain

[101] Kaiser, *Oil & Gas Journal*, *supra* note 66.

to be decommissioned.[102] (More than half the structures remaining are not owned by independents, a fact that should allay concerns about the ability of independent producers to meet their obligations even after catastrophic losses.[103])

	Producing		**Idle**		**Auxiliary**		**Total**	
Hurricane	**Removed**	**Remaining**	**Removed**	**Remaining**	**Removed**	**Remaining**	**Removed**	**Remaining**
Ivan	4	1	1	0	1	0	6	1
Katrina	25	7	9	1	3	0	37	8
Rita	27	16	16	4	5	1	48	21
Gustav, Ike	27	5	14	3	9	2	50	10
TOTAL	**83**	**29**	**40**	**8**	**18**	**3**	**141**	**40**

There is, moreover, no evidence indicating that the insurance market has been incapable of covering the risk of catastrophic loss. Insurers currently afford OCS operators coverage for the cost of replacing a toppled production facility and additional coverage for "removal of wreck" and "removal of debris."

Furthermore, technical innovations since those five hurricanes have shown that industry continues to reduce the cost of addressing both idle and toppled iron. Operators have gained substantial experience with production facility removal in the Gulf in the last four years, finding cost-saving efficiencies in both the process of decommissioning and in the equipment used. Stone Energy, for example, removed nearly 100 idle structures in a two-year period at a cost of 67% of the original estimates.[104] In addition to rigless methods to plug and abandon wells, previously discussed, operators are saving cost in removing toppled structures by new methods of cutting underwater and by using "claw" devices that grab toppled decks in one chunk, avoiding the expense of cutting and lifting in multiple smaller chunks.[105] Other technologies and decommissioning strategies are also under development.[106] There is a grave risk that a government attempt to bond or insure for a once-in-a-generation catastrophic failure will grossly over-commit capital to bonds that could otherwise be used for both oil and gas development and for investment in decommissioning technology.

Respectfully,

Barry Russell, President
Independent Petroleum Association of America

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[102] *Id*.
[103] *Id*.
[104] S. Rassenfoss, "Aging Offshore Fields Demand New Thinking," *Journal of Petroleum Technology* 50, at 52 (Nov. 2014).
[105] *Id.* at 54-56.
[106] *Id.* at 58-62. *See also* A. Stokes, "Decommissioning Costs Can Be Reduced," *Offshore Technology Conference Paper* OTC-25247-MS (2014).

ATTACHMENT A

ATP's 2011 and 2010 10-K Statements, which provide the basis for the ratio calculations contained herein, are publicly available at:

http://www.sec.gov/Archives/edgar/data/1123647/000119312512117694/d281331d10k.htm
http://www.sec.gov/Archives/edgar/data/1123647/000119312511068655/d10k.htm

The following are snapshots of tables from above links.

Source for EBITDA(X) Calculation (income statement from 2011 10-K):

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2011	2010	2009
Revenues:			
Oil and gas production	$ 687,208	$ 437,997	$298,490
Other	—	—	13,664
	687,208	437,997	312,154
Costs, operating expenses and other:			
Lease operating	122,202	132,544	84,956
Exploration	1,251	1,174	264
General and administrative	43,242	43,948	43,469
Depreciation, depletion and amortization	298,574	220,657	152,780
Impairment of oil and gas properties	57,639	63,267	45,799
Accretion of asset retirement obligation	15,000	13,827	11,676
Drilling interruption costs	19,691	23,647	—
Loss on abandonment	3,916	4,829	2,872
Gain on exchange/disposal of properties	(27,000)	(26,720)	(12,433)
	534,515	477,173	329,383
Income (loss) from operations	152,693	(39,176)	(17,229)
Other income (expense):			
Interest income	223	696	710
Interest expense, net	(326,411)	(222,104)	(40,884)
Derivative income (expense)	25,191	(22,419)	(712)
Gain (loss) on debt extinguishment	1,095	(75,316)	—
	(299,902)	(319,143)	(40,886)
Loss before income taxes	(147,209)	(358,319)	(58,115)
Income tax (expense) benefit:			
Current	1,327	859	(545)
Deferred	(19,395)	35,414	23,079
	(18,068)	36,273	22,534
Net loss	(165,277)	(322,046)	(35,581)
Less income attributable to the redeemable noncontrolling interest	(26,622)	(15,503)	(13,380)
Less convertible preferred stock dividends	(18,583)	(11,248)	(2,856)
Net loss attributable to common shareholders	$(210,482)	$(348,797)	$ (51,817)

Source for Debt Calculation (partial balance sheets from 2010 and 2011 10-K):

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 65,678	$ 154,695
Restricted cash	20,113	30,270
Accounts receivable (net of allowance of $225 and $225, respectively)	70,628	92,737
Deferred tax asset	480	8,191
Derivative asset	2,194	1,688
Other current assets	28,050	26,408
Total current assets	187,143	313,989
Oil and gas properties (using the successful efforts method of accounting):		
Proved properties	4,875,232	4,291,440
Unproved properties	22,945	20,402
	4,898,177	4,311,842
Less accumulated depletion, depreciation, impairment and amortization	(1,760,756)	(1,407,206)
Oil and gas properties, net	3,137,421	2,904,636
Restricted cash	10,000	10,000
Deferred financing costs, net	40,873	48,353
Other assets, net	13,337	13,124
Total assets	$ 3,388,774	$ 3,290,102
Liabilities and Equity		
Current liabilities:		
Accounts payable and accruals	$ 265,620	$ 230,703
Current maturities of long-term debt	33,848	21,625
Asset retirement obligation	52,536	43,386
Deferred tax liability	138	—
Derivative liability	68,816	37,893
Current maturities of other long-term obligations	113,657	86,521
Total current liabilities	534,615	420,128
Long-term debt	1,976,157	1,857,784
Other long-term obligations	451,797	472,500
Asset retirement obligation	115,981	123,472
Deferred tax liability	27,493	16,956
Derivative liability	522	6,425
Total liabilities	3,106,565	2,897,265

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 65,678	$ 154,695
Restricted cash	20,113	30,270
Accounts receivable (net of allowance of $225 and $225, respectively)	70,628	92,737
Deferred tax asset	480	8,191
Derivative asset	2,194	1,688
Other current assets	28,050	26,408
Total current assets	187,143	313,989
Oil and gas properties (using the successful efforts method of accounting):		
Proved properties	4,875,232	4,291,440
Unproved properties	22,945	20,402
	4,898,177	4,311,842
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Total current liabilities	534,615	420,128
Long-term debt	1,976,157	1,857,784
Other long-term obligations	451,797	472,500
Asset retirement obligation	115,981	123,472
Deferred tax liability	27,493	16,956
Derivative liability	522	6,425
Total liabilities	3,106,565	2,897,265

Source for debt structures used to calculate Adjusted Debt (from 2010 and 2011 10-K):

From 2011 10-K:

Other Long-term Obligations

Other long-term obligations consisted of the following (in thousands):

	December 31, 2011	December 31, 2010
Net profits interests	$ 336,669	$331,776
Dollar-denominated overriding royalty interests	42,324	52,825
Gomez pipeline obligation	71,676	73,868
Vendor deferrals – Gulf of Mexico	17,493	7,096
Vendor deferrals – North Sea	94,710	90,874
Other	2,582	2,582
Total	565,454	559,021
Less current maturities	(113,657)	(86,521)
Other long-term obligations	$ 451,797	$472,500

Net Profits Interests – Beginning in 2009, we have granted dollar-denominated overriding royalty interests in the form of net profits interests ("NPIs") in certain of our proved oil and gas properties in and around the Telemark Hub, Gomez Hub and Clipper to certain of our vendors in exchange for oil and gas property development services and to certain finance entities in exchange for cash proceeds. During April 2011, we closed an NPI transaction in the Telemark Hub for $40.0 million. The purchaser acquired an existing vendor NPI for $19.7 million, thereby extinguishing the existing NPI liability of $20.8 million, and contributed an additional $20.3 million toward the development of the Telemark Hub in exchange for a larger percentage of the net profits from production at the Telemark Hub that will continue until the purchaser recovers $40.0 million, plus an overall rate of return.

The interests granted are paid solely from the net profits, as defined, of the subject properties. As the net profits increase or decrease, primarily through higher or lower production levels and higher or lower prices of oil and natural gas, the payments due the holders of the net profits interests increase or decrease accordingly. If there is no production from a property or if the net profits are negative during a payment period, no payment would be required. We also accrete the liability over the estimated term in which the NPI is expected to be settled using the effective interest method with related interest expense presented net of amounts capitalized on the Consolidated Statements of Operations. The term of the NPIs is dependent on the value of the services contributed by these vendors or the cash proceeds contributed by the finance companies coupled with the timing of production and future economic conditions, including commodity prices and operating costs. Upon recovery of the agreed rate of return, the NPIs terminate. Because NPIs were granted on proved properties where production is reasonably assured, we have accounted for these NPI's as financing obligations on our Consolidated Balance Sheets. As such, the reserves and production revenues associated with the NPIs are retained by the Company. We expect approximately 60%, or $205 million of the NPIs to be repaid over the next 12 months based on anticipated production, commodity prices and operating costs.

Dollar-denominated Overriding Royalty Interests – During April, June and December 2011, we sold, for an aggregate of $65.0 million, three dollar-denominated overriding royalty interests ("Overrides") in our Gomez Hub properties similar to those sold in 2009 and 2010. These Overrides obligate us to deliver proceeds from the future sale of hydrocarbons in the specified proved properties until the purchasers achieve a specified return. As the proceeds from the sale of hydrocarbons increase or decrease, primarily through changes in production levels and oil and natural gas prices, the payments due the holders of the overriding royalty interests will increase or decrease accordingly. If there is no production from a property during a payment period, no payment would be required. The percentage of property revenues available to satisfy these obligations is dependent upon certain conditions specified in the agreement. Upon recovery of the agreed rate

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of return, the Overrides terminate and our interest increases accordingly. Because of the explicit rate of return, dollar-denomination and limited payment terms of the Overrides, they are reflected in the accompanying financial statements as financing obligations. As such, the reserves and production revenues are retained by the Company. Related interest expense is presented net of amounts capitalized on the Consolidated Statements of Operations. As of December 31, 2011, if there is sufficient production from a certain property, we will incur up to $7.2 million of contingent interest costs. We expect approximately 93%, or $39 million of the Overrides to be repaid over the next 12 months based on anticipated production and commodity prices.

Gomez Pipeline Obligation – In 2009, we sold to a third party for net proceeds of $74.5 million the oil and natural gas pipelines that service the Gomez Hub. In conjunction with the sale, we entered into agreements with the purchaser to transport our oil and natural gas production for the remaining production life of our fields serviced by the *ATP Innovator* production platform for a per-unit fee that is subject to a minimum monthly payment through December 31, 2016. Such minimum fees, if applicable, can be recovered by ATP in future periods within the same calendar year whenever fees owed during a month exceed the minimum due. We remain the operator of the pipeline and are responsible for all of the related operating costs. As a result of the retained asset retirement obligation and the purchaser's option to convey the pipeline back to us at the end of the life of the fields in the Gomez Hub, the transaction has been accounted for as a financing obligation equal to the net proceeds received. This obligation is being amortized based on the estimated proved reserve life of the Gomez Hub properties using the effective interest method with related interest expense presented net of amounts capitalized on the Consolidated Statements of Operations. All payments made in excess of the minimum fee in future periods will be reflected as interest expense of the financing obligation.

Vendor Deferrals – In the Gulf of Mexico, in addition to the NPIs exchanged for development services described above, we have negotiated with certain other vendors involved in the development of the Telemark and Gomez Hubs to partially defer payments over a twelve-month period beginning with first production. We accrue the present value of the deferred payments and accrete the balance over the estimated term in which it is expected to be paid using the effective interest method with related interest expense presented net of amounts capitalized, on the Consolidated Statements of Operations.

In the U.K. North Sea, development of our interest in the Cheviot field continues. During February 2012, we entered into an amendment to one of our agreements for the construction and delivery of the Octabuoy hull and topside utility module to align the payments with the now expected delivery date of the hull. As amended, the agreements provide for a $41.1 million payment in the first quarter of 2012 and $228.9 million in 2013. As work is completed and amounts are earned under the amended agreement, we record obligations and related interest expense, net of amounts capitalized, on the Consolidated Financial Statements.

Effective Interest Rate – The weighted average effective interest rate on our other long-term obligations set forth above was 18.9% and 16.7% at December 31, 2011 and 2010, respectively.

From 2010 10-K:

Note 7 — Other Long-term Obligations

Other long-term obligations consisted of the following (in thousands):

	December 31, 2010	December 31, 2009
Net profits interests	$331,776	$180,818
Dollar-denominated overriding royalty interests	52,825	14,941
Gomez pipeline obligation	73,868	75,152
Vendor deferrals – Gulf of Mexico	7,096	7,490
Vendor deferrals – North Sea	90,874	17,053
Other	2,582	2,582
Total	559,021	298,036
Less current maturities	(86,521)	(23,094)
Other long-term obligations	$472,500	$274,942

Net Profits Interests

During 2009 and 2010, we granted dollar-denominated overriding royalty interests in the form of net profits interests ("NPIs") in certain of our proved oil and gas properties in and around the Telemark Hub, Gomez Hub and Clipper to certain of our vendors in exchange for oil and gas property development services. The interests earned by the vendors are paid solely from the net profits, as defined, of the subject properties. As the net profits increase or decrease, primarily through higher or lower production levels and higher or lower prices of oil and natural gas, the payments due the holders of the net profits interests increase or decrease accordingly. If there is no production from a property or if the net profits are negative during a payment period, there is no payment required. We also accrete the liability over the estimated term in which the NPI is expected to be settled using the effective interest method with related interest expense presented net of amounts capitalized on the Consolidated Statement of Operations. The term of the NPIs will be dependent on the value of the services contributed by these vendors coupled with the timing of production and future economic conditions, including commodity prices and operating costs. Because NPIs were granted on proved properties where production is reasonably assured, we have accounted for these NPI's as financing obligations on our Consolidated Balance Sheet. As such, the reserves and production revenues associated with the NPIs are retained by the Company. We expect approximately 75% of the NPIs to be repaid over the next 24 months based on projected production, commodity prices and operating costs.

During November 2010, a NPI originally granted during 2009 in exchange for vendor services was acquired by an investor, who repaid the vendor $39.2 million outstanding under the original NPI, extended the payout term of the NPI, and increased the size of the obligation to $100.0 million. The proceeds of the transaction were $60.3 million, net of transaction costs, and we recognized a gain on debt extinguishment of $2.9 million.

Dollar-denominated Overriding Royalty Interests

In October 2009, we sold a dollar-denominated overriding royalty interest ("Override") in our Gomez Hub properties for $14.5 million, net of costs. During 2010, we sold Overrides (primarily dollar-denominated) in future production from the Gomez Hub properties for $140.0 million ($121.1 million net of transaction costs and fourth quarter 2009 royalty payments). These Overrides obligate us to deliver proceeds from the future sale of hydrocarbons in the specified proved properties equal to the purchasers' original investments, plus an overall rate of return. As the proceeds from the sale of hydrocarbons increase or decrease, primarily through changes in production levels and oil and natural gas prices, the payments due the holders of the overriding royalty interests will increase or decrease accordingly. If there is no production from a property during a payment period, there is no payment required. The percentage of property revenues available to satisfy these obligations is dependent upon certain conditions specified in the agreement. Upon payment of the agreed dollar amounts, the ownership of the Overrides reverts to us. Because of the explicit rate of return, dollar-denomination and limited payment terms of the Overrides, they are reflected in the accompanying financial statements as financing obligations. As such, the reserves and production revenues are retained by the

Company. Related interest expense is presented net of amounts capitalized on the Consolidated Statements of Operations. We expect the Overrides to be repaid over the next 12 months based on projected production and commodity prices.

Gomez Pipeline Obligation

In 2009, we executed an asset purchase and sale agreement for net proceeds of $74.5 million pursuant to which the Company sold to a third party the oil and natural gas pipelines that service the Gomez Hub at MC Block 711. In conjunction with the sale, we entered into agreements with the third party to transport our oil and natural gas production for the remaining production life of our fields serviced by the *ATP Innovator* for a per-unit fee that is subject to a minimum monthly payment through December 31, 2016. Such minimum fees, if applicable, can be recovered by ATP in future periods within the same calendar year whenever fees owed during a month exceed the minimum due. We remain the operator of the pipeline and are responsible for all of the related operating costs. As a result of the retained asset retirement obligation and the purchaser's option to convey the pipeline back to us at the end of the life of the fields in the Gomez Hub, the transaction has been accounted for as a financing obligation equal to the net proceeds received. This obligation is being amortized based on the estimated proved reserve life of the Gomez properties using the effective interest method with related interest expense presented net of amounts capitalized, on the Consolidated Statements of Operations. All payments made in excess of the minimum fee in future periods will be reflected as interest expense of the financing obligation.

Vendor Deferrals

In the Gulf of Mexico, in addition to the NPIs exchanged for development services described above, we have negotiated with certain other vendors involved in the development of the Telemark and Gomez Hubs to partially defer payments over a twelve-month period beginning with first production. We accrue the present value of the deferred payments and accrete the balance over the estimated term in which it is expected to be paid using the effective interest method with related interest expense presented net of amounts capitalized, on the Consolidated Statements of Operations.

In the U.K. North Sea, development of our interest in the Cheviot field continues. We have arranged with the fabricator of the floating production facility to defer $121.5 million of committed expenditures: $54.5 million to be paid in 2011 and $67.0 million to be paid in 2012. As work is completed, we record obligations and related interest expense, net of amounts capitalized, on the Consolidated Statements of Operations.

The weighted average effective interest rate on our other long-term obligations was 16.7% at December 31, 2010.

Source for Interest Expense (excluding the effects of capitalized interest) used to calculate EBITDA/Interest Expense ratio (interest expense detail tables from the Management's Discussion and Analysis of Financial Condition and Results of Operations section in the 2011 10-K):

Interest Expense, Net

Interest expense, net of amounts capitalized is set forth in the following table (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Interest expense	$355,657	$275,404	$150,984
Capitalized interest:			
ATP Titan – Telemark (Gulf of Mexico)	—	40,400	102,200
Octabuoy – Cheviot (North Sea)	29,246	12,900	7,900
Total capitalized interest	29,246	53,300	110,100
Interest expense, net	$326,411	$222,104	$ 40,884

Source for Noncash Interest Expense used to calculate EBITDA/Cash Interest Expense ratio (Partial Cash Flow Statement from 2011 10-K):

ATP OIL & GAS CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31,		
	2011	2010	2009
Cash flows from operating activities			
Net loss	$(165,277)	$ (322,046)	$ (35,581)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities –			
Depreciation, depletion and amortization	298,574	220,657	152,780
Impairment of oil and gas properties	57,639	63,267	45,799
Gain on exchange/disposal of properties	(27,000)	(26,720)	(12,433)
Accretion of asset retirement obligation	15,000	13,827	11,676
Deferred income tax expense (benefit)	19,395	(35,414)	(23,079)
Derivative (income) expense	(38,188)	20,090	39,648
(Gain) loss on debt extinguishment	(1,095)	18,973	—
Stock-based compensation	6,683	6,825	7,951
Amortization of deferred revenue	—	(19,336)	(39,893)
Noncash interest expense	35,320	28,078	13,262
Other noncash items, net	(694)	3,245	2,443
Changes in assets and liabilities –			
Accounts receivable and other current assets	59,061	(31,979)	50,402
Accounts payable and accruals	(29,491)	23,213	(53,168)
Other assets and liabilities	(32,836)	40	20
Net cash provided by (used in) operating activities	197,091	(37,280)	159,827

ATP Ratios and Calculations

	2011	2010	2009
Net Loss	(165,277)	(322,046)	(35,581)
Add back:			
expense/(benefit)	18,068	(36,273)	(22,534)
Net interest expense (includes noncash interest expense and is reduced by capitalized interest)	326,411	222,104	40,884
DD&A	298,574	220,657	152,780
Accretion	15,000	13,827	11,676
Impairment	57,639	63,267	45,799
Exploration	1,251	1,174	264
	716,943	484,756	228,869
EBITDAX	**551,666**	**162,710**	
193,288			
Adjusted Debt Calculation			
Current maturities of long-term debt	33,848	21,625	16,838
Long-term debt	1,976,157	1,857,784	1,199,847
More "Traditional" Debt	2,010,005	1,879,409	1,216,685
"Other" debt (part of other long-term obligations but are effectively creative debt)	336,669	331,776	180,818
Net profits interests			
Dollar-denominated overriding royalty interests	42,324	52,825	14,941
Gomez pipeline obligation	71,676	73,868	75,152
Vendor deferrals – Gulf of Mexico	17,493	7,096	7,490
Vendor deferrals – North Sea	94,710	90,874	17,053
Other Debt	562,872	556,439	295,454
Adjusted Debt	**2,572,877**	**2,435,848**	**1,512,139**
Adjusted Debt/EBITDAX	**4.7x**	**15.0x**	**7.8x**
Interest expense excluding effects of capitalized interest	355,657	275,404	150,984
Noncash interest expense adjustment	(35,320)	(28,078)	(13,262)
Cash interest expense	**320,337**	**247,326**	**137,722**
EBITDAX/Cash Interest Expense	**1.7x**	**0.7x**	**1.4x**

<u>Definitions/Calculations:</u>

EBITDA(X) - Start with Net Income/(Loss) and then add back income taxes, interest expense, depreciation, depletion and amortization, and impairment of oil and gas properties. For successful efforts companies like ATP, exploration expense is also added back.

Adjusted Debt - Bank revolver debt, other long-term notes and current maturities of long-term debt listed in the Liabilities section of the balance sheet. Also includes other long-term obligations that are effectively "creative debt". In other words, Adjusted Debt includes all long-term liabilities in which the company is contractually obligated to pay a third party. It does not include ARO or deferred tax liability (which is attributable to differences in accounting for GAAP and tax purposes at the current tax rate).

Cash interest expense - Interest expense excluding the effects of capitalized interest, less noncash interest expense, if any.