The news of the summer of 2010 was dominated by the Deepwater Horizon disaster in the Gulf of Mexico. While media attention was naturally focused on the worst oil spill in the nation’s history, two other notable oil spills occurred during the same time period, namely the Enbridge pipeline spill in Michigan and the allision of a tugboat with an abandoned oil well in Louisiana’s Barataria Bay. While the Coast Guard was busy responding to these spills, Congress decided to abandon Climate Change legislation and Environmental Protection Agency launched a study to determine if hydraulic fracturing of oil shales should be federally-regulated.

Since oil is at the heart of the three areas of the committee’s focus - environment, energy and natural resources - we decided to devote this issue of our newsletter to the regulation of oil spills and oil-related facilities. The first article sets the stage by discussing the framework of the Oil Pollution Act (“OPA”) and the Clean Water Act (“CWA”). Bill Anderson’s article follows with an intriguing article covering how the OPA liability caps may be illusory. Then, Jon Waldron follows the money with his piece on the Draft Protocol for the Gulf Coast Claims Facility (“GCCF”) which has been proposed by Ken Feinberg, the administrator of the $20 billion Gulf Coast Escrow Fund (“GCEF”) and how it compares to the claims process available under OPA. Still in the warm waters of the Gulf, Drew Cohen follows with an explanation of the Outer Continental Shelf Lands Act (“OCSLA”)- the principal law for awarding drilling leases- and the legal challenges to the drilling moratorium that followed the Deepwater Horizon blowout.

Moving inland, Chuck Bowman discusses the liability associated with the numerous pipelines that crisscross the United States carrying enormous volumes of petroleum products and hazardous liquids. We then conclude this issue with an article by Pat Zaepfel on perhaps the most contentious energy and environmental regulatory issue-hydraulic fracturing.

In other committee news, I am please to announce that our committee completed our book project on environmental issues in business and corporate transactions. We are finalizing some interesting sample forms and anticipate publication in the early fall.

Program Chair David Roth has launched our webinar series that is designed for younger attorneys who want to learn more about environmental laws and the experienced hands who might need a refresher course. The programs are one hour and the next installment will be on due diligence. Our initial program “Everything about CERCLA You Were Afraid to Ask: Superfund Basics for Environmental Business Lawyers” was such a hit that we have decided to take it on the road and will be part of our CLE program for the Spring 2011 Meeting.

David Johnson recently agreed to serve as a webmaster. He will be responsible for populating our website with interesting content. If you come across any interesting cases that you think merit attention, please contact David and he will be sure to post it.

Finally, I want to encourage younger attorneys to become actively involved in our committee. We have lots of interesting committee work that can be both a wonderful learning experience as well as provide you with great networking opportunities.
The rediscovery by Congress of the Oil Pollution Act’s (“OPA”) $75 million cap on liability for damages1 in the wake of the Deepwater Horizon disaster spurred proposals to raise or eliminate that cap. Senator Robert Menendez, joined by Senators Frank Launenberg and Bill Nelson, introduced his “Big Oil Bailout Prevention Act” to raise the OPA cap to $10 billion.2 Led by Senator Vitter, Republicans proposed their own plan to raise the cap.3 Notwithstanding the OPA cap, BP P.l.c. has since agreed to establish a $20 billion escrow fund to address its liability.4 As BP’s escrow suggests, the cap is not likely to be practical impediment to the government’s ability to persuade the responsible parties to respond to damage claims without regard to the cap. In addition to the power of public opinion and OPA’s own exceptions that nullify the cap,5 the government has in its arsenal the threat of criminal prosecution invoking the Alternative Fines Act.6 In short, despite the show of shock and outrage in Congress, the OPA liability cap may be more political fodder than a practical limit on the responsible parties’ liability

THE LIABILITY CAP

Subject to narrow defenses and certain limits, OPA makes parties who are responsible for an oil spill liable for the costs of removal and for “damages.” More precisely, it imposes liability on “each responsible party for . . . a facility from which oil is discharged.”7 In the case of an offshore facility on the Outer Continental Shelf such as the Deepwater Horizon well, “responsible party” means “the lessee or permittee of the area in which the facility is located.”8 OPA borrows the standard of liability from, and it defines removal costs by reference to, the oil spill provisions in section 311 of the Clean Water Act.9 But it has its own expansive definition of “damages.” The term means damages for injury to natural resources; for injury to property, including economic losses; loss of subsistence use of natural resources; loss of governmental tax and other revenues; lost profits and diminished earning capacity from injury to property or natural resources; and the increased costs of public services, “including protection from fire, safety, or health hazards” caused by the oil spill.10 Notably, however, this definition of “damages” does not include personal injury, private medical monitoring costs, or emotional distress.

Subject to specified exceptions, OPA then sets limits on the liability it imposes. Different limits apply to vessels, to onshore facilities and deepwater ports, and to offshore facilities. For vessels and onshore facilities, the statutory caps apply to OPA liability for both removal costs and damages, as defined.11 In the case of offshore facilities, responsible parties’ OPA liability “shall not exceed . . . the total of all removal costs plus $75,000,000.”12 OPA also directs the President to adjust these caps no later than July 11, 2009, and every three years thereafter, to reflect significant changes in the Consumer Price Index.13

SAVINGS CLAUSE

OPA contains a broad savings clause that preserves the States’ ability to impose additional liability or requirements relating to oil discharges, pollution or spill cleanup and removal.14 It also preserves the authorization of the United States and the States to impose additional liability or requirements under other laws or to impose “any fine or penalty (whether criminal or civil in nature) for any violation of law.”15

POTENTIAL VIOLATIONS OF LAW

The Attorney General has announced a criminal investigation into the Deepwater Horizon incident and the resulting oil spill. Among the potentially criminal prohibitions implicated is section 311(b)(3) of the Clean Water Act (“CWA”).16 Section 311(b)(3) prohibits discharges of oil into or upon U.S. waters, shorelines or the contiguous zone and in connection with activities under the Outer Continental Shelf Lands Act.17 Section 309(c) of the CWA in turn makes any violation of section 311(b) a criminal offense if it is “negligent(ly)” or “knowing(ly)” violated.18 A “negligent” violation of section 311(b)(3) is a misdemeanor punishable by up to a fine of up to $25,000 per day of violation and a year’s imprisonment, and a “knowing” violation is a felony subject to a $50,000 per day fine and up to 3 year’s imprisonment.19 Although the Department of Justice will likely not limit its inquiry to potential violation of section 311(b)(3), that may be one of the easiest criminal charges to prosecute, if its investigation finds negligence.
THE ALTERNATIVE FINES ACT

Wherever the government pursues criminal charges, it may seek fines under the Alternative Fines Act ("AFA"), in lieu of those stated in section 309(c) of the CWA or other organic statutes. The AFA specifies two different bases for fines other than those specified in the substantive law; it is the threat of the second one that gives the government extraordinary leverage. Under the first, a sentencing court may order an organization found guilty of a felony to pay a fine of up to $500,000. Alternatively, under the second, if the offense results in either pecuniary gain to the defendant or pecuniary loss to another the court may impose a fine equal to twice the gross gain or twice the gross loss. If the imposition of a gain- or loss-based fine would "unduly complicate or prolong the sentencing process," however, it is not to be imposed. Hence, a criminal prosecution would pose the threat of a criminal fine equal to twice the aggregate pecuniary losses caused by the offense. Recent estimates of a $22.7 billion loss in just tourist revenues presents the prospect of a fine in excess of $45 billion for BP.

The AFA was the basis of the agreed $50 million fine in the plea agreement approved by the court in United States v. BP Products North America, Inc. That case grew out of a fatal explosion and fire at the defendant’s Texas City, Texas refinery. The defendant pled guilty to a felony violation of the Clean Air Act. In seeking the court’s approval of the plea agreement and a fine of $50 million, the Department of Justice explained that it based the fine on the refinery’s pecuniary gain of $25 million in the form of savings it reaped from the violation. Several victims groups urged the court to base an AFA fine instead on their aggregate gross losses (including worker’s compensation claims). But the court found that to do so would “unduly complicate or prolong” the sentencing process.

Certainly, actually imposing a criminal fine of twice the pecuniary losses resulting from the Gulf oil spill would be very difficult, but whether it is too difficult would be up to the trial judge. Unfortunately, the legislative history and case law provide scant guidance on when an alternative fine shall be deemed "unduly to complicate or prolong" sentencing. What is clear is that the sentencing court has broad discretion to decide whether the use of section 3571(d) would “unduly complicate or prolong the sentencing process,” and on appeal the Courts of Appeals will apply an abuse-of-discretion standard. In United States v. Gibson, the district judge had refused to apply the AFA because “I might be here for a long time and still have lots of questions about the amount, and I’d be[en] engaging in speculation and guesswork. . . and certainly I think it’s going to complicate matters, and it’s going to prolong this sentencing.” The Sixth Circuit found this justification by the district court judge sufficient and upheld the judge’s decision.

The court in BP Products North America, Inc. looked for guidance to other statutes that contain similar “undue complication” standards, particularly the Victims and Witness Protection Act (VWPA) and the Mandatory Victims Restitution Act (MVRA). Based on its reading of those cases, the court concluded that basing a fine on pecuniary losses under 3571(d) is likely “unduly to complicate or prolong” sentencing when there are multiple victims, causation issues are disputed, or when disputed future losses are involved. It found that all three factors were present in that case.

Other courts have not seen these factors as necessarily dispositive, however. In an MVRA case, although the decision was reversed on other grounds, the Second Circuit upheld the district court’s view that it was not too complex to order restitution to “thousands” of fraud victims. The court noted that the undue complication” exception exists to permit the court to forego restitution if it is unduly burdensome. Similarly, in United States v. Hand, the Third Circuit stated that “difficulties of measurement do not preclude the court from ordering a defendant to compensate the victim through some restitution [under the VWPA].” In another VWPA case, the Tenth Circuit upheld the district court’s award of lifetime future earnings to the estate of a three-month old homicide victim, a necessarily complex determination.

In the civil litigation stemming from the Exxon Valdez disaster, both the Ninth Circuit and the district court used the potential AFA fine as a benchmark to conclude that the jury’s punitive damage award passed constitutional muster. Both courts noted Exxon’s criminal liability could have been an AFA fine of twice the pecuniary loss caused by its offenses. While the Supreme Court ultimately vacated the amount of the lower courts’ punitive damage award in Exxon Shipping Co. v. Baker, the Court did not question the lower courts’ logic regarding the possible fines under the AFA.

CONCLUSION

It remains to be seen whether the Department of Justice’s investigation into the Gulf Spill will lead to criminal charges, and whether, if so, it will be able to
obtain a conviction. But even the prospect of a criminal prosecution poses a risk to the defendant of imposition of a fine under the AFA. While a determination of the baseline gross losses to double under 18 U.S.C. 357(d) would be extraordinarily complex, even a slight threat of a criminal fine in the tens of billions, on top of the civil claims for those losses under state laws, would be an enormous incentive for the potential criminal defendant to agree to disregard the cap on OPA liability for damages. As a result, the nominal $75 million cap on OPA liability for damages is unlikely to be an impediment to the government’s ability to persuade BP to accept liability for damages and losses well in excess of $75 million.

Endnotes

3 S. 3375, 111th Cong., 2nd Sess. § 102 (2010).
5 See 33 U.S.C. § 2704(c)(1),(2).
7 OPA § 1002(a), 33 U.S.C. § 2702(a).
10 See OPA § 1002(b), 33 U.S.C. § 2702(b).
11 See OPA § 1004(a)(1)-(4), 33 U.S.C. § 2704(a)(1)-(4). The owner or operator of any Outer Continental Shelf bears all costs of removal incurred by any federal, state or local government agency without regard to any limits or defenses. See id. § 1004(c)(3), 33 U.S.C. § 2704(c)(3).
13 Id. § 1004(d)(4), 33 U.S.C. § 2704(d)(4). The President delegated this authority to the Coast Guard for vessels and onshore facilities and to the Minerals Management Service (“MMS”) for offshore facilities. Exec. Order No. 12,777, 56 Fed. Reg. 54775 (Oct. 22, 1991). The Coast Guard has adjusted the limits for vessels and onshore facilities, 75 Fed. Reg. 750 (Jan. 6, 2010), but the MMS has not adjusted the cap for offshore facilities.
14 Id. § 1018(a)(1), 33 U.S.C. § 2718(a)(1).
15 Id. § 1018(c), 33 U.S.C. § 2718(c).
17 Id.
18 Id. § 1319(e).
19 Id. § 1319(c)(1)(B), (2)(B).
21 Id. § 3571(c)(2), (d).
22 Id.
25 Id. at 695-96.
26 Id. at 707.
27 Id.
28 409 F.3d 325 (6th Cir. 2005).
29 Id. at 342.
30 Id.
33 610 F. Supp.2d at 691.
34 Id. at 695.
36 863 F.2d 1100, 1104 (3d Cir. 1988).
37 Id.
38 United States v. Serawop, 505 F.3d 1112 (10th Cir. 2007).
40 270 F.3d 1245; 290 F. Supp.2d at 1107-1108.
HAZARDOUS LIQUIDS PIPELINES – REGULATION AND DUE DILIGENCE
By Charles Brownman

1. OVERVIEW / INTRODUCTION

Since being introduced sometime in the mid- to late-1800s, pipelines have been recognized as being the best method of transporting large quantities of oil, refined petroleum products and natural gas over land. Compared to shipping by rail, pipelines have a lower cost per unit, larger capacity, and frequently offer more flexibility. In 2005, then-U.S. Transportation Secretary Norman Y. Mineta recognized pipelines as being the “unsung heroes of our economy.”

Today, a vast network of more than 180,000 miles of pipelines crisscross the lower 48 states, comprised of approximately 55,000 miles of crude oil trunk lines (larger diameter pipelines that connect producing regions with consumer areas), 30,000-40,000 miles of crude oil gathering lines (smaller diameter pipelines that gather oil from wells and connect to the larger trunk lines), and about 95,000 miles of petroleum product lines, flow lines associated with well operations, and contaminated water pipelines containing the water left following separation from the crude oil and other hydrocarbons.

The following diagram illustrates how hazardous liquids move through pipelines from the well to consumers:

Pipelines are closely-regulated; however, despite that oversight, many pipelines still corrode and leak due to numerous causes (including environmental abuse, external damage, inherent manufacturing or installation defects, soil movements and instability, and third party damage).

Since most pipelines are buried — anywhere between two and five feet below the surface — it is difficult, expensive and time-consuming to dig them up and inspect them visually.

From these facts, one could conclude that pipeline leaks are neither uncommon nor unexpected, so that environmental risk and damages are part of the cost of doing business. Because of the knowledge that pipelines frequently leak it has made estimating, assessing and allocating the cost of these environmental risks a difficult and important task for both the sellers and buyers of a pipelines, This article is intended to provide a brief exposure of the regulatory paradigm and the methods of using due diligence to minimize the buyer's exposure to liability from pipeline leaks.

2. TECHNICAL BACKGROUND: WHY DO PIPELINES CORRODE AND LEAK?

There are several reasons why oil corrodes a pipeline. First, when oil is pumped out of the ground, it contains “contaminants” that include water, carbon dioxide and
sulfur. (In fact, the amount of sulfur contained in the oil is the basis for the oil being categorized as “sweet” or “sour”.) If enough contaminants collect in a steel pipe over a long-enough amount of time, the contaminants can eat away at the steel. Second, when produced out of the ground, the crude oil is hot, and the oil is then heated further to enhance its flow; however, the heat exacerbates corrosion. For those reasons, pipelines use “pipeline inspection gauges” (commonly referred to as “pigs”) to inspect and clean the pipeline without stopping the flow of the product in the pipeline; but contaminants can still collect and cause corrosion of the steel.

One would think that with improved technology and materials, corrosion (the second leading cause of pipeline leaks and “reportable incidents”) would never occur. However, using stainless steel pipes to further minimize the possibility of corrosion is considered overly expensive; even if it were not, the cost of replacing the tens of thousands of miles of steel pipe already in place would be staggering.

Pipeline manufacturers do paint the outer surface of the pipeline with a protective coating, but doing so on the inside of the pipe is not feasible – either before the lengths are welded together (the welding and assembly process would effectively destroy and eat away at the coating), or after assembly (the pipe is too long to effectively coat the inside).

Also, once a pipeline is buried below ground, the pipeline is subject to soil shifting and instability, environmental damage, and damage from third party excavations, all of which (in addition to normal manufacturing defects and bad welding) can cause corrosion.

3. THE REGULATORY SYSTEM

Because crude oil is volatile and flammable, the relevant pipeline safety law defines it as a “hazardous material”; therefore, pipelines that transport crude oil and refined petroleum products are considered and regulated as “hazardous material” pipelines.

Oil pipeline regulation is handled primarily by two federal agencies – the Federal Energy Regulatory Commission (“FERC”), which provides oversight on more of the commercial aspects of pipelines (such as permitting, siting and transmission rates); and the Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (“PHMSA”), which establishes and enforces design, construction, operation, maintenance, testing and inspection standards. (In addition to FERC and PHMSA as the primary regulators, other, more narrowly-focused federal agencies that can be (and often are) involved in regulation, reporting and oversight include the Environmental Protection Agency (especially when there is a spill or a leak); the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly the Minerals Management Service) (when the pipelines are offshore); and the Occupational Safety and Health Administration (regarding working conditions and employee safety)). In addition, state and local governments can also regulate pipelines, primarily through zoning and land use regulations, environmental requirements, fish and wildlife protections, historic preservation, and highway/street transportation limitations.

The PHMSA’s authority stems from the 1994 Pipeline Safety Act (the “PSA”), which combined and recodified, without substantive changes, the two then-existing pipeline safety statutes, the Hazardous Liquid Pipeline safety Act of 1979 (formerly found at 49 U.S.C. §§ 2001 to 2014) and the Natural Gas Pipeline Safety Act of 1968 (formerly found at 49 U.S.C. §§ 1671 et seq.). But it has been over the last decade that there has been a significant increase in the amount and scope of legislation and regulation governing pipelines.

Characterized by some as “a piece of legislation with sweeping mandates and impacts upon the [pipeline] industry”, the Pipeline Safety Improvement Act of 2002 (the “2002 PSIA”) not only re-authorized the federal government’s pipeline safety program through 2006, it tightened federal safety requirements by mandating inspections within five to ten years, and established a pipeline hierarchy – having pipeline operators differentiate pipeline segments based on where they were, the lands around them and the impact a leak or release would have. Operators were required to (i) identify and designate such critical areas either as “high consequence areas” (or “HCAs”; these include navigable waterways, and areas of high population or high population density”) or as “unusually sensitive areas” (“USAs”; environmental resources or drinking water areas that would be unusually sensitive to damage from a release of a hazardous liquid), and (ii) conduct a risk-based analysis of these areas by performing baseline integrity assessments (known as PHMSA’s “integrity management program”).

In the course of the next re-authorization cycle, Congress passed the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006 (the “PIPES” Act). Continuing the regulatory expansion begun in the 2002 PSIA, the PIPES Act (i) broadened the assessment and
management of safety-related risks by having PHMSA work more closely with states to minimize damage caused by excavation (still one of the leading causes of fatal pipeline incidents\(^\text{14}\)), (ii) mandated confirmation by a senior executive attesting to the accuracy of a pipeline’s integrity management program performance reports, (iii) expanded the scope of PHMSA’s regulatory jurisdiction to include “low stress (i.e., low pressure) pipelines” (this was added in reaction to an oil leak of approximately 250,000 gallons into Prudhoe Bay, caused by a quarter-inch hole in a corroded low-pressure pipe operated by BP that went undetected for five days\(^\text{15}\)), and (iv) strengthened PHMSA’s enforcement capabilities.

The enforcement procedures and sanctions utilized by PHMSA can be found in the Code of Federal Regulations,\(^\text{16}\) and they include Warning Letters (when PHMSA believes that a violation exists), Notices of Probable Violations (which begin the enforcement actions), and informal hearings (which are not required to conform to the Administrative Procedure Act, but which still lead to Final Orders containing civil penalties). Two such cases involved Chevron USA, Inc. and Kinder Morgan Energy Partners, L.P..\(^\text{17}\)

**CURRENT AND FUTURE REGULATORY PROCEEDINGS**

Despite the passage of the 2002 PSIA and the 2006 PIPES Act, regulators have not kept up with issuing regulations for these laws permitting oversight gaps to still exist. For example, in response to the requirement in the PIPES Act for oversight of low-stress pipelines, PHMSA published a Final Rule in June, 2008 that applied Phase 1 of a planned two-phase approach to regulating all rural onshore hazardous liquid low-stress pipelines.\(^\text{18}\) This Final Rule applied to only seventeen percent of existing large-diameter, low-stress pipelines, and PHMSA stated that it would need to come back with a second rulemaking to regulate all other applicable low-stress pipelines.\(^\text{19}\) On June 22, 2010, PHMSA issued its Notice of Proposed Rulemaking (“NOPR”) to have its existing pipeline safety regulations apply to all low-stress pipelines within five years of the effective date of the new regulations.\(^\text{20}\)

The diagrams below, presented to a House subcommittee on June 29, 2010, depict the current status of PHMSA’s low-stress pipeline regulation.

In addition to the ongoing low-stress pipeline proceedings, other types of pipelines remain exempt from PHMSA’s safety regulations, including pipelines located offshore and in inlets of the Gulf of Mexico; and pipelines that transport hazardous liquids through onshore production, refining, storage or manufacturing facilities. Numerous safety and environmental groups have suggested that such exemptions weaken the public’s confidence that the PHMSA is properly ensuring pipeline safety, and “result in regulatory coverage that is piecemeal at best and confusing, difficult to implement and enforce, and inadequate at worst.”\(^\text{21}\)

As a result of the Deepwater Horizon oil spill in the Gulf of Mexico, PHMSA issued a June 2010 Advisory Bulletin reminding onshore hazardous liquid pipeline operators to review and update mandatory oil spill response plans to ensure that it includes a response to a “worst case discharge”.\(^\text{22}\)

Finally, because PHMSA’s current authorization is due to expire this year (the PIPES Act only re-authorized it though 2010), the House Subcommittee on Railroads, Pipelines, and Hazardous Materials held a June 29 hearing to take testimony and reexamine PHMSA’s regulatory actions.
4. BUYING A PIPELINE

As previously stated, pipelines are likely to corrode and leak. Therefore, if you buy a pipeline, the chances are you will be confronted by a spill and potential remediation, plus other kinds of liabilities.

(A) A WORD ABOUT ACQUISITIONS AND LIABILITY

While it is outside the scope of this article to discuss in detail the structure of a purchase and sale agreement ("PSA"), or allocations of liability in the context of a business transaction, what can be said is that the issues of who retains or accepts pre-closing and ongoing liabilities after closing, and how/when those liabilities are identified and quantified, are two of the most hotly-negotiated major points in any pipeline deal. These issues initially manifest during the most basic discussion of a deal’s structure — whether the buyer will be purchasing assets or stock — and then carryover into various sections of the PSA.

In a stock deal, the purchaser acquires the entity that owns the assets, meaning that purchaser will acquire both the assets and liabilities of the entity being sold. Alternatively, an acquisition of assets allows the buyer (at least in theory) to avoid liabilities; however, a buyer may still be liable, under certain circumstances the buyer may be held liable based on a variety of theories of “successor liability” developed by various jurisdictions over the last thirty years.23

(B) TRANSACTIONAL DUE DILIGENCE

In most transactions, the buyer’s objective of understanding all the current and potential liabilities and other issues related to the asset or entity being sold (especially given the possibility of inadvertently acquiring liabilities) conflicts with the seller’s reluctance to provide information, knowing that it might be liable if its disclosures are ultimately deemed to be incomplete, false, misleading or inaccurate. But business considerations (such as the timing of the closing, the purchase price, and requirements mandated by the buyer’s lender) will often result in the PSA that includes some environmental representations regarding the condition of the pipelines or environmental contamination, combined with disclosure schedules containing most of the information sought by the buyer.24

Environmental representations typically cover matters such as the pipeline’s past use; timely and complete governmental filings; the presence (or lack thereof) of hazardous materials; pending or threatened governmental or third party actions; and whether or not any cleanup programs are planned or are ongoing. Once drafted and combined with any applicable disclosures, the representations often serve as a starting point for the buyer’s due diligence efforts, which will be the buyer’s primary way of determining what liabilities (and potential liabilities) it might be managing or dealing with, post-closing.

The buyer’s environmental investigation will usually take the form of an environmental due diligence audit (an overall assessment of a company’s compliance and performance program)25, or an Environmental Site Assessment (“ESA”). An ESA can be performed at two levels — “Phase I” and “Phase II”.

A Phase I ESA provides an overview of the environmental condition and environmental history of a particular property, with the goal being to identify actual and potential problems based primarily on a review of documentation and regulatory databases, and a walk-through inspection of the site, but not the collection of physical samples. If significant problems are discovered during the course of the Phase I inspection, the report will generally recommend specific follow-up testing, remediation and/or studies. Those follow-up procedures and tests constitute the basis of the Phase II ESA. The Phase II ESA is a more intrusive investigation that includes collection and analysis of soil and/or groundwater samples to determine the quantitative values of different contaminants in the samples.

The general trend in acquisitions is to permit a buyer to avoid or mitigate some environmental liabilities if it undertakes a thorough environmental due diligence review. In April, 2000, the Environmental Protection Agency (“EPA”) issued a final policy statement that revised portions of its 1995 Policy on “Incentives for Self-Policing” (commonly referred to as the “Audit Policy”), established standards for conducting a Phase I ESA, and established conditions which, if met, could result in significant mitigation of some penalties imposed on the buyer for environmental violations that occurred before the assets were purchased by the buyer.26 In March of this year, EPA scheduled a “listening session” to listen to the views of both stakeholders and the general public on the current practices for its “All Appropriate Inquiries” (“AAI”) standards, which allows bona fide prospective purchasers to have a defense against Superfund liabilities when buying certain kinds of properties.
5. **CONCLUSIONS / PRACTICAL CONSIDERATIONS**

The conclusions to be drawn from this brief overview are these:

- First, despite regulatory oversight, better equipment and more training, a leak, spill or other “reportable incident” is almost certain to occur. Therefore, a pipeline operator should prepare for that occurrence, before it occurs, by having a spill response plan in place, training its employees what to do (and perhaps more importantly, what NOT to do) and who to call when a spill happens, and making sure their insurance will adequately cover the cost of the spill and cleanup.

- Second, regulatory compliance cuts both ways. The contents of spill reports can be used by third party claimants, so care should be taken in the preparation of spill reports, and counsel should review them before they are filed with the appropriate regulatory agencies.

- Third, in addition to obtaining broad representations from the seller, a buyer of a pipeline should access all reports made to the regulatory agencies, talk to the appropriate operating personnel of the seller, and conduct, at a minimum, a Phase 1 ESA.

**Endnotes**

1  Charles Brownman is a Houston-based attorney who has worked for over 25 years as in-house counsel for large and small companies in all phases of the energy industry.


4  See id. at 1, 2.


8  See Subcommittee Staff Summary, supra note 3.


14 Quarterman, supra note 5.


17 See McCown, supra note 8, at 48-49 (describing and discussing more fully the cases).


19 Id. at 31,641.


21 Subcommittee Staff Summary, supra note 1, at 5 (citing comments filed with PHMSA in a proposed rulemaking by the Pipeline Safety Trust).

THE OUTER CONTINENTAL SHELF LANDS ACT REVISITED: THE STATUS OF THE HORNBECK CASE AND RECENT LEGISLATION

By Drew F. Cohen*

INTRODUCTION: DRILL, BABY, DRILL! V. HUSH, BABY, HUSH!

In the dog days of summer 2008, “Drill, Baby, Drill!” resolutely punctuated the thick air at every Republican stump speech. Popularized by then Republican Vice Presidential candidate Sarah Palin, the refrain became the Grand Old Party’s call to arms for increasing domestic production of oil while resisting the Democrat’s push for increased reliance on renewable energy resources.1

The slogan lost steam in the months following President Obama victory over Arizona Senator John McCain, but it has recently resurfaced; reconstituted as a fairly different sort of rallying call for opponents of offshore drilling: “Hush, Baby, Hush!”2 Although quieted, the ‘Drill, Baby, Drill’ camp may still ultimately win out this summer.

Indeed, in recent months President Barack Obama and Congress have been roundly criticized for their response to the April 20 Deepwater Horizon rig explosion in the Gulf of Mexico (the “Gulf”) that triggered one of the worst environmental disasters in U.S. history.3 Among some of the harshest critics of the Administration’s response to the disaster were those who disagreed with the President’s decision to place a blanket six-month moratorium on offshore drilling operations in the Gulf.

Owners and operators of vessels, shipyards, and supply service companies which support offshore drilling activities in the Gulf’s Outer Continental Shelf have since challenged the suspension alleging that it ran afoul of the federal Outer Continental Shelf Lands Act (the “OSCLA”) – the same statute which the Secretary of Interior argued empowered him to issue the suspension.4

THE MORATORIUM & ITS POTENTIAL IMPACT

On April 30, 2010, in response to the damage caused by the Deepwater Horizon drilling platform explosion and resultant oil spill, President Obama ordered Kenneth Salazar, the Secretary of the Interior, to review the “safety of oil and gas exploration and production operations on the outer continental shelf” and issue a report in 30 days.4 The subsequent recommendations “identified an initial set of safety measures that can and will be implemented as soon as practicable.”5 In the meantime, the Secretary recommended a moratorium on wells drilled using floating rigs that were operating 500 feet from the coastline in the Gulf. President Obama heeded the Secretary’s warning and on May 30 directed the Bureau of Ocean Energy, Regulation, and Enforcement to issue a six-month moratorium on “drilling [any] new water well” and to cease “spudding any new deepwater wells.”6 Although wells currently drilling and producing oil were unaffected by the decree, thirty-three government permitted exploratory oil rigs were forced to halt operations.7

Louisiana Governor Bobby Jindal was quick to criticize the President’s decision: “This ill-advised and ill-considered moratorium... creates a second disaster for our economy, throwing thousands of hardworking folks out of their jobs and causing real damage to many families.”8 The local economies, already experiencing sharp declines in mainstay industries such as tourism, fishing, shrimping and oyster exports, have become increasingly dependent on direct and indirect jobs created by offshore drilling. The now idle exploratory oil rigs employ over 8,000 people who earn $57.7 million per month in wages.9 Should the exploratory oil rigs decide to relocate, the critics contend, the ripple effect would be felt throughout the local economy impacting...
an estimated 32,000 jobs supported by the oil rig employees. In essence, “oil and gas production is quite simply elemental to Gulf communities.”

UNDERSTANDING THE MORATORIUM IN THE CONTEXT OF THE OSLA

The Outer Continental Shelf Lands Act (“OSCLA”) was signed into law on August 7, 1953. Despite the lack of publicity, the statute forcefully asserted, for the first time, exclusive federal jurisdiction over the Continental Shelf – an area located primarily along the Atlantic and Gulf coasts equal to almost one-tenth the size of the continental United States. Congress immediately recognized the economic value and national importance of the submerged land at stake. Around the time the bill was signed into law it was said that “[t]he mineral resources and food potential of [the Continental Shelf]...make its acquisition more important to the nation than the Louisiana Purchase.” Instead of having a patchwork of competing state laws governing the area, Congress decided that federal jurisdiction would best “provide for the development of its vast mineral resources” through leases to private developers.

Subsequently, Congress tasked the United States Department of the Interior (the “DOI”) with the responsibility of administering sections of the OCSLA “relating to the leasing of the outer Continental Shelf” and for enacting “such rules and regulations as may be necessary to carry out such provisions.” Since 1978, courts have considered the OCSLA to have established “four distinct statutory stages to developing an offshore oil well: (1) formulation of a five year leasing plan by the Department of the Interior; (2) lease sales; (3) exploration by the lessees; (4) development and production.” Using a competitive bidding system, the Secretary typically awards five-year oil and gas leases to the highest bidder. If the Department “finds that such longer period is necessary to encourage exploration and development in areas because of unusually deep water or other unusually adverse conditions” it can opt to extend the initial lease term to ten years.

Under certain circumstances, the Secretary of the Interior may suspend a lessee’s drilling activities. Pursuant to the OSLA, the Secretary may prescribe regulations “for the suspension or temporary prohibition of any operation or activity, including production, pursuant to any lease or permit... if there is a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), or to the marine, coastal, or human environment.” To permanently cancel a lease the Secretary may initiate a hearing. After the hearing, the lease may be cancelled if the Secretary finds that the (1) “continued activity pursuant to such lease or permit would probably cause serious harm or damage to life”, property, any mineral, national security or defense, or to the environment; (2) “the threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time;” and (3) “the advantages of cancellation outweigh the advantages of continuing such lease or permit force.”

In accordance with this directive, the DOI authorized Regional Supervisors in the Bureau of Ocean Energy Management, Regulation, and Enforcement, a subvision of the DOI, to suspend offshore drilling activities in the event that such “activities pose a threat of serious, irreparable, or immediate harm or damage. This would include a threat to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal or human environment.” The Regional Supervisors can also order a suspension of activities – called a “Suspension of Operations” or “SOO” -- “[w]hen necessary for the installation of safety or environmental protection equipment.”

INJUNCTIVE ENJOINMENT OF THE MORATORIUM: HORNBECK OFFSHORE SERVICES V. SALAZAR

The DOI issued a six-month moratorium on offshore drilling activities in the Gulf under the auspices of the OSLA. In response, owners and operators of vessels, shipyards, and supply service companies which support offshore drilling activities in the Gulf’s Outer Continental Shelf challenged the suspension alleging that the moratorium was not permitted by the OCSLA. In Hornbeck Offshore Services v. Salazar, the case that has garnered the most media attention, Plaintiffs’ complaint was based on “the effect of the general moratorium on their oil service industry business, on the local economy, and puts in play the issue of the robustness of a Gulf-wide industry and satellite trades.” The district court ultimately agreed and issued a preliminary injunction enjoining the moratorium.

The Hornbeck Court was particularly critical of the DOI’s Report (the “Secretary’s Report”) which resulted in the order to suspend offshore drilling activities. The Secretary’s findings were so general that the “Court was unable to divine or fathom a relationship between the findings and the immense scope of the moratorium.” Moreover, the court found that the report failed to discuss alternatives to a blanket suspension, set a
A finding by the court that the report was “arbitrary and capricious” significantly weakened the Government’s case, since the OSCLA seems to suggest that SOOs should be individually tailored. In particular, the OSCLA authorizes a suspension of “all or any part of a lease or unit area.”31 The regulations further stipulate that “[t]he Regional Supervisor will set the length of the suspension based on the condition of the individual case involved.”32 The Hornbeck Court interpreted this language to mean that the OSCLA “contemplate[s] an individualized determination” for each SOO.33 As a result, the court invalidated the agency’s carte blanche suspension of offshore drilling suggesting the DOI examine the policies and safeguards of each lessee separately.34 The ruling concluded that the moratorium was not narrowly tailored enough to “justify the immeasurable effect on the plaintiffs, the local economy, the Gulf region, and the critical present-day aspect of the availability of domestic energy in this country.”35

MOVING FORWARD: HORNBECK & THE DEEPWATER HORIZON’S IMPACT ON THE OSCLA

The district court’s decision in Hornbeck was appealed on June 24 to the U.S. Court of Appeals for the Fifth Circuit. On July 8, a three-judge panel issued a 2-1 decision denying the Obama Administration’s request to stay the district court ruling.36 This decision is temporary, however, pending a further review to determine whether the injunction should become permanent.37 The outcome will likely impact the fate of other similar complaints regarding the legality of the six-month moratorium.38

In anticipation of a possible backlash from decisions like Hornbeck and in response to the general public’s distain for how Washington oversaw the Deepwater Horizon oil spill, Congress has introduced legislation to restrict offshore drilling and give the OSCLA more teeth. H.R. Bill 5657 would amend the OSCLA to better protect the outer Continental Shelf’s marine and coastal environment by prohibiting oil and gas activities altogether in “important ecological areas.”39 The proposed legislation also includes a series of rigid guidelines that the Secretary would have to adhere to before issuing leases.40 Another House bill, H.R. 5459, and a companion bill in the Senate, S. 3346, would increase the maximum civil liability for noncompliance with such Act or any term of a lease, license, or permit issued from $20,000 to $75,000 per day and increase the criminal penalties from $100,000 to $10,000,000.41 Finally, “The SAFEGUARDS Act of 2010,” would amend the OSCLA to “modernize and enhance the Federal Government’s response to oil spills [and] to improve oversight and regulation of offshore drilling.”42 The SAFEGUARDS Act would require the President to update the National Contingency Plan every five years, directing the Secretary of Interior to develop additional regulations for leaseholders, and giving the Coast Guard additional responsibilities in the event of another oil spill. 43

The Hornbeck Court recognized that the “Deepwater Horizon oil spill [was] an unprecedented, sad, ugly and inhuman disaster” yet it still dissolved the Administration’s moratorium on offshore drilling.44 In response, it appears that Congress is seeking to amend the OSCLA to provide the President and the Secretary more authority to restrict future oil and gas leases and permits. With powerful interests on both sides influencing the offshore drilling debate, it is too soon to determine whether, ‘Drill, Baby, Drill’ or ‘Hush, Baby, Hush’, will be chanted from the rooftops.

Endnotes


30 C.F.R. § 250.172(b).

Id. at 637.

30 C.F.R. § 250.160.

Id. at 639.

See id. at 631 (“The report makes no effort to explicitly justify the moratorium…”)

Id. at 637.

Id.

30 C.F.R. § 250.168.

Id. § 250.170(a).

Hornbeck Offshore Servs., 696 F.Supp.2d at 368.

See id.

Id. at 369.

Hornbeck Offshore Servs. v. Salazar, No. 10-30585 (5th Cir. July 8, 2010).

Id.

See e.g. Complaint, Enesco Offshore Co. v. Salazar, No. 2:10 CV 01941 (E.D. La. July 9, 2010) (alleging, among other charges, that the six-month moratorium on deepwater drilling in the outer Continental Shelf violated the OSCLA).


Id.


Id.

Hornbeck Offshore Servs., 696 F.Supp.2d at 368.
FRACING UNDER FIRE
By Patrick H. Zaepfel of Kegel Kelin Almy & Grimm, LLP, Lancaster, Pennsylvania

Gaslands, a documentary now showing on HBO, paints a frightening image of a rural America devastated by natural gas production, leaving previously natural areas unfit for man or beast. Judging the accuracy of the portrait painted in Gaslands is a task better left for media critics and scientists, but, if nothing else, Gaslands underscores the need for a public discussion of the costs and benefits of natural gas production, in light of domestic energy consumption that many assert is unsustainable and a lack of moral leadership toward sustainability.

WHAT IS FRACING?

One of the most controversial aspects of natural gas production is the well development technique known as hydraulic fracturing, more commonly referred to as “fracing.” Fracing is a well development technique for enhancing the recovery of oil and natural gas (methane) from underground formations. After a well is drilled, fracing begins by placing explosive charges down the borehole, detonating them to perforate the well casing, and then injecting a mixture of water, chemicals and sand down the well under very high pressure. The pressure-driven slurry is forced into the receiving rock, cracking into it to create and expand fissures and to stimulate the flow of natural gas. Sand and other similar materials in the slurry (propping agents or “proppants”) hold these fissure open to ensure the gas recovery is maintained, while chemicals serve as antibacterial and scouring agents, friction and scale inhibitors, and surfactants.

Increasing gas flows by as much as 20 times, fracing is widely used because of its effectiveness, but critics complain about the environmental impacts associated with fracing. These impacts arise from the proprietary mixture of fracing fluids, which may contain chemicals such as 2-butoxyethanol, formaldehyde, sodium hydroxide, glycol ethers, and naphthalene, as well as the release of methane into drinking water supplies. Environmentalists point to incidents of contamination from fracing and other natural gas drilling activities in Alabama, Colorado, New Mexico, Virginia, West Virginia and Wyoming.¹

Fracing is used on both traditional, vertical wells and the newer, horizontal wells, which at depth turn at a 90 degree angle to follow a given elevation. The proportions of water, proppants, and chemicals used in a given well depend on the particular fracing technique used and the development of a deep horizontal well is not an insignificant undertaking. While the thumbnail estimate of the cost to drill and install a vertical natural gas extraction well is somewhere around $1 million, the cost of the deep horizontal well is somewhere around $3 million.² To develop a vertical well, fracing can use 800,000 gallons of water and 200,000 pounds of sand per well, and these quantities increase significantly as the well turns horizontal. In addition, installation and development of the natural gas well results in the production of various sorts of wastewaters, including “produced” water (borehole groundwater that would otherwise inhibit a flow of natural gas) and flowback wastewaters, which is a high-salinity brine after being used as frac fluid and that is commonly contaminated with metals, radiological material and other pollutants.

Despite current outcries over fracing, the basic technique is nothing new -- Halliburton developed it in 1949 and it has been used around the country ever since, in many different geologic formations. Gas production, however, has entered into a new era with the advent of improved deep horizontal drilling, which allows extraction of commercially-viable quantities of natural gas from hitherto unproductive gas deposits. This drilling method is used most prominently in shale formations, some of which underlie more fertile landscapes than those traditionally associated with the oil and gas industry, heightening concerns about fracing’s environmental impacts.

Domestic shale formations, such as the Barnett shale in Texas and the Marcellus shale underlying parts of Pennsylvania, New York, West Virginia, Maryland, Ohio and Virginia, are estimated to contain previously unimagined amounts of recoverable natural gas. There are at least 21 identified domestic shale formations being utilized or investigated for natural gas production. The U.S. Department of Energy estimates that, by 2020, shale gas will comprise 20% of the United States’ natural gas supply.

The Marcellus shale alone has been estimated to contain up to 516 trillion cubic feet of recoverable gas. While this estimate has been criticized as overinflating the recoverable reserves, if it is accurate, this volume would supply the United States with natural gas for over 22 years (at current consumption rates). At the current (New York) wellhead rate of around $8 per thousand cubic feet, this volume would equate to over
$2.6 trillion worth of natural gas. At this point, it is difficult to determine the accuracy of this estimate, but even at the more conservative estimate of 50 trillion cubic feet of recoverable gas, the economic impact of this shale gas resource cannot be ignored.

Fracing is used in many natural gas extraction geologies, but is particularly useful in shale formations because, while shale poreholes are often fairly tight, many shale formations are brittle and susceptible to fracturing. In addition, the combination of fracing with horizontal drilling allows for greater exploitation of naturally occurring vertical fractures that are apparent in certain shale formations. Frac slurry in a horizontal borehole, under pressures up to 8,000 psi, can crack shale as much as 3,000 feet in each direction from the wellbore. Fracing is performed not only during the installation of a new gas well, but also occasionally during its lifespan, to reinvigorate the well’s production.

Two other innovations have also increased the productivity and usefulness of horizontal fracing, specifically the development of multistage fracing along both vertical and horizontal axes and the use of real-time, micro-seismic analysis to assess whether a particular frac job has been effective. In addition, in the five decades since Halliburton first invented fracing, variations in frac methods and slurries have become more robust. These methods have had varying degrees of success in different geologic formations, and operators have learned how to maximize frac productivity by selecting the best method for a given geology.

“UNREGULATED” FRACING

As indicated in Gaslands and a multitude of articles and publications, environmental and community activists allege that fracing can cause groundwater contamination and migration of methane into drinking water supplies. In Dimock, Pennsylvania, 14 groundwater wells have been contaminated with methane, allegedly due to fracing activities at nearby wells owned by Cabot Oil. In response, the Pennsylvania Department of Environmental Protection and Cabot have modified an existing administrative consent order to require Cabot to replace impacted groundwater wells, to plug three wells suspecting of being related to the contamination, and to pay a $240,000 civil penalty. Other concerns include contamination of groundwater by total dissolved solids (“TDS”) and the fracing chemicals themselves. Such contamination has been identified in wells in Sublette County, Wyoming, including benzene reportedly at levels exceeding 1,500 times levels acceptable under the Safe Drinking Water Act (the “SDWA”). Reports state that this contamination may be related to a nearby cracked well casing.

Considering that fracing typically occurs thousands of feet below grade, however, tying such contamination to a specific well or a particular fracing event is problematic. The gas industry asserts that contamination from the transport of the fracing chemicals into drinking water is unlikely, at least if a well has been properly cased and the frac job is relatively deep, because subsurface shale formations are typically bound on both sides by confining formations. As a practical matter, causation is often made even more difficult by the lack of background data from the contaminated groundwater wells to demonstrate that they were unaffected prior to the drilling and fracturing of the suspected natural gas well or wells.

Compounding environmental concerns, the precise chemical formulations used in a particular fracing slurry are generally not available to the public and are generally not reported to regulatory authorities. While information regarding the formula of some fracing slurries are available, some of the well developers consider these formulas to be proprietary trade secrets and resist disclosure.

Part C of the SDWA establishes a regulatory system for the protection of underground sources of drinking water and requires the U.S. Environmental Protection Agency (the “EPA”) to promulgate minimum requirements for state underground injection control (“UIC”) programs. In 1997, the EPA-approved UIC program for Alabama was challenged for failing to classify fraced natural gas wells as underground injection wells. At that time, the EPA interpreted “underground injection” as encompassing only those wells whose “principal function” was the underground emplacement of fluids, meaning that it did not consider fracing to be regulated. On review, the Eleventh Circuit Court of Appeals in Legal Environmental Assistance Foundation, Inc. v. EPA (“LEAF I”) found that the EPA’s regulatory interpretation was inconsistent with the language of the SDWA and remanded to the matter to the EPA.

In 2003, the EPA obtained the agreement of a handful of the country’s more prominent well developers that they would not use diesel fuel in their frac formulations. In 2004, EPA released the report of an EPA-convened study panel, Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs, which concluded that fracing did not threaten water supplies and that no further study was warranted. Soon afterward, an EPA
whistleblower, Weston Wilson, released a 20-page letter criticizing the EPA’s study, alleging that the EPA had limited real-world data to support its conclusions and that the Peer Review Panel was marred by conflicts of interest. In response, Rep. Henry Waxman (D-CA) requested that the EPA Inspector General examine whether political influence had an improper role in the study, and many public commentators pointed fingers at Vice President Dick Cheney, the former C.E.O. of Halliburton and head of President Bush’s energy policy task force.

Congress, however, did not wait for the Inspector General’s report. In 2005, it enacted the Energy Policy Act, which amended the SDWA to clarify that the statute did not regulate fracking, unless it included diesel fuel. More specifically, Congress modified the definition of “underground injection” to exclude “the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities.” With the technical controversy arguably mooted, the EPA Inspector General never issued a report in response to Rep. Waxman’s request.

While critics decry this so-called “Halliburton exemption,” it is worth remembering that even prior to its passage, the EPA was not generally regulating the injection of frac chemicals. Some states have filled the resulting void. While other EPA regulations do require that Material Safety Data Sheets on all chemicals be maintained on site, Pennsylvania posts general listings on its website. In Colorado, the state can request the submission of frac chemicals being used at a particular well. North Carolina currently bans both fracturing and horizontal drilling. Even in the face of these various efforts, though, fracting is not comprehensively regulated and details regarding the practices at a given well remain guarded, leading environmental and public advocates to seek federal assistance.

RECENT DEVELOPMENTS IN THE REGULATION OF FRACING

Despite all this history, fracting formulations may soon become more freely available to the public. On June 9, 2009, the Fracturing Responsibility and Awareness of Chemicals Act (the “FRAC Act”) was introduced as companion bills in the U.S. Senate and House of Representatives to eliminate the exemption. If enacted, the FRAC Act will remove the Halliburton exemption and amend the SDWA to include “the underground injection of fluids or propping agents.” The FRAC Act also would require the public disclosure of the chemicals contained in the fracturing process, including a posting on the Internet and immediate disclosure in the face of a medical emergency. While the bill has not moved far along in the legislative process, it has been read, referred to committees for review and public meetings have recently been announced.

Meanwhile, the EPA and the states are not standing idly by. In January 2010, the EPA unveiled a new “Eyes on Drilling” phone tipline (1-877-919-4EPA), and, in March 2010, announced that it would convene a new panel to review the environmental impacts of fracting. New York and the Delaware River Basin Commission have announced moratoria on drilling of production wells. Pennsylvania has promulgated a series of new regulations addressed squarely at the gas industry, including regulations setting forth more stringent TDS and chloride discharge limitations and is still pursuing new regulations governing the casing of gas wells. The Wyoming Oil and Gas Conservation Commission recently proposed a regulatory change that would require full disclosure as a matter of course. In addition, landowners have begun to file lawsuits over groundwater alleged to be contaminated by natural gas drilling operations, which will buttress state and federal efforts to tighten down on fracting practices.

CONCLUSION

Given all this activity, it perhaps is no surprise that the gas industry is rethinking its position on disclosure. Range Resources, the first company to develop a viable Marcellus shale well, recently announced that it would disclose its frac formulations to the public, presumably in a more comprehensive manner than is currently required. Full disclosure may be the only way to fend off growing public concerns and perhaps such candor will lead to a greater understanding between industry and the activist community.

Endnotes

2 Lisa Sumi, Shale Gas: Focus on the Marcellus Shale, Oil & Gas Accountability Project, *8-9 (May 2008), available at
The Oil Pollution Control Act of 1990 (“OPA”) was enacted in response to the Exxon Valdez spill in 1989. However, OPA’s reach extends far beyond oil spills from oil tankers to include property with storage tanks, pipelines and abandoned wells where discharges of oil could escape to surface waters. In addition to the liability, OPA imposes a panoply of structural, equipment and operating requirements that substantially increases responsible parties’ operating costs.

Following is an overview of OPA and the section 311 of the federal Clean Water Act (CWA). Other articles in this newsletter will discuss specific liability associated with pipelines and abandoned wells or other structures. Readers should also be aware that parties who are or have “contributed to” the past or current handling, or storage of hazardous wastes that “may” pose an “imminent and substantial endangerment” to human health or the environment could be required to remEDIATE contamination under section 7002 or 7003 of the Resource Conservation and Recovery Act (“RCRA”).

Section 311 of the CWA and OPA are the primary federal programs for responding to oil spills. Section 311 of the CWA imposes liability on owners or operators of vessels and facilities that discharge harmful quantities of oil in into the navigable waters of the United States, adjoining shorelines, the waters of the contiguous zone, in connection with activities under the Outer Continental Shelf Lands Act or when the discharge may affect natural resources of the United States. The Environmental Protection Agency (“EPA”) is primarily responsible for regulating non-transportation-related facilities and responding to spills in inland waters while the U.S. Coast Guard is responsible for vessels and marine transportation-related facilities.

To impose liability under OPA, a plaintiff must show that (1) the defendant is a responsible party (“RP”), (2) for a vessel or facility, (3) from which there has been a discharge of oil or substantial threat of a discharge of oil, (4) into navigable waters and, (5) that resulted in removal costs and damages. To understand OPA liability, it is necessary to understand the definitions of a couple key terms.

Responsible party - For purposes of defining a vessel’s RP, OPA distinguishes between offshore facilities and onshore facilities. For vessels, an RP is “any person owning, operating, or demise chartering the vessel.” Interestingly, this definition does not include the owner of the oil cargo aboard the vessel. Unlike the Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), liability is limited to owners and operators of vessels or facilities. Cargo owners who would be akin to arrangers or generators under CERCLA have no liability though an earlier version of OPA did provide for such liability.

For offshore oil facilities, the RP is the lessee, permittee of the area in which the facility is located or the holder of a right of use and easement granted under state law or the Outer Continental Shelf Lands Act (“OCSLA”). For onshore facilities and pipelines, an RP is the entity that is “owning or operating” the facility or pipeline. For abandoned offshore facilities, the RP is the entity that owned or operated such facility immediately prior to such abandonment.

Removal costs - includes all expenses incurred to contain or remove a discharge oil from water and shorelines or any actions that are necessary to minimize or mitigate damage to the public health or welfare, including but not limited to fish, shellfish, wildlife, public and private property, shorelines, and beaches.

Navigable Waters - The definition of waters under OPA is not necessarily as broad as that under the wetlands program of section 404 of the CWA. Some courts have held that OPA’s jurisdiction is limited to what has been considered historically navigable waters.

Scope of OPA Liability

With limited exceptions, RPs are jointly and strictly liable for all removal costs incurred by a governmental authority. RPs are also strictly liable for removal costs that are incurred consistent with the National Contingency Plan and damages to third parties affected by substantial threats of or discharges of oil. The following damages may be recovered from RPs:

- Damage to natural resources;
- Injury or economic losses resulting from destruction of real or personal property;
- Damages or loss of use of natural resources used for subsistence;
- Lost tax revenue, royalties, rents, or net profit shares suffered by federal, state, or local govern-
ments due to injury to real or personal property;
- Lost profits or impaired earning power because of injury to real or personal property or natural resources;
- The net costs of providing increased or additional public services during or after removal activities.20

Limitations on Liability and Exceptions to the Limitations

OPA contains liability limitations for owners or operators of vessels or facilities. The maximum liability limitations are based on the size and nature of the vessel or facility. The liability for responsible parties of vessels greater than 3,000 gross tons is $1,900 per gross ton for each spill with a maximum liability of $16 million for double-hulled oil tankers with single-hull vessels having limits of $3K per gross ton or $22M. For smaller oil tankers, the liability limits are $1,900 per gross ton or $4 million for double-hulled vessels and $3K per gross ton or $6 million for single-hulled vessels.21 All other vessels (e.g., dry cargo vessels) face a maximum liability of $950 per gross ton or $800K, whichever is greater.22

Owners or operators of offshore facilities that are not deepwater ports, such as oil platforms, are liable for all cleanup costs plus $75 million per oil spill, while the RP for onshore facilities and deep water ports are liable for up to $350 million per spill.23

The liability limitations will not apply and the RP will face unlimited liability if the spill is (1) proximately caused by the gross negligence or willful misconduct of the responsible person, (2) failure to comply with an applicable federal safety, construction, or operating regulation, or (3) failure or refusal to report a spill, to cooperate or assist governmental authorities with a removal action when requested, or to comply with an order without sufficient cause.24

Prior to OPA, there was a question whether the liability of vessel owners for oil spills was capped by the Limitation of Liability Act of 1851.25 Under this statute, the liability of ship owners is limited to the value of the vessel and its cargo. Thus, if a vessel was severely damaged or sank, the liability of its owner could be less than the maximum liability provided in the CWA. However, OPA expressly provides that the Limitation of Liability Act shall not limit the liability imposed on RPs under federal or state laws.26

Likewise, prior to OPA, any costs due the U.S. government constituted a maritime lien on the vessel, which could be enforced in an action in rem in any district court where the vessel was located.27 This provision was deleted by the OPA but it is still possible that the Federal Government and third parties may be able to assert a maritime lien that would have priority over a lender’s security interest. Under the U.S. Ship Mortgage Act of 1920, damages arising out of maritime torts are given preferred maritime lien status with priority over ship mortgages and certain other maritime liens. There is no statutory definition of what constitutes a maritime tort; instead it is an evolving concept of case law. In general, however, a maritime tort is one occurring on navigable waters that has some connection with traditional maritime activities. In adopting OPA, Congress did not indicate whether the strict liability under the statute would also constitute a maritime tort that would be afforded preferred maritime lien status. Thus, this issue probably will have to be resolved on a case-by-case basis by the courts.

It is important to note that OPA does not pre-empt state laws. A number of coastal states have enacted oil spill laws that may provide for higher or unlimited liability than those provided for in OPA. For example, of the 24 states that have oil spill statutes, 15 provide for strict liability and in 11 of those states, the liability is unlimited. Thus, Thus RPs that might be able to qualify for one of the OPA liability caps might find themselves subject to additional liability under a state oil spill law or state common law.28

Oil Spill Financial Responsibility (“OSFR”)

Under OPA, vessels over 300 tons must have evidence of financial resources sufficient to meet the maximum amount of liability that the vessel or facility would be subject to under OPA. 29 Responsible parties for Covered Offshore Facilities (“COF’s”) are required to maintain sufficient financial resources based on the worst case oil spill discharge.30 The minimum OSFR is $35 million per COF located in the Outer Continental Shelf and $10 million per COF located in state waters. The minimum OSFR coverage increases with the worst case spill discharge scenario, maxing out at $150 million for the worst oil spills that exceed 105,000 barrels. OPA does not require evidence of financial resources for onshore facilities.

Defenses to Oil Spill Liability

An RP may avoid liability for removal costs or damages if it can demonstrate that the discharge or substantial threat of a discharge of oil were due to an act of God, an act of war, or a third party. 31
For all practical purposes, the third-party defense is the only viable defenses available to RPs. To assert this defense, the RP will have to show that the discharge was SOLELY due to an act or omission by a third party who was not an agent or employee of the RP nor in a contractual relationship with the RP. In addition, the RP must show that it exercised due care with respect to the oil that was discharged and took precautions against foreseeable acts or omissions of the third party as well as the foreseeable consequences of those acts or omissions. If the RP can establish this defense, the third party will be considered an RP. The most common third-party claims filed for discharges are due to vandalism but the owner or operator has to show that it took all reasonable precautions to prevent such conduct and inadequate security, particularly during a strike or an ill-conceived Spill Prevention Control and Countermeasure (“SPCC”) will prevent the owner or operator from shifting liability to the third party.

The difficulty of asserting the third party defense was illustrated in Smith Property Holdings v. U.S. There, a subcontractor of a developer of luxury housing in Washington, DC ruptured a buried culvert during excavation activities that released a substantial quantity of oil-contaminated water onto the site. Approximately 5 gallons of oil were discharged to a nearby creek. The owner filed a spill report within the NRC and complied with an Emergency Removal/Response Administrative Order. The owner then filed a claim with the Oil Spill Fund for reimbursement of its $772,000 in cleanup costs and $1,175,416 in lost profits from oil cleanup-related construction delays. The owner asserted it was not responsible for the oil spill because the oil came from an off-site source, that it had only excavated soil, performed a Phase I and had no reason to know about the abandoned culvert. The Coast Guard denied all but $172,000 of the claim because the owner had failed to establish that the oil had migrated from another source and that the excavation was the cause of the spill. The court upheld the government’s view.

An RP will lose its complete defense to liability for removal costs or damages if it (1) fails to comply with its spill reporting obligation, (2) fails to provide “all reasonable cooperation and assistance” requested by the OSC or other responsible officer regarding removal activities, or (3) fails to comply “without sufficient cause” with an order issued under section 311 of the CWA. The likely effect of these broad exceptions to the affirmative defenses is to nullify the ability to use the defenses.

In addition, an RP will not be liable to a claimant to the extent that the incident for which the claimant seeks reimbursement or damages was due to the gross negligence or willful misconduct of the claimant.

The Coast Guard and Maritime Transportation Act of 2004 (CGMTA) created an additional defense to liability known as the innocent landowner defense. This defense provides that an owner or operator of a facility that is the source of a discharge or substantial threat of discharge of oil into the navigable waters or adjoining shorelines or the exclusive economic zone will not be considered to be in a “contractual relationship” with a responsible party if that entity is able to show that it did not know and had no reason to know that oil that is the subject of the discharge or substantial threat of discharge was located on, in, or at the facility. To establish this showing, the entity has to show that it undertook all appropriate inquiries using generally accepted good commercial and customary standards and practices into the previous use and ownership of the facility. The innocent landowner defense does not apply to parties who fail to comply with spill reporting obligations, fail to cooperate with officials implementing removal actions or fail to comply with an order without sufficient cause. In addition, the entity seeking the defense must cooperate with responsible parties conducting removal actions and comply with any land use restrictions. CGMTA also added liability protection to local governments who take title through tax foreclosure or eminent domain.

To facilitate implement the Coast Guard was required to promulgate regulations establishing the standards for satisfying all appropriate inquiries. In 2008, the Coast Guard promulgated its OPA All Appropriate Inquiries (“AAI”). The OPA AAI is consistent with the AAI rule published by the EPA but not identical. Persons seeking to conduct all appropriate inquiries Persons conducting all appropriate inquiries may use the procedures included in the ASTM E 1527-05 “Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process,” standard to comply with this OPA AAI rule but are not required.

Finally, CGMTA added a secured creditor defense that parallels the safe harbor for lenders in the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). The OPA secured creditor exemption excludes from the definition of owner or operator “a person that is a lender and that holds indicia of ownership primarily to protect a security interest in a vessel or facility” provided that while the borrower is in possession of such vessel or facility the lender does not exercise decision-making control over a ves-
sell’s environmental compliance activities or undertake day-to-day management of the vessel. Like its CERCLA counterpart, the OPA secured creditor exemption insulates lenders following foreclosure if the lender sells, re-leases (in the case of lease financing), liquidates, maintains business activities, winds up operations, undertakes an OPA 90 removal action, or takes any other measures to preserve, protect, or prepare the vessel or facility prior to the sale or disposition “at the earliest practicable, commercially reasonable time, on commercially reasonable terms.”44

**Contribution and Indemnity**

RPs are authorized to bring contribution actions against persons who may be liable under OPA or any violations of state or federal law.45 In addition, an RP may file a contribution claim for removal costs or damages incurred above its statutory limit. Contribution actions must be filed within three years of the date of judgment or a judicially-approved settlement.46

OPA allows parties to reallocate liability among themselves including indemnity agreements. However, indemnity agreements are only effective between the parties and shall not have the effect of transferring a claim the government or third party may have for damages or removal costs away from the RP.47

**Oil Spill Liability Trust Fund**

OPA created the Oil Spill Liability Trust Fund (the “OSLTF”), which can be used to immediately remove or otherwise respond to discharges or threatened discharges of oil.48 Parties who have incurred removal costs or damages may file claims against the OSLTF only AFTER they have first presented their claims to the RP or its guarantor.49 If a claim presented to an RP is not settled within 90 days, the claimant has the option of either commencing a civil action against the RP or submitting its claim to the OSLTF. A claim may not be presented to the OSLTF if the claimant has filed a cost recovery against the RP.50

In 1996, Congress required RPs to make interim, short-term damage payments representing less than the full amount of the claims to expedite payment of claims.51 However, this apparently did not improve claims processing enough so Congress added a loan program in 2004 whereby the OSLTF may award low-interest loans to a “fisherman or aquaculture producer claimant” with pending claims against RPs or where the RP fails to make interim payments. The loans shall be for a period of five years.52

RPs also may file claims against the OSLTF, provided they could assert a complete defense to liability and are entitled to a limitation of liability addition.53 Furthermore, the RP may assert a claim only for the amount of the removal costs, damages, and other monies actually paid by the RP or its guarantor that exceeds the limitation of liability for the particular RP, as provided for under the OPA.54

Any action for removal costs must be brought within three years of the termination of the removal action, whereas any action for damages must be filed within three years after the date the loss was reasonably ascertainable or the natural resource damage assessment was completed.55

**Spill Reporting Requirements**

The “person in charge” of a facility or vessel that has discharged “harmful” quantities of oil must report the spill to the National Response Center (“NRC”) as soon as that person becomes aware of the discharge. EPA has determined that discharges of oil that result in a “sheen” or cause a violation of an applicable water quality standard are harmful and must be reported.56

**Spill Prevention**

EPA first promulgated SPCC regulations in 1973 with the goal of minimizing the impact of discharges of oil and hazardous substances into navigable waters and adjoining shorelines.57 In 2008 and 2009, EPA adopted tougher SPCC requirements and expanded the scope of regulated facilities. The new requirements take effect on November 10, 2010. The revised SPCC rule applies to owners or operators of non-transportation-related facilities that:

- have an aboveground oil storage capacity greater than 1,320 U.S. gallons, or completely buried oil storage capacity greater than 42,000 U.S. gallons;
- drill, produce, store, process, refine, transfer, distribute, use, or consume oil or oil products; and
- could reasonably be expected to discharge oil to U.S. navigable waters or adjoining shorelines.

One of the requirements of the SPCC rule is that storage tanks be equipped with secondary containment systems to prevent oil spills from migrating into soil, groundwater, or surface water.58 It is important to note
that currently some states require secondary containment for small aboveground storage tanks (“AST”s). It is also important to note that owners or operators of facilities are not required to submit their SPCC plans to EPA nor are regulated facilities required to register or otherwise notify the EPA that they are subject to the SPCC requirements.

**Federal Response Plans**

In addition to SPCC plans, a smaller set of facilities are required to prepare Facility Response Plan (“FRP”). Unlike SPCC plans, facilities must submit their FRP plans to EPA. This requirement applies to owners and operators of offshore and onshore facilities that could reasonably be expected to cause “substantial harm” to the environment by discharging oil into or on navigable waters. The FRP requirement applies to both marine-transportation-related facilities and non-transportation-related facilities that handle, store, and transport animal fats and vegetable oils.69

The FRP plan describes how the facility will respond to oil spills.60 The FRP should identify the response personnel and equipment, flow path of potential spills and vulnerable natural resources, evacuation and notification plans, and response training programs, including drills and exercises.

**OPA Enforcement**

Pursuant to the Federal Civil Penalties Inflation Adjustment act, EPA issued a rule revising the statutory penalties that may be imposed under OPA.64 Effective January 13, 2009, any person who is an owner, operator, or “person in charge” of a vessel or facility that suffered a discharge may be subject to a civil penalty of up to $37,500 per day or $1,100 per barrel of oil discharged.65 However, where the discharge was due to gross negligence or willful misconduct, the minimum civil penalty is increased to $140,000 per day or up to $4,300 per barrel of oil.63

Persons who fail to remove or carry out a government order to remove the oil discharge may be subject to civil penalties of up to $37,500 per day of violation or an amount three times the cost incurred by the OS- TLF.64 Administrative penalties are also available but persons assessed such fines cannot also be liable for a civil penalty.65

Criminal penalties are also available. For discharges attributable to the negligent operation of a vessel or facility, the fine ranges from $12,500 to $25,000 and imprisonment of up to one year. The penalty for a release due to a knowing violation is a $5,000 to $50,000 fine and up to three years’ imprisonment, while a fine of up to $250,000 and maximum imprisonment of 15 years may be imposed for persons who knowingly place another person in imminent danger of death or serious bodily injury.66

**Application to Transactions**

In the wake of the Deepwater Horizon explosion, the Enbridge pipeline leak in Michigan and the abandoned well in Louisiana, owners and operators of oil-related facilities are likely to come under increased scrutiny. Thus, it will be important for purchasers of oil-related assets to carefully review potential OPA liability.

Many leases have been held by multiple lessees over the years which might have assignments with a variety of terms and conditions. Often times, the oil related facilities may have been abandoned in connection with a lease. Thus, during a due diligence review, it is important to assess potential historic liabilities that may be associated with abandoned oil production or processing facilities even though those assets are no longer reflected on their books. If a discharge takes place from an abandoned facility or vessel after the effective date of OPA, the owner immediately prior to abandonment could be liable. It is important to review current and historical practices for such structures during due diligence such as maintenance procedures and frequency of maintenance on the facility.67 Because of enhanced enforcement and the new SPCC requirements, it is advisable that owners of regulated facilities and purchasers review compliance to determine if ASTs must be equipped with secondary containment systems. Even where not required, secondary containment systems may be a best management practice for ASTs because of their location, such as near floor drains, to minimize the possibility that oil could be discharged into the environment.68

OPA provides virtually no guidance on what constitutes ownership so courts often defer to state law to determine the owner. Likewise, because OPA does not define “abandonment” liability may hinge on how state law interprets ownership of abandoned oil-related equipment under mineral leases. In some cases, the abandoned equipment may be considered personal property of the lessee but in other instances may be treated as part of the real property.69

Parent corporations may also be held liable or their subsidiaries cleanup costs. However, ever since the United States Supreme Court decided U.S. v. Bestfoods the ability to go have the parent corporations have been
significantly limited. In *Bestfoods* the Court held that a parent corporation may only be liable under CERCLA for the acts of its subsidiary if the corporate veil can be pierced or if the parent directly operated the facility where the discharge originated. The Court in *Bestfoods* did not rule whether state or federal common law would apply to the veil piercing analysis and many subsequent courts have applied state law. However, *Bestfoods* did suggest that a parent’s relationship with its subsidiary must be “eccentric under accepted norms of parental oversight of a subsidiary’s facility” to be liable for damages under CERCLA.

To be liable as an “operator” under CERCLA, the Court decreed that a corporate parent “must manage, direct, or conduct operations specifically related to pollution, that is, operations having to do with the leakage or disposal of hazardous waste, or decisions about compliance with environmental regulations”. The Court said there may be three instances where a parent could be held liable as operator of its subsidiary’s facility: (1) when the parent operates the facility in the stead of its subsidiary or alongside the subsidiary in some sort of a joint venture; (2) when a dual officer or director departs so far from the norms of parental influence; and (3) when “an agent of the parent with no hat to wear but the parent’s hat” manages or directs activities at the facility. Because CERCLA’s definition of “operator” for an onshore facility is virtually identical to OPA’s definition of “operator” for an onshore facility, courts frequently apply the *Bestfoods* “operator” analysis in OPA cases involving onshore facilities. For example, in some instances, courts have imposed liability on parent corporations for violations of the CWA where the parent was deemed to be a mere alter ego.

A general tenet of corporate law is that a purchaser of corporate assets is generally not liable for the seller’s liabilities unless one of four exceptions apply: (1) the purchaser expressly or impliedly assumed the predecessor’s liability, (2) there was a consolidation or merger of the seller and purchaser, (3) the purchasing corporation was a mere continuation of the selling corporation, or (4) the transaction is entered into fraudulently to escape such obligations. Because of the broad remedial purposes of environmental laws like CERCLA, there had been a trend of expanding the liability of asset purchasers under the “Substantial Continuity” test which focused on the continuation of the business rather than continuation of the corporate entity. However, following *Bestfoods*, courts are returning to the traditional exceptions to liability for the asset purchasers.

Following the passage of OPA, many tanker operators reorganized their corporate structures to shield parent companies from liability under OPA. A number of fleet owners divested themselves of their tankers and barges, and turned to chartering independently owned vessels to transport oil in US waters.

Because of the high profile oil spills that occurred this year, the prospect of new oil spill legislation, owners, investors and lenders to businesses involved in the petroleum industry should expect increased challenges to new petroleum-related projects under environmental laws like the National Environmental Policy Act and demands for increased regulation such as for the use of hydraulic fracturing to increase production from natural gas shales. Indeed, just recently CERES, a network of socially-conscious investors and environmental groups sent letters to 27 oil and gas companies asking each company to disclose information by Nov. 1 regarding its spill prevention and response plans for offshore operations worldwide. The letter asked for details on the following issues: Investments in spill prevention and response activity, including offshore drilling and spill response capability; Spill contingency plans for managing deepwater blowouts; lessons learned from the BP spill, including their position on possible new regulations and more robust enforcement on offshore drilling in the gulf and elsewhere; possible actions to improve their safety contractor selection and oversight practices; and governance systems for overseeing management of offshore oil and gas operations. CERES also sent a letter to 26 insurance companies that provide insurance for offshore drilling activity, asking if insurers are considering adjustments to their overall exposure to offshore oil and gas operations. This second letter was prompted by estimates developed by Swiss Re suggesting that the total insured losses associated with the Deepwater Horizon explosion and spill could exceed $3.5 billion—which would surpass the $2.2-2.5 billion/year in insurance premiums worldwide for oil and gas exploration.

As a result, it is quite possible that the petroleum industry continue to restructuring in the coming years to shield the parent companies from excessive liability. While such transaction activity will be good news for business lawyers, it is important that the business lawyers also understand the environmental issues associated with the assets (or understand enough to know when to bring in environmental attorneys to help complete or structure the transaction) being exchanged are carefully examined to minimize environmental liability from historic and current operations. Finally, the business lawyer should not forget that despite the restructuring their may still be the traditional claims such as negligence, nuisance, trespass and strict liability for potential toxic tort and property damage claims.
Endnotes

1. 33 U.S.C. 2701 et sq.


3. 42 U.S.C. 6972 and 6973, respectively.

4. At some facilities, there may be both marine-transportation and non-transportation-related facilities (e.g., storage tanks). In such circumstances, the Coast Guard jurisdiction extends from the vessel to the first valve inside the secondary containment structure around an above-ground storage tank. See 33 CFR 154.1020.

5. A facility is any structure, group of structures, equipment, or device other than a vessel that may be used to produce, explore, drill, store, handle, transfer, process, or transport oil, including any motor vehicle, rolling stock, or pipeline used for such purposes. 33 U.S.C. 2701(9).


7. An offshore facility is any facility of any kind located in, on, or under any of the navigable waters of the United States, and any facility of any kind which is subject to the jurisdiction of the United States and is located in, on, or under any other waters, other than a vessel or a public vessel. 33 U.S.C. 1321(a)(11).

8. On onshore is any facility located on, in, or under any land and includes motor vehicles and rolling stock. 33 U.S.C. 1321(a)(10).


12. 33 U.S.C. 2701(32)(B) and (E), respectively.


14. 33 U.S.C. 2701(30)

15. 33 U.S.C. 2701(31).

16. 33 U.S.C. 1344


24. 33 U.S.C. 2704(c).

25. 46 U.S.C. 183 et seq.


27. Id.


29. 42 U.S.C. 2716(a)

30. 33 U.S.C. 2716 (c). A COF includes any structure and all its components (including wells completed at the structure and the associated pipelines), equipment, pipeline, or device (other than a vessel or other than a pipeline or deepwater port licensed under the Deepwater Port Act of 1974 (33 U.S.C. 1501 et seq.)) used for exploring for, drilling for, or producing oil or for transporting oil from such facilities. This definition includes a well drilled from a mobile offshore drilling unit (MODU) and the associated riser and well control equipment from the moment a drill shaft or other device first touches the seabed for purposes of exploring for, drilling for, or producing oil, but it does not include the MODU itself. A pipeline can be a COF if it is used to transport oil from a facility engaged in oil exploration, drilling or production. Shore-based petroleum terminals, marinas


33. 33 U.S.C. 2703(a)(1)-(3).


37. 33 U.S.C. 2703(c).

38. 33 U.S.C. 2703(b).


40. 33 USC 2703(c)
41. 33 USC 2703(d)(3)
42. 33 USC 2703(d)(2)
43. 73 FR 2146 (1/14/08)
44. 33 USC 2701(26)
45. 33 U.S.C. 2709.
47. 33 U.S.C. 2710.
48. 33 U.S.C. 1321(c).
49. 33 U.S.C. 2713.
50. 33 U.S.C. 2713(c).
51. 33 USC 2705(a)
52. 33 USC 2713(f).
53. 33 U.S.C. 2708(a).
54. 33 U.S.C. 2708(b).
55. 33 U.S.C. 2717(f).
56. 40 CFR 110.3
57. 40 CFR Part 112
59. 40 CFR 112.2; 33 CFR 154.1020
60. 40 CFR Part 112.20; 30 CFR Part 254
61. 73 FR 75340 (12/11/08)
63. 33 U.S.C. 1321(b)(7)(D).
64. 33 U.S.C. 1321(b)(7)(B).
66. 33 U.S.C. 1319(c)
70. Id at 71-72
71. Id. at 66-67
72. Id at 71
75. B.F. Goodrich v. Betkoski, 99 F.3d 505 (2nd Cir. 1996). Factors courts have looked at in determining if there was substantial continuity between the former corporation and the asset purchaser include whether the “successor maintains the same business, with the same employees doing the same jobs, under the same supervisors, working conditions, and production processes, and produces the same products for the same customers.

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