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USA

Hearing on Impacts of Abandoned Offshore Oil and Gas Infrastructure and the Need for Stronger Federal Oversight

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Prepared for the US House Committee on Natural Resources, Subcommittee on Energy and Mineral Resources

October 14, 2021

Chair Lowenthal, Ranking Member Westerman, and distinguished members of the Subcommittee:

My name is Rob Schuwerk and I am the North American Executive Director of the Carbon Tracker Initiative, Inc. Carbon Tracker is a non-profit think tank focused on research and analysis of how the transition to low-carbon energy will impact fossil fuel intensive sectors.

Some of my recent work at Carbon Tracker has focused on decommissioning obligations to dismantle long-lived infrastructure—known under U.S. accounting standards as "asset retirement obligations" or "AROs". Our research suggests that these obligations may cost more and come due sooner than many expect, and that the liabilities far exceed the financial assurance that covers them.[1]

Today, I want to cover a few topics related to offshore liabilities:

- First, the size and nature of the problem.
- Second, why oil and gas infrastructure is not retired in a timely fashion today.
- Third, why changing industry incentives is key to preventing these costs from falling on taxpayers.
- Fourth, the urgency of the issue not just for taxpayers but also for industry, as evidenced by the recent Fieldwood bankruptcy.

Offshore obligations are like saving for retirement

Today's hearing relates to offshore retirement obligations. In many ways, these are like everyday citizens' retirement needs to accumulate savings over time for a huge cost after their

[1] See, Carbon Tracker, *It's Closing Time, the Huge Bill to Abandon Oilfields Comes Early* (2020); *cf.* U.S. GAO, *Oil and Gas: Bureau of Land Management Should Address Risks form Insufficient Bonds to Reclaim Wells*, (Sept. 2019).

working days are over. When an entity begins development of an offshore well or other installation, a new Asset Retirement Obligation (ARO) is created. Fulfilling that ARO is a requirement of the lease that operators willingly undertake in order to drill for, and profit from, oil and gas production.

However profitable a well is over its useful life, a point comes when it is no longer economic to operate. At that point, it must be plugged and reclaimed. This costs money, which clearly cannot come from an unproductive well. Neither the federal government nor states have required that oil and gas operators set aside money during a well's economic life to pay for its eventual closure, so most companies have not done so. Historically, the money to pay for closure has come from an operator's other producing properties. In other words, the cost to retire old wells has been paid for out of the income from newer, more productive wells. So long as the industry was growing, this was not seen as a problematic approach.

It is often said that it's never too early to start thinking about retirement. However, the oil and gas industry largely hasn't been saving for these retirement costs. If industry fails to meet its obligations, taxpayers and landowners will left with the bill.

Our research suggests that states and industry are underestimating the costs. Even in a functioning regulatory regime that requires full financial assurance, accurate cost estimates are necessary to ensure that taxpayers are protected. For example, we estimate *onshore* plugging costs alone will come to $280 billion.[2] Available bonding data suggests that states on average have secured less than 1% of that amount in surety bonds. This means that oil and gas producing states are susceptible to serial operator defaults and exposed to hundreds of billions of dollars in orphan well liability risk.

I. Offshore oil and gas decommissioning will likely cost tens of billions of dollars

Similar concerns exist with respect to offshore oil and gas infrastructure. The Bureau of Safety and Environmental Enforcement (BSEE) estimates that offshore AROs could range from $35 to over $50 billion.[3] Meanwhile, financial assurance requirements are about $3.47 billion, less than 10% of the expected liability.[4] In the offshore context, financial assurance typically takes the form of a surety bond, with sureties agreeing to BOEM's provisions governing such bonds. In effect, the surety bond provider agrees to cover a fixed amount of costs if the operator fails to fulfill its decommissioning obligations.

Some portion of these costs will be paid by industry, but it is almost certain that, barring intervention, a significant portion of it will be left to the public. This is because there is a material amount of inactive, non-revenue generating infrastructure still in the Gulf. The New

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[2] Carbon Tracker, *Billion Dollar Orphans: Why Millions of Oil and Gas Wells Could Become Wards of the State* (2020).
[3] These calculations are based on BSEE's "Decommissioning Cost Estimates," available here and BOEM's "Property and Collateral List Reports" dataset, available here.
[4] Bureau of Ocean Energy Management. "Property and Collateral List Reports." Downloaded 10/4/21.

York Times estimates, based on federal data, suggest that 47% of pipeline segments and 75% of platforms in the Gulf are inactive or abandoned.[5]

The Government Accountability Office (GAO) has found that BSEE's cost data may result in the underestimation of costs going forward, since (1) the underlying data are from wells in shallower water depths when compared to remaining infrastructure, (2) 97% of pipelines have been permitted to "decommission-in-place" (i.e., leave the pipelines on the seafloor), resulting in much cheaper costs than removal and (3) BSEE has no program for observing or ensuring that decommissioning efforts are properly conducted.[6]

Prompt decommissioning is important because of the risk of spills that impact the health and livelihoods of coastal communities and damage sensitive wildlife habitat. Hurricane Ida, for example, resulted in 55 spill reports—an unprecedented number of spills from a single event.[7] Another example is the recent spill of potentially 144,000 gallons of oil off the California coast.

Leaving oil and gas infrastructure in place can be a ticking time bomb, with the potential for damage from storms, accidents and corrosion all leading to more costly decommissioning efforts. If infrastructure is left for years, it may remain long after responsible parties have become incapable of removing it, putting the government and taxpayers on the hook.

II. The current regulatory regime provides operators with insufficient incentives to timely decommission wells or account for the full cost of decommissioning

Regulations require that offshore wells must be plugged and infrastructure must be decommissioned within one year after the lease termination (unless approved for some other use). However, this retirement obligation is rarely triggered, since leases are rarely terminated or allowed to expire. The result is a large amount of idled and inactive offshore wells and platforms.[8] Our initial analysis of BOEM data indicates that only about a third of the unplugged wells in the Gulf of Mexico have shown any production in the last 12 months.

These idled wells pose a financial threat to not only the government and taxpayers, but also past operators and lease holders who remain obligated to decommission assets if current operators cannot.

Why is infrastructure not promptly retired?

The fundamental roadblocks relate to *uncertainty* and *incentives*. The *uncertainty* comes from the difficulty determining when wells are neither economic nor capable of becoming so. The *incentive* problem is as follows: retiring wells costs money, but provides no current or future revenues, so industry has no incentive to make clear that a well's useful life has come to an end, much less incur decommissioning costs.

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[5] Blacki Migliozzi and Hiroko Tabuchi, Sept 26, 2021. "After Hurricane Ida, Oil Infrastructure Springs Dozens of Leaks." *New York Times*. Available at: https://www.nytimes.com/interactive/2021/09/26/climate/ida-oil-spills.html

[6] https://www.gao.gov/assets/gao-21-293.pdf

[7] https://www.nytimes.com/interactive/2021/09/26/climate/ida-oil-spills.html

[8] 30 CFR § 250.1710.

The Uncertainty Problem

Uncertainty about the right time for plugging can be seen in the Bureau of Safety and Environmental Enforcement (BSEE)'s enforcement policies. Enforcement only occurs long after there could be any shadow of a doubt as to whether there remains any future beneficial use.

BSEE's guidance to operators focuses on enforcement only years after a well is no longer useful for operations or capable of production.[9] BSEE guidance provides that a well or platform is "no longer useful for operations" if it has not produced or been used for exploration in more than five years and is not capable of producing in paying quantities.[10] "Paying quantities" is considered to be amounts yielding, "a positive stream of income after subtracting normal expenses."[11] After the initial five years, operators have an additional three to five years, depending on whether it's a well or platform, to decommission the infrastructure. In other words, even when it is clear to all parties that infrastructure is no longer productive, it is currently permissible to delay decommissioning for up to ten more years.[12]

With such long periods of idle iron, the government runs a risk that operators will become incapable of fulfilling decommissioning obligations. Profits from other wells may be gone, having been distributed to owners or shareholders.

Such delays are made worse by the formulas BSEE uses to determine whether to plug the wells. Decommissioning should be fully funded before a well becomes uneconomic, by which I mean, when decommissioning costs exceed the net value of future production. In the current environment these costs are not fully funded when a well is drilled, nor do BSEE's formulas for considering the economics of wells include these outstanding decommissioning costs. The result is that wells might be operated long past the point at which future revenues could reasonably be expected to cover decommissioning costs.

If the industry were to keep producing oil and gas, and therefore new revenues, in perpetuity, this might be less of a concern. However, the infrastructure is growing old, and exploration companies are moving on, transferring "mature" assets to entities with far less financial capacity to settle these obligations. Delays in requiring prompt retirement of uneconomic assets is partly to blame for this dynamic.

The Incentives Problem

The second problem is fundamentally about misaligned economic incentives. At the most basic level, current financial assurance and decommissioning rules charge no risk premium to companies that decide to defer decommissioning of late-life infrastructure, making it a costless and virtually risk-free option.

[9] 30 CFR § 250.1711.
[10] BSEE, NTL No. 2018-G03 (Dec. 11, 2018).
[11] BSEE, NTL No. 2018-G03 (Dec. 11, 2018).
[12] BSEE, NTL No. 2018-G03 (Dec. 11, 2018).

Decommissioning obligations are like an interest-free balloon loan from the government to the operator-–the lessor/operator agrees to pay whatever it takes to decommission the assets, but it doesn't have a fixed point at which it has to pay that obligation back, nor does it have to make payments on that obligation commensurate to the growing risk. All the while, the value of the underlying reserves is depleted as oil and gas is extracted.

In theory, an operator should set aside cash from a period of peak production to cover plugging costs, but no economically rational firm would choose to repay sooner than it must, nor save for it if it weren't required to do so. Producers will always choose to retain the option to restart production if the option is free.

However, if the ARO loan carried a commercial interest rate and the option to restart production was costly, producers would be incentivized to decommission non-economic offshore assets in a timely manner.

The problem is that BSEE does not obtain enough collateral or financial assurance to incentivize operators to timely decommission infrastructure. As noted above, BSEE holds financial assurance worth less than 10% of the estimated costs of decommissioning the remaining offshore infrastructure—and there's good reason to believe coverage is less than 10%, since those cost estimates may be low. The logical choice for operators is to maintain the financial assurance and avoid incurring actual plugging costs for as long as possible, even as fields deplete.

III. The uncertainty and incentives problems can be addressed by full cost bonding and financial assurance

The government can protect taxpayers—and, as discussed below, other operators—while addressing the uncertainty and incentives problems by requiring full-cost financial assurance equivalent to the full expected costs of carrying out all decommissioning obligations. This could take the form of a surety bond, as is the prevailing instrument in offshore, or a sinking fund or other form of restricted cash equivalent earmarked for decommissioning.

How does this work? Requiring a full-cost bond from operators forces them to take decommissioning costs into account. With the right incentives in place, it puts the decision of whether to continue producing or shut down in the hands of those best positioned to determine the economically rational course, the operators. If wells are still economic to operate, considering both the carrying cost of the financial assurance and the expected future revenues from the well, the operator will continue production. If not, then the operator will shut the well down. And in any case, the public is shielded from the impact of unfunded decommissioning costs.

A requirement for full cost bonding is neither onerous nor unusual. A secured lender would typically require that any collateral be worth as much or more as the amount lent—there is no reason why the government, in leasing drilling acreage, should expect less. Moreover, the amount sought is simply the amount that the operator would be expected to pay to settle an obligation it voluntarily undertook when it entered into the lease.

Finally, requiring full cost bonds would increase certainty for all operators and lessors in the chain of title of current offshore infrastructure, since they all hold contingent liabilities with respect to existing infrastructure.

IV. The recent Fieldwood bankruptcy illuminates how more federal oversight is needed to protect taxpayers

One of the more significant risks to taxpayers (and predecessor operators), is operator bankruptcy. Such bankruptcies are neither rare nor surprising—older assets have typically been sold to "mature field" operators that do not have greenfield or new drilling programs, nor the potential revenues that such programs can bring. They may also pose greater credit risks than the companies from which they have purchased these mature assets. When such companies go bankrupt, the decommissioning liability may fall first upon working interest owners, then predecessor operators and finally to the taxpayer, if those operators are unable to pay.

To understand the dynamics at play, it is important to understand the legal concept of "joint and several liability."[13] Under current regulations, all past and current operators are jointly and severally liable for decommissioning costs,[14] though current operators bear initial responsibility.[15] This is a good rule, since it ensures that those who have benefited from oil and gas extraction are the first to pay for the burdens of dismantling declining infrastructure.

Companies cannot get out of these obligations through contract, though they can re-order payments between themselves. Depending on how their agreements are structured, they may or may not be effective in bankruptcy.

Bankruptcy is an ongoing concern for offshore companies. BOEM estimated that since 2009, there have been more than 30 bankruptcies of companies with offshore assets bearing $7.5 billion in decommissioning liability.[16] The recent *In re Fieldwood Energy LLC*[17] bankruptcy, with more than $1.8 billion of total debt,[18] illustrates the current dynamics.

Fieldwood Energy LLC ("Fieldwood") was created in 2012 to acquire and operate mature oil and gas assets in the Gulf of Mexico and, in 2013, acquired a number of shallow water properties from Apache Corporation.[19] The company went through a bankruptcy restructuring

[13] There is also a related accounting concept: "contingent liability." These are liabilities that could be imposed on a firm, assuming one or more conditions are met, or contingencies occur. While all publicly traded companies must report their liabilities and, under certain circumstances, contingent liabilities, very few companies actually disclose contingent liabilities until it is nearly certain they are exposed. For the most part, such contingent liabilities remain, effectively, off balance sheet.
[14] See 30 CFR § 556.604(d).
[15] See 30 CFR § 556.604(f).
[16] https://www.natlawreview.com/article/doi-releases-proposal-to-revise-supplemental-financial-assurance-requirements
[17] *In re Fieldwood Energy LLC*, Case No. 20-33948 (Bankr. Ct., S.D. Tex.).
[18] Dane Declaration, at 18.
[19] "Declaration of Michael Dane in Support of Debtors' Chapter 11 Petitions and First Day Relief," (Dkt. No. 29), *In re Fieldwood Energy LLC*, Case No. 20-33948 (Bankr. Ct., S.D. Tex.), at 2 ("Dane Declaration").

in 2018 and, despite its short and checkered financial history, acquired additional offshore assets—deep-water platforms from Noble Energy—upon exiting bankruptcy.

Fieldwood returned to bankruptcy with another plan in 2020. It's prepackaged bankruptcy plan included an agreement with Apache on allocating some of its remaining liabilities; Fieldwood characterized the decommissioning costs as "among the Company's most significant liabilities."[20]

Fieldwood eventually produced a bankruptcy plan that provided that certain offshore assets be passed into new companies created for the sole purpose of decommissioning, with any additional costs to be sought from prior operators/ lessors, exposing those entities to liabilities that they may have thought that had rid themselves of. Indeed, several large oil and gas companies challenged the disclosure statement for the reorganization plan on the basis that it provided insufficient information about the extent of the costs that they would be liable for.

The way in which these liabilities can boomerang shows the bigger problem that needs to be addressed:

It is no secret that mature assets are likely to need to be decommissioned first—many have long-since passed from active drillers to companies like Fieldwood. If these mature asset operators cannot pay, the costs could snowball towards predecessors-in-interest. This could be triggered by downturns like the oil price declines of 2014-2016 and 2020 which doomed Fieldwood, or by a cascade of liability through operators that have not prepared for retirement. If the predecessors can't pay or no longer exist, taxpayers will be next.

In addition, the details of the case present several things for the committee to consider. In short, each of these demonstrates what commercial actors do to protect themselves from decommissioning risks and they—unlike the government—have voluntarily obliged themselves to meet these liabilities:

- At the time of bankruptcy, Fieldwood held $1.16 Billion in surety bonds (or equivalents) for decommissioning. This is far less than the approximately $9 billion in decommissioning-related claims filed by the U.S. government.[21] This suggests that all parties were significantly underestimating the liability.
- Of the $1.16 billion in surety bonds, only $177 million were in favor BOEM. Apache, by contrast, had $498 million in surety bonds to ensure that Fieldwood covered its obligations to Apache for the same liabilities.[22] This suggests that the government is asking for and receiving far less than a private party would give. Worth noting also is that by fully bonding these liabilities, predecessors in interest are also protected.

[20] Dane Declaration, at 4.
[21] "Chevron U.S.A. Inc. and Noble Energy, Inc.'s Objection to Debtors' Motion for Entry of an Order Approving (I) the Adequacy of the Disclosure Statement, (II) Proposed Voting and Tabulation Procedures, (III) Procedures for Executory Contract Assumption and Assignment, and (IV) Procedures for Assignment and Transfer of Property of the Estate," (Dkt. No. 880), *In re Fieldwood Energy LLC*, Case No. 20-33948 (Bankr. Ct., S.D. Tex.), at 6 ("Chevron Objection").
[22] Dane Declaration, at 24.

- Apache contractually required Fieldwood to perform a minimum of $80 million a year on decommissioning or place a certain portion of net profits into a trust for Apache's benefit if Fieldwood failed to reach these thresholds. This trust, along with the surety bonds, provided security in the event that Fieldwood didn't properly decommission former Apache assets. This provision sought to ensure that Fieldwood made regular progress on decommissioning; to my knowledge, nothing as robust exists under federal law today.
- Apache allowed Fieldwood to reduce the total security provided by the trust and surety bonds if, at all times, they "exceed[ed] 125% of the Debtors' remaining decommissioning liabilities..."[23] In other words, it sought to be comfortably over-secured against decommissioning liabilities.
- These facts show what private parties do to protect themselves against decommissioning liability, and further, what even operators like Fieldwood would be willing to agree to in terms of decommissioning. This suggests that the government could reasonably obtain far more security than the 10% of estimated liability that it currently has.

Conclusions

In sum, there are tens of billions of offshore decommissioning liabilities, and less than 10% of those are covered by financial assurance. Because it is difficult to know when a well should be shut down, the government cannot easily mandate a fixed moment to decommission wells and infrastructure. Because firms do not have to factor in the full cost of plugging wells, and because they have no financial incentive to plug wells, they are incentivized to leave them idled for as long as possible.

The government can address this by providing a financial incentive to plug the wells; specifically, by requiring full-cost financial assurance that is only released when the work is done. Recent bankruptcies reveal how these costs and risks can readily ripple through operators, showing the urgency of the problem, and further, the level of security that private operators require to protect themselves against the risk of boomeranging decommissioning liabilities. On behalf of taxpayers, the government should expect nothing less.

[23] Dane Declaration, at 15.