Ohio River Valley Institute

FILLING THE HOLE
PART II: THE SOLUTION

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The Ohio River Valley Institute is an independent, nonprofit research and communications center founded in 2020. We equip the region's residents and decision-makers with the policy research and practical tools they need to advance long-term solutions to some of Appalachia's most significant challenges. Our work includes in-depth research, commentary, and analysis, delivered online, by email, and in-person to policy champions, emerging leaders, and a range of community partners.

EXECUTIVE SUMMARY

This second of a two-part study examines options and proposes a comprehensive solution to paying for the decommissioning of the oil and gas industry in Pennsylvania, Ohio, and West Virginia. Part I established that the regulatory systems have accumulated tens of billions of dollars of unfunded liability and nurtured what the state of Pennsylvania called a “culture of non-compliance.”

There are three basic options: industry bears the cost of plugging, the public bears the cost of plugging, or the public bears the cost of *not* plugging. Principle and precedence support the industry paying for decommissioning. The resurgence of shale production creates an opportunity to remedy inadequate planning because, within the oil and gas industry, production from shale wells has the necessary funds. Building on research and the lessons of previous jurisdictions, we propose a comprehensive plan which could be implemented at a state or national level to require plugging by those who can afford it and to raise funds from the industry to pay for plugging insolvent wells. In addition to cleaner air and better water, solving the problem creates sustained employment and economic activity without taxes on the general public.

Key Findings:

- Previous attempts to reform existing policies to protect taxpayers, including in California and Colorado, have either completely failed or yielded only incremental protections.
- The responsibility to clean up hazardous abandoned oil and gas wells should, by convention and principle, fall on the shoulders of the industry that created and profited financially from the sites. What is more, in some cases, shale gas companies historically owned the non-shale wells of the region.
- Major reforms to existing policies are also required in order to prevent shale wells from falling into the same situation as non-shale wells.
- The one hope of funding current liabilities in these states without burdening the general public is to levy a new, dedicated fee on production. The proceeds are best routed into a central fund that is available to a central authority to plug all orphaned or abandoned wells. The plan also requires a fully funded escrow for new wells, tightened performance and enforcement provisions, and an amnesty program for small producers.
- The cost per unit of production becomes small when the cost of decommissioning all of the wells is spread across the producing reserve base of 115 trillion cubic feet plus additional proved reserves of 71 trillion cubic feet of new drilling. Historically, drilling has reportedly earned rates of return over 50%.
- Depending on the scope of the costs intended to be covered by the fund (instead of being placed directly on the most appropriate operators), the cost could range from $0.05 to $0.21 per Mcf at today’s costs.
- While the proposed solutions could be implemented at a state-by-state level, implementation at a regional or national level would be more efficient.
- The proposed solutions do not impair existing energy supply or meaningfully curtail future drilling. The effect on energy prices would be very small. By contrast, the Energy Information Administration estimates that exporting natural gas will increase consumer prices by multiples of the impact of the resolution fee.
- The same concept can be applied nationally since about 30% of the national liability exists in states like California, Michigan, and Illinois with relatively little remaining production statewide to fund in-state liabilities.
- Using a public figure of $271 billion to decommission all existing wells nationwide and industry-reported figures of remaining reserves, a fee of only about $3.43 per barrel and $0.17 per Mcf could pay for decommissioning of all of the wells in the country.
- In the three Appalachian states studied, the proposal would directly increase oil and gas employment an estimated 32% over current levels, create over 19,000 new jobs in total, and would not suffer layoffs when commodity prices cycle down.

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INTRODUCTION

The contrast between the old oil and gas industry and the new oil and gas industry stands as stark in the tri-state area as anywhere in North America, and the challenges are as acute. Pennsylvania, Ohio, and West Virginia face hundreds of thousands of old, impoverished wells in need of decommissioning at the same time that they host a small contingent of young, highly profitable shale wells. Plus, they also house hundreds of thousands of unidentified wells abandoned before the modern era of record-keeping and plugging standards. These three populations present distinct—and competing—issues of economics and public health and safety. As the public issues created by unplugged old wells become more apparent, governance needs to find a new way to rebalance the competing interests.

Pennsylvania gave birth to the commercial petroleum industry in the mid-19th century, and by the late 19th century the global epicenter of oil production had shifted to Ohio. Production oscillated and declined for decades, and generations of wells were left behind without modern plugging to obstruct flow and without central records of their location. Only a few years ago, before the explosive growth of the shale revolution, Pennsylvania, Ohio, and West Virginia had become sleepy backwaters of the oil and gas industry, with wells producing at extremely low rates. But the states returned to national prominence with the shale revolution, this time dominating natural gas production. The contrasts between the well groups are brighter in Appalachia, but most oil-producing states have the same three populations in various proportions.

In the middle of last century, at about the same time when regulatory agencies recognized the need to plug old wellbores to prevent unwanted flows of formation fluids to the surface and into aquifers, the agencies also recognized the need for financial assurance in advance to make sure that the required work would be completed. After all, there is, by definition, no more profit to be had from a well that is ready to be plugged. The conventional tool of financial assurance has been a surety bond posted by the oil company to cover a portion of the costs, but the system of bonding did not evolve as the industry did, and it no longer serves its intended purpose.

The required bonds probably never sufficed to cover all the obligations even for small companies, and the bonds were proportionally smaller for larger companies. Evidently regulators believed that large companies presented small risks, presuming continuous growth and reinvestment of a non-renewable resource. In the same period, regulators attempted to keep the liability to a minimum by requiring prompt plugging of wells after they stopped producing. Oil companies kept a short list of liabilities by paying the decommissioning costs of individual wells as they came due.

But financial assurance did not adapt as reality and regulations evolved. The value of required bonds increased too little, sometimes going 40 or even 70 years without increase. Thus, they did not escalate with the cost of oilfield services or with the scope of decommissioning operations expected. After the price collapse of 1986, regulators across the country allowed oil companies to warehouse idle wells instead of plugging them promptly, causing an inventory of liabilities to accumulate . The non-renewable resources have matured into a new phase of their lifecycle, and most companies focus now on depleting old wells instead of drilling new ones. Experience has shown that the threat of failure by large companies is, indeed, large.

Parallel dynamics played out nationwide and left many jurisdictions in similar positions. A number of these jurisdictions have attempted in recent years to reform their systems of financial assurance so that industry will pay its end-of-life obligations. Mostly they attempted to dial up the parameters of the same conventional policy tools. Reforms faced stiff opposition and ended in compromises. Research has shown that most states now possess financial assurance sufficient to cover only a few percent of the obligations,[1] and other research has shown that large segments of unplugged wells are no longer capable of funding their own decommissioning even if all future profits were directed to the task instead of to owners.[2]

Policymakers now face three basic options: change policies to require industry to fund its clean-up, allow the clean-up to fall on taxpayers, or plan not to do the clean-up. The possibilities of repurposing wells or paying for plugging with charitable donations remain remote and, at best, partial solutions. Meanwhile, the need for clean-up was canonized decades ago, and evidence of the risk of old wells continues to grow.

Regulations have become so outdated that any effective change will be painful; there is no easy answer. But the options reduce to a zero-sum problem: either the oil and gas industry funds its clean-up at the end of life, or the public will pay some combination of economic and environmental costs.

In practice, landowners and governments have trusted oil and gas companies to meet the obligations owed them even while companies' assets depleted over decades, but the resurgence of new production creates an opportunity to remedy delinquent planning. Solving the problem creates cleaner air, better water, plus sustained employment and economic activity without taxes on the general public.

HISTORICAL POLICIES TO ENSURE FUNDING

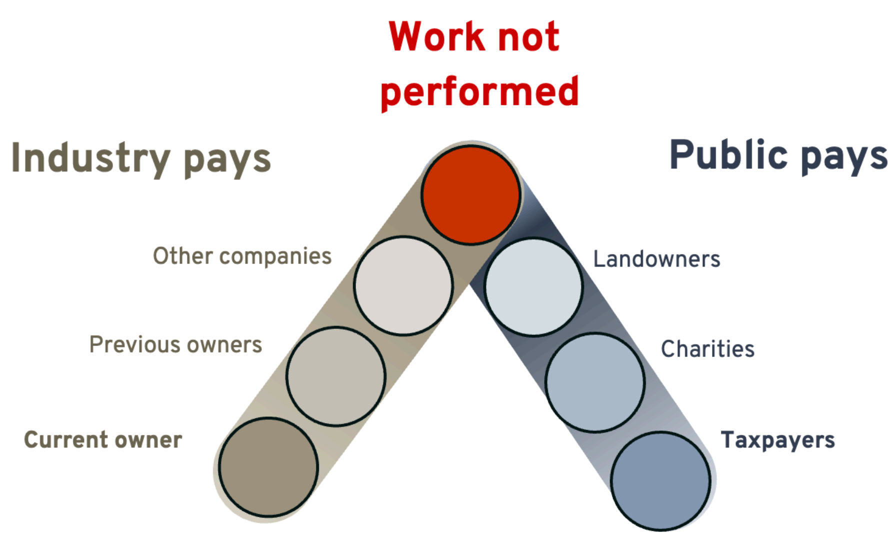
The policy objective—meeting the public need for clean-up with funds from industry—has only increased since financial assurance policies were first created in the middle of last century. But existing policy is hardly working better than no policy at all. The situation requires a radical policy change to compensate for the radical shortfall.

To consider what kinds of policies might prove effective, we consider two design techniques. We examine first principles of policy, and we examine how other jurisdictions have tried to solve the same problem and failed. Together these buttress the need for a new policy and help structure a new design fit to the current reality of the industry being regulated.

First Principles

Governance must first decide whether out-of-use oil and gas infrastructure should be cleaned up and secured or allowed to stand and decay in place. Though methods and enforcement have changed a great deal, the idea of the necessity of clean-up has stood since the last century. Second, governance must decide who should bear primary financial responsibility: either industry or the public. These are the three fundamental choices facing policymakers. If the industry does not pay for the clean-up, then either the work will not be done, or members of the public will pay for it. Figure 1 shows the three options and the range of candidates within each.

Figure 1: Range of candidates to fund decommissioning of depleted oil and gas production infrastructure.



The need for decommissioning and clean-up has stood since the middle of the last century, when states created plugging standards and financial assurance of those responsibilities. The sprawl of urban areas into previously producing areas, the increased recognition of environmental needs, and the increased recognition of the impact of leaks suggest that *not decommissioning* is not an advisable option.

In other jurisdictions, oil and gas industry organizations have argued that policies to ensure funding are not necessary, calling those proposals a solution to a problem that does not exist. It is true, as demonstrated above, that the number of wells historically orphaned to the care of the state have constituted a small minority of wells. On the other hand, solutions work best in advance of a problem, and the same data above shows a massive, impending liability related to a population of wells with no plan and no hope of paying for decommissioning.

Historically, policy has been deemed necessary long before such liability accumulated. The fact that such policy has long existed speaks also to the continuing truth that there is little inherent or market-based motivation for oil companies to clean up. The costs of pollution are rarely internalized to the market, and companies pay little for the pollution they leave behind. Plus, the risk of failure is limited for most owners; bankruptcy (or merely dissolution without any assets) shields investors while liabilities route to public programs.[3] The lack of policy to enforce clean-up continues to function as permission not to clean up.

Existing policy to protect the public has relied on the broader, canonized principle that the "polluter pays." The obligation to do the work and the financial assurance of meeting that obligation fall to the oil company that operates. If the current one defaults, some jurisdictions allow liability to fall back to previous owners, leaning on the idea that previous owners profited from the wells. When wells are orphaned to the state, most programs draw funds from taxes or fees on oil companies to perform the duties. Setting aside the opportunity cost of those funds, the pervasive and perpetual structure of oilfield decommissioning policy has recognized the responsibility of the industry over the public.[4]

There is an argument that landowners should pay the cost of cleaning up the former oil company assets on their property because they benefit most directly from the decommissioning. Apart from an argument of fairness, it is highly doubtful that landowners can systematically fund the repairs to their property. Some wells may be plugged and remediated by charities or other forms of benevolence like voluntary carbon offsets, but it is also highly unlikely that these sources can—or would—clean up the full scope of the expired infrastructure on behalf of the oil and gas industry. If oil companies fail to perform the clean-up, then the government—funded by taxpayers—becomes the ultimate guarantor, the only entity with both means and motivation to perform the work.

To play devil's advocate, there is also an argument that the oil and gas industry has provided such a valuable public service that its historical and current profits do not suffice, that the deal should be renegotiated, and that corporate profits should be further supplemented by taxpayers assuming the cost of decommissioning. Moreover, the argument further requires that oil companies should be excused for not having arranged to meet their well-known obligations under the long-standing laws and regulations. We do not find these arguments compelling for economic or moral reasons.

The most sensible and practical policies would burden oil and gas companies with the costs, directly or indirectly. The current problem lies in the failure of existing policies.

Historical Policies Failed

Historical financial assurance policies have been set separately by dozens of regulators, yet they mostly have used the same mechanisms differing by a few input variables.[5]

- Tiered guarantees of funds (in various forms), with small amounts to cover large numbers of wells with "blanket" bonds.
- State-run program to decommission orphan wells of defunct oil companies with funds from active oil companies.
- Wells are allowed to stand idle.

Though the policies often allowed for escalation of the required assurance, escalation was rare. In the case of federal lands, for instance, one aspect of the required bond amounts had not been updated for 50 to 70 years.[6] Together the lack of escalation and the intentionally limited scope have left assurance deeply inadequate. Multiple studies have found that the guarantees have amounted to only a few percentage points of estimated costs in each state while the nationwide costs run in the hundreds of billions of dollars.[7]

Policy Revisions Also Failed

A number of jurisdictions have recently tried to revise their financial assurance policies, but those mostly tried to use the same mechanisms: Colorado, California, Arkansas, Bureau of Land Management (BLM), and Bureau of Ocean Energy Management (BOEM). The reforms mostly required years to accomplish, and they mostly have proven ineffective, with even the strongest reforms falling short of guaranteeing protection for taxpayers.

The Bureau of Land Management increased its bond amounts by 15 to 20 times for various tiers, yet the fact that they kept blanket bonding means that, if it is successfully implemented, the plan would increase financial assurance from 1% to 4% of the exposure.[8] The BOEM plan was finalized last spring and promptly challenged in federal court by a coalition of oil-producing states and industry associations,[9] though it called for increases only on current operators proven to have limited financial resources. If upheld and implemented, it would only marginally increase the total financial assurance, still relying primarily on the balance sheet of large companies.[10]

Colorado's governor in 2018, followed by the Colorado legislature in 2019, mandated reform to guarantee that "every obligation" of industry would be met. The long process of negotiation and implementation ended up with financial assurance initially of slightly *lower value* than before the reforms.[11] Even including orphan well funds, miscellaneous bonds and federal grants, the six years of reform efforts ended with the full spectrum of provisions providing assurance for only 7% to 9% of the estimated statewide costs.[12] When the design of the reforms was announced in 2022, it was praised as "the strongest rule in the nation,"[13] and it still may be. Still, it falls far short of guaranteeing protection for Colorado's people and lands where 57% of the wells in the state are in regions estimated not to make enough money in their remaining life to fund decommissioning even if all proceeds were dedicated to the task.[14]

Varieties of policies, reforms, and potential reforms

Recent policy reforms have mostly followed or adapted the existing policy playbook. Some new ideas have been implemented and others discussed. Most have poor track records or low expectations, while the most effective ideas have gotten little or no traction.

Higher bond values, but still applied as blanket bonds: The required financial assurance was so small that even dramatic increases left dramatic shortfalls. More importantly, reforms to the bond amounts did not require funds for every well. Instead, reforms continued allowing "blanket bonds" for which a modest sum is meant to secure a large number of wells. The structure appears to rely on the invalid presumption that large companies represent small risk; systematic, correlated risk threatens companies of all sizes.

By-well bonds: It has been proposed that reforms disallow blanket bonds so that the total financial assurance from each company is proportional to the total liability it is meant to assure. Despite its obviousness, the concept has gotten little traction. It would require most from large companies, plus companies with low-rate producers may not be able to afford it.

Bonding tailored to size and financial strength: In California, this provision has been slow and difficult to implement one company at a time. Plus, its ceiling of $30 million per company does almost nothing to address the two California-only companies, now merged, that together represent about half of the wells in the state. In Colorado, the tailoring process was also time-consuming, and it contributed to the small decrease in financial assurance. In federal waters, tailoring reforms to target the poorest companies led to a legal challenge as described above.

Gradual increases: BLM and BOEM proposals allowed a couple of years of phase in. Industry insisted upon—and got—more years to reach compliance. Colorado allowed 10 to 20 years for its most marginal companies to comply. In all cases, it is not clear that the still-partial assurance will be achieved before companies cease to exist.

Fees on industry to pay for orphan wells: These programs collect modest sums since they are designed to pay-as-you-go. The current incarnation is thus not suited to the systemic risk of default. The precedent, though, has merit: Surviving oil companies bear the cost of default instead of non-industry taxpayers. Our proposal extends this long-standing element of policy.

Required plan or pace of plugging: Texas and Colorado both have provisions for plans or requirements to plug or decommission a fraction of idle wells over a number of years. The Colorado policy has no track record yet, participation is voluntary, and consequences for failure are non-existent.[15] The Texas provision requires in principle that 10% of idle wells each year be decommissioned or returned to production, but it similarly has enough loopholes that its orphan well population continues to grow while many wells in the state stand idle but unplugged.

Fees on idle wells: As an alternative mechanism to motivate the decommissioning of existing idle wells using an economic motivator rather than prescription, some states have passed and others have discussed requiring operators to pay an annual fee for permission to let wells stand unplugged and idle. The policy, however, has failed to consider how the magnitude of the fee weighs against the cost of decommissioning. In Colorado, for example, a perpetual annual fee of $225 translates to a present value of $2,250 when discounted at 10%.[16] By comparison, the average cost of decommissioning is estimated at $130,000 per well in Colorado, so the economic decision by oil companies remains unchanged; it still makes better financial sense *not* to plug wells.

In principle, the policy could be effective, but we estimate based on normal oil and gas industry investment criteria that the annual fee would need to be around a quarter or a third of the cost of the delayed decommissioning work in order to make plugging financially more attractive than paying fees. Adding complication, the cost of decommissioning can vary widely. A single fee state-wide could be unbearable for some producers and ineffective for others.

Full bonding at transfer: Arkansas was among the first states to adopt this policy. California recently passed a law requiring full bonding of all wells when ownership of the wells is transferred, but the intent failed its first test as the purchaser threaded an evident loophole by acquiring the stock of the operating company instead of its assets. Many acquisitions in Colorado in recent years have used the same previously uncommon mechanism of stock transfer instead of asset transfer.

Blacklist: The Department of Energy and Natural Resources (DNR) of Louisiana recently used its existing authority to disallow operating licenses to companies if any of their officers have been officers of companies that previously orphaned wells in the state.[17] A number of states consider the track record of violations by the receiving company before approving a transfer, but three states historically have considered the track records of officers and/or owners before allowing a transfer.[18] The effect of the provisions has not been documented, but it is known anecdotally that in other jurisdictions some executives do take responsibility for new wells even after orphaning their previous wells.[19]

Predecessor liability: The most effective historical policy is the joint and several liability of co-owners and previous owners, notably on federal lands and in federal waters. Though enshrined in law and contract, the provisions faced—and offshore provisions still face—stiff legal challenges as predecessors seek legal recourse to avoid the liability.

As a go-forward solution, however, the policy has one major problem: potential limitations on the ability to make it retroactive. As the proverb goes, the best time to implement the strategy was 20 years ago, but the second-best time is now. Still, none of the financial assurance reforms in recent years have added provisions for predecessor liability.

Industry Objections to Reforms

More effective policy reforms might have been implemented except for the objections raised by industry about potential harm and unintended consequences. Reforms for the Appalachian states should consider insights and arguments from industry about unintended consequences raised in other jurisdictions.

Oil and gas industry advocates have argued in other jurisdictions that reforms to financial assurance will drive some companies out of business, harm local economies, decrease the amount of secure local supply, and increase the cost of energy to Americans. The proposals for bonding reform, indeed, regressively affected small companies more than large ones, though the consequential harm to economies and communities turns out to be inconsequential because the total production from small companies remains small.[20] Nevertheless, the new policies we propose consider and address this and other objections of industry.

A NEW MODEL FOR FUNDING

Given the failure of existing policies and the strident resistance of industry to significant strengthening, we propose a new architecture for financial assurance that honors first principles and prior policies and conforms to the current configuration of the industry, giving companies options and viable pathways to success. It builds on proposals made by others and extends provisions to address objections of industry. Our objective is to keep the cost of decommissioning on the most appropriate players in the oil and gas industry but in such a way that abates disruption, particularly for small oil companies. In total, they increase requirements and enforcement but also leave more control and more choice to the oil companies than other policies on how to meet those obligations.

The plan outlines five interlocking pieces to create enough regulatory fencing to achieve the public good of industry financed well decommissioning:

1. A centralized agency to adopt legacy, orphan, surrendered, and future bankrupt wells,
2. A production excise tax to fund the centralized agency to plug wells and manage program,
3. Full escrow for new (or new and recent) wells,
4. Tightened performance and enforcement provisions, and
5. An amnesty program for small producers to sidestep enforcement.

The plan begins with a small excise tax on production to fund a new, government-sponsored enterprise (not a government agency) that can take final and permanent responsibility for legacy and orphan wells, as well as existing and new wells if elected by active companies. The same entity also serves as a clearinghouse for information on best practices and costs, as a reinvestment vehicle to assist the transition of the oil and gas industry, and as an enforcer of existing responsibilities through civil and bankruptcy law.

Meanwhile, active companies would be required to catch up with accumulated liabilities then to maintain a timely plugging program. Companies that have operated and planned in good faith should not have a problem meeting the obligations, but those who have not would suffer the loss of the right to operate. To assist with the transition, an amnesty program is proposed to mitigate the consequences of the catch-up policy. They would maintain their employment temporarily but would transfer ownership and responsibility to the decommissioning entity.

For new wells, companies would be required to place the full cost of decommissioning in an escrow account which they would continue to own but which could be invested by the same independent panel as the excise tax, including investment back in oilfield communities, workers, and companies.

Government-sponsored entity as receiver

Legislation would establish a government-sponsored entity to assume responsibility for orphan, legacy, bankrupt, and potentially orphan wells. Closely-related functions of research, expertise, knowledge-dissemination could be vested in the same new entity or in an agency that remains part of the government.

Previous proposals[21] named these the Abandoned Well Corporation (AWC) to bear responsibility for the wells and the Abandoned Well Administration (AWA) partly as extension of the DOI's existing Orphan Wells Program Office to serve the function of capacity-building. The pair of entities (or a combined entity)[22] would follow in the model of the Resolution Trust Corporation (RTC) which successfully unwound the saving-and-loan crisis of 30 years ago. It would bear responsibility for resolving the current and future unfunded liability accumulated by the oil and gas industry. To be clear, the operational function is not a government agency subject to political vagaries, but a government-sponsored entity with independent governance and still subject to state laws and regulations.

Such a separate and independent participant in the issue of decommissioning could strengthen the policy system and outcomes by adding value without usurping control, offering unique insights and novel functions not present in the current governance framework.[23] It could accelerate action on currently orphaned wells, while improving efficiency and effectiveness. It could hire and train personnel and commission the building of necessary equipment. It could respond to emergency blowouts, and it could promptly take responsibility for vast numbers of old wells which may leak in the future. In addition, it could assume the long-term liability for future failure of wells plugged according to its published standards even if plugged by third parties. All of that while subject to the laws of each separate state concerning the operation and decommissioning of oil and gas wells.

The AWA/AWC would also serve as an expert knowledge center for government and industry. It would, for example, build and maintain a national database of wells including documentation of legacy wells. It would participate in the study of risks and best practices for permanent plugging and would plug wells to those standards (in addition to all state requirements). It would publish information about its cost of decommissioning for use in planning by companies and policymakers.

Importantly and novelly, AWA/AWC would also involve itself in pursuit of existing legal remedies. Like the RTC before, a federal government-sponsored entity would be designated as the receiver of bankrupt oil companies, assuming the right and the responsibility to operate, repair, sell, and/or decommission the oilfields. If an organization is created at a state level instead, then it would be at least helpful for bankruptcy law to be clear that normal business operations include clean-up and thus supersede lenders' rights. The national or state-level receiver thus enjoys also the right, means, and motivation to pursue claims of fraudulent transfers and predecessor liability against previous owners.

Its initial operation could be funded with a loan or grant from the billions stored in the federal Oil Spill Liability Trust Fund, but a new tax on production—as well as the proceeds of legal recourse against predecessors—would fund future operations.

Production excise tax

A severance or excise fee would be levied on production to fund the AWA/AWC. Previous policies and proposals envision a dollar-per-year fee on idle or on active wells.[24] Our proposal of a production tax is less regressive than a per-well fee and is able to raise greater funds, and we rely on other strategies to govern the timing of decommissioning.

The tax would be set initially to accumulate within a few years a fund sufficient to cover the wells it initially adopts plus a reasonable estimate of wells to be orphaned in the future. But it should be revised annually and independently by the AWA/AWC—not a regulatory or legislative process and including downward revisions if suggested by the data—to adapt to changing knowledge and conditions. Still, it should at all times be projected to provide necessary funds plus a safety margin based on proved reserves remaining.

Table 1 below summarizes a scoping estimate of the "Oilfield Resolution Excise Fee" (OREF or "resolution fee"). Based on existing proved reserves as reported by the EIA[25] and our estimate of existing liability quantified above, the table shows what the fee would need to be over the lifetime of existing wells in order to provide for various degrees of coverage.

Table 1: Notional calculation of lifecycle fees to fund AWA/AWC.

Range of Estimates for Resolution Fee

Assets and liabilities	Pennsylvania	West Virginia	Ohio	**Total**
Producing shale gas reserves (Bcf)	70,191	28,184	16,248	**114,623**
Non-producing shale gas reserves	34,807	20,042	16,114	**70,963**
Non-shale liability ($ billion)	$16.1	$8.4	$7.3	**$31.8**
<u>Small Program Design</u>				
Volumes expected to be subject		Only Producing		
Fraction of liability to cover		25%		
Margin for legacy and unknowns		20%		
Fee per Mcf	$0.05	$0.05	$0.07	**$0.05**
% of $3.00 / Mcf	1.5%	1.7%	2.3%	**1.7%**
% of $4.00 / Mcf	1.1%	1.3%	1.7%	**1.3%**
<u>Larger Program Design</u>				
Volumes expected to be subject		Producing and Non-producing		
Fraction of liability to cover		80%		
Margin for legacy and unknowns		20%		
Fee per Mcf	$0.15	$0.17	$0.22	**$0.16**
% of $3.00 / Mcf	4.9%	5.6%	7.2%	**5.5%**
% of $4.00 / Mcf	3.7%	4.2%	5.4%	**4.1%**
<u>Most Robust design</u>				
Volumes expected to be subject		Only Producing		
Fraction of liability to cover		100%		
Margin for legacy and unknowns		25%		
Fee per Mcf	$0.19	$0.22	$0.28	**$0.21**
% of $3.00 / Mcf	6.4%	7.3%	9.4%	**7.1%**
% of $4.00 / Mcf	4.8%	5.4%	7.1%	**5.4%**

If the AWA/AWC expected ultimately to take responsibility for 25% of the total liability plus a 20% safety margin, then the fee over the lifetime of remaining production would need to average only about $0.05 per Mcf from only existing wells. To provide for 80% of the liability with the same safety margin but relying also on the income from undrilled wells, the fee increases to only about $0.16 per Mcf across the region. In the most robust version of the program to cover 125% of the entire non-shale liability, the fee becomes only $0.21 across the region, though higher in Ohio. Moreover, the fee would also be tax deductible, so the incremental cost shown above is offset by lower corporate income tax.

For the sake of the public, it is preferable to structure the fee as a cost unit (Mcf) as described above because it provides more confidence in collections. For oil companies, the fee would be slightly more advantageous structured as a percentage of price received so that the cost would diminish when low commodity prices pinch cash flow. However, the savings would be a fraction of the fee which is already measured in pennies.

The tax could be levied against all wells so that all operators are contributing, as modeled above. The amnesty program outlined below provides some recourse for cases in which losing two percentage points of revenue triggers insolvency. Alternatively, wells could be exempted when producing less than a prescribed rate without increasing the value of the fee significantly. Wells producing less than 90 Mcf per day qualify for existing tax breaks based on their being "stripper" wells. At this point, though, most Appalachian wells producing 90 Mcf per day are much more profitable than the average well, so the threshold rate could be set lower.

The funds accumulated while production remains high would be invested by an independent board to accrue interest in hopes of offsetting future cost inflation. The investment board would be specifically charged with favoring investments to support oilfield communities, oilfield workers, and new energy projects by oil companies. It could, for instance, prioritize investments in municipal bonds in oilfield communities, venture capital funding of oilfield technology start-ups, and/or loans to oilfield workers so that they can retrain to work in decommissioning or renewable energy. It would not, however, make loans collateralized by producing wells which fund its operations, and its oilfield investments would have to fit below a ceiling so that the fund does not have concentrated, correlated risk.

Alternatively, the resolution tax could be structured more like recent policies and without a central agency to do the decommissioning: the proceeds could be collected into a central fund and disbursed to states through a grant program. This structure resembles both the long-standing Abandoned Mine Lands model and the recent grant programs of the Infrastructure Investment and Jobs Act (IIJA). In fact, the existing federal programs and offices could be renewed and recapitalized with the resolution fee to continue the same work funded by oil companies instead of federal taxpayers.

Full escrow at completion of new wells

The AWA/AWC becomes a reliable guarantor of existing wells, so financial assurance requirements would change only for new wells. At completion of a new well, the operator of the well would place in escrow an amount of money recommended or set by the AWA/AWC equal to its estimate of the current cost of the full breadth of decommissioning. However, the owner of the well continues to own the funds as well as the investment growth managed with the proceeds of the excise tax. Title to the funds would transfer as an asset along with title to the wells, something akin to the "site-specific trust funds" piloted in Louisiana.

Alternatively, full escrow could be required also of wells drilled recently or of wells producing more than a specified rate in a recent year. For example, it could be required for all wells drilled since 2010 or for all wells producing an average of 30 barrels of oil equivalent per day or more during 2023. These scenarios would require allowing a few years for companies to supply the funds, but the time period would not need to be as long as to work off accumulated liabilities as described below.

Whether applied only to future wells or also to recent wells, the escrow funds could be held either by a private entity and reinvested in bonds or similar low-risk options of their choosing, or the funds could be held and managed in a dedicated vehicle as described below to hold the resolution funds in until they are deployed. Private escrow would allow more control by the oil company, but as described above centralized escrow would make funds available for supporting oilfield entities.

At the end of the economic life of the wells, the operator would have two options of how to handle the last step. The operator could choose either to decommission the wells (to standards set by regulators in consultation with the AWA/AWC) and then claim the accumulated funds from escrow,[26] or it can elect to turn over both the wells and the (sufficient) escrow funds to the AWA/AWC. The AWA/AWC would then take responsibility to decommission the infrastructure and, later, to repair the wells if they are breached in the future. If the operator defaults on its decommissioning obligation before making an election, the wells and the escrow funds fall to the AWA/AWC.

Performance and Enforcement

The provisions above provide for a way to pay for the systemic risk of orphan and legacy wells, but policy should still attempt to stem the flow of orphan wells. To put the cost of decommissioning most directly on the responsible companies requires policies for tightened performance and enforcement. Without changes, oil and gas companies will continue to face the moral hazard created by current policies, and the situation will only deteriorate.

Based on prior experience negotiating and enforcing policy reforms as well as other studies of reforms,[27] the following appear to be the most practical and most effective solutions to create accountability and consequences for failure to plan for and meet statutory obligations. Oil companies with plans and intentions to fulfill their obligations should not have to face the consequences of—or hold an objection to—enforcement against so-called "bad actors." Accountability for companies to perform will reduce the need for production fees to fund orphan wells, protect the reputation of the industry, and provide for the needs of the public.

Predecessor liability

Lawmakers should create joint and several liability of predecessor owners for the full cost of decommissioning effective at the earliest date legally available. Generally, operators earlier in the life of a well recover more of the profits generated, and it makes more sense for a predecessor to pay the cost of decommissioning than for the costs to be borne by other companies that never saw any financial benefit from the well.

Of course, the provision has no benefit unless it is enforced. In other jurisdictions, oil companies have stridently resisted enforcement of predecessor liability, and these new laws will likely face the same kind of resistance. As receiver of bankrupt oil fields, AWA/AWC will have the right and means to pursue previous owners, plus it could maintain the right and responsibility to plug and decommission the fields while the cases are prosecuted.

Enforcement does not raise the standard of what must be done; it does require more timely performance and increases the consequences of non-performance. On the other hand, timeliness comports with the fact that projected cash flow is greater in early years than later years, and consequences follow from the importance of the obligation.

Alternative: Security at transfer

Predecessor liability maintains the guarantee of larger companies when they sell wells to smaller companies. A similar effect can be created in theory by requiring full financial security of wells on transfer, but the policy and its implementation in practice require more complexity and difficulty to achieve the same degree of security. Specifically, the policy must specify the type of security, the amount of security, and the type of transfer.

Some form of third-party bonding, if set high enough, could serve the purpose, but as oil and gas industry advocates have pointed out, financial guarantors may not have the appetite for this volume of contracts. In either event, the plan will require the option for escrow as described above for the new wells.

The amount of security would need to be set initially with only as much information on costs as is available at that time. Setting it too low fails its purpose, but setting it too high risks creating potential impediments to well transfers. The purpose of the policy is better served by erring on the high side, but setting the amount becomes a point of negotiation and contention in the absence of good data.

Lastly, experience in Colorado and especially in California proves how policy can be skirted because there are several ways that ownership can be transferred. Historically, most transfers have moved only the fields themselves, each company continuing to exist separately. But in recent years and in these jurisdictions, major transfers have occurred at the corporate level. That is, the purchaser buys the company instead of its fields, adopting a corporate subsidiary. The corporate owner and operator stays the same while the ownership of the corporation changes.

The option of a corporate transfer is simple and accessible in many cases. Though the same name stands on the signs, the oil fields are guaranteed by different portfolios and different balance sheets, managed by different owners with different strategies, and potentially by different financial relationships between subsidiaries. The threshold for requiring security at transfer must address change of beneficial ownership at the corporate level.

Minimum decommissioning activity

Oil and gas companies should be required promptly to catch up with their current obligations.

Oil and gas companies should be required to have completed decommissioning (or have placed in escrow necessary funds) within seven years for all its wells that will have been idle for two years or more. Alternatively, the wells must have permanently re-established some form of economic activity, either production or re-purposing. That is, at the end of seven years, operators should have zero wells that have been inactive or substantially inactive for the previous two years or have placed in escrow enough funds to do the work when equipment becomes available.

Seven years considers the fact that cash flow from existing wells comes preferentially in early years. Because production declines, longer time frames offer less incremental cash flow but instead create motivation to further delay the expenditures. It is also approximately consistent with the uniform standards of fraudulent transfer so that monies paid out to owners instead of paying to meet the statutory obligations could be recovered in bankruptcy.

Operators should be required to meet this ultimate deadline with intermediate milestones of cumulative progress increasing by 20% of initially idle inventory every year. However, regulators should also grant one-year grace periods to operators before enforcement action begins. In this way, policy can protect the target date of seven years while retaining some flexibility for decommissioning of wells idled in the interim and for possible dips in commodity prices. To help meet the objectives, regulators should also promptly approve a set of principles that allow wellbores to be re-purposed for other economic activities.

Oil companies would retain the right to choose which wells to decommission, could set aside the funds in escrow instead of performing the work immediately, and could pace the costs as cash flow allows as long as they met cumulative milestones. This scope of activity does not require full funding of eventual liabilities; it requires only that oil companies catch up with their current liabilities.

Opt-in

In addition to the no-cost amnesty program outlined below, operators would have the option to access the services and liability protection of the AWA/AWC by placing in escrow an amount of money set by the AWA/AWC. A voluntary participation could substitute for performing the work in the field under the minimum decommissioning plan, and it could supersede predecessor liability by making AWA/AWC liable. This opt-in makes it more feasible for companies to transfer marginal wells and manage predecessor liability, and it makes it possible to provide timely financial assurance within the logistic limits of the industry to complete the accumulated work over seven years.

Prompt plugging

At the end of seven years, operators should be required to decommission wells promptly when they are not active for at least 6 continuous months out of two years, or some similar standard to indicate active production and reduce manipulation. Few wells not productive for this period return to production,[28] and this definition helps minimize manipulation by uneconomic production.

Tax deductibility

Costs expended for decommissioning would remain tax deductible as expenses, so savings in corporate taxes would offset the costs.

What is more, many oil companies benefit from a federal depletion allowance of 15%. The significant tax break was intended to support reinvestment in the capital-intensive and economically important industry, but at this point many of the companies that benefit from the deduction make little or no reinvestment in supply. Instead, they focus on depleting late-life fields at low cost.

This previously strategic federal subsidy could be replaced with an analogous policy to fit the current strategic needs. Oil companies would deduct decommissioning costs a second time up to the same 15%. That is, they would no longer have the standard deduction, but they could get the same effect by deploying capital in secure decommissioning which is the more relevant capital expenditure and policy objective for small producers at this point.

Attestation

Corporate structures have become more complicated in the oil and gas industry in the decades since operations first required a license from the state. For a complete evaluation and review by state authorities, operating licenses could be filed and reviewed on a combined basis like that for federal income taxes, including signatures from each separate entity as is the practice now, for the families of related entities.

More importantly, as a matter of accountability, each year's renewal of operating licenses would require an attestation signed by the officers of the organization that they understand the state's requirements for decommissioning, have quantified the associated costs, and have a viable plan to fund those obligations.

Recourse

If an operator cannot pay its obligations, then forcing compliance is not likely. If an operator falls behind its required funding schedule or cannot attest to a viable plan to fund obligations, then its operating license would be promptly revoked. The company would be required either to sell its fields or to file bankruptcy for failure to meet its financial and statutory obligations.

Blacklisting

Owners and executives of newly bankrupt companies should forfeit the right to own, manage, or drill other wells unless or until they have paid the full cost of decommissioning the bankrupt company. Similarly, enforcement would need to apply to families of corporations as described in operator renewals.

Executives and companies should have the opportunity to remove their names from the blacklist resolving the issue they created, namely by funding the decommissioning of wells they orphaned.

The AWA/AWC could maintain a shared list of people and entities blacklisted in each jurisdiction so that other jurisdictions could decide whether to trust individuals responsible for orphaning wells in other jurisdictions.

Amnesty program for old wells and small companies

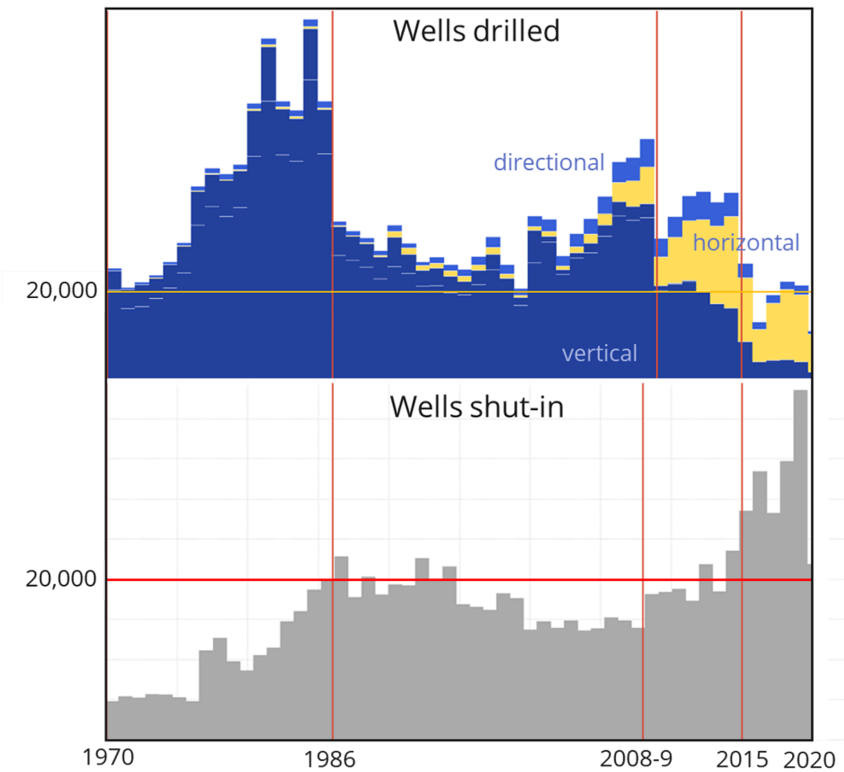
Although the performance and enforcement standards above do not require full funding of their obligations or even immediate funding of current obligations, they are likely to require more than many oil and gas companies can afford. As oil and gas industry advocates warn, any significant increase in financial responsibility is likely to precipitate the orphaning of a significant number of wells sooner rather than later. Thus, any effective plan for reform requires the ability to handle the near-term consequences, and an amnesty program can help to smooth the transition.

To be clear, the statutory and regulatory requirements for decommissioning have stood and been understood for many decades. Any amnesty program would be a bailout for companies who did not manage their obligations responsibly. Still, some form of amnesty remains essential as a practical matter. The primary question becomes how to define the scope of amnesty, namely which wells and perhaps which companies.

In its simplest form, amnesty could be extended to all wells drilled before a certain date so that companies no longer bear responsibility for large parts of their portfolios. Companies could be granted a few years to make a final election of whether they want to keep their older wells for ongoing or future production or whether they would rather quit claim to the wells to the care and responsibility of the AWA/AWC without further consequences.

Prior analysis shown in Figure 2 illustrates the number of wells starting and ending production onshore U.S. from 1970 to 2020.[29] That analysis found the average unplugged well was drilled in 1986, nearly 40 years ago. Shifting the responsibility for wells more than 20 years or 30 years old would make the AWA/AWC responsible—if elected by the operator—for the majority of the outstanding plugging liability.

Figure 2: Timing of wells drilled and wells shut-in based on Purvis, 2022.



If based on drill date alone, the amnesty would apply equally to small family companies, to large private-equity companies, and to large public companies like ExxonMobil. A second criteria[30] could be based on the size or ownership structure of the company, so that small or family businesses would have the option for amnesty while more sophisticated companies would be expected to meet their decommissioning obligations.

Under either criterion for amnesty, the companies surrendering some or all of their wells could also opt to become temporary contract employees of the AWA/AWC to continue operating the same wells. They would thus shed their liability but maintain their employment in the short term and have the opportunity to earn an offer of full-time employment from the AWA/AWC as the wells are incorporated into the entity's systems. On the other hand, the principals of the companies would also accept blacklisting and thus forfeit the right separately to own, operate, or drill wells in the future until their remaining wells come into full compliance with updated accountability standards.

The amnesty program requires careful planning and some potentially severe restrictions to prevent fraud and exploitation, particularly a second criteria about the nature of the company.[31] However, it does provide a way to address the concerns of industry about the effects of a step-change in policy on small businesses and local communities. It also helps to bridge the possibility of near-term orphaning of wells triggered by policies intended to reduce long-term orphaning as warned by industry advocates by creating the means to handle an influx of wells.

Interplay and options

The construct above involves multiple parts, each with independent merit, but no single part addresses the full range of dynamics. Plus, there remains ample opportunity for details of each element to be altered in a way that allows manipulation or machination to circumvent the intended purposes. The effectiveness of any single policy and of the network of policies will depend on the care and especially on the timelines.

The centralized agency, funded by the resolution fee, addresses non-shale and legacy wells. Full escrow at completion protects the liability of future drilling. Enforcement removes the moral hazard inherent to existing policies and helps reduce further orphaning of existing wells, and the amnesty program gives companies a way forward under the step-change. The interlocking parts can be implemented in each state separately, in the country as a whole, or as a combination of state and national reforms, but experience in other matters and in other jurisdictions demonstrates the value of a comprehensive, uniform solution.

Completeness

An independent agency to manage the end of life and decommissioning departs most from previous policies and may fall most easily in the face of opposition. On the other hand, it also addresses the largest and most difficult wedge of the problem, and more empirically, the examples of Canadian provinces demonstrate the shortfall of lesser policies.

The last oil price cycle in 2015 triggered a wave of oil company bankruptcies in both the US and Canada, but the Canadian provinces took the opportunity to extend and strengthen previous reforms from recent years, including many enumerated above. Systematically if not uniformly, they taxed oil companies to pay for plugging current orphan wells, they required oil companies to perform a minimum amount of decommissioning work every year as prescribed each year by the regulator, they created models of plugging costs inside the regulators to manage the prescriptions, they monitored operators' financial health, they limited well transfers, and they created collaboratives for best practices.

That second, more robust round of reforms was launched mostly around 2018, and already the regulators recognize the need for further, more significant reform. The model of decommissioning cost in Alberta, for instance, demonstrated a massive liability. Worse, internal estimates by the regulator put the cost up to three times the public total used in discussions and planning.[32] Meanwhile, the mandatory plugging program, though largely met by industry, has made little progress.[33]

In 2024, the premier of Alberta appointed an independent "special advisor" to study further the issue of a "mature asset strategy." After two years of preceding and focused work, his final report was recently published. Among a number of ideas, that report outlined the need for bankruptcy reform, centralized study of best practices, and ideas for "special purpose entities" (SPEs) called "HarvestCo" and "ClosureCo" to handle late-life production, decommissioning, and long-term liability funded by industry.[34]

Alberta is now heading into its third generation of tightening reform and seems to have arrived at the conclusion that the best route for its oil industry includes entities like the AWA/AWC dedicated to the task. "These [SPE] models," the report reads, "are intended to accelerate closure, reduce costs, improve outcomes, streamline operations, minimize or eliminate insolvencies, and fulfill financial obligations to all stakeholders."[35] Years of study and months of collaborative discussions appear to have arrived at many of the same ideas outlined above, including the need for fees on industry to fund a "ClosureCo."

Level of government

Piecewise implementation at the state level gives maximum autonomy to states, but not all states have enough production from young wells to fund the decommissioning of old wells. Also, some states with young production can expect drilling to continue longer than other states. Implementation would require the same negotiation and implementation dozens of times independently, creating inefficiency and delay and risking failure of the policies by industry capture of regulators.

On the other hand, national implementation of the plan would create the most comprehensive, most timely, and most efficient solution. A national fee would also ensure a level playing field across plays for all oil and gas producers and provide uniformity. For maximum effectiveness, states would adopt a uniform code of performance and enforcement; not doing so would cause a higher default rate in some states and thus require more funds from national taxes. Inconsistent enforcement would allow some states to freeload on fees paid from other states.

If states are willing to accept the possibility of freeloading by their peers, then the AWA/AWC and supportive parts of the plan could be created nationally and made available as an option across the country without requiring the performance and enforcement provisions. The AWA/AWC could still offer responsibility for orphan wells, the voluntary amnesty program, advice on best practices and costs of decommissioning, voluntary escrow of plugging funds, assumption of long-term liability after decommissioning, and reinvestment of escrowed funds without requiring a change in state regulations.

In the same way that the Canadian experience with oilfield reform offers lessons to the current challenge, so does the U.S. experience with reforms of coalfield decommissioning. The Surface Mining Control and Reclamation Act (SMCRA) passed in 1977 after years of contentious debate, and it created, among other changes, the Abandoned Mine Lands (AML) fund with taxes on production to help cover orphaned liabilities.

Although in retrospect it managed a degree of success,[36] the SMCRA suffered severe and extended setbacks during implementation. The federal government under President Reagan followed a Heritage Foundation outline to force "over fifty percent of [the responsible agency's] experienced personnel to leave the agency through firings, undesirable field transfers, and sheer intimidation" and to rewrite 90% of the rules previously written and upheld in court.[37] The biggest discrepancies and shortfalls came, though, from the lack of follow-through by individual states.[38]

Coal production grew steadily for over 30 years after the passage of the SMCRA, but when demand reversed and scores of coal companies filed bankruptcy, many sites—including over 600,000 acres in just seven states—sat unreclaimed, and financial assurance proved inadequate. (Fortunately, a national tax on coal provided for some of these orphaned liabilities.) It is interesting also to note that *post mortem* review found three dynamics that led to the systemic failure, and we note that all three exist in today's oil industry: inadequate bonding, isolation of liabilities in corporate subsidiaries or sales, and not clearly accounting for the reclamation liabilities in their balance sheets.

A national AWA/AWC achieves the most synergy at the lowest and most uniform cost to oil companies and provides for states with no financial option other than the general public. Isolation in an independent authority provides essential protection against both federal and state manipulation, as well as potential manipulation if the funds were given directly to private companies. As for concerns about relinquishment of states' power, it should be noted that, whether the AWA/AWC is implemented provincially or nationally, states would maintain all other aspects of state-level regulation. Indeed, many of the proposed reforms can be accomplished only at the state level. States would still collect their own taxes, set their own bonding requirements, regulate commercial transfers, regulate minimum standards to which wells must be plugged, and enforce those regulations. In fact, while serving as operator of orphaned wells, the AWA/AWC would be subject to the supervision of the states' regulators.

EFFECTS OF FULL ASSURANCE AND FEE

Assuming that the structure would accomplish the primary purpose of cleaning up oilfield infrastructure with funds from the oil and gas industry, then the question becomes how the incidental costs and benefits, especially the concerns of the oil lobby, compare to those primary benefits. The AWA/AWC concept would not directly affect government revenues, but it would move around a good deal of money and moving money around could affect oil companies' production (thus indirectly taxes and energy supply), consumers' prices, and communities' economies.

On oil companies, production, and drilling

In theory, increasing costs of production could reduce the supply and could, in turn, increase costs or decrease security of supply to consumers. However, the policy structure protects existing production. Further, practical and empirical data show that these concerns will have no material effect on future production.

Wells continue producing, in theory, as long as they continue making money, so the supply of oil and gas from existing wells would change if wells ceased to produce earlier. A fee of only a few percentage points would only affect a minute end of wells' economic life, the time when they produce the lowest volume and the least profit. As described above, the states' lowest producing wells combined contribute only a small percentage of production.

Moreover, to protect this sliver of economic activity, the lowest producing wells could be exempted from the fee below a given production rate. If the fee did not apply, for instance, below 20 Mcf/d, then it would cease to apply well before empirical, historical economic limits. Given the distribution of current production rates, the fee with a low-rate exemption would hardly affect the profitability of wells owned by small and large gas companies. So, it would neither decrease supply to consumers nor accelerate bankruptcy.

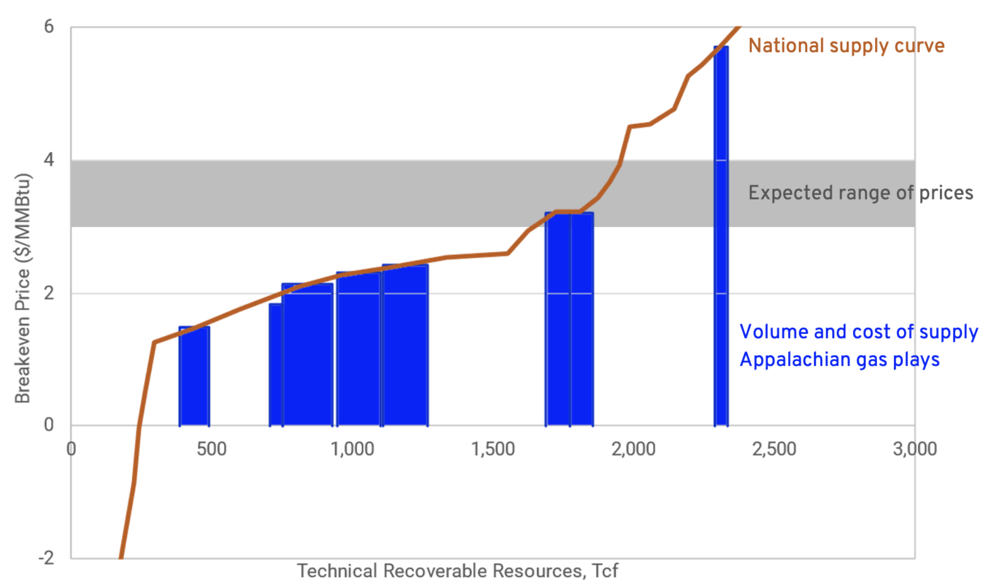
An increase in costs could, in theory, change future investment decisions and thus alter the overall supply of gas. New wells are drilled because they are expected to return sufficient profit. The proposal requires the modest cost of decommissioning up front and slightly reduces the revenue retained by drillers. It is possible that the combined effects would suffice to push some projects below the threshold of profitability and disqualify their drilling.

We have taken three approaches to test the effect of increased cost on the supply of gas: studies of macroscopic cost of supply, analysis of individual well returns, and studies of the effects of analogous policies.

Supply curve

If the price of a market commodity is set by the balance of supply and demand, then an increase in the cost of supply curve can increase that balance-point price. Consulting firm McKinsey & Company has published independent and widely-cited estimates of the gas supply curve showing what gas price justifies incremental drilling on average in various plays, and part of its most recent[39] is reproduced in Figure 3 below with an emphasis on Appalachian gas.

Figure 3: North American half-cycle break-even price for natural gas by McKinsey & Company.

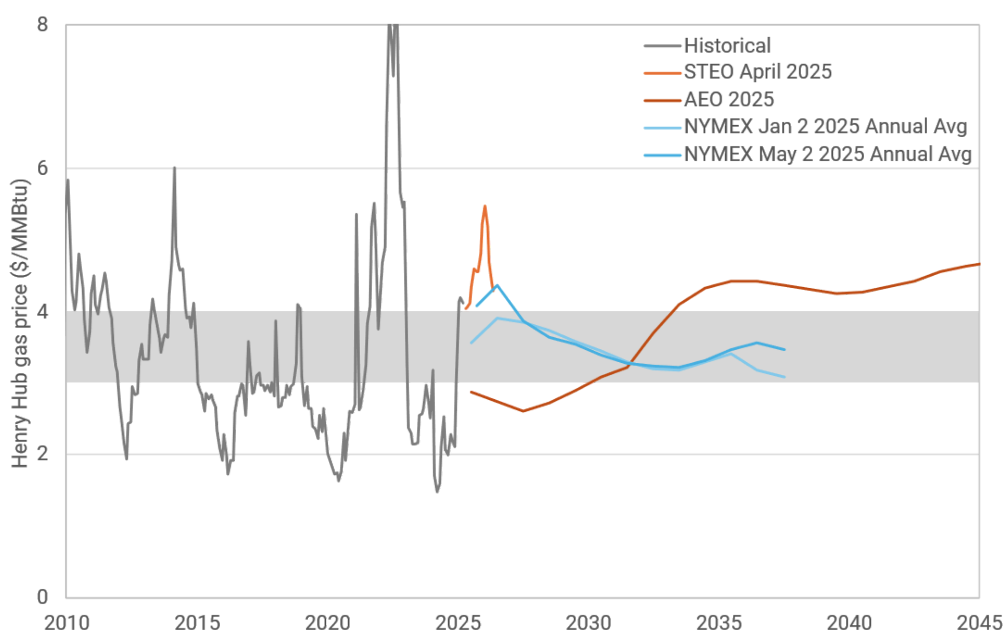


The orange line is the overall cost supply curve of technically recoverable resources available in the long-term, and the gray area shows a price range of $3.00 to $4.00 per MMBtu as highlighted in the original graph. The blue bars represent the price (y-axis) at which volumes (x-axis) in Appalachian can be economically produced. Some gas resources associated with oil plays remain economic even with negative gas prices; the oil production is so valuable that the wells would still be economically viable if they had to pay (instead of getting paid) to dispose of the gas. Among gas plays, the cheapest supply on the continent comes from Appalachia. They calculate that these states can provide hundreds of trillions of cubic feet for a break-even price of $2.43 or less plus one substantial play area with an average cost of $3.21. Of course, not all of this gas gets to market at once, so the marginal price is set not by the gas in the ground but by the gas that gets into the market.

A more recent analysis by oil-industry researchers describes a lower break-even gas price for the dominant Marcellus play in Appalachia.[40] It is not clear whether the stated prices represent wellhead prices received or benchmark prices, but on their face, the calculations show that the two core areas of the Marcellus achieve a 10% rate of return at about $1.80 /Mcf while its non-core area requires a little more than $3.00 /Mcf. Whether wellhead or benchmark, the authors find break-even prices in the same range as McKinsey, below expected market prices.

For comparison, the EIA's most recent Annual Energy Outlook[41] projects natural gas prices in the medium to long term in the same range based on its own econometric supply-and-demand model, and it calls mainly for prices below $3.00 or above $4.00. The 2023 Annual Energy Outlook, however, projected a reference case price with less swing, $3.07 in 2026 dipping then rising to $4.01 in 2042. The EIA also publishes a shorter-term and higher resolution price forecast monthly, its Short Term Energy Outlook (STEO).[42] Figure 4 below shows the agency's history of benchmark Henry Hub prices along with its short-term and long-term outlooks. We have also posted on the same chart the average futures contract prices for each year as settled on the New York Mercantile Exchange on the first day of trading of 2025 and of May 2025. These serve as a measure of the market expectations of future prices.

Figure 4: History and forecast of Henry Hub natural gas prices per EIA.



Projected prices consistently and significantly exceed expected break-even costs of drilling in Appalachia. A small increase in the cost of supply of Appalachian gas does not drive the market price of gas because Appalachia is generally not the marginal producer. Recent gas prices have been low enough that some companies are presently slowing work, but the work of McKinsey shows that gas companies can still, on average, drill and earn an excess return on most Appalachian plays at gas prices expected in the future. Of course, if drilling becomes temporarily uneconomic due to short-term dips, then the same drilling will likely become economic again when prices swing to the high side.

If levied at a national level, such a fee would affect the entire supply curve and could affect the supply of gas. Previous research has estimated that the change in drilling has been about 30% less than the driving change in prices.[43] Assuming the increased cost functions like a decreased price implies that a 5% increase in cost would reduce drilling by 3.5%, but the wells lost are the least productive, implying a lower change in supply.[44]

More important than a resolution fee, the prospect of increased exports of liquified natural gas (LNG) presents the greater possibility of further increases in market price. Using its same econometric model, the EIA calculated that increased exports could raise commodity prices by $0.54 to $1.04 over the Reference case shown above.[45] That is, increasing exports of natural gas is estimated to impact consumer costs far more than funding decommissioning. With or without decommissioning reform, increased exports have the potential to raise excess profits in the region.

Individual well returns

While McKinsey & Company and literature looked at averages across plays from a large-scale perspective, gas companies make analyses and decisions at a more granular level using more concrete internal data. For another test of the possibility of changes in supply, we examined and adapted the public statements of profitability made by gas companies in the region. Investor presentations may have incentive to overstate results, but they also have better data, better resolution, and theoretical accountability to investors.

Gas companies have long claimed that drilling generated extraordinary returns in the region, though the specifics have disappeared from investor presentations in recent years. Table 2 below attempts to put a wide variety of presentations of profitability into a more comparable form. It shows ranges of rates of return across various areas of the various plays, not other indicators of profitability. It also shows the returns only for a nominal gas price of $3.00 even though contemporaneous prices were often higher or lower. When the companies did not report returns at that price, we used the lowest price for which they reported returns, namely $4.00.

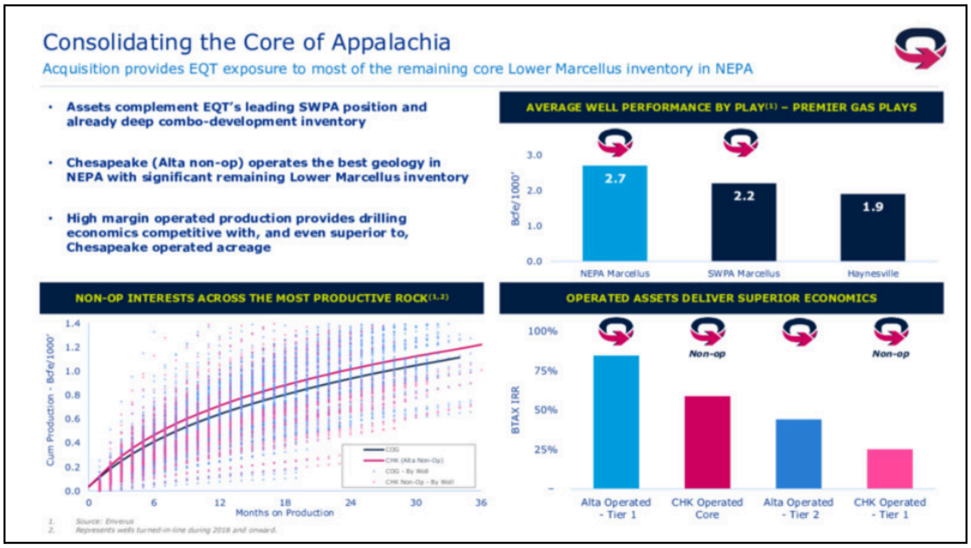
Table 2: Ranges of rates of return reported by public companies 2010 to 2021.

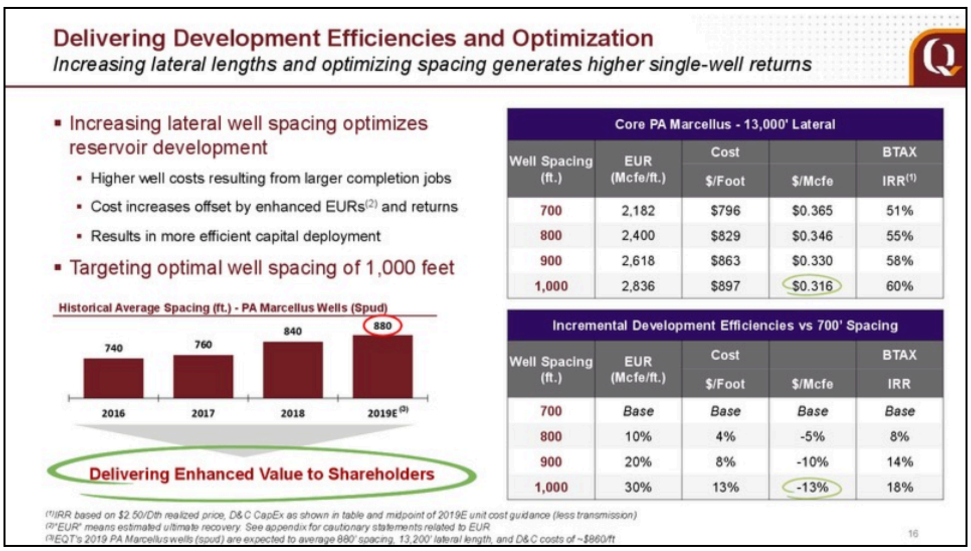
Rate of Return at $3.00 /MMBtu*

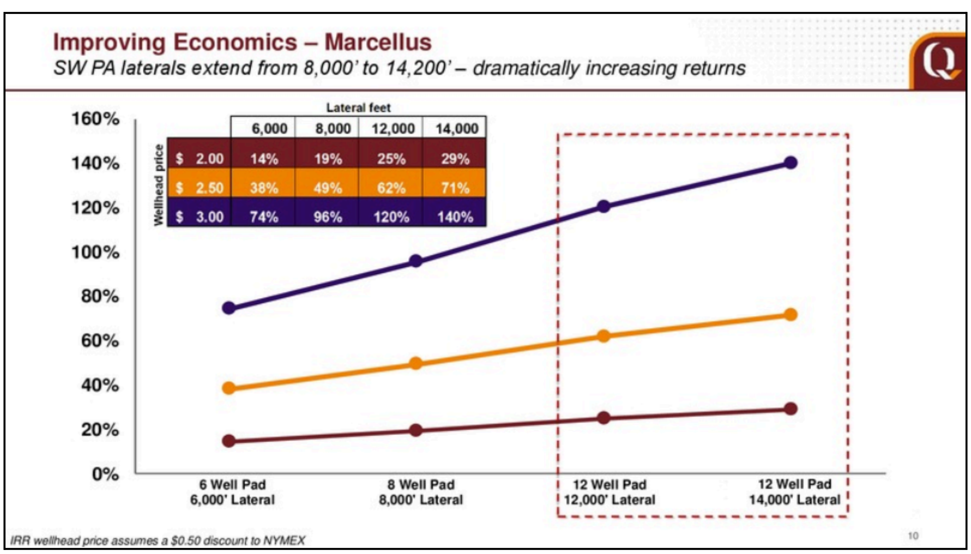
Year	Range Resources	EQT	Rice	CNX
2010	50% to 60%*			
2011	70%*	~60%		
	74%*	~45%		
	79%*	~25%		
2012	15% to 58%	~30%		
	15% to 77%			
2013	36% to 82%	~9% to ~65%		
	20% to 71%			
	23% to 71%			
	36% to 82%	~10% to ~100%		
2014	36% to 81%		7% to 57%	
	39% to 81%			
	84% to 104%*			
2015	85% to 104%*	~9% to ~50%	8% to 36%	
	39% to 147%*		8% to 32%	
	33% to 140%*	~20% to ~60%		
2016	26% to 42%	67%	42% to 49%	~65% to ~80%
	25% to 54%			
2017	52% to 55%	61% to 115%	72% to 92%	
		68% to 122%		
		68% to 137%		
2018	64% to 72%	60% to 140%		~80% to ~100%
				~65% to ~140%
2019	68% to 69%			
	54% to 61%			
2020				
2021		~25% to ~80%		

*$4.00 /MMBtu, lowest price reported

Figure 5: Examples of returns reported by EQT in investor presentations of (from top to bottom) May 6, 2021, April 25, 2019, and September 4, 2018. See Appendix A for examples of slides presented by the companies.





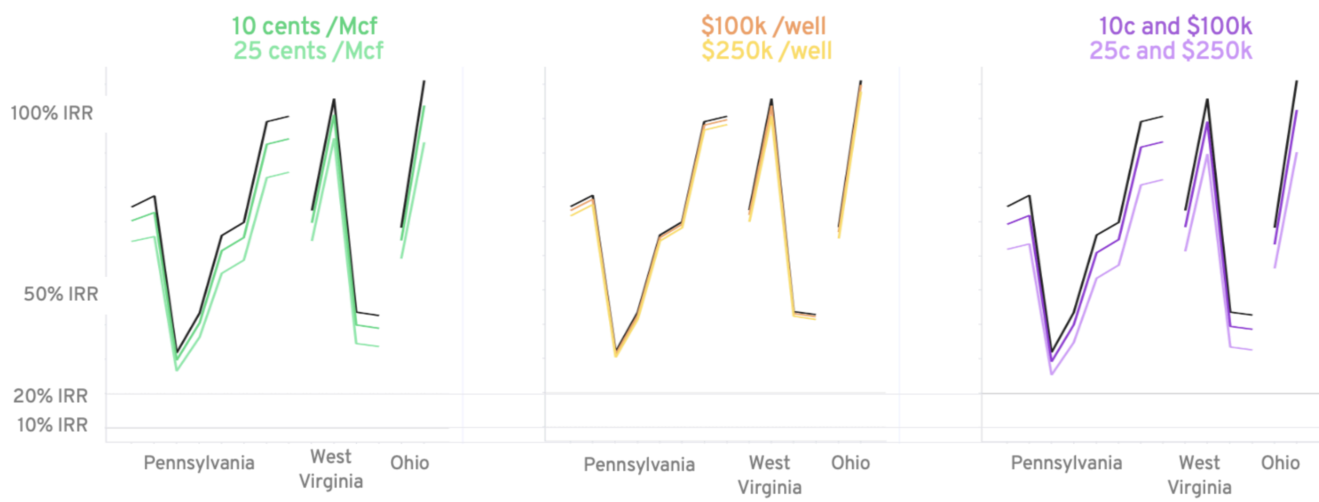


The returns vary with time as design and costs evolve, but they show consistently robust returns over historical development at the $3.00 low-side price of gas expected in the future. Similarly, Figure 5 shows three examples of statements of returns made by EQT from 2018 to 2021, and Appendix A includes a broader sample of returns reported by public gas companies in the region.

To evaluate the effects of a resolution fee and escrow cost on drilling returns and thus drilling activity, we reproduced then modified the most recent reported returns we found. CNX Gas Corporation provided detailed inputs to its economic calculations for eight areas over the two plays in 2018,[46] and we found these recoveries and returns to be compatible with those reported by other companies. We were able to reproduce the stated internal rates of return in standard economics software.

Since that time, relevant inputs have continued to evolve, but our work for this demonstration does not adjust for changes in costs, lateral length, spacing, or well productivity though costs in particular may have reduced returns in those years. We did, however, substitute a futures price array from the early part of this year that begins just over $3.00 and ends just below $4.00 in 2036 to bring the inputs more up to date. Then we added to the economics ranges of the types of costs outlined above, and Figure 6 shows the results.

Figure 6: Effect of decommissioning costs on returns for drilling of new wells.



In all three graphs, the black lines show our reproduction and update of the rates of return reported by CNX unburdened by fees discussed above. Each line shows the calculated returns in various areas and reservoirs of a single state. The colored lines represent the returns after consideration of extra costs, and each graph shows the effect of different costs. The left graph shows (in green) the effect of the cost per unit of production, the second graph shows (in yellow) the effect of full escrow at completion, and the last graph shows (in purple) the compound effect of both kinds of costs.

The figure shows that all of the base cases and all of the sensitivity cases calculate rates of return well above a minimum threshold. Most offer still-extraordinary rates of return from 50% to 100%. Thus, this extrapolation of previously self-reported returns suggests that, even with modest evolutions of some inputs over recent years, drilling in the three states remains profitable and that the range of proposed costs will not make new drilling uneconomic as prices move in the coming years.

On cost of energy to consumers, local economies, and employment

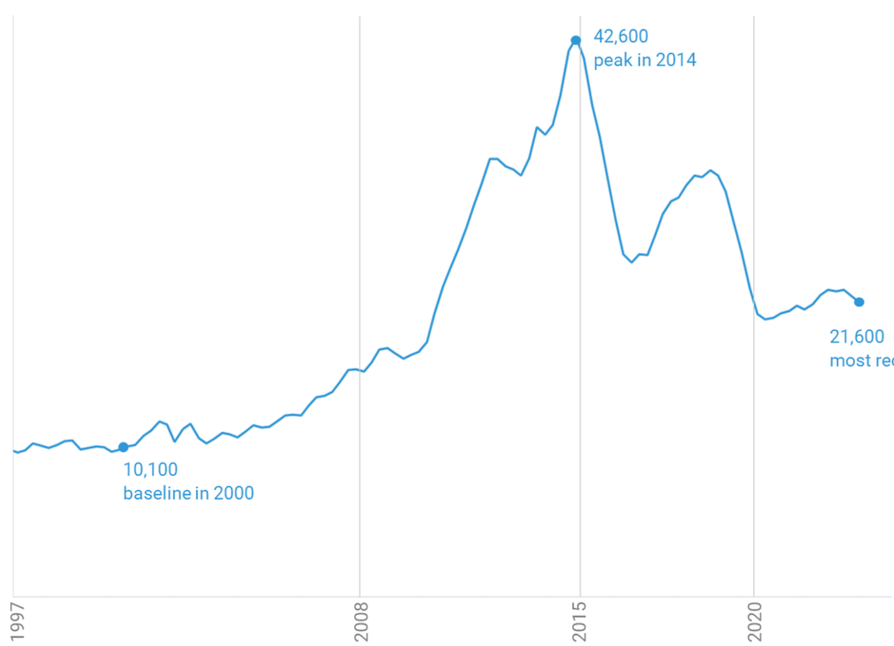
The policy has little to no effect on the cost of energy to consumers for precisely the same reasons that it has little to no effect on the supply of gas; price does not change when supply does not change.

Even if there is a societal cost by loss of production and employment, previous research attempted to scope the social costs (using the generalized elasticity of drilling to price changes described above) to the social benefits of decommissioning and found that when financial assurance is scaled appropriately, net social benefits outweigh net costs "[i]n the majority of plausible scenarios."[47]

The cost of the resolution fee is mostly not borne by local consumers because the large majority of the tariffed production is sold outside of the region. On the other hand, the money that is collected from remote purchasers of local production will be spent on local employment in the local economy.

Figure 7 below shows how employment in the upstream oil and gas industry in the three states has evolved. Employment was low and steady around 10,000 jobs before gas prices increased and the shale revolution began in the early 2000s. Rapid growth through 2014 peaked at 42,600 jobs in late 2014 but then reversed about as quickly and hit a minimum in late 2019 before the arrival of COVID and its closures. Unlike previous cycles, employment hardly moved during 2021 and 2022 when prices persisted above $4.00 /Mcf. By the third quarter of 2023, sector employment had declined by half from its peak and was beginning to trend down again even while total production from the peak maintained its all-time high. The secular decline and the lack of reversal with the recent price spike suggest that upstream employment is not likely to rebound in the foreseeable future.

Figure 7: Total upstream employment in the oil and gas industry in Pennsylvania, West Virginia and Ohio according to the U.S. Bureau of Labor Statistics.



By contrast, a large-scale program for decommissioning old wells would create significant local employment in many of the same communities. Annual reports of the economic impact of federal funds used for plugging wells determine the jobs created for the funds expended,[48] and the most recent calculation found a total impact of 10 jobs created by each $1 million spent. Using the ratio of direct to total wells from a previous report, the most recent analysis implies 3.6 jobs created directly for each million dollars. Spending $38.3 billion evenly over 20 years would translate to over 6,900 oil and gas jobs in each of those years, a 32% increase. What is more, it would result in over 19,000 jobs per year of total economic activity, and the work would be more steady and more predictable than the drilling rollercoaster from 2005 to 2020.

It is true that the same additional employment would be created if the decommissioning work were performed with public money instead of a fee on gas production. However, that public money would come from the same local and regional taxpayers, a closed loop of costs and benefits. A resolution fee takes money from gas company dividends to owners nationwide and, perhaps, distant buyers of the production. The best thing that policymakers can do to promote employment in the oil and gas industry is to create a new industry of well decommissioning, and the financial benefit to the state is much larger if the new investment comes from production fees rather than from public pocketbooks.

Effect of other policies

The theory of the impact of new costs on production (and thus energy supply and tax revenue) can be postulated with hypothetical calculations, but the best data comes from empirical studies of what actually happened in the past when costs were increased. Of course, the studies need to account for first-order drivers of activity, especially geology and commodity prices. Two studies examined a range of consequences of new policies that increase costs during the modern era,[49] and they arrive at consistent conclusions.[50] Some small companies exited the industry, but the effect on overall production was trivial while environmental performance of remaining companies improved. Other studies looked at the migration of drilling as a result and at the net social benefit, and those also arrived at consistent conclusions: Higher environmental costs create greater social welfare.

Effects on industry and public

Boomhower (2019) examined the effects of increased bonding in Texas in 2012 but especially in 2002; Lange & Redlinger (2019) examined the effects in 2012 of increased bonding and other costs in North Dakota. Both studies support the conclusion that these policies have little effect on overall production.

Boomhower provides an economic rationale for what to expect. He explained how bankruptcy law creates an economic advantage for small firms able and willing to compromise environmental protections, making them "judgment-proof" and creating a distortion in the market. Forcing more costs onto these structurally-advantaged companies should offset the advantage and send some out of business. However, his theory also predicts that the best producing wells in their portfolios should be transferred to larger companies.

The empirical data bore out both of these predictions. He observed that a number of small firms shut down after an increase in bonding requirements took effect but that most of their production was transferred to larger operators. The production that was shut-in was trivial to overall supply. On the other hand, the pace of well orphaning fell sharply, if temporarily, and the pace of citations by the state regulator for environmental violations also fell significantly. The companies that remained were better corporate citizens, at least in the short term. In the author's words:

> *"About 5 percent of producers left the market immediately. These exiting firms were small and had poor environmental records."*
>
> *". . .[T]he primary effect of the policy was to reallocate wells from small to large producers. The bond requirement moved about 4 percent of wells operated by the smallest 80 percent of firms to new operators. Another 1 percent of the wells operated by these firms were shut down, primarily representing low-producing wells where social cost. . .is most likely to exceed social benefit."*
>
> *"Environmental outcomes improved sharply."*
>
> *". . .[C]lear evidence of an approximately 70 percent decrease in orphan wells. . ."*

Lange & Redlinger (2019) built off of Boomhower and undertook a study of a change in bonding and, especially, the cost of handling drilling waste in 2012 in North Dakota.

When the new rules were passed, industry decried the burden. The president of the North Dakota Petroleum Council objected, "They are the most onerous regulatory changes we've ever seen." He specifically complained that the regulations are "now overly burdensome and among the most stringent and costly in the nation," with an estimated cost of up to $400,000 per well.[51] The regulator's assistant director agreed they were "the most significant changes we have made in the 31 years I've been with the Commission."[52]

Lange & Redlinger (2019) looked back at the two years of activity after the change compared to the prior two years, and in order to normalize for other factors, the authors compared activity around the states' border with Montana which did not have a corresponding change. Thus rigorously controlled for other variables, the authors conclude:

> *"Results find no statistical change in the pace of drilling wells after the [North Dakota] regulations came into effect."*

> *"The reduction in production for small operators in [North Dakota] after the regulation went in effect, relative to production in [Montana], is about 0.5%. The reduction in production from small operators seems to be coming from operator exit."*

The authors found that 8% of operators exited, but still the effect on drilling and production was trivial at best.

What is more, the authors also corroborated a statistically significant reduction in the number of environmental incidents in North Dakota[53] as was documented in Texas. They write without caveat,

> *"The regulation is associated with a level shift down in the number of incidents that occur while drilling, which is consistent with higher bond requirements encouraging better safety and exit of relatively unsafe operators."*

Social welfare

Despite the fact that setting bonding requirements to the level of the actual cost of reclamation is better for public welfare, jurisdictions have almost universally set their bonding requirements lower than the actual cost of reclamation. This fact may be explained by states setting policy to maximize revenue without regard to the costs associated with that revenue, [54] perhaps due to tax competition, in which one jurisdiction attempts to garner more immediate or more total investment by lowering the costs on producers by a couple of percentage points. However, research shows that if a jurisdiction does not need all possible revenue in the short term, then it is more appropriate and more sensible to consider the efficiency of the regulation, that is, the net effect of both increased revenues and increased costs.

Boomhower (2019) extrapolates his quasi-experimental results to the clear implication for policymakers:

> *"The results suggest that by screening out firms and wells that insurers perceived to be high risk, and increasing accountability for remaining firms, the bond requirement mitigated the harmful incentive effects created by bankruptcy protection. A back-of-the-envelope comparison of the value of avoided environmental damages and compliance costs suggests that the policy yielded substantial welfare gains."*

If, as shown in both the Texas and North Dakota studies, there is little or no change in the drilling activity or in production as a result, then the protections for the public have little or no cost to public tax revenues.

Quantitative analysis by Harleman (2018) put more numerical flesh on the bones by looking at the net social benefit in Pennsylvania of bonding up to $400,000 per horizontal well. His conclusions were similarly straightforward:

> *"By setting bonds to closely match reclamation costs, Pennsylvania would have to give up relatively little to prevent taxpayers from bearing reclamation and environmental costs. . . . In the majority of plausible scenarios, these benefits outweigh the wages and royalties paid to state residents that would be forgone if operators respond to increased bonds by drilling fewer wells."*

> *"State officials should set bonds equal to the best estimates of reclamation costs, and revise them when evidence on the true cost of reclamation becomes available."*

A more comprehensive analysis by the Federal Reserve Bank of Kansas City found that drilling is relatively inelastic to severance costs (a good proxy for the proposed cost here) and that increased revenues outweigh lost drilling in the short and medium terms.[55]

The authors examined the relative changes in drilling activity on either side of the borders of 17 states as severance tax changed on one side or the other during a 31-year history ending in 2015. Their theoretical foundation shows that, when normalized for geology, an increase in costs in one jurisdiction should cause a minor shift in drilling to the other side of the cost divide. The analysis corroborates their theory and prior work: The effect exists in the near term and that it is minor.[56]

> *"Numerical work. . .shows a highly inelastic relationship between oil production and severance taxes, assuming optimal production and exploration over time. More recent papers using detailed analyses of a single state also find that the effect of severance taxes is small. . ."*
>
> *"Our core econometric results show that oil drilling is inelastic with respect to severance taxes. . ."*

The implication for tax competition is stated mildly, "The policy implication is that state governments should use caution when considering the use of lower tax rates to attract more drilling from neighboring states." For a reasonable range of severance taxes, the increased revenue more than offsets the near-term decrease in drilling. In a generic example, the authors show that increasing severance tax from 4.6% to 6.6% would have the net effect of increasing revenue by 25% in the near term. Conversely, cutting severance tax reduces more revenue than it adds.

NATIONAL IMPLEMENTATION

Pennsylvania, Ohio, and West Virginia could each implement a statewide fee to resolve their own statewide problems. However, New York, Kentucky and most other states do not have the option to draw upon a fresh wave of high-value shale production to pay for the past wave of historical liability. A synergistic, national implementation of the fee could spread the costs of the national industry across national production and still keep the costs of the overdue intervention to a low level. Below we examine the well count, estimate the costs, and spread those costs across remaining reserves to estimate a national resolution fee. For simplicity, we estimate the fee on the assumption that it would cover decommissioning of all wells, old and new.

The estimate begins with the number of unplugged wells in the country, both active and inactive. The EIA reports each year the number of actively producing wells in most states, and we collected wellcounts directly from the remaining few states.[57] Available counts on inactive and unplugged wells were not readily available. We relied upon the peer-reviewed work of Williams, et al (2020) which determined by-state totals for inactive, plugged, and undocumented wells then reported its national average fraction of inactive wells only.[58]

To estimate the total cost of decommissioning these wells, we estimate the costs separately for non-shale and for shale horizontal wells. For the cost of non-shale wells, we look to the same recent report of the IOGCC.[59] In the absence of data from this source, we applied the national average (excluding Alaska). For horizontal shale wells, we assumed the low-side $261,000 per well derived above. Combining with the wellcounts leads to the rough estimate of $271 billion to decommission all of the existing wells in the country.

Lastly, we compile the reported reserves by state from the same EIA annual reserve report described above. [60] However, the reserves were not available separately for a number of states. For these, we assume that the reserves are too small to calculate a meaningful estimate of the fee.

Table 3 compiles the inputs described above and estimates a rough, higher side of what the resolution fee would need to be. The wellcount appears to include many wells of unknown condition which would not all need plugging. Plus, some bonds do exist, and many wells will be plugged by their operators. On the other hand, costs may turn out to be higher, and some of the plugged wells (uncounted) may need to be re-plugged in the future. Some of the reserves would come from stripper wells which would be excluded from the fee. On balance, we find it useful for discussion.

Of the 36 states with unplugged oil and gas wells, the calculations suggest concretely that five would require a fee greater than $10 per barrel of value equivalent[61] and implies difficulty in another 15 states. If these states could not implement an in-state fee because the wells produce such low rates, then about 30% of the national liability would remain for local taxpayers in major jurisdictions like California, Michigan, and Illinois.

However, if levied nationally, the calculation suggests that a fee of only $3.43 per barrel and $0.17 per Mcf could pay for decommissioning of all of the wells in the country.

Table 3: Estimation of a resolution fee by state and across the country.

	Unplugged Wells		Costs Per Well		Total Cost	Oil Reserves (million stb)		Gas Reserves (Bcf)		Cost per BOV	
State	**Non-shale**	**Horiz Shale**	**Non-shale**	**Horiz Shale**	**(billions)**	**Producing**	**Total proved**	**Producing**	**Total proved**	**Producing**	**Total proved**
Texas	708,536	82,455	$ 33,117	$ 261,000	$ 44.99	13,083	20,309	99,476	170,262	$ 2.49	$ 1.56
North Dakota	19,260	17,455	$ 208,376	$ 261,000	$ 8.57	3,400	4,965	9,661	12,982	$ 2.21	$ 1.53
Oklahoma	212,916	16,878	$ 21,203	$ 261,000	$ 8.92	1,297	1,830	28,602	41,771	$ 3.27	$ 2.28
New Mexico	86,320	12,099	$ 144,246	$ 261,000	$ 15.61	3,184	6,192	14,943	30,690	$ 3.97	$ 2.02
Pennsylvania	414,326	11,152	$ 85,291	$ 261,000	$ 38.25	36	68	71,504	106,311	$ 10.59	$ 7.10
Colorado	87,328	10,126	$ 80,711	$ 261,000	$ 9.69	784	1,442	15,480	22,586	$ 6.22	$ 3.77
Arkansas	13,248	5,492	$ 33,704	$ 261,000	$ 1.88	35	39	6,119	6,455	$ 5.51	$ 5.20
Louisiana	157,373	5,436	$ 73,551	$ 261,000	$ 12.99	290	446	18,799	40,296	$ 10.56	$ 5.28
West Virginia	*284,169*	*4,170*	*$ 117,490*	*$ 261,000*	*$ 34.48*	*85*	*174*	*30,890*	*50,932*	*$ 21.16*	*$ 12.67*
Ohio	133,600	3,129	$ 125,285	$ 261,000	$ 17.55	121	348	16,712	32,825	$ 18.35	$ 8.82
Wyoming	39,377	3,040	$ 11,955	$ 261,000	$ 1.26	866	1,072	13,530	15,261	$ 0.82	$ 0.69
Kansas	309,482		$ 10,634	$ 261,000	$ 3.29	307	335	3,029	3,151	$ 7.18	$ 6.68
California	*164,732*		*$ 182,029*	*$ 261,000*	*$ 29.99*	*1,220*	*1,492*	*906*	*1,070*	*$ 23.70*	*$ 19.40*
Illinois	*102,561*		*$ 47,988*	*$ 261,000*	*$ 4.92*	-	-	-	-	-	-
Kentucky	*69,987*		*$ 36,508*	*$ 261,000*	*$ 2.56*	-	-	-	-	-	-
Indiana	*45,063*		*$ 64,341*	*$ 261,000*	*$ 2.90*	-	-	-	-	-	-
Montana	37,816		$ 75,678	$ 261,000	$ 2.86	222	388	409	624	$ 11.80	$ 6.83
Utah	35,992		$ 37,435	$ 261,000	$ 1.35	280	634	2,853	3,668	$ 3.19	$ 1.65
Michigan	*32,266*		*$ 63,338*	*$ 261,000*	*$ 2.04*	*44*	*46*	*1,298*	*1,302*	*$ 18.77*	*$ 18.39*
New York	*26,345*		*$ 50,656*	*$ 261,000*	*$ 1.33*	-	-	-	-	-	-
Alabama	*20,421*		*$ 46,484*	*$ 261,000*	*$ 0.95*	*24*	*27*	*1,253*	*1,307*	*$ 10.95*	*$ 10.28*
Mississippi	*20,109*		*$ 80,000*	*$ 261,000*	*$ 1.61*	*102*	*113*	*201*	*250*	*$ 14.36*	*$ 12.82*
Virginia	*13,960*		*$ 66,640*	*$ 261,000*	*$ 0.93*	-	-	-	-	-	-
Tennessee	*10,406*		*$ 3,474*	*$ 261,000*	*$ 0.04*	-	-	-	-	-	-
Alaska	5,964		$ 3,551,354	$ 261,000	$ 21.18	2,703	3,357	121,796	125,238	$ 2.41	$ 2.20
Nebraska	5,158		$ 41,000	$ 261,000	$ 0.21	13	13	26,834	46,017	$ 0.16	$ 0.09
Missouri	*3,258*		*$ 5,200*	*$ 261,000*	*$ 0.02*	-	-	-	-	-	-
Nevada	*963*		*$ 66,640*	*$ 261,000*	*$ 0.06*	-	-	-	-	-	-
South Dakota	941		$ 66,640	$ 261,000	$ 0.06	9	9	-	-	$ 6.97	$ 6.97
Arizona	*932*		*$ 52,936*	*$ 261,000*	*$ 0.05*	-	-	-	-	-	-
Florida	*820*		*$ 66,640*	*$ 261,000*	*$ 0.05*	-	-	-	-	-	-
Washington	*734*		*$ 66,640*	*$ 261,000*	*$ 0.05*	-	-	-	-	-	-
Oregon	*557*		*$ 66,640*	*$ 261,000*	*$ 0.04*	-	-	-	-	-	-
Iowa	*189*		*$ 66,640*	*$ 261,000*	*$ 0.01*	-	-	-	-	-	-
Maryland	*15*		*$ 66,640*	*$ 261,000*	*$ 0.00*	-	-	-	-	-	-
Idaho	*14*		*$ 66,640*	*$ 261,000*	*$ 0.00*	-	-	-	-	-	-
Shale states (11)	2,156,453	171,432			$ 194.2	23,181	36,885	325,716	530,371	$ 4.92	$ 3.06
Non-shale states (25)	908,685	0			$ 76.5	4,924	6,414	158,579	182,627	$ 5.95	$ 4.92
Total (36 states)	**3,065,136**	**171,432**			**$ 270.7**	**28,105**	**43,299**	**484,295**	**712,998**	**$ 5.17**	**$ 3.43**
States >$10/BOV	**797,501**	**4,170**			**$ 82.0**	**1,475**	**1,852**	**34,548**	**54,861**	**$ 88.93**	**$ 73.57**
Number of states	**20**										

CONCLUSION

Pennsylvania, West Virginia and Ohio offer a case study and a cautionary tale. A long and successful history of oil and gas production has ended with hundreds of thousands of unplugged wells and tens of billions of dollars of private liability creating public risk. Little or no inherent market forces motivate oil companies internally to do the work. Still, weak policies and weak enforcement relied upon the good faith of oil companies. It is clear that these strategies are now succeeding hardly better than no policy at all.

The problem of funding decommissioning will not be solved by marginal revisions to policies that have so far fallen short. Other jurisdictions with smaller problems have made tremendous effort without material movement. So, it is time either to give up on the objective or to embrace some kind of transformational policy of taxing either the public or the industry. As it stands, the only option to protect the public health and pocketbook is to place a fee on shale production.

Fortunately, the costs and benefits of the options are clear. Not performing the work harms or risks harm to the public physically. Broad taxes to do the work hurt the public financially. A targeted tax on the remaining industry does hurt its profits, but it does not materially affect the work done, and it keeps a little more of the proceeds of the shale plays within the states and communities producing the gas. If public interests are the motivation and measure of policy, then the time for transformational policy has arrived, and the opportunity is worth tens of billions of dollars.

ENDNOTES

1. (Olalde, 2024; Schuwerk & Rogers, 2020a, 2020b)

2. (Purvis, 2023b, 2024; Purvis & Purvis, 2023)

3. (Boomhower, 2019; Spence et al., 2019)

4. The exception is the billions in federal funds dedicated in 2021's Bipartisan Infrastructure Law to empower and advance the state programs and the industry of decommissioning.

5. (Ho et al., 2016; IDLE AND ORPHAN OIL AND GAS WELLS: State and Provincial Regulatory Strategies, 2019; Naher et al., 2023)

6. (Bureau of Land Management, 2023)

7. (Olalde, 2024; Schuwerk & Rogers, 2020a, 2020b)

8. (Purvis, 2023a)

9. (Mccartney, 2024)

10. (Risk Management and Financial Assurance for OCS Lease andGrant Obligations Impact Analysis, RIN: 1010-AE14, 2024)

11. (Gibson & Schuwerk, 2024)

12. (Purvis, 2024)

13. (Castle, 2022)

14. (Purvis, 2024)

15. (Purvis, 2024)

16. (Purvis, 2024)

17. (Edwards, 2024)

18. (Transfer of Infrastructure and Liabilities—Assessment Criteria and Considerations Toolbox for State and Provincial Regulators, 2018)

19. (Olalde, 2024)

20. (Purvis, 2023b)

21. (Biven, 2021, 2022; Boettner, 2021; Boettner & Herzenberg, 2021)

22. Our concept of the role of the AWA/AWC may not exactly parallel the detailed prescription of previous proposals, and our concept could be differentiated as the Oilfield Resolution Trust Corporation (ORTC), named in reference to the RTC and intended to function as a single, unified, more independent entity. Nevertheless, we subsequently refer to the entity as AWA/AWC for continuity with prior proposals.

23. (Bang, 2023; Chalfant & Corrigan, 2019)

24. (Biven, 2022; Biven & Palacios, 2022; Peltz, 2023)

25. Note that this figure assumes that, unlike the proposal above, the fee also applies to stripper wells. We estimate that the difference is minor.

26. It may be advisable for some portion of the escrow funds to stay with the AWA/AWC so that it has the means to fund any work necessary if the plugging fails in the future.

27. (Biven & Palacios, 2022; Mitchell & Casman, 2011)

28. (Peltz, 2024)

29. (Purvis, 2022)

30. Given that the date criteria may apply to most or even all of the portfolios of many companies, it may be more practical as well as more equitable to apply amnesty to entire companies as the sole criteria instead of a secondary criteria.

31. A sketch of provisions is included as Appendix B.

32. (Weber, 2024)

33. (Graney, 2024)

34. (Jones, 2025)

35. (Yager, 2025)

36. (Yonk et al., 2019)

37. (Dunlap & Lyon, 1986)

38. (Desai, 1991; Dunlap & Lyon, 1986; McGinley, 2022)

39. (Dalena et al., 2022)

40. (Saputra et al., 2024)

41. (EIA Annual Energy Outlook, 2025)

42. (Short-Term Energy Outlook—U.S. Energy Information Administration (EIA), April 2025)

43. (Newell et al., 2019)

44. (Harleman, 2018)

45. (AEO2023 Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market, 2023)

46. (CNX Gas Corporation, 2018)

47. (Harleman, 2018)

48. (Bipartisan Infrastructure Law Projects in Four Programs Support over 28,000 Jobs and $3.3 Billion to the Economy in Fiscal Year 2024, 2024; Bipartisan Infrastructure Law Projects in Three Programs Support an Average of 17,669 Jobs and $2.0 Billion to the Economy in Fiscal Years 2022 and 2023, 2023; Braybooks, 2023)

49. (Boomhower, 2019; Brown et al., 2018a; Lange & Redlinger, 2019a)

50. It may be noted that a fourth analysis came to contrary results, but it did not account for the fact that the new costs corresponded to a 13-year low in gas prices. (Kim & Oliver, 2017) A subsequent analysis tested the effect of prices and found that they—not the increased costs—explained the drop in activity. (Black et al., 2018)

51. (MacPherson, 2012)

52. (Lange & Redlinger, 2019b)

53. No data was available for comparison to Montana.

54. (Yang & Davis, 2021)

55. (Brown et al., 2018b)

56. The authors do not examine the effect of an increase in severance tax on the total number of wells or volume of production ultimately produced, only on near-term interstate competition. So it is most relevant to jurisdictions focused on maximizing near-term revenue and not long term revenue.

57. (About Oil And Gas In Illinois, n.d.; Missouri Department of Natural Resources, n.d.; Oregon Department of Geology and Mineral Industries : Mineral Land Regulation & Reclamation : Mineral Land Regulation and Reclamation : State of Oregon, n.d.; The Distribution of U.S. Oil and Natural Gas Wells by Production Rate with Data through 2022, 2023; Illinois Department of Natural Resources, n.d.; Williams et al., 2020)

58. (Williams et al., 2020)

59. (IDLE AND ORPHAN OIL AND GAS WELLS: STATE AND PROVINCIAL REGULATORY STRATEGIES Supplemental Information on Orphan Well Plugging and Site Restoration, 2024)

60. (Energy Information Administration, 2024)

61. Barrels of value (BOV), using 20 Mcf equivalent to 1 barrel of oil based on long-term pricing equivalence.

APPENDIX A: EXAMPLES OF EXPECTED RETURNS FROM INVESTOR PRESENTATIONS

[Click here to view & download.]

APPENDIX B: SKETCH OF PROVISIONS FOR AN AMNESTY PROGRAM

An amnesty program could be easily exploited or defrauded, and prevention will require tight rules strictly enforced, such as the following:

Defined point in time: Both the size and scope defined at a single point in time before the bill was widely known. Regulatory filings can be used to establish the date a well was spud, drilled, or began production. For limitations related to the nature of the company, the assignment to the AWA/AWC must include all interests, in all wells, in all affiliates on an as-of date before companies have had enough time to manipulate their ownership structure.

Size of the company: The program could be available only to small companies who might have gotten into the situation accidentally. Size can be used as a proxy for sophistication, and the threshold could be defined by:

a. number of unplugged wells. Perhaps somewhere between 50 and 200.
b. production or revenues over the previous 12 calendar months. This threshold could provide amnesty to companies with hundreds of idle wells.
c. number of employees. SBA defines "small" oil company as fewer than 1,250 employees which is far too high to be unsophisticated. A threshold of 10 or 20 wells would apply to a large number of companies.

Nature of company ownership: A combination of Secretary of State filings, federal tax returns, and submission of private documents might suffice to determine whether a company is owned by individuals or by other corporate or investment vehicles.

Offered only once: Companies have only one opportunity to apply, and that window is open for only 9 to 12 months. If only the drill date criterion is used, then the window could be opened to two or three years without increasing the risk of manipulation.

Warranty in assignment: In the assignment, the owners must warrant that they understand and meet all of the criteria, subject to rejection and/or punitive fines and/or criminal prosecution for lying to the federal government.

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