Bonding Requirements for Oil and Gas Wells in Pennsylvania: Cost-Based Recommendations

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1 June 2021

BONDING REQUIREMENTS FOR OIL AND GAS WELLS IN PENNSYLVANIA: COST-BASED RECOMMENDATIONS

A REPORT TO THE PENNSYLVANIA ENVIRONMENTAL QUALITY BOARD

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Bonding Requirements for Oil and Gas Wells In Pennsylvania: Cost-Based Recommendations

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Executive Summary

Pennsylvania law requires that all oil and gas well operators properly decommission their wells at the end of the well's useful life, an act often referred to as well plugging. Since 1985, it has also required that operators set aside money, a bond, before drilling so as to guarantee funds for the well's plugging. The law sets bond amounts but gives the Pennsylvania Environmental Quality Board (EQB) the authority to adjust amounts "every two years to reflect the projected costs to the Commonwealth of performing well plugging."[2]

From 1989 to 2020, the Commonwealth has paid to plug more than 3,000 wells, spending $15,100 per well on average and a minimum of $3,400 per well. By comparison, the current bond amount for a conventional well is $2,500 for an operator with few wells and, because of blanket bond provisions, $250 for an operator with 100 wells. Using data on the wells the Commonwealth has paid to plug, this report projects the cost to the Commonwealth of plugging wells in the future and makes three recommendations to the Environmental Quality Board:

1. **Adjust the bond amount to $25,000 per conventional well and $70,000 per unconventional well for the 2021-2022 period.** These amounts match projected plugging costs for a well plugged in this period and, under current law, should apply to new wells and wells drilled after April 17, 1985. The projected cost for conventional wells is based on the historical cost incurred by the Commonwealth and the observed growth rate in plugging costs. It is also consistent with what a major operator paid to plug its own wells in the 2018-2020 period. Costs to the Commonwealth, however, will likely be higher if future plugging contracts cover fewer wells than they have historically. The unconventional well amount is based on cost relationships observed in the data and differences in the characteristics of conventional and unconventional wells.
2. **Revisit bond amounts every two years to consider new information on plugging costs and to update bond amounts accordingly.** Plugging costs rose over the last three decades, growing 3.2 percent per year after accounting for inflation and changes in the types of wells being plugged. In addition to a general rise in costs, changes in the types of wells that are being plugged and the scale of plugging can also affect projected costs. Periodic consideration of new information is especially important for unconventional wells for which there is currently limited publicly available data on plugging costs.
3. **Discontinue the use of blanket bonds or bond caps.** Blanket bonds or caps create a large discrepancy between the projected cost of plugging and bond amounts. Moreover, financially secure operators already pay less to meet bond requirements in the form of lower rates charged by private insurers ("sureties").

Current bond amounts expose the Commonwealth to the risk of having to pay plugging costs for many wells. If adopted, the recommended amounts ensure that well operators bear the full financial responsibility of plugging their wells. This will continue to be the case if the Environmental Quality Board reconsiders bond amounts biennially using updated cost projections.

Adjusting bonding amounts will also encourage and enable more plugging, which restores well sites to alternative uses and reduces the risk that unplugged abandoned wells leak methane, oil, brine, or metals-rich liquids into their surroundings. This will free residents and municipalities to farm, build, or

[2] 58 Pa. Cons. Stat. § 3225.

simply enjoy the full extent of their land unencumbered by tanks, pipes, or contamination and the associated risks. This will benefit local economies as properties appreciate in value and the tax base expands.

The recommended adjustment to unconventional well bonds would increase operator costs by one-fifth of the cost of the unconventional well Impact Fee. The adjustment for conventional wells is smaller in absolute terms but might cause some wells to shift to more financially secure operators.

Introduction

Since 1921, the Commonwealth of Pennsylvania has required that oil and gas well operators decommission their wells when abandoning them.[3] Subsequent enforcement was limited and operators abandoned many wells over the rest of the 20th century without proper decommissioning, in part because of energy price drops that left operators without money to continue in business and plug old wells.[4]

Since 1985, the Commonwealth has required that an operator set aside funds, known as bonds, before drilling. The Commonwealth releases the operator from the bond requirement once the operator properly decommissions the well, which involves restoring the well site and filling the well with cement, an activity often referred to as plugging.[5] Most oil and gas producing states have bond requirements so as to encourage compliance with the law and to fund plugging when an operator is financially unable to do so.[6] Bonds therefore act as insurance that protects state governments and taxpayers from having to pay for plugging when operators become financially distressed.

Pennsylvania law gives the Environmental Quality Board the authority to adjust bond amounts "every two years to reflect the projected costs to the Commonwealth of performing well plugging."[7] The statement recognizes that unplugged wells abandoned by defunct operators become the responsibility of the Commonwealth, which then has to pay for plugging. It also recognizes that the bond amount should match the cost of plugging, so that operators—not the Commonwealth and its taxpayers—pay for plugging.

From 1989 to 2020, the Commonwealth paid to plug more than 3,000 wells. Using the associated cost data, this report projects the cost to the Commonwealth of plugging wells in coming years and makes three recommendations to the Environmental Quality Board. First, the Board should adjust the bond amount to $25,000 per conventional well and $70,000 per unconventional well for the 2021-2022 period. The amounts match projected plugging costs for a well plugged in this period and, under current law,

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[3] Act 322 of 1921 introduced the first plugging requirements for gas wells. Similar requirements for oil wells had existed since the late 1800s. 58 Pa. Con. Stat. § 3203 defines an abandoned well as "any well that has not been used to produce, extract or inject any gas, petroleum or other liquid within the preceding 12 months, or any well for which the equipment necessary for production, extraction or injection has been removed, or any well, considered dry, not equipped for production within 60 days after drilling, redrilling or deepening, except that it shall not include any well granted inactive status."

[4] Weber, McClure, and Simonides, *The Boom, the Bust, and the Cost of Cleanup: Abandoned Oil and Gas Wells in Pennsylvania and Implications for Shale Gas Governance*.

[5] Through the rest of the report, I will use "plugging" to refer to all that is involved in decommissioning a well according to state standards.

[6] Davis, *Policy Monitor—Bonding Requirements for US Natural Gas Producers.*

[7] 58 Pa. Con. Stat. § 3225.

should apply to new wells and wells drilled after April 17, 1985. Second, it should revisit bond amounts every two years to consider new information on plugging costs and to update bond amounts accordingly. Plugging costs rose over the last three decades, growing 3.2 percent per year after adjusting for inflation and changes in the types of wells being plugged. Lastly, the Board should discontinue the use of blanket bonds or bond caps because they create a discrepancy between bond amounts and projected plugging costs.

By encouraging and enabling more well plugging, adjusting bond amounts will reduce the risk that abandoned wells leak methane, oil, brine, or metals-rich liquids into their surroundings. Abandoned wells have also been shown to discourage building in their vicinity. Well plugging and site restoration frees local residents and property owners to farm, build, or simply enjoy the full extent of their land unencumbered by tanks, pipes, or contamination and the associated risks. This has broad benefits for local economies in the form of higher property values and a larger tax base.

The recommended adjustment to unconventional well bond amounts would increase operator costs by far less than did the unconventional well Impact Fee, which the Commonwealth introduced in 2012 and applied retroactively to all unconventional wells.[8] Despite increasing costs by more than would the recommended bond adjustment, the Impact Fee had imperceptible effects on drilling and production. The recommended adjustment for conventional wells is smaller in absolute terms but might cause some wells to shift to operators that are more financially secure.

In the next sections, the report explains the purpose of plugging wells, the role of bonding, and current bond policy. It then presents the methods, data, and findings for the projected cost to the Commonwealth of plugging wells in the 2021-2022 period. The final sections address the role of blanket bonds, the wells to which adjusted bond amounts should apply, and the likely effects of the adjusted amounts on the oil and gas industry in Pennsylvania.

The Purpose of Plugging

Unplugged abandoned wells create a pathway for subsurface gases or liquids to migrate into groundwater, the soil, or to the surface. Deterioration of the steel casing surrounding a well bore—or the cement surrounding the casing—opens this pathway for migration.[9] Plugging wells and restoring their sites addresses problems caused by wells already leaking and constraining land use. It also largely eliminates risk from wells that may cause damage in the future, a risk that grows as wells age and their steel and concrete deteriorate.

Several studies and cases illustrate the health risks posed by unplugged abandoned wells and therefore the benefit of plugging them. Water in and around unplugged wells can contain pollutants, such as barium, chloride, and arsenic.[10] In a sample of 46 abandoned wells discharging water on the Navajo

[8] 58 Pa. Con. Stat. § 3225.

[9] Alboiu and Walker, *Pollution, management, and mitigation of idle and orphaned oil and gas wells in Alberta, Canada*.

[10] Woda et al., *Methane concentrations in streams reveal gas leak discharges in regions of oil, gas, and coal development.*

Nation, 15 wells had water with levels of arsenic above EPA standards.[11] Arsenic is a carcinogen and even short-term exposure can harm health.[12] Further, methane leaking into groundwater can create foul-smelling and toxic hydrogen sulfide when it oxidizes.[13] The potential for groundwater contamination is illustrated by a study of oil-and-gas-related groundwater contamination events in Texas and Ohio. The study found that unplugged abandoned wells accounted for 14 percent and 22 percent, respectively, of contamination events over the study period, generally the 1980s through the early 2000s.[14]

Unplugged abandoned wells also leak gases into the air, particularly methane. Emissions of methane can harm air quality when methane oxidizes and creates ozone. Ozone is harmful when inhaled, causing damage to the heart and lungs and worsening chronic conditions such as asthma.[15] Further, if methane leaks into enclosed spaces it can cause an entire house to explode, though this is not common.[16] Globally, methane is a potent greenhouse gas, with roughly 30 times more warming potential than carbon dioxide over 100 years and as much as 87 times higher over 20 years.[17] A study of methane leaks from abandoned oil and gas wells in Pennsylvania found that such wells account for as much as seven percent of the annual anthropogenic methane emissions in the Commonwealth. To put the number in perspective, it is equivalent to the annual greenhouse gas emissions from 200,000 to 250,000 passenger cars.[18]

In addition to the environmental and health risks, unplugged abandoned wells take up space and are an eyesore on the landscape, appearing as uncultivated or unmowed islands in fields or backyards. Wellheads, which are made up of pipes and valves, often extend about six feet into the air and can be accompanied by metal tanks, pipes, and pumps, all of which are removed as part of plugging. By removing well equipment and the risks associated with an open well, plugging expands land-use possibilities for the surrounding acreage. A recent study found that, over nearly fifty years, there was roughly twice as much building activity in the two acres surrounding wells that were plugged compared to the two acres surrounding wells that were not plugged.[19] This illustrates how unplugged wells constrain or deter local residents from fully using their property.

Forgoing construction on and investment in land with unplugged wells has broad implications for community well-being because it suppresses the local tax base that funds local schools, roads, and other services. The same study estimates that by depressing investment, an unplugged well reduced the market value of the typical surrounding property by around $22,000 (12 percent). In the case of the school district in the study area with the most abandoned unplugged wells—McGuffy School District—this tax base

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[11] U.S. Environmental Protection Agency, *Technical Memorandum: Investigation of Abandoned Wells on Navajo Nation*.
[12] U.S. Environmental Protection Agency, "Drinking Water Standard for Arsenic."
[13] Dusseault, Jackson, and MacDonald, *Towards a Road Map for Mitigating the Rates and Occurrences of Long-Term Wellbore Leakage;* U.S. Department of Labor, "Hydrogen Sulfide".
[14] Kell, *State Oil and Gas Agency Groundwater Investigations*.
[15] *Nuvolone, Petri, and Voller, The effects of ozone on human health*.
[16] Quinton, "Why 'Orphan Oil and Gas Wells Are a Growing Problem for States."
[17] U.S. Environmental Protection Agency, "Understanding Global Warming Potentials."
[18] Kang et al., *Direct measurements of methane emissions from abandoned oil and gas wells in Pennsylvania.*
[19] Harleman, Weber, and Berkowitz, *Environmental Hazards and Local Investment: A Half-Century of Evidence from Abandoned Oil and Gas Wells.*

effect translates into $112 less school revenues per student each year.[20] The forgone revenue across all schools and local governments in the county exceeds $500,000 annually.[21]

The Purpose of Bonds

Oil and gas operators are legally bound to plug their wells when they abandon them, and the Pennsylvania Department of Environmental Protection can fine operators that do not comply with plugging requirements. Fines, however, are meaningless when applied to operators that have dissolved or have no means to pay them. The upfront nature of bonds avoids this problem. Because operators post bonds as a requirement for receiving a permit to drill a new well, the bond amount is secured even if the operator later falls into financial distress. Bonds, therefore, act as an insurance policy that protects the Commonwealth from having to use public revenues to pay an operator's plugging liabilities.

The history of oil and gas development and policy in Pennsylvania underscores the value of such insurance. The Commonwealth has had plugging requirements for both oil and gas wells since the 1920s, and enforcing the requirements became easier in 1955 when the Commonwealth added permitting requirements, which allowed it to establish each well's location and ownership. Despite those policies, an estimated 20 percent of wells drilled between 1955 and 1984 (when bonding requirements were introduced) were abandoned without plugging.[22] Many of these wells will likely become the responsibility of the Commonwealth to plug.

For the Commonwealth and its taxpayers to fully avoid the burden of plugging costs, the bond amount must cover plugging costs on average.[23] Some wells will cost more than the average and others less, but if set correctly, the savings from cheap wells will cover the extra costs of expensive wells. If instead the bond amount is below average plugging costs, the Commonwealth's plugging program will run a deficit and require another revenue source to cover its costs.

Current Bond Amounts

The law governing both conventional and unconventional wells states that bond amounts "may be adjusted by the Environmental Quality Board every two years to reflect the projected costs to the Commonwealth of plugging the well."[24] Moreover, the law governing bond amounts for conventional wells directs the Environmental Quality Board to "undertake a review of the existing bond requirements for conventional oil and gas wells."[25]

[20] Ibid.
[21] This estimate is based on the analysis in Harleman, Weber, and Berkowitz but not reported in the paper.
[22] Weber, McClure, and Simonides, *The Boom, the Bust, and the Cost of Cleanup: Abandoned Oil and Gas Wells in Pennsylvania and Implications for Shale Gas Governance*.
[23] Setting bond amounts equal to average plugging costs would not be appropriate if operators were more likely to leave high-cost wells unplugged. This is possible but hard to establish.
[24] 58 Pa. Con. Stat. § 3225.
[25] 72 P.S. § 1606-E.

Current bond amounts, however, are the unadjusted amounts initially specified by law. The law currently requires a $2,500 bond for each conventional well drilled on or after April 18, 1985.[26] In lieu of the $2,500 per well bond, the law allows operators to post a "blanket bond" of $25,000.[27] This allows operators with more than 10 wells to post a smaller total bond using a blanket bond instead of a per well bond. With 100 wells, for example, an operator would post $250 per well[28] instead of $2,500 per well.

In the late 2000s, operators began drilling more and more wells in the Marcellus and then Utica shale formations. Exploiting the formations required unconventional methods, namely horizontal drilling and hydraulic fracturing, and such wells became known as unconventional wells. In 2012, the Commonwealth adopted laws specific to unconventional wells. The law currently sets a $10,000 bond for each unconventional well, but also caps the total bond amount for an operator with many wells, with the cap acting as a type of blanket bond.[29] The caps vary with operator size. An operator with 50 wells need only post $290,000 in bonds, or $5,800 per well.[30] An operator with more than 150 wells need only post $600,000. Thus, an operator with 240 unconventional wells faces a per well bond amount of $2,500.[31]

Well operators can satisfy bond requirements in different ways, including a corporate surety bond or a deposit of cash, certificates of deposit, or U.S. Treasury bonds.[32] A surety bond acts like an insurance policy. In general, the operator pays an insurer (the surety) a percent of the bond amount each year, and the surety agrees to pay a third party (in this case the Commonwealth) the bond amount if conditions specified in the bond are met (in this case the failure of the operator to plug its well). The rate a surety elects to charge and the bond amount determine the cost of the bond incurred by the operator. At a 5 percent rate, a $10,000 bond costs an operator $500 each year.[33] Rates depend on an operator's financial health, with more financially secure firms facing lower rates and therefore lower costs to satisfy the same bond requirement.

Methods for Projecting Plugging Costs for 2021-2022

The focus of this report is projecting the per well plugging cost that the Commonwealth is likely to incur from plugging wells in the 2021-2022 period. The projection, in turn, is to aid the Environmental Quality Board in adjusting bond amounts to match the projected costs to the Commonwealth of performing well plugging. This section explains the methodology used to project this cost.

Conventional Plugging Costs

To project the cost of plugging a conventional well in the 2021-2022 period, I start by calculating the sample average cost per well for plugging from the 1989–2020 period (in 2020 dollars). This is the

[26] 25 Pa. Code § 78.302.
[27] 72 P.S. § 1606-E.
[28] $25,000/100 wells.
[29] Bond amounts are less for unconventional wells with a total bore length less than 6,000 feet, which applies to few if any unconventional wells since they are generally greater than 6,000 feet in vertical length in addition to several thousand feet in horizontal length.
[30] $5,800 = $290,000/50 wells.
[31] $2,500 = $600,000/240 wells.
[32] 52 Pa. Con. Stat. § 3225.
[33] 0.05 x $10,000.

total cost across all contracts divided by the total number of wells plugged. It would be a reasonable projection of average plugging costs in 2021-2022 if inflation-adjusted costs were constant over time, but they are not—costs have consistently risen over time. To project costs for 2021-2022, I estimate the growth rate in plugging costs using a regression model to account for changes in the location and types of wells being plugged over time. I then apply the estimated growth rate in plugging costs to the sample average well, which was plugged in 2005. See Appendix A for estimation of the growth rate and the calculation of the projected cost.

The key assumption of this approach is that the average well that *has been* plugged by the Commonwealth has characteristics similar to those of the average well that *will be* plugged by the Commonwealth, at least when considering characteristics that affect plugging costs. I test this assumption in two ways. First, I compare the projected cost of plugging a conventional well with the plugging costs incurred over the 2018-2020 period by a large operator of conventional wells in Pennsylvania. Second, I compare the characteristics of wells plugged by the Commonwealth with those of conventional wells drilled over the 2010-2018 period.

Unconventional Plugging Costs

Unlike the case of conventional wells, the Commonwealth of Pennsylvania has plugged no unconventional wells, nor am I aware of other states in the Appalachian basin that have done so. This is because unconventional gas wells, also known as shale gas wells, are relatively new to the region, having only been drilled on a large scale starting in the late 2000s. Private plugging of unconventional wells in Pennsylvania has occurred, but the associated cost data is not publicly available. If collected moving forward, this information could inform future decisions by the Environmental Quality Board.

The cost of plugging conventional wells in Pennsylvania may nonetheless provide a reasonable foundation for estimating unconventional costs. The Commonwealth applies similar plugging regulations to both well types. In coal areas, for example, regulations for both wells require a 200-foot section of cement around the bottom of the surface casing, followed by sections of cement and non-porous material through the rest of the vertical portion of the well bore.[34] Firms plugging both conventional and unconventional wells in Pennsylvania will also face similar material and labor costs.

Given the similarity in plugging regulations and prices for materials and labor, I follow the same methodology for unconventional wells as for conventional wells with one difference. I adjust the sample average plugging cost before applying the growth rate in costs. The adjustment accounts for two large differences between sample conventional wells and unconventional wells. First, unconventional wells are deeper than the average conventional well plugged from 1989 to 2020, which increases costs. Second, essentially all unconventional wells in Pennsylvania are gas wells, which historically have cost more to plug than oil wells. See Appendix B for details on the adjustments and regression model used to assess the effect of depth and well type on plugging costs.

[34] 25 Pa. Code § 78.92(b) and § 78a.92(b). In the case of an unconventional well whose bore extends horizontally, the operator must then place a mechanical plug to block off the vertical part of the well from the horizontal part.

Data

The Pennsylvania Department of Environmental Protection (DEP) provided a dataset with all wells that it has paid to have plugged since 1989, when it plugged its first well, through November of 2020. The dataset contains 3,134 wells and includes, among other variables, the well permit number, the contract number, and the total cost of the contract under which the well was plugged. I put all contract costs in 2020 dollars using the Consumer Price Index (CPI-U). I exclude 35 out-of-scope wells for reasons described in Appendix C, leaving 3,099 wells covered by 255 contracts.

The DEP dataset does not include each well's depth, which is a determinant of plugging costs. To assign depth to each well, I combined an additional DEP-provided dataset of the location of DEP-plugged wells with geospatial data from the Pennsylvania Department of Conservation and Natural Resources (DCNR) on oil and gas fields and pools, which includes each pool's average producing depth.[35] I mapped the DEP-plugged wells over the DNCR pools and assigned to each well the average depth of the pool in which it is located. In doing so, I estimated the depth of 3,060 wells covered by 226 contracts.

Using the well permit number in the DEP plugging data, I added two variables from other state data sources. These were the earliest year when the well appeared in any state records, which is a rough measure of when the well was drilled, and an indicator for whether the well was in a coal region. Older and more deteriorated wells are generally more expensive to plug. Wells in coal regions can also involve different plugging practices, which can affect costs. Incorporating the additional variables improves parts of the analysis by better accounting for differences in well characteristics that can affect cost. For example, it aids in estimating the growth rate in plugging costs apart from changes in the types of wells being plugged over time. The additional variables, along with the depth variable, are available for 3,040 wells from 211 contracts.

The data described above are used to create a contract-level dataset, which is the basis of the analysis. This is a practical necessity because DEP plugging contracts generally only have a total cost for the entire contract, not a unique cost for each well. Because the focus of this report is on the typical well, not the typical contract, I weight contract values by the number of wells in the contract, so that the resulting statistics represent the average well.[36] By comparison, the average of unweighted contract values reflects the average contract.

Values presented in the report reflect the largest sample of wells and contracts possible. Thus, the simple average cost per well is based on the largest sample of 3,099 wells (255 contracts). The average cost per foot of depth is based on the 3,060 wells (226 contracts) for which depth data are available. Analysis involving the two additional well variables uses 3,040 wells (211 contracts).

[35] The oil and gas pool geospatial data can be found by searching the DCNR's elibrary at www.dcnr.pa.gov/ELibrary/Pages/default.aspx.

[36] The well-weighted contract average is equivalent to summing the total costs across all contracts and dividing by the number of wells, which is why the weighted contract average refers to the average well, not the average contract.

Findings: Projected Costs for Conventional Wells

Over the 1989-2020 period the average well plugged cost the Commonwealth $15,118 (Table 1, the "Weighted" column). This does not reflect current plugging costs since the average year of plugging is 2005. The cost per well for the average contract (Table 1, "Unweighted" column) is higher and reflects economies of scale in plugging discussed in detail in a later section. Because most wells are plugged under a large, lower-cost contract, the plugging cost of the average well is lower than for the average contract.

Costs range substantially across contracts, with per well costs ranging from $3,422 to nearly $485,000. The standard error of the weighted average cost, however, is fairly small, at $472. This means that a sample of wells randomly drawn from the same population of previously plugged abandoned wells would likely have an average cost in the range of $14,200 to $16,000.

Table 1. Summary Statistics for Well Plugging Contracts

Variable	Average Weighted	Average Unweighted	Minimum	Maximum
Plugging Cost Per Well ($)	15,118	49,008	3,422	484,677
Plugging Cost Per Foot ($)	8	20	1	219
Depth Per Well (Feet)	1,925	1,832	450	7,174
Contract Size (Wells)	55	12	1	179
Year Plugged	2005	2005	1989	2020
Emergency Contract (0/1)	0.01	0.08	0.00	1.00
Well Type				
Share Oil Wells	0.83	0.43	0.00	1.00
Share Gas Wells	0.12	0.36	0.00	1.00
Share Oil & Gas Wells	0.04	0.13	0.00	1.00
Share Other	0.01	0.09	0.00	1.00
Share of Wells in Coal Regions	0.06	0.22	0.00	1.00
Estimated Year Drilled	1995	1988	1891	2015
Number of Contracts	211 to 256			
Number of Wells	3,040 to 3,099			

Notes: The data are drawn from various datasets of the Pennsylvania Department of Environmental Protection and Department of Conservation and Natural Resources. All tabulations are by the author. As noted in the text, not all information is available for every well or contract. The weighted average is the contract average weighted by the number of wells in the contract. All monetary values are in 2020 dollars.

As mentioned in the methods section, it is important to adjust the plugging cost of the sample average well for changes in cost over time. Figure 1 shows a scatter plot of plugging costs per foot (in 2020 dollars, log scale) and the year plugging occurred, with the data adjusted for differences in contract and well characteristics (See Appendix A for details). It shows that plugging costs rose over the three-decade period even after adjusting for inflation. The slope of the best-fit-line line (estimated in log scale) gives the real annual growth rate, which is 3.2 percent.[37] Performing the same analysis but without adjusting for inflation gives a nominal growth rate of 5.6 percent.

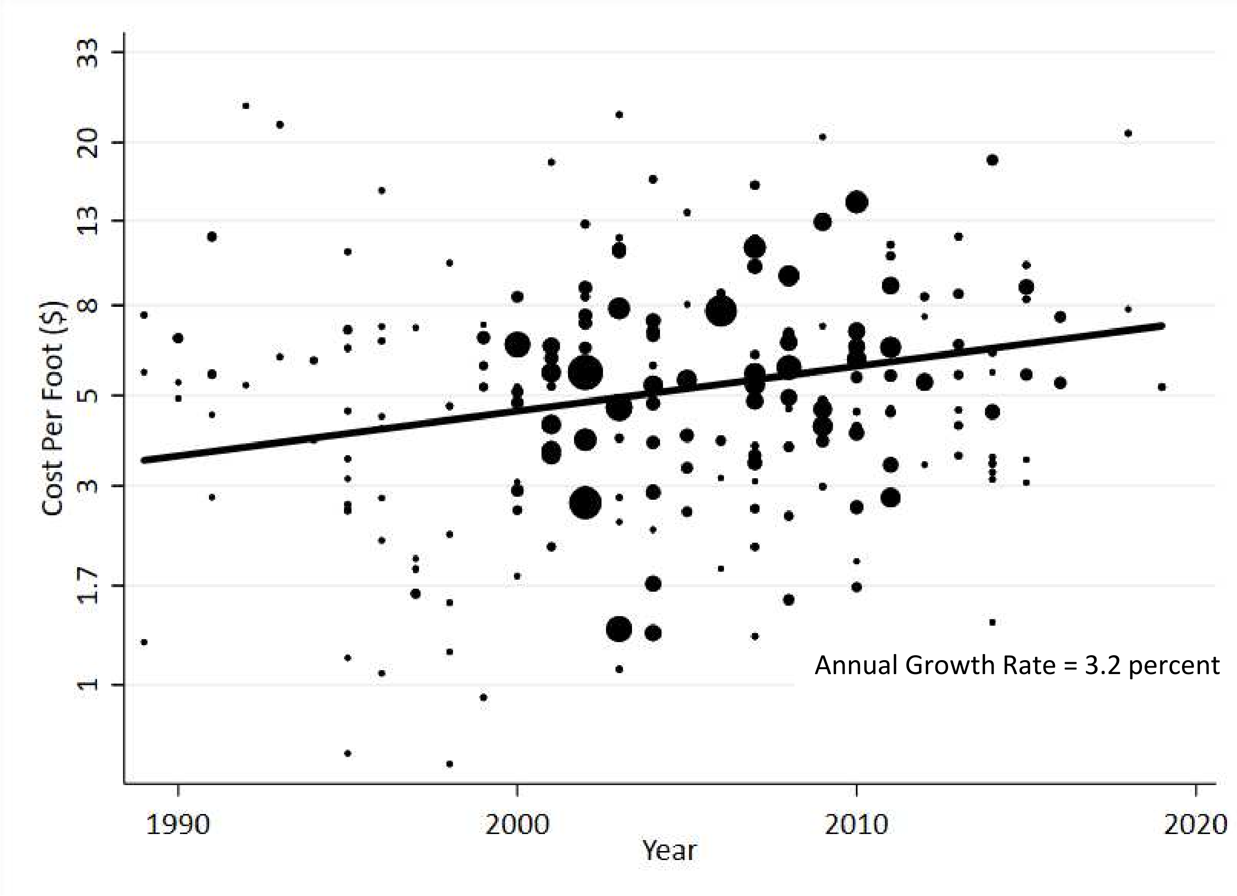

Figure 1. Inflation-Adjusted Plugging Costs Have Grown Over Time

Notes: The vertical axis is plugging cost per foot in 2020 dollars and is shown on a log scale, increasing by increments of roughly 0.5 log points. Each dot represents a well plugging contract. The data shown have been adjusted to account for changes in contract and well characteristics over time. See Appendix A for details. The size of the dots reflects the weight given to the observation (the contract) based on the number of wells in the contract. Larger dots indicate contracts with more wells.

The average plugging cost per well combined with the real and nominal plugging cost growth rates provide what is needed to estimate the plugging cost for 2020 and project the cost for 2021-2022. Doing so gives an estimated 2020 plugging cost of $23,829 per well (in 2020 dollars) and a projected 2021-2022 cost of $25,164 per well (in 2021 dollars).

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[37] Plugging and site restoration standards have changed over time, mostly due to Act 13 of 2012. Breaking the study period into before and after Act 13 reveals a growth rate of 3.0 percent before 2012 and 8.5 percent after 2011. That the global average (pooling data from both periods) is 3.2 percent reflects the greater weight given to earlier years when more wells were plugged. I use the global average growth rate as it should better reflect the growth rate moving forward. It is likely that Act 13 caused a temporary increase in the growth rate, with the rate returning to its long-run average after the full incorporation of the changes in plugging practices.

The projected cost for 2021-2022 supports the recommendation of a conventional bond amount of 25,000 per well for the 2021-2022 period. The Environmental Quality Board should revisit the amount every two years, taking into account updated information on plugging costs. The recommended $25,000 amount could become outdated in several years because of inflation and rising real costs. For example, if plugging costs continue to grow at their historical rate, conventional well plugging costs would rise to more than $31,000 by the end of 2025 (in 2025 nominal dollars).[38] In addition, the composition of wells needing to be plugged can change over time, resulting in a higher or lower average cost.

Assessing the Projections

As noted in the methods section, the reliability of the 2021-2022 projection depends in part on whether sample wells are unique in ways that affect plugging costs. One way to gauge their uniqueness is to compare their plugging costs to those of other wells, such as those plugged by the private sector.

A comparison with recent private sector plugging costs suggests that wells plugged by the Commonwealth are not unique in ways that have large effects on plugging costs. Diversified Gas and Oil is a large operator of conventional wells in Appalachia, and in August of 2020 it released a report providing its spending on wells plugged from 2018 through the second quarter of 2020. For the 192 wells that it plugged in the Appalachian region, it reports an average cost of $24,280 per well. Not all of the wells were in Pennsylvania, but Diversified also reports an estimate of per well costs by state, reporting $23,638 for Pennsylvania wells in coal regions and $19,259 for wells outside of them.[39] The costs are similar to the estimated 2020 cost based on wells plugged by the Commonwealth ($23,829).

Another way to gauge the uniqueness of the wells plugged by the Commonwealth is to compare their characteristics with those of conventional wells drilled in recent years. The comparison should reveal how conventional drilling has evolved, which is important because adjusted bond amounts would apply to recently drilled and soon-to-be-drilled wells. To conduct this comparison, I used data from the DEP and analyzed all wells drilled between 2010 and 2018, comparing them to the previously discussed dataset of plugged wells.

On the whole, the comparison also suggests that the plugged well sample is not unique (i.e., is roughly consistent with more recent conventional wells). The average wells of each sample have similar depth and likelihood of being in a coal region. This is notable given the difference in well age across the two samples. The average estimated year drilled is 1995 for plugged wells and 2011 for recently drilled wells. The primary difference between recently drilled wells and wells plugged by the state is the hydrocarbon focus, with the recently drilled wells focused on gas plays, or a mix of oil and gas, and fewer wells in pure oil plays. On the whole, then, the sample of wells plugged by the DEP are likely to provide reasonable estimates of the plugging costs that the Commonwealth is likely to incur in the near future. At the same time, there are some differences between older wells and recently drilled wells, which highlights the value of the Environmental Quality Board periodically revisiting bond amounts with updated cost data.

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[38] = $25,000 x (1.056)^4, where 0.056 refers to the nominal growth rate in plugging costs.

[39] Diversified Gas & Oil, *Asset Retirement Supplement for the ARO Liability.*

Table 2. Comparing Plugged Wells and Recently Drilled Conventional Wells

	Average Values		
	Plugged Wells	Recently Drilled Wells	Difference
Depth (Feet)	1,925	2,087	162
Oil Well (0/1)	0.83	0.57	-0.26
Gas Well (0/1)	0.12	0.21	0.09
Oil and Gas Well (0/1)	0.04	0.16	0.12
Other Well (0/1)	0.01	0.08	0.07
Well in Coal Region (0/1)	0.06	0.06	0.00
Estimated Year Drilled	1995	2011	16
Number of Wells	3,040	2,923	

Notes: Data are from various datasets of the Pennsylvania Department of Environmental Protection and Department of Conservation and Natural Resources. All tabulations are by the author. The Estimated Year Drilled refers to the first year that the well appears in state records.

Findings: Projected Costs for Unconventional Wells

I project a plugging cost of $70,000 for an unconventional well in 2021. The number reflects the same methodology used to project costs for conventional wells but with two adjustments to account for differences between unconventional wells and the conventional wells reflected in the DEP plugging data.

The first difference is that unconventional wells are deeper, which increases plugging costs.[40] Plugged wells have an average depth of 1,925 feet compared to an estimated 6,300 feet for unconventional wells.[41] Statistical modeling of the plugging cost data indicates that each foot in depth adds $1.90 in cost, which gives an adjustment of $8,313.[42] The second adjustment is for well type. Most of the conventional wells plugged were oil wells whereas essentially all unconventional wells are gas wells. The same statistical model that relates depth to plugging costs shows that natural gas wells cost an average of $21,376 more to plug than other wells. The resulting adjustment is $18,803.[43] These two adjustments sum to a slightly more than $27,000 increase in cost of plugging from the sample average conventional well.

To arrive at the $70,000 projection, I add the total adjustment to the sample average conventional well cost and then apply the same growth rates in plugging costs as estimated for conventional wells. See Appendix B for details of the calculations and statistical modeling. As with the projected cost for conventional wells, the projection and recommended bond amount for unconventional wells apply to the 2021-2022 period. The Environmental Quality Board should revisit the amount every two years, taking into account updated information on plugging costs. This is especially important in the case of unconventional wells because there is currently no publically available data on the cost of plugging unconventional wells in Pennsylvania.

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[40] Ho et al., *Managing environmental liability: an evaluation of bonding requirements for oil and gas wells in the United States.*

[41] Weber, McClure, and Simonides, *The Boom, the Bust, and the Cost of Cleanup: Abandoned Oil and Gas Wells in Pennsylvania and Implications for Shale Gas Governance*.

[42] $8,313 = (6,300 feet – 1,925 feet) x $1.9 per foot. See Appendix B for a discussion of this calculation.

[43] $18,803= (1.0 – 0.12036) x 21,376 per gas well, where .12036 is the weighted contract average share of gas wells (see Table 1).

Assessing the Projection

There is more uncertainty over the projection for unconventional wells than for conventional wells because of the lack of data on unconventional well plugging costs. Yet, the projection is arguably the most well-founded of any projection for unconventional wells in Pennsylvania.

A 2011 study estimated the cost of plugging unconventional wells in Pennsylvania based on well plugging data from Wyoming from 1997 to 2007, and reported that plugging a single unconventional well would cost about $110,000.[44] The authors, however, did not account for differences in terrain and labor and material costs between Wyoming and Pennsylvania. Costs for plugging in Pennsylvania may be different than incurred in other states. For example, one study of plugging costs reports that a drilling rig, which is used to prepare a well for plugging, can cost $85 an hour in Kansas and $240 an hour in Pennsylvania.[45] The estimate of $110,000 also assumed that the horizontal portion of unconventional wells needs to be plugged. Current Department of Environmental Protection regulations cited above make it clear that this is not the case in Pennsylvania—operators need only put a mechanical plug near the bottom of the vertical portion of the well.

A forthcoming study that uses Pennsylvania conventional well plugging data estimates unconventional well plugging costs ranging from about $92,000 to $129,000.[46] These estimates, however, are conditional on wells being plugged in fairly small groups, resulting in small contract sizes. As the next section discusses, per well plugging costs decrease with contract size, and this report's projections are based on the historical average contract size.

The authors of the forthcoming study note that site restoration costs may differ between conventional and unconventional wells.[47] Unconventional wells are found on large pads that host multiple wells whereas conventional wells are more scattered across the landscape. The net effect of the differences on plugging costs (including site restoration) could be positive or negative–larger pads would require more restoration costs but ease of site access and clustering of wells on a pad would reduce it. Because there is no firm way to estimate the impact of this factor, it is not reflected in this report's projection.

Contract Size and Economies of Scale in Plugging

Both the conventional and unconventional well projections are based upon the average well in the DEP plugged well dataset, which is associated with an average contract size of 55 wells.[48] (The focus on the average well is because the recommended bond amount seeks to match the projected plugging cost for the average well, not the average contract.) The projections, therefore, assume that future wells

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[44] Mitchell and Casman, *Economic incentives and regulatory framework for shale gas well site reclamation in Pennsylvania.*
[45] Ho et al., *Managing environmental liability: an evaluation of bonding requirements for oil and gas wells in the United States.*
[46] Weber, McClure, and Simonides, *The Boom, the Bust, and the Cost of Cleanup: Abandoned Oil and Gas Wells in Pennsylvania and Implications for Shale Gas Governance*.
[47] Weber, McClure, and Simonides, *The Boom, the Bust, and the Cost of Cleanup: Abandoned Oil and Gas Wells in Pennsylvania and Implications for Shale Gas Governance*.
[48] The average contract does not have 55 wells. Rather, the average well is plugged under a contract with 55 wells.

will be plugged under similarly sized contracts. The assumption is important because larger contracts have lower average costs. The lower cost stems from at least two sources. First, a large contract provides steady work for well plugging firms, potentially for an entire year. Plugging firms, which tend to be small, value this stability and therefore offer lower bids for larger contracts. Second, wells in the same contract are often near each other, which allows a firm to spread the cost of moving equipment over multiple wells. Clustering can also allow a firm to use the same staging area and access roads for multiple wells, saving labor and equipment time.[49]

Economies of scale in plugging are evident in the data. Figure 2 shows a scatter plot of plugging costs per well (vertical axis) and contract size (horizontal axis), with a best-fit curve shown as a solid black line. Costs decline dramatically as contract size increases from 1 to 15 wells. However, the rate of the decline slows greatly afterward, with contracts of 100 wells having only marginally lower costs per well than contracts of 50 wells.

The declining economies of scale shown in Figure 2 imply that the potential for an overstatement of costs is low since larger-than-expected contracts will bring only marginally lower cost. In contrast, the potential for understatement of costs is large if most wells in the future are plugged under small contracts. Over the entire sample, 1989-2020, the typical well was plugged under a contract covering 55 wells. However, the largest contracts in the data occurred in the 2000-2011 period when the Pennsylvania Department of Environmental Protection had greater funding (through the Growing Greener legislation).[50] Since 2011, a decrease in funding has translated into smaller contracts, with a more recent wells plugged under a contract with 14 wells. This highlights how greater funding for plugging, perhaps through higher bond amounts, could reduce the average plugging cost per well incurred by the Commonwealth.

Contract sizes have varied over time and may increase or decrease in the future. Given uncertainty over future contract sizes, this report's recommended bond amounts are based on the historical contract size for wells plugged by the Commonwealth. However, assuming the more recent contract size of 14 wells would increase the projected plugging cost and recommended bond amount to $38,000 for conventional wells and $83,000 for unconventional wells. The adjustment is based on the estimated non-linear relationship between contract size and per well plugging costs shown in Appendix Table B1.[51]

[49] These details are informed by an interview of an executive of a firm specializing in well plugging in the Appalachian basin.
[50] The level and sources of funding for well plugging can be seen by visiting: www.dep.pa.gov/Business/Energy/OilandGasPrograms/OilandGasMgmt/LegacyWells/Pages/Well-Plugging-Program.aspx.
[51] The adjustment is a $7,711 increase, which I add to the sample average cost per well. The growth rate in plugging costs is then applied to this adjusted average cost as described by equations (A1-A2) and (B1-B2).

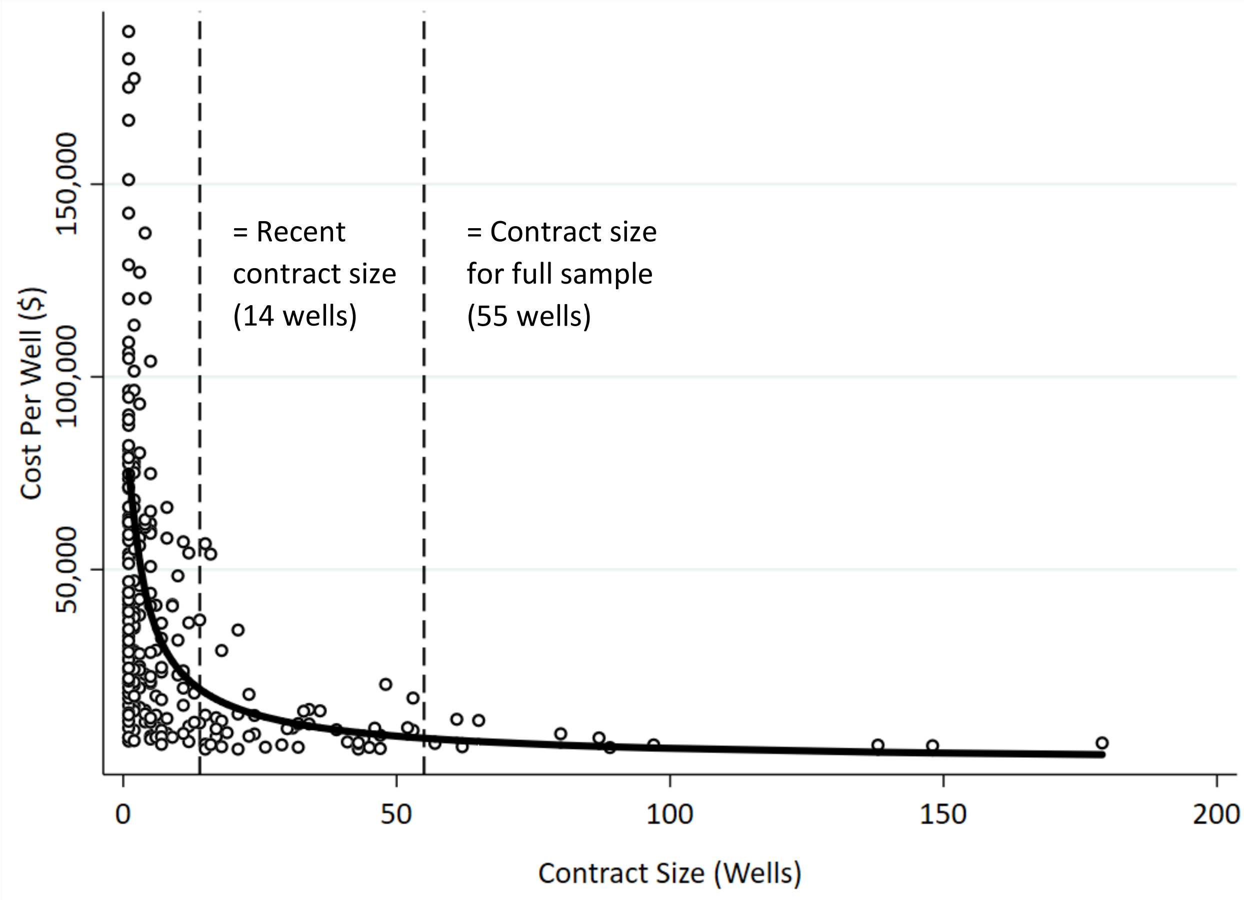

Figure 2. Plugging Costs Decline with Contract Size

Notes: The vertical axis is cost per well in 2020 dollars. Each dot represents a well plugging contract. For clarity of exposition, the vertical axis is limited to a maximum cost of $200,000 per well.

Blanket Bonds

As noted in the section on current bond amounts, blanket bonds (for conventional wells) and bond caps (for unconventional wells) imply that per well bond amounts can be much lower than the commonly cited bond amounts of $2,500 and $10,000 per well. Blanket bonds may have been justified by noting that they limit the total financial burden of bonds on large and financially stable operators. Alternatively, large plugging projects have a lower average cost, also justifying a lower bond amount.

Neither justification is warranted given the bond amounts recommended in this report. With surety bonds, larger—and presumably more financially secure—operators pay less to comply with bonding requirements. This is because sureties base their rates on an operator's finances and the risk that it defaults on its plugging obligations. Thus, a surety bond equal to plugging costs allows lower-risk firms to pay less while also ensuring that the Commonwealth is able to cover the costs of plugging if the operator defaults on its obligations.

Regarding the second potential justification, economies of scale in plugging occur in the range of 1 to 15 wells as shown in Figure 2. There are little, if any, economies of scale in plugging after 50 or so wells, meaning that average plugging costs remain unchanged as contract size increases beyond this size.

Blanket bonds, in contrast, presume that average costs attenuate to zero as contracts grow larger. This is clearly not the case.

If blanket bonds are allowed in their current form, projected plugging costs will exceed, perhaps by a large amount, bond amounts received by the Commonwealth. This report therefore recommends discontinuing the use of blanket bonds or caps and instead recommends that the Commonwealth apply the recommended per well bond amounts to operators of all sizes. Doing so will ensure that the Commonwealth spends, on average, as much on plugging as it receives from forfeited bonds.

To What Wells Should Adjusted Bond Amounts Apply?

Under Pennsylvania statute, bonding requirements apply to all wells in existence after April 17, 1985.[52] Applying adjusted bond amounts in a manner consistent with current law means applying them to new wells and those drilled after the 1985 date, only distinguishing between conventional and unconventional wells as the law does.

This application of adjusted amounts is also consistent with the scope that existing law gives the Environmental Quality Board to adjust bond amounts. The law states that bond amounts "may be adjusted every two years to reflect the projected costs to the Commonwealth of performing well plugging."[53] Because the Board's authority to adjust bond amounts is rooted in projected plugging costs, an uneven application of the adjustment could be justified if there were a basis for expecting new wells to have very different plugging costs than existing wells. The comparison of old and recently drilled wells previously presented in this report suggests no clear basis for the distinction. Thus, if the bond amount were not applied retroactively, the Commonwealth's plugging program would still have insufficient funds to plug the wells that become its responsibility in coming years. Further, this report recommends that the EQB revisit bond amounts every two years, so that it can adjust bond amounts based on any differences in plugging costs between new wells and existing wells that new data may reveal.

The Likely Effect of Bond Adjustments on the Oil and Gas Industry

This section describes the likely effects of adjusted bond amounts on the oil and gas industry based on the experience of Pennsylvania when it introduced its per well Impact Fee for unconventional wells and based on the experiences of Texas and North Dakota when they increased bond amounts. The experiences suggest that the adjustments will improve environmental outcomes, have little effect on aggregate industry activity, and potentially shift wells among operators.

To gauge likely impacts, I first illustrate the potential cost increase associated with adjusted bond amounts. I assume that operators currently post $1,000 for the typical conventional well and $5,000 for

[52] 58 Pa. Con. Stat. § 3225.
[53] 58 Pa. Con. Stat. § 3225.

an unconventional well.[54] I further assume a well life of 30 years, a discount rate of 5 percent, and a bond rate of 5 percent.[55]

The adjusted bond amount would increase annual costs by $3,250 per unconventional well, which has a present value of $50,000 over the life of a 30-year well (Table 3). To put the present value cost in perspective, it is about one-fifth that of the unconventional well Impact Fee. Operators in Pennsylvania pay an Impact Fee of about $50,000 per unconventional well in its first year and about $250,000 over the life of the well.[56]

The industry's response to the introduction of the comparatively more costly Impact Fee suggests that adjusted bond amounts would not affect the number of wells drilled or production. A 2018 study found no systematic change in these outcomes around the introduction of the Impact Fee and compared to areas across the border in West Virginia and Ohio, which did not change their fees or taxes over the same period.[57] The authors did find that leasing declined but attributed this decline primarily to timing of the Fee, which was introduced when natural gas prices were very low and credit lines tight.

Table 3. The Estimated Cost of Bonds at Current and Adjusted Levels

	Well Type	
	Conventional	Unconventional
Assumptions		
Rate on Surety Bond (%)	5	5
Discount Rate (%)	5	5
Current Bond Amount ($ Per Well)	1,000	5,000
Recommended Bond Amount ($ Per Well)	25,000	70,000
Estimates ($ Per Well)		
Current Annual Cost	50	250
Current Present Value of Costs Over 30 Years	769	3,843
New Annual Cost	1,250	3,500
New Present Value of Costs Over 30 Years	19,216	53,804
Change in Annual Cost of Bonding ($ Per Well)	1,200	3,250
Change in Total Cost of Bonding ($ Per Well)	18,447	49,960

54 Assuming the use of blanket bonds, these per well bond amounts would correspond to a conventional operator with 25 wells ($1,000 = $25,0000 / 25 wells) and an unconventional operator with 120 wells ($5,000 = $600,000 / 120 wells). The cost of current bond amounts would be higher for smaller operators and lower for larger operators.

55 There is limited data on the bond rates paid by oil and gas operators in Pennsylvania; however, one surety reports on its website that a lower-risk applicant will likely "pay no more than 5% of the bond amount." See www.bryantsuretybonds.com/oil-and-gas-surety-bond. Operators can satisfy bond requirements in different ways (e.g., depositing U.S. Treasury Bonds) and will presumably adopt the lowest cost option. If surety bonds represent the cheapest option, they will provide an accurate indication of actual cost; if not, they will overstate it.

56 Black, McCoy, and Weber, *When externalities are taxed: The effects and incidence of Pennsylvania's impact fee on shale gas wells.*

57 Ibid.

Estimates from another recent study show a muted effect of higher bond amounts on unconventional oil and gas activity. The study explored the effect of North Dakota's policy changes, which, among other things, increased per well bond amounts from $20,000 to $50,000 for all existing and new wells.[58] It found that higher bond amounts along with increased regulation had no statistically discernable effect on drilling or production.

The adjusted bond amount would increase annual costs by $1,200 per conventional well, or about $18,000 over the life of a 30-year well (in present value terms). A study of the Texas experience provides insight into what might happen to the conventional well industry. In the early 2000s, Texas introduced a bonding requirement of $2 per foot. In the short term the requirement caused about five percent of operators to exit the market.[59] Exiting operators were small on average and had poor environmental records. Over time, the requirement shifted wells across operators, with about four percent of wells operated by small operators shifting to new operators. As a result, the number of unplugged and abandoned wells decreased by 70 percent and violation of water regulations fell by a quarter. This is a plausible outcome for Pennsylvania—operators unable to pay to the insurance against leaving a well unplugged could exit the market, and their wells could shift to more financially secure operators. Such a shift would protect the Commonwealth from bearing plugging costs since operators unable to pay for insurance (bonds) are probably unable to pay to plug their wells.

It is possible that the adjustment could prematurely shift some existing wells to the responsibility of the Commonwealth. This would happen if the adjustment bankrupts an operator and no other operator wants to acquire the acreage and wells. For such marginal wells and operators, it is likely that the bond adjustment simply changes when the transfer to the Commonwealth happens, not whether it happens. Moreover, with the adjustment the Commonwealth gains financial protection in cases where operators currently can afford the new bonds on existing wells but will eventually fall into financial distress and abandon their wells without plugging them.

It is also worth noting that if Pennsylvania adjusted bond amounts upward it would not be unique among major oil and gas producing states. In addition to North Dakota's bond amount increase referenced above, in 2019 the state increased bond amounts on injection wells from $50,000 to $100,000 and reduced the number of inactive wells that can be covered under a blanket bond.[60] In the same year, Alaska also increased its bond amounts considerably, and Mississippi introduced an annual fee on idle wells.[61]

Conclusion

Thanks to the Pennsylvania Department of Environmental Protection's orderly recording of its plugging activity and costs, much can be said about the well-plugging costs that the Commonwealth has incurred and is likely to incur moving forward. The law prescribing bond amounts appears to anticipate analysis of such data and its consideration by the Environmental Quality Board so that bond amounts can be adjusted to reflect the projected costs to the Commonwealth.

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[58] Lange and Redlinger, *Effects of stricter environmental regulations on resource development.*

[59] Boomhower, *Drilling Like There's No Tomorrow*.

[60] Industrial Commission of the State of North Dakota, "Case No. 27828 Order No. 30278". https://www.dmr.nd.gov/oilgas/or30278.pdf

[61] Peltz and Saunders, "How oil & gas states did (and did not) protect land and water in 2019".

Based on analysis of the cost data, this report recommends for the 2021-2022 period a bond amount of $25,000 per conventional well and $70,000 per unconventional well. This adjustment—and subsequent reviews and adjustments by the EQB—will help protect residents and property owners in oil and gas producing areas who would otherwise be harmed or constrained by unplugged abandoned wells. It will also protect the Commonwealth and its taxpayers from shouldering the liabilities of private oil and gas operators that fall into financial distress. By adopting this report's recommendations, the EQB can therefore restore the financial responsibility of well plugging to well operators and remove it from the Commonwealth.

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Appendix A: Conventional Well Plugging Costs

I estimate the plugging cost for a conventional well in the 2021-2022 period by adjusting the sample average plugging cost for changes in costs over time. Let $\bar{c}$ be the sample average cost per well over the 1989-2020 period, $\bar{y}$ the year that the average well was plugged, and $\hat{r}_r$ the estimated real annual growth rate in plugging cost, accounting for any changes in well characteristics over time. The estimated plugging cost for a conventional well in 2020 is then:

$$Estimated\ Cost\ (Con)_{\ 2020} = \bar{c} \cdot (1 + \hat{r}_r)^{(2020-\bar{y})} \tag{A1}$$

If $\hat{r}_n$is the estimated nominal growth rate in plugging costs (unadjusted for inflation), the projected plugging cost for a conventional well in 2021-2022[62] (in 2021 dollars) is then:

$$Projected\ Cost\ (Con)_{\ 2021-22} = Estimated\ Cost\ (Con)_{\ 2020} \cdot (1 + \hat{r}_n) \tag{A2}$$

I estimate the real growth rate in plugging costs using the following regression where the unit of analysis is the contract but the regression is weighted by contract size. The dependent variable is the natural log of plugging costs per foot.

$$Ln(Plugging\ Cost\ Per\ Foot_{it}) = \delta Year\ Plugged_{it} + X_{it}\gamma + \delta_c + \varepsilon_{it} \tag{A3}$$

The term δ_c is a county fixed effect based on the modal county of wells in contract *i* executed in year t. The county fixed effect makes for comparisons of plugging costs within the same county, thereby holding constant factors such as remoteness, terrain, and geology. This accounts for the possibility that plugging costs changed over time because the location of wells being plugged also changed.

The variable Year Plugged is the calendar year (e.g. 2005) when wells in contract *i* were plugged. The vector X includes other variables associated with the contract and its wells and that may affect plugging costs. In its most comprehensive form it includes the natural log of the number of wells in the contract (Contract Size), the shares of wells in the contract of various types (e.g. gas wells), a variable indicating an emergency contract, the share of wells in a coal region, and the average estimated year drilled of contract wells as indicated by the first year the well appears in state records. Their effect on plugging costs is captured by the vector of coefficients in γ. The term ε_{it} captures all variation in the log of plugging costs per foot not captured by the variables in the model.

Multiplying the estimated coefficient on the variable Year Plugged ($\hat{\delta}$) by 100 gives the percent change in per foot plugging costs for each 1-year increase in Year Plugged. Because plugging costs are already adjusted for inflation, this coefficient gives the real annual growth rate in plugging costs over the period holding constant all the other variables in the model. Put differently, $\hat{\delta} = \hat{r}_r$.

Table A1 shows the results from three regressions based on equation A3. The first column includes all the wells in the DEP plugging summary data with depth data, the second includes only wells with additional variables and the third uses this smaller sample and includes two additional control variables. The estimated growth rate—the coefficient on Year Plugged—changes little as the sample is restricted

[62] I consider plugging costs over the 2021-2022 period to equal the cost estimated for the last day of 2021, which is what is given by the formula that applies the nominal annual growth rate to the estimated 2020 plugging cost, assuming that the 2020 cost estimate reflects costs on the last day of 2020.

and more variables are added. The main estimate is 3.2 percent with a 95 percent confidence interval of 2.6 percent to 3.7 percent.

Table A1. Plugging Costs Per Foot (Ln) and Contract and Well Characteristics

	1	2	3
Year Plugged	0.031	0.031	0.032
	(0.002)	(0.003)	(0.003)
Ln(Contract Size)	-0.437	-0.433	-0.399
	(0.012)	(0.012)	(0.013)
Share Oil Wells	-1.116	-1.250	-1.212
	(0.672)	(0.901)	(0.695)
Share Gas Wells	-0.674	-0.803	-1.189
	(0.671)	(0.898)	(0.716)
Share Oil and Gas Wells	-0.944	-1.069	-1.413
	(0.672)	(0.902)	(0.706)
Emergency Contract	-1.064		
	(0.708)		
Share Wells in Coal Region			-0.683
			(0.175)
Estimated Year Drilled			0.011
			(0.001)
Control for County	Yes	Yes	Yes
Number of Contracts	226	211	211
Number of Wells	3,060	3,040	3,040
Adjusted R-Squared	0.51	0.50	0.64

Notes: Robust standard errors are in parenthesis. The regression is based on contract-level data but weighted by the number of wells per contract. The sample of contracts analyzed in columns 2 and 3 does not have any emergency contracts, which is why no results are reported for that variable.

As noted in the main text, the data depicted in Figure 1 are adjusted for changes in contract and well characteristics over time. This is done by excluding the variable Year Plugged from the regression in column 3 of Table A1, in which case the resulting regression error $\hat{\varepsilon}$ reflects variation in plugging costs holding constant factors other than time. Figure 1 then depicts $\hat{\varepsilon}$ on the vertical axis and Year Plugged on the horizontal axis.

Appendix B: Unconventional Well Plugging Costs

I estimate the cost of plugging an unconventional well by adjusting the sample average conventional cost ($\bar{c}$) for differences in the characteristics of the two well types. Let $\bar{X}_{con}$ and $\bar{X}_{un}$ be vectors of the characteristics of the average conventional and unconventional well and let $\hat{\beta}$ be the relationship between a one unit change in a variable in X on per well plugging costs. This adjustment for differences in average well characteristics, such as well depth, can be incorporated into equation (B1) to estimate the cost of plugging an unconventional well in 2020:

$$Estimated\ Cost\ (Un)_{2020} = \bar{c} \cdot \left((\bar{X}_{un} - \bar{X}_{con}) \cdot \hat{\beta}\right) \cdot (1 + \hat{r}_r)^{(2020 - \bar{y})} \quad \text{(B1)}$$

Similarly, the projected cost for 2021-2022 (in 2021 dollars) would be:

$$Projected\ Cost\ (Un)_{2021-22} = Estimated\ Cost\ (Un)_{2020} \cdot (1 + \hat{r}_n) \quad \text{(B2)}$$

The real and nominal growth rates ($\hat{r}_r$ and $\hat{r}_n$) are the same as those used for conventional wells and described in Appendix A. I estimate the relationship between per well costs (at the contract level) and well characteristics, given by β, using the regression equation:

$$Plugging\ Cost\ Per\ Well_{it} = Z_{it}\beta + \delta_c + \epsilon_{it} \quad \text{(B3)}$$

where δ_c is a county fixed effect that accounts for any differences in average plugging costs across counties. In its most comprehensive form, the vector Z includes the average depth of wells in the contract, the contract size and the contract size squared (to capture declining economies of scale), the share of contract wells that are gas wells, a variable indicating an emergency contract, the share of wells in a coal region, and the average estimated year drilled of contract wells as indicated by the first year the well appears in state records. The term ϵ_{it} captures all variation in plugging costs per well not captured by the variables in the model.

Table B1 shows the results from two regressions based on equation B3. The unit of analysis is the contract, but the regression is weighted by contract size. Column 1 shows the results of a simple model that only includes depth, contract size, and the year plugged (and no county fixed effect). Column 2's results are based on a model with county fixed effects and the comprehensive version of Z. I use the $\hat{\beta}$ from this more comprehensive model when making the adjustment in equation (B1) because the comprehensive model should more reliably estimate the effects of well depth and type on plugging costs. These are the two characteristics incorporated into the adjustment because they most differ between sample wells and the typical unconventional well.

Based on the short model, an additional foot of depth adds $5.00 to plugging costs. Adding more variables reduces the coefficient on average depth to $1.90, but also shows that contracts with a greater share of natural gas wells have higher costs, suggesting that a contract consisting of all gas wells costs about $21,000 more per well than a contract with no gas wells.

Table B1. Contract and Well Characteristics and Plugging Costs Per Well

	1	2
Average Well Depth (Feet)	5.0	1.9
	(0.5)	(0.5)
Contract Size (Number of Wells)	-681.2	-270.4
	(34.1)	(26.3)
Contract Size Squared	3.1	1.2
	(0.2)	(0.1)
Year Plugged	335.2	278.2
	(132.9)	(105.4)
Share Gas Wells		21,376.1
		(3,545.7)
Share of Wells in Coal Regions		-5,852.3
		(13,524.1)
Estimated Year Drilled		102.0
		(43.9)
Control for County	No	Yes
Number of Contracts	226	211
Number of Wells	3,060	3,040
Adjusted R-Squared	0.27	0.27

Notes: Robust standard errors are in parenthesis. The regression is based on contract-level data but weighted by the number of wells per contract.

Appendix C: Data

The following contracts and wells were removed from the Pennsylvania Department of Environmental Protection's well plugging summary dataset, which left 3,099 wells:

- 1 contract that was in process and had no cost data (7 wells).
- 1 contract where it was noted that site restoration but not plugging occurred (1 well).
- 20 wells across various contracts where instead of a plugging date, it was noted: "not plugged," "not a well," "prev plugged," "stray gas," "unable to locate," "water," "gas drip," or "well not found." Because they were not plugged, these wells were ignored when calculating average values for each contract.

Mapping the DEP wells onto oil and gas pool outlines permitted approximating each well's depth. Some wells could not be mapped onto pools but where other wells in the same contract had depth data, I imputed missing depth data with the contract mean depth. After imputation, depth data were available for 3,060 of the 3,099 wells left after the above exclusions.

I created two additional variables from data not found in the DEP plugging summary dataset. These were an indicator for whether the well was in a coal region and the estimated year the well was drilled as indicated by the first year that the well was observed in state records. Data for both variables were obtained through the Department of Conservation and Natural Resources' EDWIN database. The database is a repository of oil and gas well data from multiple sources, including from various Department of Environmental Protection reports.