RFF REPORT

Plugging the Gaps in Inactive Well Policy

Jacqueline Ho, Alan Krupnick, Katrina McLaughlin, Clayton Munnings, and Jhih-Shyang Shih

With assistance from RFF Visiting Fellows Nathan Richardson (University of South Carolina) and Lucija Muehlenbachs (University of Calgary)

MAY 2016

RESOURCES FOR THE FUTURE

Plugging the Gaps in Inactive Well Policy

Jacqueline Ho, Alan Krupnick, Katrina McLaughlin,
Clayton Munnings, and Jhih-Shyang Shih*

With assistance from
RFF Visiting Fellows Nathan Richardson (University of South Carolina)
and Lucija Muehlenbachs (University of Calgary)

Contents

1. Introduction 3

2. Classifying Wells by Production, Abandonment, and Ownership Status 4

3. The Scale of the Inactive Well Problem 5

Key Findings and Recommendations 5

The Literature on the Environmental Risks of Inactive Wells 6

Pollutants and Impacts 6

Risk Pathways and the Role of Well Construction in Minimizing Leakage Risk 6

Factors Affecting the Magnitude of Risk 9

Empirical Estimates of Magnitude of Pollution Potential 11

Number of Inactive Wells in 13 States 13

4. Regulations on Inactive Oil and Gas Wells 16

Key Findings and Recommendations 16

Methodology 16

Review and Comparison of State and Federal Regulations 17

Discussion of Regulatory Elements 21

Policy Recommendations and Conclusions 44

---

*Ho, research assistant, Resources for the Future (RFF); Krupnick, RFF senior fellow and co-director of RFF's Center for Energy and Climate Economics; McLaughlin, research assistant, RFF; Munnings, research associate, RFF; Shih, fellow, RFF.

5. Conclusions, Recommendations and Future Research 46
Bond Amounts 47
Well Management and Monitoring 47
Inactive and Orphaned Well Programs 48
Environmental Risks of Inactive Wells 48
Inactive Well Regulations and Programs 49
Appendix A. Average Well Depth and Associated Average Bond Amounts by State.... 51
Appendix B. State Oil and Gas Regulations 55
Acknowledgements 78
References 78

1. Introduction

The environmental and financial consequences of a large and probably growing number of inactive wells remain largely unexplored. Based on some new work on methane leaks from such wells and reports of state liabilities for plugging wells and restoring production sites, a closer look at these issues is warranted.

Regulatory, environmentalist, academic and industry attention has focused much more on the environmental consequences of oil and gas development from active wells than on those from inactive wells, or wells that have ceased production. This focus is understandable given concerns about drilling, fracking, waste handling and the like; but there are many more inactive wells than active wells—one estimate suggests that at least 3.5 million oil and gas wells have been drilled in North America (Brandt et al. 2014), of which 825,000 are currently in production.[1] The remaining wells are presumably inactive. Left unplugged or not properly plugged, inactive wells threaten human and environmental health. Recent research suggests that these wells can leak methane (a powerful greenhouse gas) into the atmosphere (Kang et al. 2014). They could also provide a pathway for surface runoff, brine, or hydrocarbon fluids to contaminate surface water and groundwater (Kell 2011; King and King 2013; King and Valencia 2014). Well sites that are not properly reclaimed can contribute to habitat fragmentation (Drohan et al. 2012) and soil erosion, and equipment left on-site can interfere with agricultural land use and threaten wildlife habitat (DOI 2015). Whether even properly plugged wells can leak is still an open question.

Even if wells have a responsible operator on record, they may still represent a potential environmental risk and financial liability to states. Due to a lack of monitoring capacity, a well that has been inactive for an extended period of time and is noncompliant with environmental standards may be allowed to remain in temporary abandonment or inactive status, such that they can be reactivated when market or technology conditions improve, instead of being permanently plugged and abandoned. Eventually these wells may become orphaned. For instance, a 2014 performance audit of the inactive well program managed by Louisiana's Office of Conservation found that 46.5 percent of 11,269 wells identified as having future utility had held that status for more than 10 years; 22.8 percent of the 8,682 wells that were ultimately orphaned had been in future utility status prior to becoming orphaned (LLA 2014). Any growth in the number of orphaned wells adds to the already-large population of legacy orphaned wells from an earlier era.

A further risk is posed by wells that will become inactive in the future. It is possible that future wells will be less problematic than historic wells because of better regulations for plugging and abandonment, improved technologies for well construction (such that the original bore hole and casings are in better shape for plugging), and growing public pressure on regulators and industry to protect against environmental risk. However, even if less risky, each additional well produced will eventually add to the growing stock of inactive wells. In addition, even wells that have been properly plugged with modern technologies may leak as cement is subject to shrinkage, cracking, and other types of failure.

This report discusses the environmental and regulatory challenges of inactive wells, with an eye towards reforming their regulation. Section 2 briefly reviews definitions and classifications. Section 3 assesses the magnitude of the concerns related to inactive wells that are left unplugged by identifying the specific environmental threats posed by leaking wells and by estimating the number of inactive wells in the United States. Stringent regula-

[1] This total may be an underestimate—many historic wells were drilled before well-permitting regulations were introduced and thus may not be recorded.

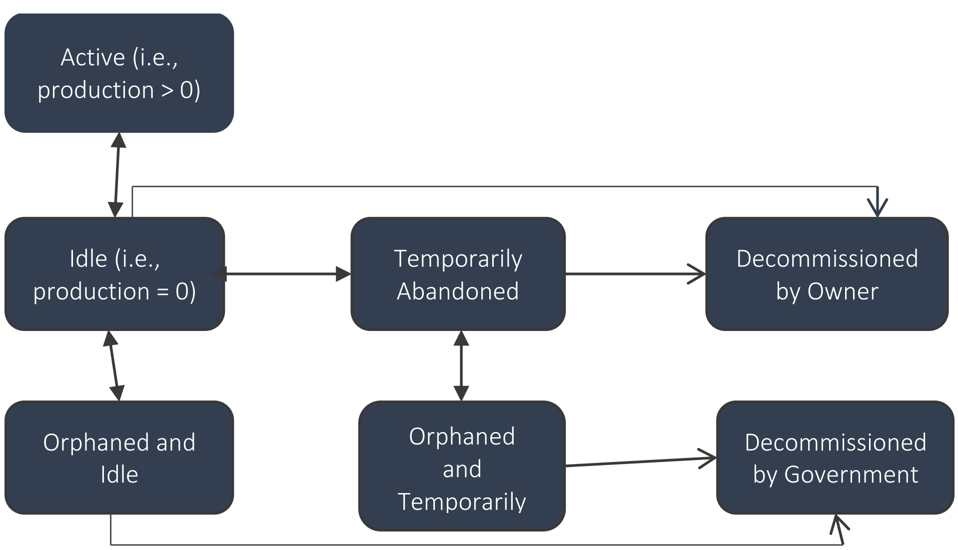
tions are essential for mitigating such environmental and financial risks; thus, Section 4 reports on a survey of inactive well regulations in 22 oil and gas states and on BLM lands. The section identifies the regulations that are the most crucial and discusses the heterogeneity in regulatory approaches across the governments. Policy recommendations are aggregated and presented in Section 5. A forthcoming paper (Shih et al.) estimates the costs of plugging inactive wells in order to reduce these risks, including a discussion of the financial liability to governments that they represent and the extent to which these costs are internalized by private operators. At times we refer in this report to findings in that paper.

2. Classifying Wells by Production, Abandonment, and Ownership Status

Some states use different definitions to describe similar well statuses. We therefore introduce generic terms meant to coherently capture categories of inactive wells, while acknowledging that these terms differ from definitions used by a significant number of states. Indeed, many states do not use the term "inactive wells" as we do throughout this report.

We identify seven terms that classify wells into different status and ownership categories, as displayed in Figure 1 below. A well's status switches from active to inactive (or idle) after it stops producing oil and gas after a certain period of time, which ranges from one month to one year for most states. If an operator maintains ownership of that well, it either undergoes decommissioning (which we define as plugging the well bore, removing equipment, and restoring land surrounding the site) at the expense of the owner, or it becomes temporarily abandoned. Temporary abandonment is technically a transitory state, where the well might return to production or be decommissioned in the future; in practice, however, wells can remain temporarily abandoned indefinitely in certain states and circumstances. If a well does not have an owner, it is deemed an orphaned well and either undergoes decommissioning at the expense of the government or becomes abandoned. A well may become orphaned as it becomes inactive (resulting

FIGURE 1. STATUS AND OWNERSHIP OF OIL AND GAS WELLS



in an orphaned inactive well) or after it is temporarily abandoned, which results in an orphaned temporarily abandoned well. Well operators becoming financially insolvent, or simply not found at the time a well requires decommissioning, is a primary cause of wells becoming orphaned.

It is currently unclear what number of the approximately 3.0 million inactive wells in the United States belong to each of these categories. However, given the advent of unconventional wells and the growing importance of natural gas domestically and in export, the United States will likely face a rise in the number of inactive wells in the coming year.

Most of the news, popular press, and academic literature on the topic of inactive wells focuses on orphaned or temporarily abandoned wells (Mitchell and Casman 2011; Frosch and Gold 2015). Our study considers all six categories of inactive wells, because all of them (regardless of ownership or operational status) can pose environmental risks.

3. The Scale of the Inactive Well Problem

Key Findings and Recommendations

- Inactive wells can leak pollutants, including methane and brine, as well as heavy metals and naturally occurring radioactive substances; these pollutants may contaminate groundwater, surface water, or, in the case of methane, be released into the atmosphere.
- The pathways through which leakage may occur are well documented in the literature. These pathways include mechanical integrity failure, failed well casings, and cement failure. Well construction and well plugging regulations should protect against these failures.
- The likelihood of leakage from an inactive well depends on a number of factors, most importantly, the quality of well construction at the time it was drilled and the abandonment measures that have been taken.
- The empirical literature provides anecdotal evidence of leakage from wells left unplugged but does not characterize the rate at which these wells leak. We are aware of only one piece of research that provides measurements of methane leakage rates from inactive wells.
- The empirical literature does not distinguish between the environmental damage caused by different types of inactive wells (e.g., temporarily abandoned vs. plugged and abandoned wells; historic wells vs. wells drilled more recently). Although wells that have been plugged might still leak due to cement shrinkage, opinions on the extent to which this happens are divided. This is an area in need of further research.
- Data from 13 states with significant oil and gas production shows that about 12 percent of the inactive wells in these states have not been decommissioned. The percentage in each state varies significantly from one percent to 56 percent.

How much of an environmental threat are inactive wells in the United States? To answer this question comprehensively and empirically, four key pieces of information are needed: the type, quantity, and toxicity of pollutants that may leak from each well; the abandonment status (e.g., whether they are plugged) and characteristics of inactive wells (e.g., the quality of their construction) and how these affect how much of a risk they pose; the number of inactive wells; and the proximity of human and ecological populations to hazardous wells. Because currently available data and literature on these four components are limited, answering this question is challenging. This section addresses the first three of these four components, first by reviewing the literature on the environmental risks posed by inactive wells. In reviewing this literature, we highlight the major pollutants of concern, then we identify the pathways through which inactive wells can cause environmental damage and describe how inactive wells of certain types and characteristics are more risky than others. Understanding this then allows us to identify specific regulations that are important for managing the risk in inactive wells, which we address in section 3. Next we estimate the number of inactive wells in the United States using data from and individual states.

The Literature on the Environmental Risks of Inactive Wells

The pathways through which inactive oil and gas wells can cause environmental harm, if they are not properly plugged, are well documented in the engineering literature on well integrity and procedures for proper plugging and abandonment (see, e.g., King and Valencia 2014). Additionally, the literature has also commented on the conditions under which environmental risk may be exacerbated, such as subsurface geologic conditions and the proximity of ongoing production activities, as well as the effect of well construction and well plugging regulations on the degree of risk posed by inactive wells. Less well understood is the actual, quantified risk posed by the population of inactive wells in the United States, both plugged and unplugged, as there have been few empirical studies done on the topic (see, e.g., Kang et al. 2014).

Although the literature treats oil and gas wells as a collective group, we focus on the risks from gas wells. Nonetheless, most risks from oil wells would be of the same type, with the exception oil leaks.

Pollutants and Impacts

Methane is the primary pollutant of concern in natural gas. Methane from leaking wells enters the atmosphere directly, contributing to greenhouse gas emissions concentrations (Dusseault et al. 2000; Kang et al. 2014). Methane can also pose human health risks when entering shallow groundwater or surface water and contaminating household drinking water. Methane poses an explosion and an asphyxiation hazard,[2] either during well water extraction or by accumulating in basements and well pits (Jackson et al. 2013).[3] Other pollutants of concern in natural gas include nitrogen oxides, sulfur dioxide, and hazardous air toxics like benzene, toluene, ethylbenzene, and xylene (Lattanzio 2013).

Brine is another key pollutant that can migrate from hydrocarbon formations to surface water or freshwater aquifers, rendering the water non-potable, particularly if the brine has elevated total dissolved solids or contains naturally occurring heavy metals, such as barium, and radioactive materials (Jackson et al. 2013).

Pollutants in surface runoff may also flow into an unplugged wellbore and contaminate groundwater (API 1993).

Risk Pathways and the Role of Well Construction in Minimizing Leakage Risk

Oil and gas wellbores penetrate shallower strata before reaching the target hydrocarbon formations, and these strata may contain groundwater for drinking or other surface uses

[2] This asphyxiation hazard arises as a result of methane’s ability to displace the oxygen in an enclosed space.

[3] It should be noted, however, that leaking wells are not the only source of methane. The presence of natural seepage pathways allows methane to migrate slowly from hydrocarbon zones to the surface (King and King 2013).

(Davies et al. 2014). Nonproducing wells left unplugged or that have been improperly plugged may facilitate the migration of pollutants between these zones and/or the surface or atmosphere (Calvert and Smith 1994; Kell 2011; King and Valencia 2014). Leakage pathways include the migration of methane from producing or nonproducing hydrocarbon formations, or sometimes from aquifers, to the atmosphere; of brine from saltwater zones to freshwater aquifers, surface water, or surface soils; of oil and gas from hydrocarbon formations to freshwater aquifers, surface water, or surface soils; or of pollutants in surface runoff into freshwater aquifers (API 1993). Two major types of leakage pathways are *surface casing vent flow* (leakage between the production and surface casings) and *gas migration* (leakage outside the outer casing; Erno and Schmitz 1996).

For a well to leak, there must be (1) a source of fluid (gas or liquid), (2) a breakdown of one or more well barriers—that is, a pathway for the fluid to migrate either within the cement medium or adjacent to it, and (3) a driving force for the migration of fluid, such as a pressure differential in the wellbore due to a higher pressure in the hydrocarbon formation than in the wellbore annulus (the space between the wellbore and the casing; Davies et al. 2014; Bonett and Pafitis 1996). Proper well construction and P&A procedures should likely prevent such conditions and therefore protect against fluid migration, at least in the early life of the decommissioned well.

During well construction, it has been common practice since well integrity regulations were introduced to protect the various zones—groundwater aquifers, hydrocarbon formations, and the surface—using barriers such as well casing and cement, to perform what is known as zonal isolation (King and King 2013; King and Valencia 2014). Well construction elements that protect against fluid migration to the subsurface and gas emissions to the atmosphere fall into a few categories: layers of well casing, cement used to fill the annular space between casings or between the outermost casing and the wellbore, and the wellhead or Christmas-tree assembly (API 1993).

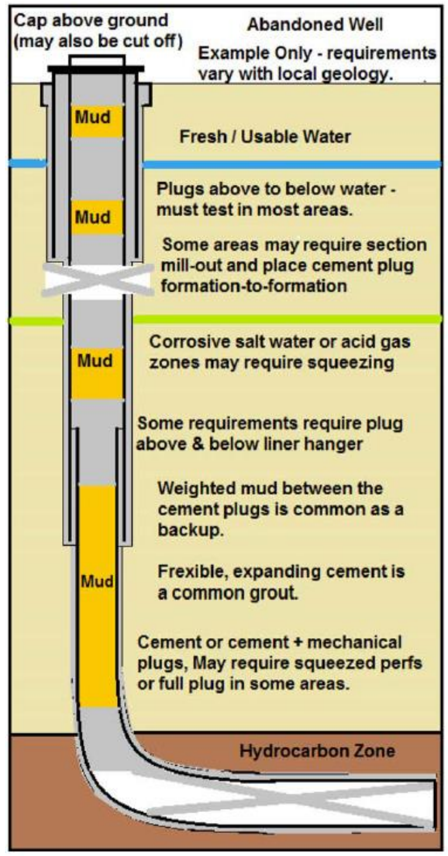
Depending on the unique geologic conditions and depth of the well, there may be one to three barriers in a low-risk area and two to five barriers in a high-risk area, where casing and cement are each considered individual barriers (King and King 2013). The most effective practices for zonal isolation include placing surface casing below a freshwater aquifer and cementing it to the surface, as well as setting production casing from the surface to the production zone and cementing it (at least for a substantial distance, if not all the way to the surface) to prevent the vertical migration of fluids behind the pipe (API 1993). There may also be multiple layers of intermediate casing between the surface and production casings depending on the depth of the well (Dusseault and Jackson 2014). To ensure the integrity of the barriers, a number of other well construction practices are important, including ensuring that the density of the cement slurry is properly designed and that mud is removed from annular spaces in the wellbore (Bonett and Pafitis 1996). Figure 2 is a diagram of a properly abandoned well showing the different zones that need to be plugged in order to ensure zonal isolation.

Thus, proper well construction is the first step towards ensuring zonal isolation over the entire lifetime of the well, including during production, after the well becomes inactive, and after P&A. P&A then builds on the completion design, further isolating parts of the wellbore. Effective P&A designs depend on robust evaluations of potential leakage pathways unique to the well (King and Valencia 2014). Depending on the quality of the well construction and P&A, leakage pathways may form in modern well construction through one or more mechanisms (leakage pathways associated with pre-regulatory wells are discussed in a later section):

- *Mechanical integrity failure*. The wellhead or Christmas-tree assembly may be inadequate to contain fluids, creating a pathway for methane to leak to the atmosphere (API 1993).
- *Casing failure*. Casing may fail due to failed casing joints, casing collapse from sustained casing pressure, and/or corrosion over time due to the presence of brine or of hydrogen sulfide, which forms sulfuric acid upon contact with water (Davies et al. 2014; Watson and Bachu 2009; King and King 2013).
- *Cement failure*. Multiple issues can contribute to cement failure. For instance, cement may shrink over time. This is particularly likely if the water content in the cement is too high, which causes the cement to lose water while setting (Dusseault et al. 2000). This causes a microannulus to develop between the cement and the rock wall and/or casing. Figure 3 is a visual representation of how cement shrinkage can create a fluid migration pathway. There is a possibility that all wells plugged with cement will eventually leak, given enough time, due to this issue of cement shrinkage (Kunz 2015), although this has not been supported by empirical research.

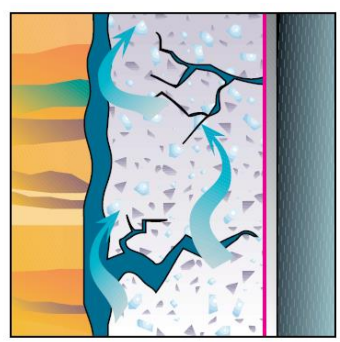
These basic pathways can cause leaks regardless of whether the well has been permanently abandoned, temporarily abandoned, or merely shut in. The risk that any of these leakage pathways may develop may be greater or lesser, depending on a variety of factors discussed in the next section.

FIGURE 2. SCHEMATIC OF A PROPERLY ABANDONED WELL



Source: King and Valencia (2014).

FIGURE 3. CEMENT SHRINKAGE CREATING MICROANNULI



Source: Bonett and Pafitis (1996).

Factors Affecting the Magnitude of Risk

The magnitude of leakage risk that any given well presents is determined by a number of factors, including the quality of well construction, the plugging and abandonment measures that have been taken, and other factors.

Well Construction

Proper well construction is the first critical safeguard against fluid migration, not just during a well's production life but also after it becomes inactive. For instance, an inadequately cemented annulus provides a conduit for gas migration to occur between hydrocarbon formations and freshwater aquifers (Dusseault and Jackson 2014). Well construction elements such as properly cemented production casing and surface casing also enhance the success of plugging operations by improving the effectiveness of cement plugs (API 1993).

The integrity of a well's construction depends primarily on its vintage, as the quality of construction depends heavily on the well construction regulations in place at the time that the well was drilled. Many historic wells in the first oil and gas states like Pennsylvania, Texas, and Ohio were drilled in the nineteenth century before well construction regulations were introduced (Calvert and Smith 1994; King and King 2013; King and Valencia 2014). The earliest wells were drilled before operators began to use steel pipe, and those wells were cased with wood (King and Valencia 2014). King and King (2013) list the major changes in well construction regulations that have been introduced since the 1820s and the estimated pollution potential associated with wells constructed at different times. The well construction elements most crucial for reducing the pollution potential from inactive-unplugged wells are:

- *Zonal isolation*: Most wells constructed after the late 1930s were required to have multiple cement and casing barriers to prevent fluid migration into freshwater aquifers (API 1993).
- *Cement quality*: The American Petroleum Institute published cement standards for well construction and well plugging in 1953, specifying eight classes of cement designed to resist various subsurface conditions such as high pressure, salinity, and sulfate concentrations (NPC 2011), although King and King (2013) cite the mid-1970s as the time period when cementing standards improved systematically throughout the industry through the introduction of cement design software and the introduction of more robust cements into the market.

In addition to the stringency of well construction regulations, market conditions at the time of well completion have also affected the integrity of construction. In their study of how wellbore characteristics affect the leakage potential of wells in Alberta, Watson and Bachu (2009) find that high oil prices are highly correlated with high leakage occurrence between 1973 and 1999. They hypothesize that increased production activity in response to high oil prices can result in limited supplies of equipment and manpower and therefore suboptimal cementing practices.[4]

Abandonment Measures

Whether open annular spaces allow for fluid migration in an inactive well also depends on the abandonment measures that have been taken in that particular well. This should not be confused with a well's official abandonment status, as different jurisdictions have different definitions for each abandonment status, and terms such as "shut in," "temporarily abandoned," "suspended," and "inactive" are often

[4] An alternative explanation for this correlation is that small, independent operators tend to emerge during times of high oil prices, and the integrity of wells drilled by these operators may be lower.

used interchangeably (API 1993). Rather, the relevant question is what barriers are put in place after the well has stopped producing. Three major categories distinguish between these abandonment measures:

1. *No isolation of hydrocarbon zone*: An operator may shut off production from a well for short periods of time in response to temporary market conditions. The operator shuts off the wellhead but leaves the casing exposed to the completion interval.
2. *Temporary isolation of hydrocarbon zone*: In most cases, a well will only be classified as temporarily abandoned if the completion interval has been isolated. However, the interval is only temporarily isolated if the isolation barrier (such as a bridge plug) can be easily drilled through and the hydrocarbon formation re-accessed. This might be the case if the operator wishes to bring the well back into production.
3. *Permanent isolation of hydrocarbon zone and freshwater aquifers*: In a permanent P&A operation, the completion interval, any intermediate oil and gas-bearing zones, and any freshwater aquifers are isolated, and the rest of the wellbore that is not cemented is filled with mud.

In general, wells that have been permanently isolated are less likely to leak than are wells that have been only temporarily isolated, or not isolated at all. Kang et al. (2015) find that plugged wells have lower leakage potential than wells that have not been plugged, although this result is not statistically significant. Nonetheless, plugged and abandoned wells could still leak. Alberta's Abandoned Well Integrity Assessment Project finds that of the wells that were plugged in and after 2008, 11.6 percent of them leak (Boyer 2015). This concern was also corroborated by an industry consultant (Kunz, 2015) and by a representative of the Alberta Energy Regulator (Taylor, 2016) that we spoke to. However, there is very little anecdotal evidence available to support this, and a few reviewers of the draft of this report said that this concern about properly plugged wells leaking was exaggerated or nonexistent.

Among wells that have been permanently plugged and abandoned, there is heterogeneity in leakage potential depending on the specific abandonment methods used. Watson and Bachu (2009) find that wells plugged using bridge plugs are more likely to leak than wells that have been plugged using cement plugs and cement retainers. A detailed description of different plugging methods can be found in NPC (2011).

Of wells that are plugged, improperly plugged pre-regulatory wells pose the greatest problem. These wells were drilled before P&A regulations were systematically introduced and were simply plugged with materials such as brush, wood, and rocks (NPC 2011). For instance, the Texas Railroad Commission began to regulate well plugging in 1919, although cementing procedures were not introduced until 1934 and freshwater aquifers were not required to be protected until 1957 (Texas RRC 2000). In general, oil and gas states began to require cement in P&A operations in the 1950s and introduced stricter standards to protect freshwater aquifers in the 1970s, along with the passage of the Safe Drinking Water Act in 1974 (NPC 2011).

Other Oil and Gas Activities

As mentioned earlier, another crucial factor influencing leakage potential is the presence of a pressure gradient or fluid buoyancy gradient within the wellbore. If there are unplugged or improperly plugged wells in an area, it becomes especially important to pay attention to the likelihood that the hydrocarbon formation that these wells penetrate becomes re-pressurized. Re-pressurization may occur due to nearby gas drilling, completion, and well stimulation activities (Jackson et al. 2013). For instance, the injection of fluids at high pressure during hydraulic fracturing can pressurize nearby offset wells that have not been shut-in (Dusseault and Jackson 2014). The pressure from the injection of CO_2 if a formation is used for CO_2 storage also presents a similar risk (Watson and Bachu 2009). Alternatively, the buoyancy of the CO_2 may itself cause CO_2 leakage to the surface after it has been injected.

Subsurface Geology

Finally, the subsurface geology of the area around an inactive-plugged or inactive-unplugged well can influence the leakage potential of the well both by increasing the risk that a leakage pathway will develop and by influencing the pressure or fluid buoyancy gradient. Wet areas and hydrogen sulfide-bearing zones can all accelerate corrosion (King and King 2013). Salt zones may increase the risk that cement will be contaminated by salt and set prematurely, thus compromising the long-term integrity of the cement plug (NPC 2011). High-pressure areas may also increase the risk of fluid migration; King and King (2013) estimate that wells in these environments may have a life of a decade or less before permanent plugging and abandonment is required.

Other Factors

Finally, the ownership status of a well and its location relative to water resources and/or human population centers are correlated with or contribute to environmental risk. A well's ownership status refers to whether it has a responsible operator on record. On average, orphaned wells are likely to have been drilled earlier than wells with an owner and are thus more likely to have lower-integrity well constructions and/or be in a deteriorated condition. In addition, operators may be willing and able to plug and abandon only the wells that are cheaper to plug, and may choose to leave the wells with higher plugging costs in a temporarily abandoned state or transfer these wells to smaller operators, who are more likely to default on their bonds, resulting in orphaned wells. These wells that are more expensive to plug may also be the wells that are in the worst condition and thus more environmentally risky.

The proximity of a well to human populations or groundwater supplies is also a crucial factor in determining the inactive wells that deserve closer attention and monitoring. Oil and gas states with well plugging programs generally have criteria for prioritizing wells to be plugged, including their location. The Kansas Corporation Commission (KCC), for example, prioritizes wells in a poor condition based on whether they are a threat to sensitive surface water or groundwater areas, and whether they are a threat to public safety in urban or suburban settings (KCC 2015).

Empirical Estimates of Magnitude of Pollution Potential

The basic leakage pathways that cause methane leakage or groundwater contamination from production wells, such as uncemented annuli or casing corrosion, are also responsible for pollution from inactive wells. The failure rate of oil and gas wells in general has been documented in empirical studies. A 1995 study by Westport Technology found that 15 percent of primary cement completions in the United States fail (Dusterhoft et al. 2002). In a more recent study, Ingraffea et al. (2014) use state monitoring records and report that 1.9 percent of the 32,678 oil and gas production wells drilled in Pennsylvania between 2000 and 2012 have some evidence of leakage and have been issued a Notice of Violation (NOV).[5] In addition to failure rates of cement and casing, local

[5] Based on this, Ingraffea et al. conclude that these 1.9 percent of wells experienced a loss of structural integrity. However, this conclusion has received criticism for conflating being issued an NOV and experiencing a loss of structural integrity, see e.g. Brown (2014) for a discussion from an industry viewpoint.

instances of pollution from both producing and inactive wells have also been documented. Erno and Schmitz (1996) and Van Stempvoort et al. (1995) have measured gas leakage through surface casing vent flow and soil gas migration from oil and gas wells in the Lloydminster area of Alberta, with the latter documenting instances of groundwater contamination. Instances of pollution specifically from inactive, improperly plugged and abandoned wells also have been documented: Lyverse and Unthank (1988) document an incident of excess chloride discharge from abandoned exploration wells into a shallow aquifer near Fort Knox, Kentucky, and Chafin (1994) describes methane discharge into shallow groundwater from abandoned wells drilled in the 1930s in the San Juan basin in New Mexico and Colorado.[6]

Although these studies are useful for understanding the mechanisms through which methane leakage and groundwater contamination from inactive wells can occur, and for providing anecdotal evidence that such pollution does occur, they do not provide empirical estimates of the rate at which pollution occurs for inactive wells specifically. Of the empirical estimates that have been published, some are disputed. Thus, given the current state of the literature, it is difficult to estimate the scale of the problem of pollution from inactive wells, whether plugged or unplugged.

To our knowledge, Kang et al. (2014) provide the only U.S. estimates of methane emissions from inactive-unplugged wells. By measuring methane emissions from a sample of 19 orphaned wells and scaling the mean methane flow rate at these wells to the estimated population of 300,000–500,000 orphaned wells in Pennsylvania, Kang et al. estimate that methane emissions from orphaned wells may have been responsible for 4–7 percent of total anthropogenic methane emissions in the state during 2010, although they acknowledge that they cannot guarantee the representativeness of their samples. Furthermore, King and Valencia (2014) argue that this figure is likely to be an overestimate, as the sample wells are not likely to represent all abandoned or orphaned wells.

Using data on methane emissions from 42 plugged and unplugged wells, Kang et al. (2015) estimate the effective permeabilities of these wells—that is, the wells' potential to leak methane. The authors estimate the effect of plugging status (plugged or unplugged), geographical location, and well type (oil, gas, or combined oil and gas) on the permeability of a well. They find that the average effective permeability of unplugged wells is higher than that of plugged wells (although this difference is not statistically significant), that permeability of plugged wells is highly variable, and that the permeability of gas and combined oil and gas wells is higher than that of oil wells.

Outside of the United States, we discussed the issue of leakage from temporarily abandoned wells with Michael Taylor, Vice-President for Climate Policy Assurance at the Alberta Energy Regulator. Data on temporarily abandoned wells in Alberta reveals that, in 2015, of 80,000 wells with this status, 5,000 were reported by owners to be leaking methane (a rate of about six percent), with an average daily leakage rate of 13 cubic meters. The maximum observed leak rate was around 500 m^3. Such wells can legally remain in this state for up to ten years, so an average leaking well could emit over this period 47,000 m^3 before it returns to production or is permanently plugged.

Kell (2011) examines the groundwater contamination rate using data on reported groundwater contamination from oil and gas wells in Ohio and Texas. Over a period of 25 years

[6] The age of these citations should be noted. Newer studies examining wells that have been more recently completed may find that these wells have a lower rate or risk of leakage.

from 1983 to 2007, 41 of 185 groundwater contamination occurrences (of a total of 65,000 wells) in Ohio were due to leakage from orphaned wells, whereas four were caused by reclamation. In Texas, 30 of 211 groundwater contamination occurrences (of a total of 250,000 wells) were caused by orphaned well leakage, and one was caused by reclamation. Of the 30 orphaned well leakage incidents, 28 were caused by the vertical migration of fluids through inadequately sealed boreholes. Most of these wells were characterized as "old" or "historic."

Number of Inactive Wells in 13 States

In addition to reviewing the various environmental risks associated with inactive wells that are not properly decommissioned, another important aspect of understanding the aggregate environmental risk posed by this population of wells is estimating the number of such wells in the United States. Here, we estimate the number of wells that have stopped producing that have not yet been decommissioned, and calculate this as a percentage of the total number of inactive wells. In so doing, we develop, for the states sharing their data with us, an upper bound estimate of the number of wells that could potentially create the types of environmental damage described above.[7]

We contacted officials from various state oil and gas agencies, prioritizing states with significant oil and gas production as well as states with larger numbers of inactive wells. In total, we managed to obtain data from 13 states.[8] Table 1 presents these results. Note that, as laid out in the report's introduction, we use the term "inactive" to refer to all wells that have stopped producing. At present, the literature on the issue of inactive wells focuses on orphaned wells, particularly those that were drilled in an earlier regulatory era. We argue that this focus needs to expand to include all wells that have ceased production. Even wells with modern well constructions can fail; additionally, all the wells being drilled today have the potential to become orphaned in the future.

"Inactive wells" as we define them here include shut-in wells,[9] which states generally consider to be part of "active" wells, temporarily abandoned wells, and wells that have been decommissioned, which states generally classify as "plugged and abandoned" and not "inactive". Although shut-in wells and temporarily abandoned wells are technically wells that have been demonstrated to have future use and do

[7] Note that even wells that have been plugged and abandoned might still leak, although the science on this is not settled and this is an area for future research.

[8] Using this state-by-state approach meant that we were not able to develop estimates of the number of inactive wells in all states across the United States. In order to do that, the proprietary database owned by DrillingInfo provides a starting point, as it contains data on all wells that have been drilled in the United States to date. For a few states, DrillingInfo's data also has the advantage of being more comprehensive than the states' own electronic databases, as DrillingInfo has digitized analog data on orphan wells. However, there is little consistency in the way states report data on well production and well statuses: production may be reported at the well level or the lease level, data is updated anywhere from twice a month to once a year, and the wells in some states lack specific well statuses (such as plugged and abandoned wells) and are only very coarsely categorized in DrillingInfo as either active or inactive. Thus, developing estimates of inactive well numbers that are both accurate and comprehensive requires working carefully with both DrillingInfo's database and data provided by state agencies themselves. This was outside the scope of our work.

[9] A shut-in well is a well that is temporarily plugged but capable of producing in the future. The well is secured, but easily re-opened. A well may be shut in due to poor market conditions, inadequate well maintenance and repairing, or lack of equipment to complete it, among other reasons.

not have to be decommissioned at this time, we include them in our count of wells, as each of these wells has the potential to cause environmental damage if it is not eventually plugged, or not properly plugged. There is also reason to believe that some of them may not be consistently monitored by state regulators; that is, some of them may be in poor enough condition to require decommissioning, but are nonetheless allowed to remain in temporary abandonment status.

Table 1 shows the proportion of inactive wells in each state that have not been permanently decommissioned, and therefore, the proportion of inactive wells that may create an environmental concern. It should be noted, however, that the current oil and natural gas price environment has resulted in more wells being shut-in; therefore, the number of inactive wells reported here may be higher than they would be under higher oil and gas prices.

Across the 13 states, the population of inactive wells is as large as 557,000, 12 percent of which have not been decommissioned. The percentage in each state varies considerably, with Ohio reporting only 1 percent of inactive wells that have not been decommissioned, and Missouri reporting 56 percent. This should not be read as a measure of each state's ability to decom-

TABLE 1. TOTAL NUMBER OF INACTIVE WELLS IN EACH STATE[10]

State	Total inactive wells	Inactive non-P&A*	Inactive P&A	Active wells	Inactive non-P&A wells as % of total inactive wells
MO	9,098	5,111	3,987	1,193	56
KY	29,546	12,338	17,208	41,371	42
MT	12,358	4,652	7,706	28,947	38
WV	36,941	14,018	22,923	18,919	38
NY	12,702	1,730	10,972	11,406	14
PA	52,091	6,895	45,196	121,011	13
ND	11,210	1,341	9,869	14,373	12
NM	46,105	4,773	37,076	52,903	10
WY	45,913	3,981	41,932	32,841	9
KS	210,868	15,465	195,403	91,472	7
CO	37,662	1,881	35,781	50,861	5
AR	24,660	948	23,712	17,680	4
OH	106,188	1,178	105,010	61,189	1
Total	**635,342**	**74,311**	**556,775**	**544,166**	**12**

Note: We use P&A—"plugged and abandoned"—here as a synonym for "decommissioned."

[10] Different states have different ways of categorizing wells. Inactive, non-P&A wells include various types of non-producing wells that have not been plugged, including orphan wells, wells of various temporarily abandoned statuses, shut-in wells, and wells approved for plugging. In certain states, for instance, in West Virginia and Montana, production data is reported only in twelve-month cycles such that it was not possible to extract wells that have been shut-in for less than twelve months and include these in our count of inactive wells. For these states, therefore, the number of non-P&A wells reported here is an underestimate. Inactive, P&A wells include wells labelled plugged and abandoned, dry and abandoned, and final restoration. Active wells include all currently producing wells, and exclude wells that were never drilled or wells with expired or cancelled permits. The numbers reported in this table are based on data gathered in February and March 2016.

TABLE 2. INACTIVE WELLS ON FEDERAL LAND VS. STATE LAND

State	Inactive non-P&A wells on federal land	Inactive non-P&A wells on non-federal land	Total # of inactive non-P&A wells	Percentage of inactive non-P&A wells on non-federal land (%)	Percentage of land under federal ownership (%)
NM	2513	1960	4473	43.8	44.4
ND	236	1105	1341	82.4	7.4
PA	195	6465	6660	97.1	2.4
KS	62	15403	15465	99.6	1.2
NY	4	1726	1730	99.8	0.9

-mission inactive wells in a timely manner, as the low percentage in states such as Ohio and Kansas also reflects the fact that many of the wells in these states were drilled a very long time ago and have since stopped producing and been decommissioned. The numbers simply illustrate the size of the population of wells presenting an environmental risk in these 13 states.

Not all of the responsibility for managing inactive wells falls to the states. To understand how much of the burden of managing inactive wells is borne by individual states versus the federal government, we also examine the number of inactive wells on different types of land, including federal land [11] as one category and state/local government/private land as another (from now on grouped here as called "non-federal land"). Wells located on non-federal lands are managed by the states.

We were able to obtain well status and location data for five states, including Kansas, North Dakota, New Mexico, New York and Pennsylvania. We merge well data from these five states with the Department of Interior's Surface Management Agency (SMA) Geographic Information System (GIS) dataset to identify the number and proportion of inactive, non-P&A wells on federal and non-federal lands.

Table 2 shows that New Mexico has 43.8 percent of non-P&A wells that are on state land, which is lower than the equivalent figure in the other four states, where more than 80 percent of non-P&A wells are on non-federal lands. This is unsurprising given that the percentage of land under federal ownership in New Mexico is the highest amongst the five states, at 44.4 percent. In the other four states, most of the land is owned by state and local governments, and private landowners. It is likely that the federal government has a relatively larger share of well plugging liabilities in Western states, which have a greater proportion of federal lands. Obtaining data and conducting this exercise for more Western states would help to verify this.

[11] Federal land includes lands administrated by agencies, such as National Park Service, Fish and Wildlife Service, Bureau of Reclamation, Bureau of Land Management, Bureau of Indian Affairs, Forest Service, Department of Interior, Department of Agriculture, Army, Navy, Air Force, Maine Corps, Coast Guard, Corps of Engineers and Department of Defense.

4. Regulations on Inactive Oil and Gas Wells

Key Findings and Recommendations

- The individual states and the Bureau of Land Management have very different approaches for regulating the management and decommissioning of inactive wells. This heterogeneity in regulations can be described in terms of their comprehensiveness (i.e., the number of regulatory elements they regulate) and their stringency (i.e., how strict their regulatory elements are).
- Shih et al. (forthcoming) note that financial assurances are often inadequate to cover the costs of decommissioning an inactive well. We recommended that bonding amounts should vary according to the major factors influencing costs, such as well depth. In this section (Table 5), we report that many states already do this, to varying extents. We therefore recommend that other states consider this approach to bonding and that all states examine our statistical results for insights into the specifics of how various factors affect costs. Given adequate data, our statistical method may even be used by the states to design bonding requirements that vary with cost factors.
- States deal with temporary abandonment in a variety of ways, some more protective of the environment than others. For states that are less protective, shortening the time a well can be temporarily abandoned and raising the bar for proving a well should stay in that condition would help reduce the likelihood that inactive wells will create environmental externalities.
- Few operators properly mark decommissioned wells with a permanent sign under the current regulatory regime. We therefore recommend that states adopt more stringent regulations for marking decommissioned wells.

State oil and gas agencies regulate a range of industry activities related to the management and decommissioning of inactive wells. Regulatory elements include requirements for operators to post financial assurances intended to cover decommissioning costs and potential environmental damages, and administrative and technical procedures for temporarily abandoning or decommissioning a well. The BLM sets regulations that govern wells undergoing decommissioning on federal lands. As with earlier research by Resources for the Future (Richardson et al. 2013), this section compares regulations across states and the BLM and, where appropriate, compares the stringency of a selection of these regulations, which provides an indication of regulatory heterogeneity across these regulatory bodies.

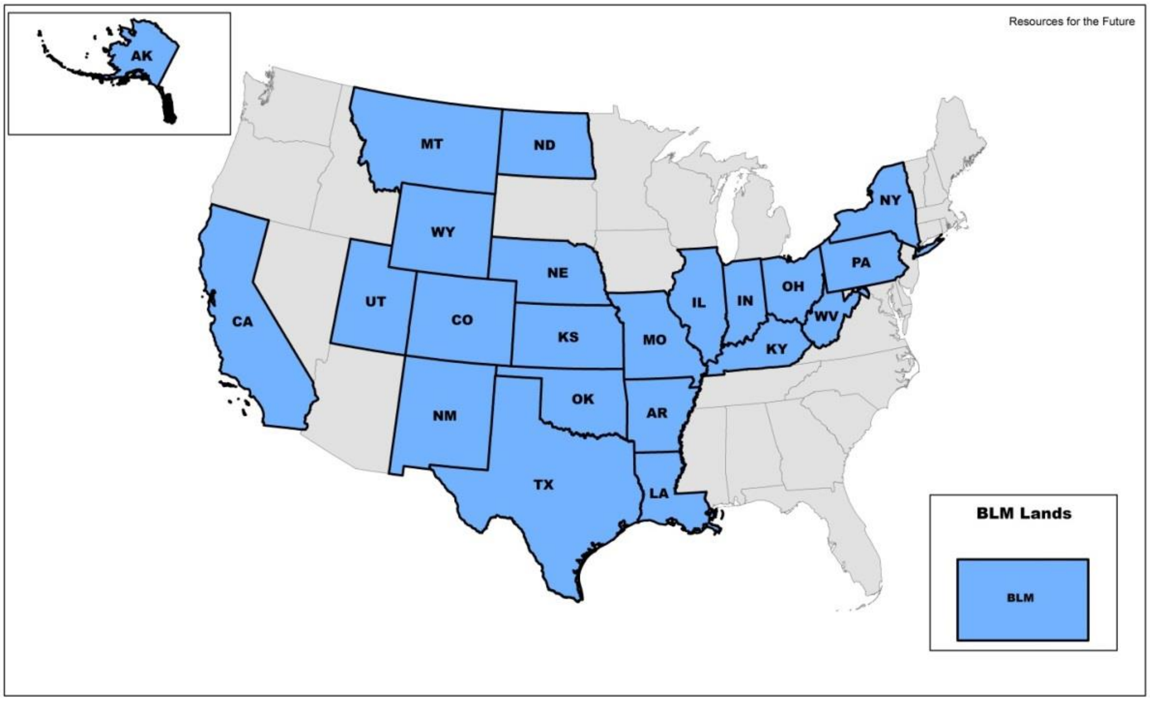
Methodology

We examine 31 regulatory elements across 22 states (see Map 1 below). We chose this sample of states by considering three criteria:

1. number of orphaned wells that are on a state's "wait list" for decommissioning, as reported by the Interstate Oil and Gas Compact Commission (IOGCC 2008);
2. a state's historical crude oil production from 1981 to 2014, as reported by the US Energy Information Administration (EIA 2015a); and,
3. a state's historical onshore natural gas production from 1992 to 2014 as reported by the US Energy Information Administration (EIA 2015b).

If a state contributes to more than 1 percent of the national total in any of these three criteria, we include it in our sample. Appendices A1 and A2 provide a detailed description of our selection process.

MAP 1. STATES INCLUDED IN OUR SURVEY OF INACTIVE WELL REGULATIONS



In the next section, we describe various regulatory elements and their importance for mitigating environmental risk. We focus only on state regulations, although we recognize that permits and field adjustments also play a part in regulating some of these activities. However, such variables are difficult, if not impossible, to capture across the states. We also do not comment on the quality of monitoring and enforcement in different jurisdictions. Two states may have identical regulations for a given element, but one state's enforcement might be more stringent than another's. Thus, we can only observe regulatory stringency and not effective stringency. In addition, we do not comment on what is "optimal" stringency or what is appropriate versus unjustified heterogeneity across the regulatory bodies. Instead, we describe regulations and note the ways in which the stringency may differ across some of these elements. Finally, we do not address certain decommissioning processes for unique types of wells, including underground injection wells, seismic exploration wells, geothermal wells, coalbed methane wells, and ratholes.

Review and Comparison of State and Federal Regulations

The 22 states we examine and the 31 regulatory elements we consider are displayed in Map 1 and Table 3 respectively. The 17 regulatory elements in the first panel of Table 3 are directly relevant to mitigating environmental impact and are therefore included in our stringency calculations. Following is an explanation of how these regulations may partially determine the degree of environmental and financial risk that the public may be exposed to:

1. The more accurately bond amounts reflect decommissioning costs and the more likely that states will be able to recover costs, then the more likely that operators will decommission their wells on schedule and/or states will have the necessary funds to plug orphaned wells (regulatory elements 1–5).

2. The easier it is for operators to idle and to apply and re-apply for temporary abandonment status for their wells, the more likely it is that wells will be left in an idle or temporarily abandoned. status indefinitely and therefore avoid proper decommissioning (regulatory elements 6–10).
3. More stringent requirements for temporarily abandoned wells help minimize the environmental harm caused by these wells (regulatory elements 11 and 12).
4. More stringent regulations on the procedures to be taken during plugging and restoration help minimize the environmental harm caused by decommissioned wells and well sites (regulatory elements 13, 15, and 16).
5. More stringent requirements for marking decommissioned wells and for reporting inactive wells help regulators identify wells that may cause environmental harm (regulatory elements 14 and 17).

The remaining 14 regulatory elements are not included in stringency analysis, either because they are not as relevant to environmental impact or are not easily comparable across states. Figure 4 compares the number of regulatory elements that each state (and BLM) explicitly regulates. Figure 5 rates the stringency of state (and BLM) regulations based on regulatory elements that are quantitative in nature, and Figure 6 does the same for regulatory elements that are qualitative in nature.

Figure 4 displays the number of elements regulated by each state, indicating the comprehensiveness of each state's regulations. If a state has explicit regulations for a regulatory element it receives a 1 and if it does not it receives a 0. Regulations for BLM also appear on the figure. As displayed in Figure 4, New York regulates the fewest regulatory elements (10 out of 17) whereas Pennsylvania regulates the most (all 17). Note that the stringency of regulations is not reflected in this figure.

Figure 5 displays states (and BLM) ranked by the average stringency of the five quantitative regulatory elements we consider. These five elements include (1) minimum individual bond amounts, in dollars; (2) minimum blanket bond amounts, in dollars; (3) well idle time, in months; (4) duration of temporary abandonment, in months; and (5) timing of restoration requirements, in months. In this figure, each regulatory element is normalized such that the least and most stringent regulations receive a score of 0 and 100, respectively. Then scores are averaged with equal weights across the five elements. We find that Alaska ranks at the top according to our five quantitative elements, with Arkansas having the least stringent regulations for these elements, about two-thirds less stringent than Alaska. No state is superior to all other states on all five elements.

Figure 6 displays states (and BLM) ranked by their stringency, as calculated using 12 of the 17 regulatory elements we consider that are binary and qualitative in nature. These include (1) type of financial assurances; (2) well characteristics that determine bonding amounts; (3) operator characteristics that determine bonding amounts; (4) permitting extensions for temporary abandonment; (5) whether notification, reporting, and inspection for temporary abandonment is required; (6) whether economic viability plays a role in determining status of temporary abandonment; (7) shut-in requirements for temporary abandonment; (8) whether well integrity testing for temporary abandonment is required; (9) the types of plugs required during decommissioning of a well; (10) whether marking of decommissioned wells is required; (11) whether restoration requirements are stringent; and (12) whether reporting is required for inactive wells. States (and BLM) with a regulation we judge to be stringent get a "1": otherwise they get a "0." So the highest score possible is 12. Pennsylvania leads the pack with a score of 11, while Kansas, Louisiana, and New York are in last place. Note that these calculations make no adjustment for regulatory elements unregulated by a state.

TABLE 3. REGULATORY ELEMENTS OF INACTIVE OIL AND GAS WELLS

Number	Regulatory Element
Panel A: Regulatory Elements Considered in Stringency Calculations	
1	Types of Financial Assurances (Qualitative)
2	Well Characteristics that Determine Bonding Amounts (Qualitative)
3	Operator Characteristics that Determine Bonding Amounts (Qualitative)
4	Minimum Individual Bond Amounts (Quantitative)
5	Minimum Blanket Bond Amounts (Quantitative)
6	Well Idle Time (Quantitative)
7	Duration of Temporary Abandonment (Quantitative)
8	Extensions for Temporary Abandonment (Qualitative)
9	Notification, Approval, and Inspection for Temporary Abandonment (Qualitative)
10	Role of Economic Viability in Determining Status of Temporary Abandonment (Qualitative)
11	Shut-in Requirements for Temporary Abandonment (Qualitative)
12	Well Integrity Testing for Temporary Abandonment (Qualitative)
13	Types of Plugs Required During Decommissioning of Well (Qualitative)
14	Marking of Decommissioned Wells (Qualitative)
15	Stringency of Restoration Requirements (Qualitative)
16	Timing of Restoration Requirements (Quantitative)
17	Reporting Requirements for Inactive Wells (Qualitative)
Panel B: Regulatory Elements Not Considered in Stringency Calculations	
18	Separate Bond for Site Reclamation
19	Surface Damage Agreements
20	Statute of Limitations
21	Liens on Equipment
22	Well Integrity Testing
23	Treatment of Wells with Different Casings
24	Treatment of Casing Removal
25	Treatment of Different Well Types
26	Cement Specifications for Plugs
27	Conversion to Freshwater Well
28	Notification, Approval, and Inspection for Decommissioned Wells
29	Ability for Regulator to Order Plugging and Replugging
30	Reporting Requirements for Inactive Wells
31	Considerations for Fugitive Methane

FIGURE 4. NUMBER OF ELEMENTS REGULATED BY EACH STATE (AND BLM)

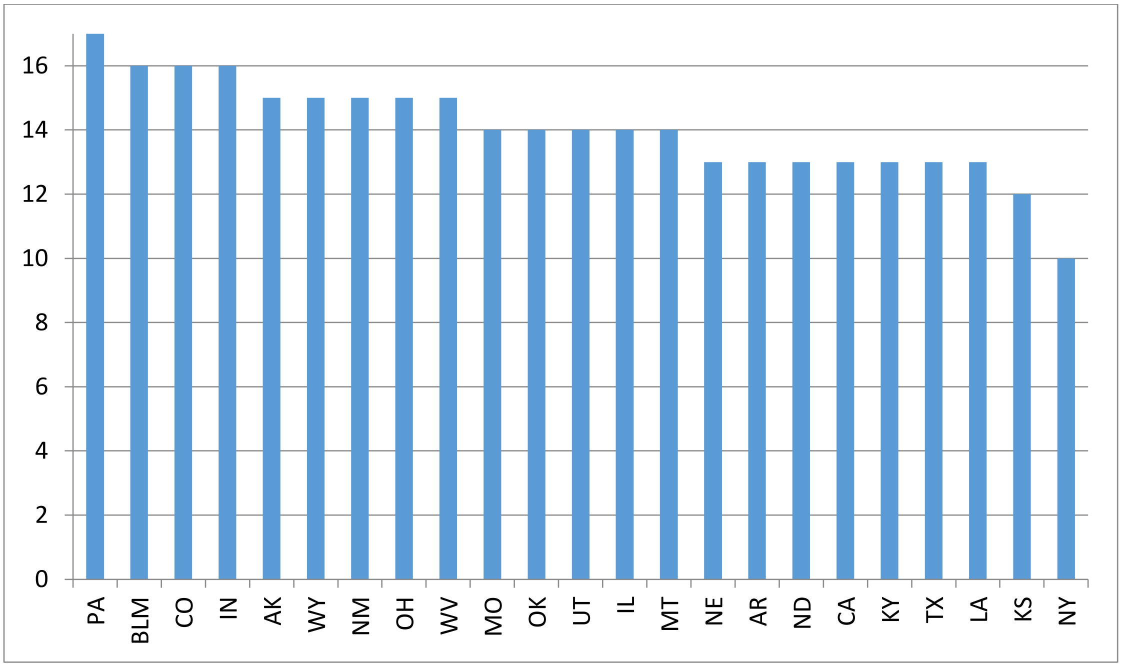


FIGURE 5. STRINGENCY BY STATE (AND BLM) ACCORDING TO QUANTITATIVE REGULATORY ELEMENTS

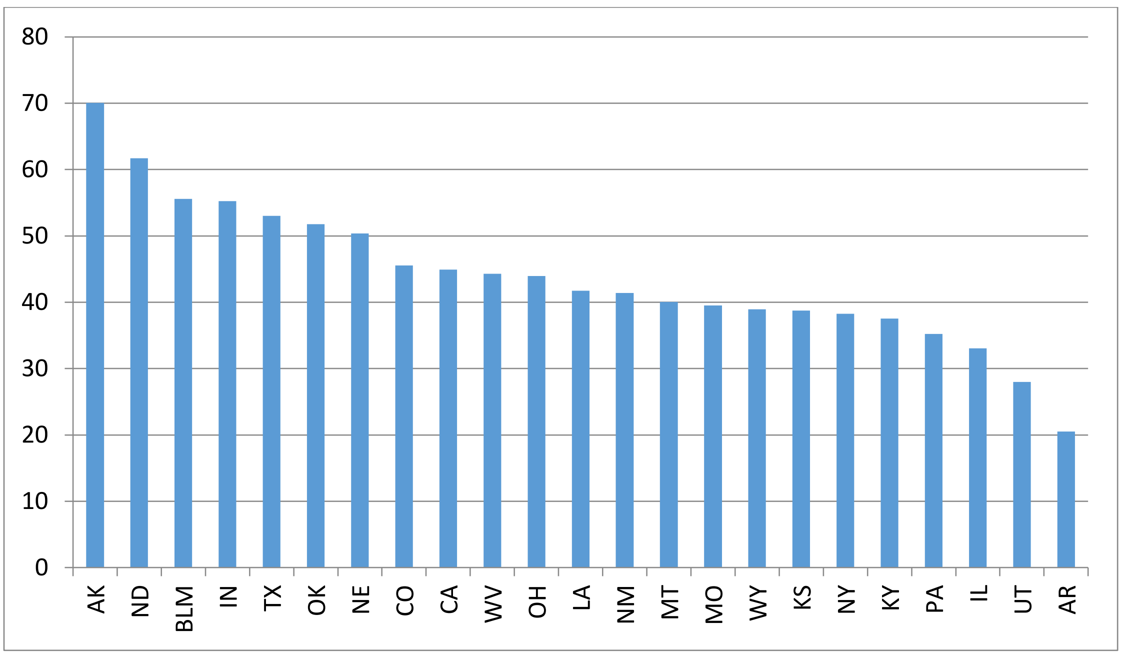
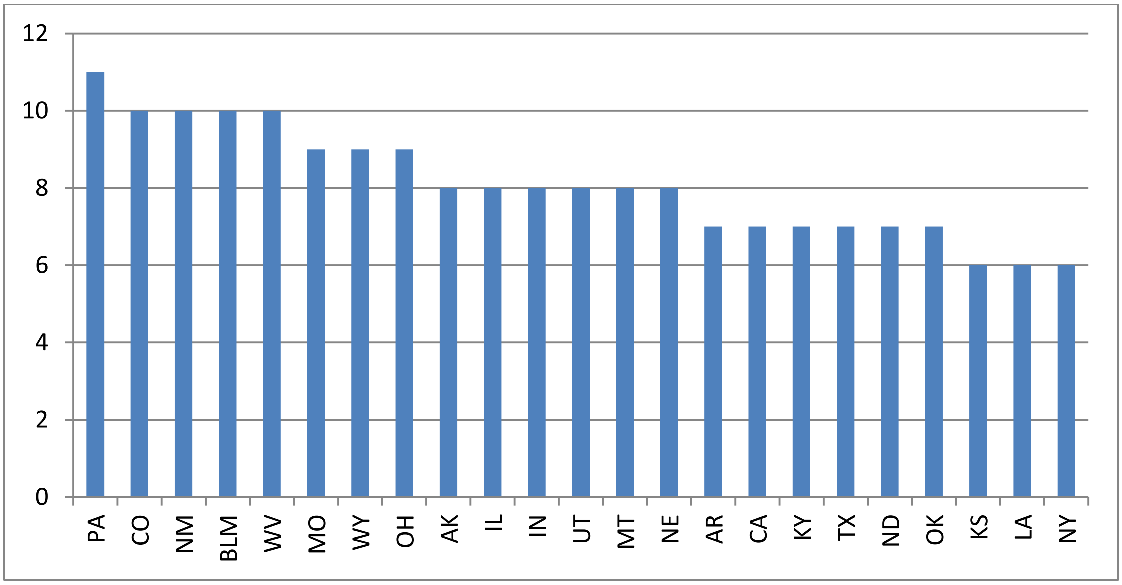


FIGURE 6. STRINGENCY BY STATE ACCORDING TO QUALITATIVE REGULATORY ELEMENTS



Discussion of Regulatory Elements

Bonding Requirements

An operator must post financial assurance for a well at the time it is drilled. States recover this financial assurance to cover the costs of decommissioning the well in the event that the operator is unable to do so. States vary in the types of financial assurance they accept and the amount they require.

Types of Financial Assurances

States allow operators to use a range of instruments for financial assurance, as displayed in Table 4. All states allow a surety bond, which involves a third party company that essentially issues and prices the bond. Other popular types of financial assurance include letters of credit, certificates of deposit, and cash. A handful of states also allow escrows, trust accounts, financial statements, and liens to serve as financial assurance. Many of these types of financial assurances come with a variety of stipulations (e.g., irrevocable, automatically renewable, whether interest on deposits accrues to operator or state) that may provide better fiscal protection for the states, however there appears to be a lack of analysis on this question. States do not typically require operators to choose a particular type of financial assurance and instead allow operators to choose from a range of options. The BLM allows operators to use surety bonds, letters of credit, negotiable Treasury securities, and cash in the forms of certified or cashier’s checks.

The form and amount of financial assurance at least partially determines the likelihood that the regulator will receive the appropriate funds for decommissioning in the event that an operator does not do so. Without sufficient funds, a regulator is less likely to have the financial means to decommission the wells that require it. Consequently, a well either will not be decommissioned or will stay in a status that is more likely to cause environmental harm for a longer period of time.

One way to distinguish between strong and weak financial assurances is to consider the mechanism through which the regulator would

Table 4. Types of Financial Assurances Accepted by States (and BLM)

State	Surety Bond	Letter of Credit	Certificate of Deposit	Cash	Escrow or Trust Account	Financial Statement	Lien	Govt. Bond	Annual Fees
AK	X	X	X						
AR	X	X	X	X					
CA	X		X	X	X			X	
CO	X		X	X	X		X		
IL	X	X	X						
IN	X		X	X					
KS	X	X					X		X
KY	X	X		X			X*		
LA	X	X	X		X				
MO	X	X	X						
MT	X	X	X					X	
NE	X		X	X					
NM	X	X		X					
NY	X							X	
ND	X			X					
OH	X	X	X	X		X			
OK	X	X	X	X		X			
PA	X	X						X	
TX	X	X		X					
UT	X	X	X	X				X	
WV	X	X	X	X	X				
WY	X	X	X						
BLM	X	X	X	X					

*This lien amount has limits.

receive funds. Cash, for example, guarantees that the state has funds upfront and is therefore quite a strong form of financial assurance (leaving aside the issue of whether the amount of cash is adequate). Other strong forms of financial assurance provide some form of guarantee by a third party that the funds will be allocated to the government in the event of a default and include surety bonds, letters of credit and perhaps escrow or trust accounts. A weaker form is liens, which allow the regulator to collect operator property if they do not pay; but such collections require legal operation, so are costly and may not be fully successful. Another weak form of financial assurance is financial statements, which require that operators provide proof of the financial health of their company—typically up to a set amount. Annual fees represent a special case. These effectively deliver cash to regulators on an annual basis, but the state that allows for them under certain circumstances (i.e., Kansas) sets the fee so low that we count the category as a weak form of financial assurance.

We use a binary and qualitative assessment when incorporating type of financial assurance into our stringency calculations for states. A state that allows for financial statements, liens, or annual fees receives a 0 and a state that does not allow for these types of weak financial assurances receive a 1. We do not consider the range of financial assurance types in our stringency calculation because most, if not all, states allow operators to choose between allowed financial assurances. Operators are therefore free to choose the type of allowed financial assurance they view as least stringent

Amount of Financial Assurance

Operators choose between individual or blanket bonds when posting financial assurance. The former type of financial assurance covers a single well, whereas blanket blonds cover multiple wells. This financial assurance is intended to cover the expected costs of decommissioning a well; yet, in practice, financial assurance amounts are often insufficient for this purpose, as discussed in Shih et al. (forthcoming) and existing literature (GAO 2011; LLA 2014). All else equal, a higher bond amount provides a more certain guarantee that wells will be properly decommissioned or that the state will have adequate financial resources to plug a well.

Table 5 shows that some states tailor bonding amounts based on well characteristics (depth, type, and location of wells) and operator characteristics (number of wells, number of inactive wells, and compliance history). As noted in Shih et al. (forthcoming), differentiating bond amounts based on the most important factors affecting decommissioning costs would help ensure that bonds, or other financial assurance requirements, more accurately reflect cost. Of these factors listed, well depth in particular has been known to strongly correlate

TABLE 5. FACTORS DETERMINING INDIVIDUAL AND BLANKET BOND AMOUNTS BY STATE

	Well Characteristics			Operator Characteristics		
State	**Depth**	**Type of Wells**	**Location of Wells**	**Number of Wells**	**Number of Inactive Wells**	**Compliance History**
AK						
AR		X *		X	X	X
CA	X			X	X	X
CO	X			X	X	X
IL	X			X		X
IN				X *		X
KS	X			X		X
KY	X	X		X		X
LA	X		X			
MO	X				X	
MT	X				X	X
NE						X
NM	X		X		X	X
NY	X					
ND						X
OH				X		
OK						X
PA	X	X		X		
TX	X			X		X
UT	X					
WV		X		X		X
WY	X				X	
BLM	X		X	X		

*Fee versus bond depending on well type (gas/oil) with cost due to the amount of plugging material and equipment rental time required. We find this effect in our statistical analysis, described in Shih et al. (forthcoming). Further, states have readily available information on well depth, which may help explain why most states use well depth to at least partially determine bond amounts. Calibrating bond amounts by well depth is important, especially as average well depths in the United States have been increasing.

Besides well depth, however, there are also several other factors that may influence cost and that could also be taken into consideration when setting bond amounts (Davis 2015). Four states (Arkansas, Kentucky, Pennsylvania, and West Virginia[12]) assign higher amounts to certain types of wells (e.g., horizontal) although it is not well understood whether and why unconventional wells may cost more to decommission than conventional wells.[13] The BLM, Louisiana, and New Mexico assign higher amounts to wells located in certain regions. This could help to capture the effects of spatial variables on cost, such as proximity to groundwater aquifers, the concentration of coal seams in a play, and the variation in prices charged by service providers operating under different market conditions.

Three operator characteristics play a role in determining bond amounts. First, in some states, the larger the number of wells owned by an operator, the smaller the amount of the individual well bond. Most states also permit operators that own many wells in the state to post a single blanket bond covering some, or all, of their wells. On the one hand, this makes sense as firms with many wells are larger, tend to have better access to decommissioning technologies, and are less likely to become insolvent. On the other hand, the price per well in tiered blanket bonds tends to go down quite significantly as the number of wells increases, offering a significant price discount to the operator. While this may help firms pool their risk, it also lowers financial coverage for the state and could leave it especially exposed in certain circumstances (e.g., a large concentrated investment by a small number of firms into a play or resource that goes bust, similar to what Wyoming has experienced with coal bed methane). One benefit of offering blanket bonds from the regulator's perspective is lower administrative costs to monitor well transfers and bond status.

Many states also use a regulator's compliance history and number of inactive wells to inform bond amounts, given that past performance may be associated with future performance. Regulators, at their discretion, may require operators with poor compliance histories to post higher bond amounts than the standard prescribed or may even prevent operators from posting new bonds or adding wells to a bond. Requiring higher bond amounts for operators with poor compliance histories, or those with a large number of inactive wells that may have an increased risk of being orphaned, helps ensure that the public does not eventually have to bear the environmental or financial burden left behind by irresponsible or bankrupt operators.

The BLM is allowed to require additional bonding based on well characteristics (i.e., location, depth, age, production capability of the associated field, and unique environmental issues) as well as operator characteristics including number of wells.

We use two binary and qualitative assessments when incorporating factors that determine bond amounts into our stringency calcula-

[12] Ar. Rule B-2.h; KRS 353.590(9); 58 Pa. Code §3225(a)(1, 2); WVC §22-6A-15.

[13] On the one hand, unconventional wells are typically deeper than conventional wells, but on the other hand, plugging of multiple wells can occur on the same pad for unconventional wells such that decommissioning costs may be lower due to economies of scale.

tion for states. Many states account for well and operator characteristics in an effort to match bond amounts to their conception of costs (i.e., decommissioning costs and costs of potential environmental damages). These states will, all else being equal, more accurately estimate costs of wells that become orphaned or create environmental damages before they are decommissioned (and the states therefore will more often have sufficient resources to deal those costs and damages). Our first stringency assessment assigns a 1 to states that account for well characteristics when determining the monetary value of individual or blanket bonds and a 0 to other states. Our second stringency assessment assigns states that use operator characteristics when setting bond amounts a 1, while other states receive a 0. We recognize that using these factors does not directly mean that the bond amounts are higher than in states that do not, although this appears to be the case in practice.

Map 2 displays the lowest possible bond amounts that states require operators to post for a single well. These amounts are typically denoted in dollar-per-well terms, and values among these states range from $500 per well in Kentucky to $100,000 per well in Alaska. Some states utilize other approaches: four states (Kansas, Louisiana, Texas, and Wyoming) calculate bond amounts in terms of dollars per foot of well depth, whereas New Mexico combines these approaches.[14] States that denote bond amounts in terms of dollars per well may further differentiate based on well depth, number of wells, and type of well (e.g., vertical or horizontal, inland versus coastal). These differentiations lead to multiple potential bond values for a well, and we therefore choose to display the lowest possible bond value in Map 2.[15] We use a continuous and quantitative assessment incorporating lowest possible individual bond amounts into our calculation of stringency across states. This assessment sets the lowest bond amount across states equal to 0 and the highest equal to 1, normalizing all values in between.

Map 3 displays the lowest possible blanket bond amounts that states require operators to post for multiple wells. The amounts are all denoted in terms of dollars, and values range from $5,000 in Kansas to $200,000 in California for certain types of blanket bonding situations.[16] States differentiate blanket bond amounts based on all aforementioned well and operator characteristics.[17] Similarly with Map 2, these differentiations lead to multiple potential bond values for a set of wells, and we therefore chose to display the minimum bond value in the map below. The BLM requires operators to post $25,000 to cover wells within a single state and $150,000 to cover all wells across the nation. We use a continuous and

[14] Note that annual well fees can be paid in lieu of bonds in Illinois and Kansas under certain circumstances. Specifically, bonds in Illinois are only required for certain operators (those in operation after 1991 and with poor compliance histories) (62 IAR I.240.240.15000(a). In Kansas, regulators allow operators to pay three percent of the amount that would be paid under an individual or blanket bond as a non-refundable fee, in lieu of a bond (KAR 82.3.120.g).

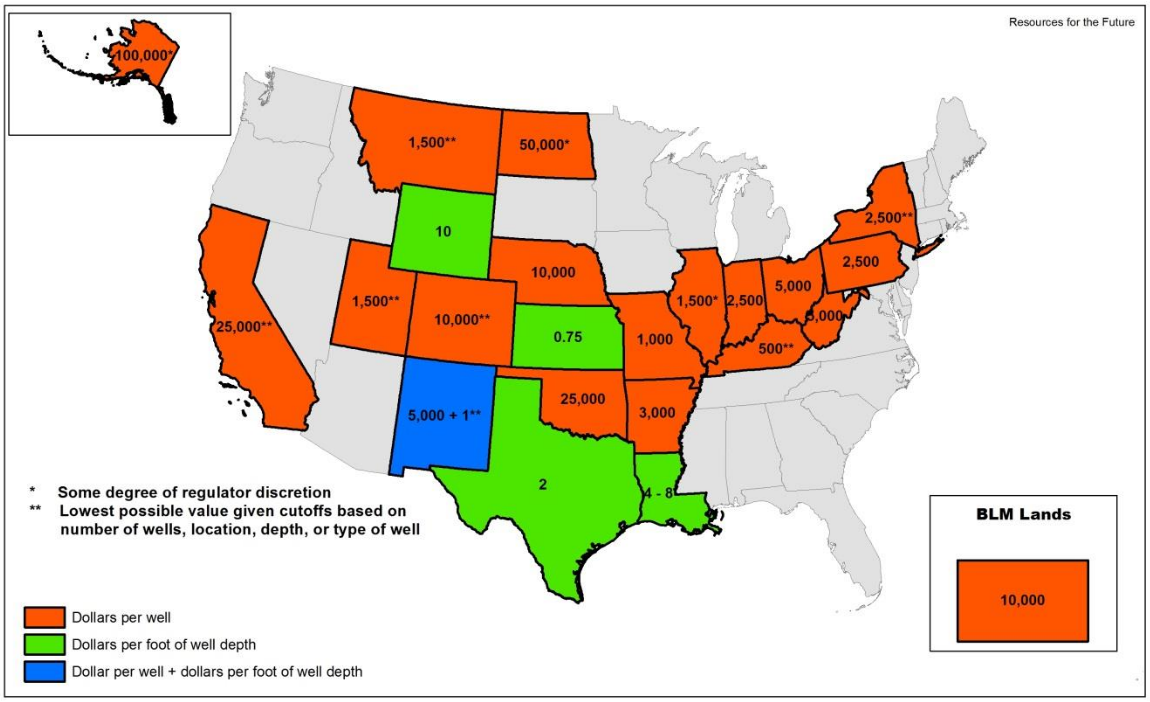
[15] For example, Illinois requires $1,500 in financial assurances for wells less than 2,000 feet and $3,000 for wells deeper than 2,000 feet. We therefore choose $1,500 dollars for our analysis, because it is the lowest possible value.

[16] California has different blanket bond amounts based on number of wells and whether the wells are also covered by an idle well fee. The relevant amounts are: $200,000 if there is no idle well fee and the operator has 20–50 wells; $400,000 if there is no idle well fee and 50+ wells; and, $2,000,000 with an idle well.

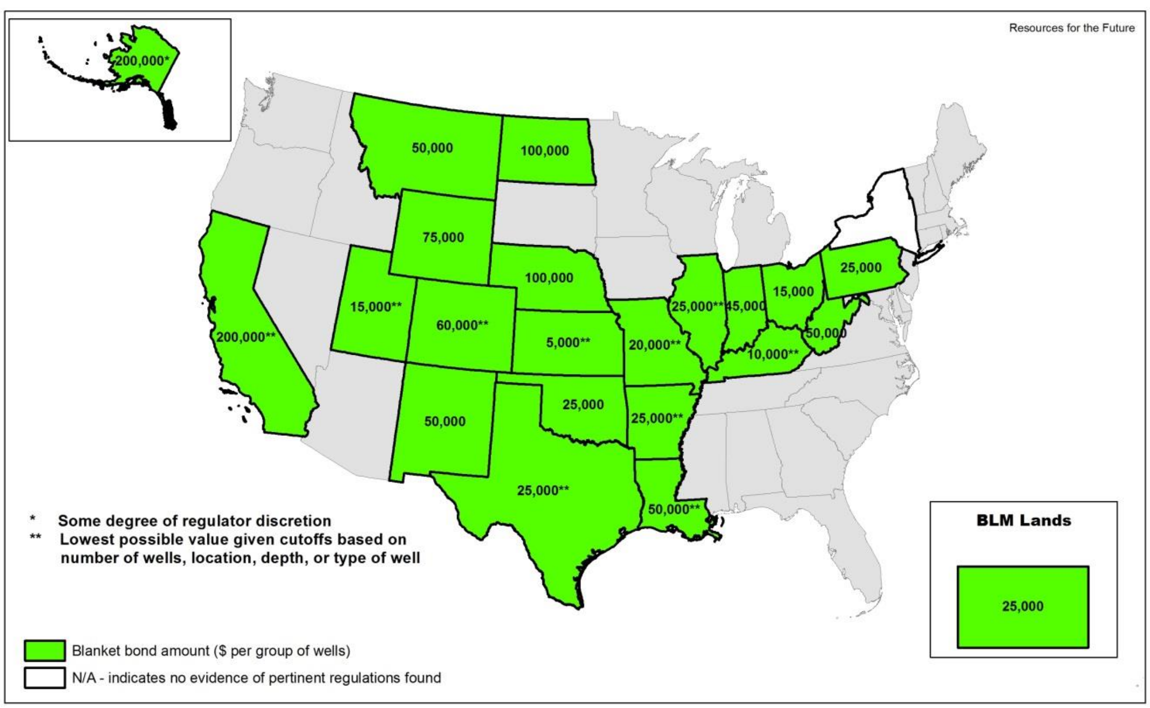
[17] For example, West Virginia has two different blanket bond amounts: $50,000 for conventional and $250,000 for horizontal wells. We therefore chose $50,000 because it is the lowest possible value.

quantitative assessment incorporating lowest possible blanket bond amounts into our calculation of stringency across states. This assessment sets the lowest blanket bond amount across states equal to 0 and the highest equal to 1, normalizing all values in between.

MAP 2. MINIMUM BONDING REQUIREMENTS FOR INDIVIDUAL BONDS



MAP 3. MINIMUM BONDING REQUIREMENTS FOR BLANKET BONDS



Treatment of Site Reclamation in Bond Amount

States generally expect financial assurances to cover all stages of well decommissioning, including site restoration. Although separate plugging and site restoration bonds may result in higher aggregate levels of financial assurance, the motivation for separating the two is not immediately clear. Four possible explanations are (1) that site restoration costs have greater heterogeneity and/or are less well understood at the outset, so regulators want to contain this variation in a separate instrument, and (2) that the time between plugging and restoration is prone to either long gaps in which risk of orphaning the well site is large, (3) that contracting for site restoration has a different supply curve than plugging and other well service contractors, and (4) that regulators want to establish a distinct bond forfeiture and return process for site restoration in addition to plugging. This latter explanation could allow for a different process or set of parties (e.g., surface owners) to be involved in bond forfeiture, or it could create an incentive structure that creates greater decommissioning compliance but worse site restoration compliance. A final thought is that because multiple wells are often on a single well site, separate site restoration bonds might better reflect the work flow of plugging different wells at different times, and then returning to site restoration at the end.

Surface Damage Agreements

One possible reason for having separate site restoration bonds listed above—establishing a different process for bond forfeiture or return that involves different parties—was observed in one novel policy arrangement we encountered during our review of state regulations: the use of surface damage agreements. These surface damage agreements are intended to provide some form of accountability to surface owners in cases where the surface and mineral estate may be severed. Seven states use surface damage agreements, three of which require up-front deposit amounts. In addition to the seven, Kentucky requires a surface owner agreement to the operator's reclamation plan and details a mediation process if the surface owner does not agree, and Ohio requires liability insurance coverage for property damage.[18]

This is an interesting approach regarding the local and distributional impacts of oil and gas development. In situations where the surface and mineral estates are owned by the same party, surface use and damage can be covered in lease provisions and other contractual arrangements. In split estate cases, however, protection for surface owners is not given special consideration. Outside of the environmental protection covered in regulations, the only recourse available to surface owners may be post-facto litigation. The surface damage agreements we found in our review generally feature some sort of negotiation between the operator and surface owner prior to drilling, and in some cases the agreement is required as part of the permit application. Although the type of damages covered is not expounded on in great detail, frequent mention was made for crop loss or loss of other surface use. Whether the agreements cover non-market values (such as recreational uses and noise) is unknown. The degree to which surface damage agreements increases monitoring, verification, and enforcement by either the regulator or through the surface owner is unknown but is a promising area of further research.

Statute of Limitations

The transfer of a well from one operator to another serves as a junction point of liability as the new operator submits new financial assurance or assumes responsibility for existing financial insurance. While states generally have stipulations on notice to be provided to the regulator and any involved financial parties at the

[18] 805 KAR 1:170(2.3, 3, 4); ORC 1509.07(A)

time of this transfer, some stipulate special liability protection, extended periods for which original or previous well owners may continue to be held responsible for plugging, or provisions establishing how far back through ownership history states may go to find financially able previous operators to defray plugging costs.

We can think of these extended liability or statute of limitations provisions as covering two basic scenarios—ones in which the new owner is noncompliant with plugging orders or becomes financially insolvent, and ones in which the previous owner had poor operating practices or well problems that only became apparent after a time delay. While we note the appearance of such language in the statutes and rules we reviewed, such liability provisions are likely also covered contractually between parties outside of systematic regulation by the state. However, the regulations we reviewed typically featured strong discussion of bond transfer, forfeiture, and release. Protections to the state generally took the form of ensuring that the regulators are notified prior to transfer and that the new operator has posted a new (or adopted the previous) financial assurance. Some states (such as Indiana) specify in greater detail that states may deny bond transfer if the new operator has a bad credit or operating history or for other reasons.

Extended liability provisions may be highly beneficial in some cases, particularly for wells of an older vintage. Older wells, especially those drilled before modern drilling and casing standards were implemented, pose a greater environmental risk and can result in greater plugging costs. Additionally, older wells are more likely to have been transferred to other operators, and so measures that ensure that these operators have some form of financial liability (as in liability provisions of the so-called Superfund law) may significantly defray fiscal costs for the state. The number of states that stipulate extended liability in regulations is small, although as noted, these provisions may exist outside of specific regulations.

Liens on Equipment

Some states establish in regulations a lien on oil and gas site equipment or resources, and infrequently such a lien may be used as financial assurance. Some states also specify the process by which they bid out state plugging contracts and how salvage value of any equipment (including casing) may factor into such payment. Use of liens or salvage value is assessed as a weak financial assurance in our review. Additionally, some lien policies allow outside parties (particularly nearby surface owners) to enter onto an orphaned or noncompliant well site and plug a well and reclaim any salvage value. Some states require salvage operators to post their own financial assurance, presumably due to environmental risk that may result from casing removal.

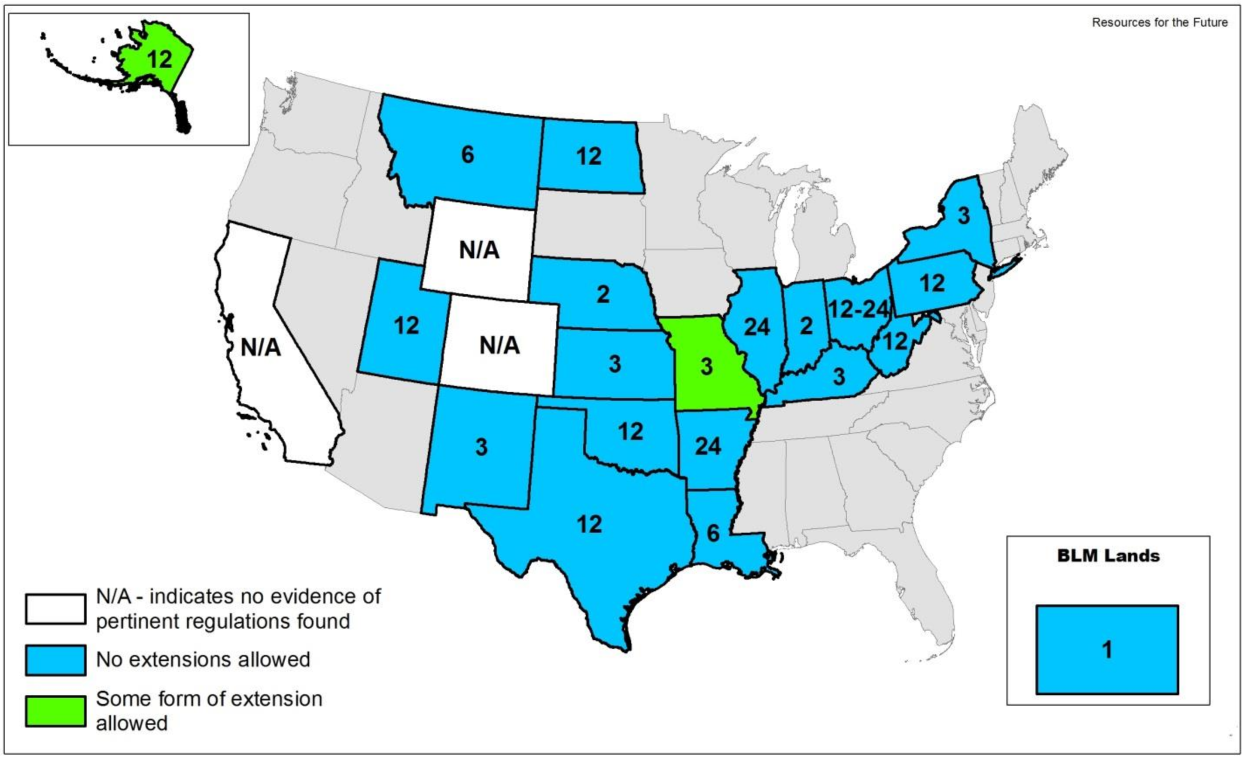
Temporary Abandonment

Well Idle Time

An idle well is one that is not currently producing oil or gas. Wells are not generally permitted to remain idle indefinitely. Instead, after a certain period of time (which we refer to as “well idle time”), operators have a choice: they can start producing again, temporarily abandon the well, or decommission it. We hypothesize that the longer a well remains idle but not properly decommissioned, the greater the odds that the well imposes environmental externalities.

Of the 22 states in our survey, 19 impose limits on well idle time. Map 4 displays these values, which range from 1 month on BLM lands to up to 24 months in Arkansas and Ohio. The map masks at least two complexities. First, several states differentiate well idle times based on certain categories of wells—especially those that are uncased, dry, or non-commercial. Dry and uncased wells in particular often have a substantially shorter

MAP 4. MAXIMUM WELL IDLE TIME (IN MONTHS)



well idle time (e.g., those in Arkansas, Illinois, and Louisiana).[19] Second, two states (Louisiana and Alaska) allow for operators to apply for extensions—granting regulators a significant degree of discretion over effective well idling time.[20]

We use a continuous and quantitative assessment when incorporating maximum well idle time into our stringency calculation for states. This assessment sets the longest maximum well idle time across states equal to 0 and the shortest equal to 1, normalizing all values in between.

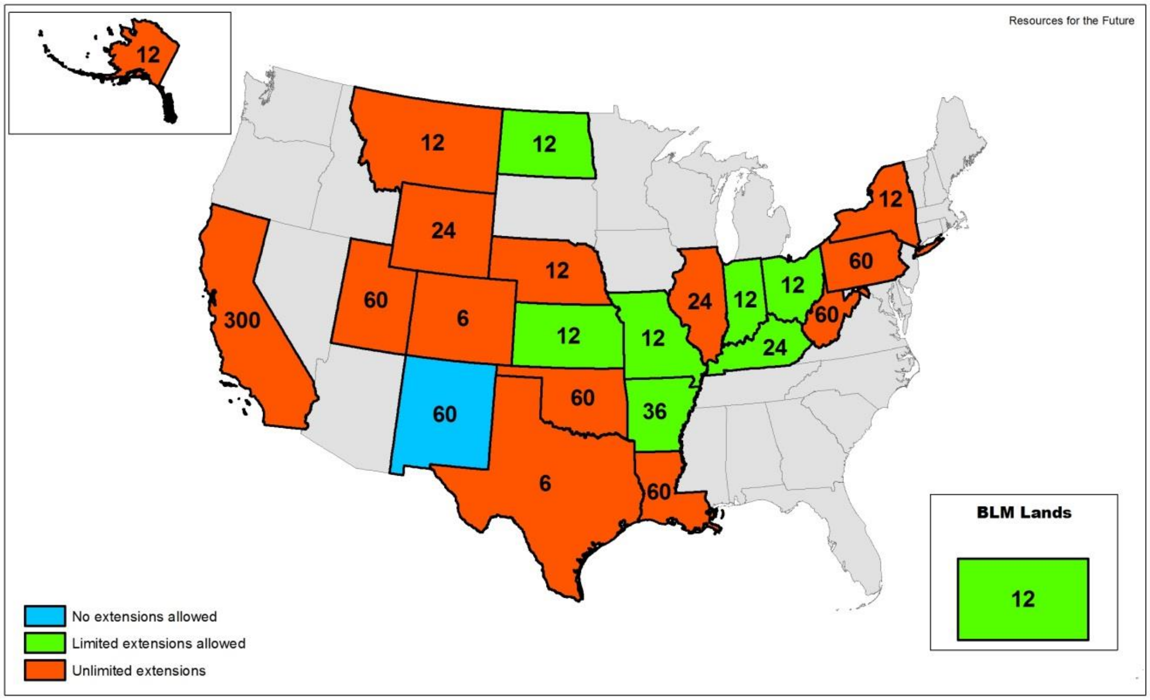
Duration of Temporary Abandonment

When a well no longer produces at an economical rate, an operator may choose to stop production but not to immediately decommission the well (Richardson et al. 2013). This well status is called temporary abandonment and most states we survey allow wells to achieve this status, which essentially allows them to remain idle but—in many cases—requires operators to take various measures to reduce the risk of that well imposing environmental externalities (as discussed in later sections). The prospect that a well may again become active (e.g., if oil or gas prices rise) is an important motivation for states to allow for temporary abandonment, as it is more costly for a well to become reactivated after decommissioning. At least one study, however, shows that operators can use temporary abandonment to simply avoid decommissioning costs even if the wells have very low future economic potential (Muehlenbachs 2015). We again hypothesize that the longer a well is not

[19] AR Rule B-7.c; 62 IAC I.240.240.1120; LAC 43:XIX§137.A.3.a

[20] 20 AAC 25.115.

MAP 5. DURATION OF TEMPORARY ABANDONMENT (IN MONTHS)



decommissioned, the greater the odds that it imposes environmental damages.

All of the states we surveyed regulate the duration of temporary abandonment. Map 5 displays these durations, which range from 6 months in Colorado and Texas to 300 months in California. Of the 22 states that regulate the duration of temporary abandonment status, all but New Mexico explicitly allow for some form of extension.[21] The extensions granted by these 21 states can be categorized either as unlimited or limited. About two-thirds of these states do not explicitly limit the number or duration of extensions that an operator could receive for a well to stay in temporary abandonment; the majority of these states include some kind of regulator discretion in approving extensions. Some states (e.g., Louisiana, Missouri, Montana, Nebraska, New York) allow for extensions seemingly without explicit regulator discretion.[22] The other one-third of the states and the BLM include explicit limits on the ability of regulators to authorize extensions, including:[23]

- Arkansas: wells that have been idled for over 10 years are not eligible for extension.
- Kansas: wells that have been shut in for over 10 years are not eligible for extension.
- Kentucky: operators can apply for one extension that lasts two years.
- North Dakota: operators can apply for one extension that lasts a single year.

[21] NMC §19.15.25.12.

[22] LAC 43:XIX§137.A.2; 10 CSR 50-2.040(5); ARM 36.22.1240, ARM 36.22.1303; NAC Title 267 Chapter 3 040.01; 6 CCR-NY 555.3.b; 6 CCR-NY 555.2.a.

[23] AR Rule B-5.h; 82 KAR 82.3.11.b; 805 KAR 1:060(1); 43 NDAR 43-02-03-55; ORC 1509.062.E, F.

- Ohio: after three renewals of temporary abandonment status, the regulator may require a surety bond no greater than $10,000 for each of the owner's wells that has approved temporary abandonment status.
- BLM: wells can be temporarily abandoned for 12 months; operators are allowed a limited extension that cannot exceed 12 months

We use a continuous and quantitative assessment to incorporate the duration of temporary abandonment into our stringency calculation for states. This assessment sets the longest duration equal to 0 and the shortest duration equal to 1, normalizing all values in between. We also use a binary and qualitative assessment to incorporate extensions for temporary abandonment into our stringency calculation for states. This assessment assigns a 0 to states that allow for extensions (either limited or unlimited) and a 1 for states that do not.

Requirements for Attaining Temporary Abandonment Status

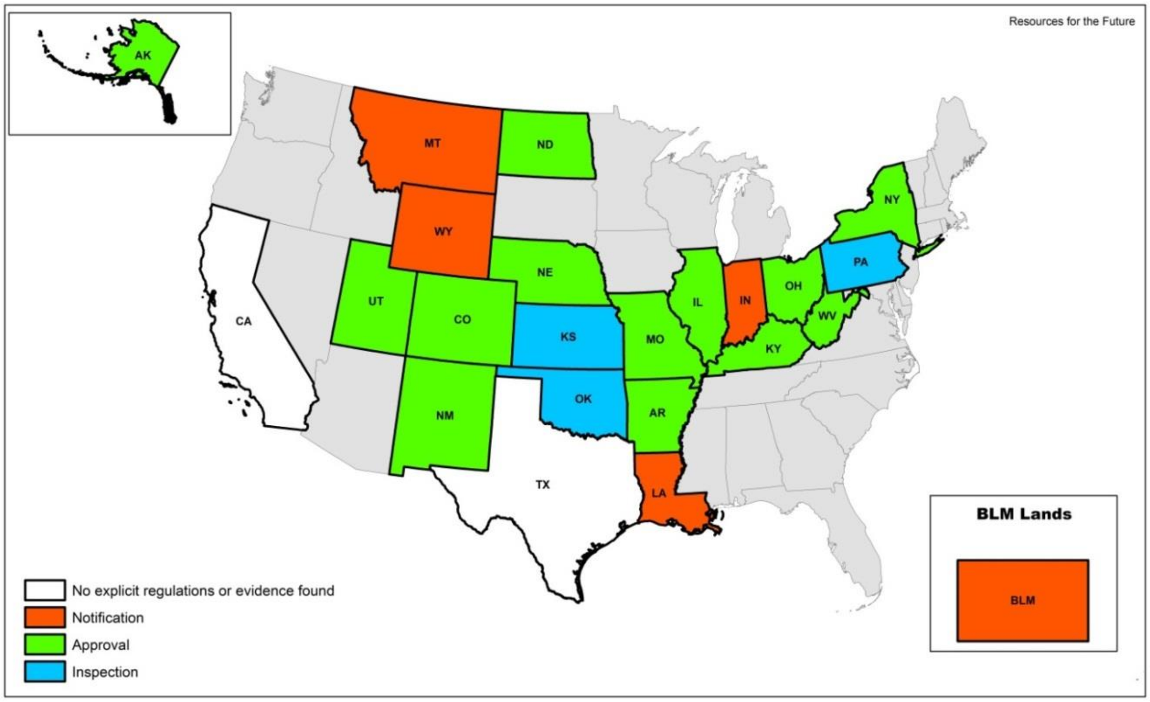
State regulators may impose three categories of requirements that operators must achieve before gaining temporary abandonment status: notification, approval, and/or inspection. We characterize notification (i.e., requiring the operator to notify the regulator of temporary abandonment status) as the least stringent and inspection (i.e., requiring the operator to receive a positive confirmation from a government inspector that the well is eligible for temporary abandonment status) as the most stringent. As displayed in Map 6, four states (Indiana, Louisiana, Montana, and Wyoming) only require notification, whereas three states (Kansas, Oklahoma, and Pennsylvania) require some form of inspection.[24] The BLM and remaining states with a formalized temporary abandonment process require some form of approval from the regulator. In our view, this approval process is more stringent than notification and less stringent than inspection.

The link between the level of requirement for attaining temporary abandonment and subsequent environmental or fiscal risk is not direct, but is an important moment for regulatory monitoring. Because temporary abandonment periods can extend for significant time during which operator and regulator monitoring of the site may decline, and because the environmental risk posed by a well increases the longer it is idle, ensuring that the well is in good condition prior to temporary abandonment can prevent serious hazards in the future. To incorporate this linkage between the approval process and environmental risk, we use a binary and qualitative assessment into our stringency calculations. States that do not have explicit regulations or only require notification receive a 0, whereas states that require approval or inspection receive a 1.

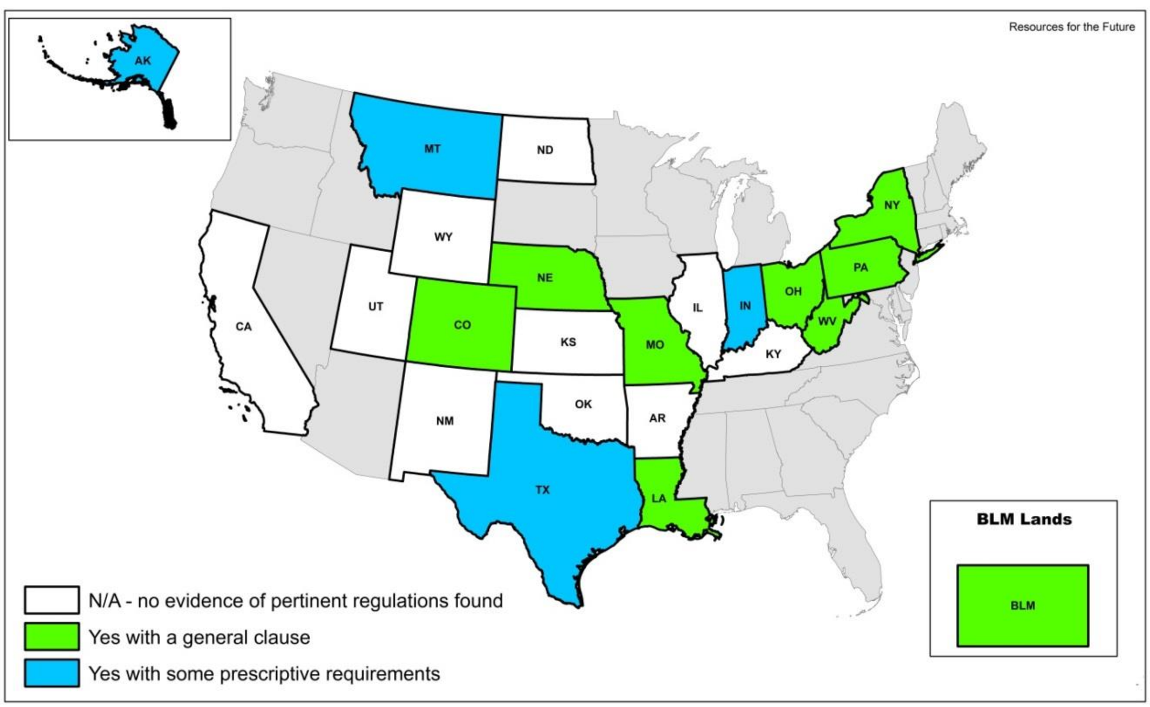
Of the 22 states we survey, 12 contain provisions that require operators to show some future usefulness of wells that are temporarily abandoned before they are granted an extension (as displayed in Map 7). These provisions likely exist, at least in part, to protect against wells remaining in a status of temporary abandonment only for operators to avoid decommissioning costs and without any intention of returning the wells to active status. We view these regulations as important for limiting the chance of environmental impacts occurring, because the regulations help limit the amount of time an operator can delay decommissioning. However, we would need to

[24] IN TR Section 6, 312 IAC 16-5-20.b; WY Rule 3.16.a; 82 KAR 82.3.11.b-c OAC 165:10-11-9; 58 Pa. Code §3214(a).

MAP 6. NOTIFICATION, APPROVAL, AND INSPECTION REQUIREMENTS FOR TEMPORARILY ABANDONED WELLS



MAP 7. PRESENCE OF A REQUIREMENT FOR OPERATORS TO SHOW FUTURE USEFULNESS OF TEMPORARILY ABANDONED WELLS



review actual operator reports to assess the rigor of statements of future usefulness, but that is outside the scope of this research.[25] The strength of these provisions varies widely by state, as displayed in the bullets below. Some states contain a generic determination from the regulator that the well has future usefulness, or they require a plan that may include an estimate of when a well will return to active status. Texas is a stringent outlier. Some examples include:

- Alaska: the request for operation shutdown must provide a full justification, including a description of the proposed condition of the wellbore, approximate date when drilling will resume, and a proposed program for securing the well during shutdown.[26]
- Colorado: usefulness must be shown annually during temporary abandonment status and when a request for extension of temporary abandonment status is submitted. [27]
- Louisiana and West Virginia: a well must be classified as having future utility.[28]
- Missouri, Nebraska, and New York: a well must be determined to have "good cause shown" or "sufficient good cause" for receiving temporarily abandoned status.[29]
- Montana: the operator must provide a report describing the operator's plan and time frame for returning to active status, plugging, or converting the well to other purposes.[30]
- Ohio: a well must demonstrate future utility, and the operator has to have a viable plan to utilize the well within a reasonable period of time.[31]
- Pennsylvania: an operator must present a plan for using the well within a reasonable period of time.[32]
- Texas: a licensed geoscientist or petroleum engineer must certify that a well has future utility. That certification must include, among other things, a cost calculation for decommissioning the well and a determination that the expert reasonably expects the well to have future economic value in excess of decommission costs.[33]

We use a binary and qualitative assessment when incorporating whether regulators consider economic viability in granting temporary abandonment into our stringency calculation for states. A state that does not consider economic viability receives a 0, and a state that does so (either via a general clause or through more prescriptive requirements) receive a 1.

Well Closure and Shut-in Requirements for Temporary Abandonment

Out of the 22 states we survey, only 12 require operators to place a temporary plug or

[25] Here and elsewhere throughout the report we recommend increased monitoring, reporting, and verification efforts by regulators as a way to detect and respond to wells before large damage is caused. However, we recognize that states may not be sufficiently resourced to provide this extra involvement. Given this, extra regulator involvement at the time of temporary abandonment approval may be especially beneficial by preventing problematic wells from becoming inactive.

[26] 20 AAC 25.110.a.2.

[27] 2 CCR-1-319.b.1.

[28] LAC 43:XIX§137.A.3.b; WVC §22-6-19.

[29] 10 CSR 50-2.040(5); NAC Title 267 Chapter 3 040.01; 6 CCR-NY 555.3.b.

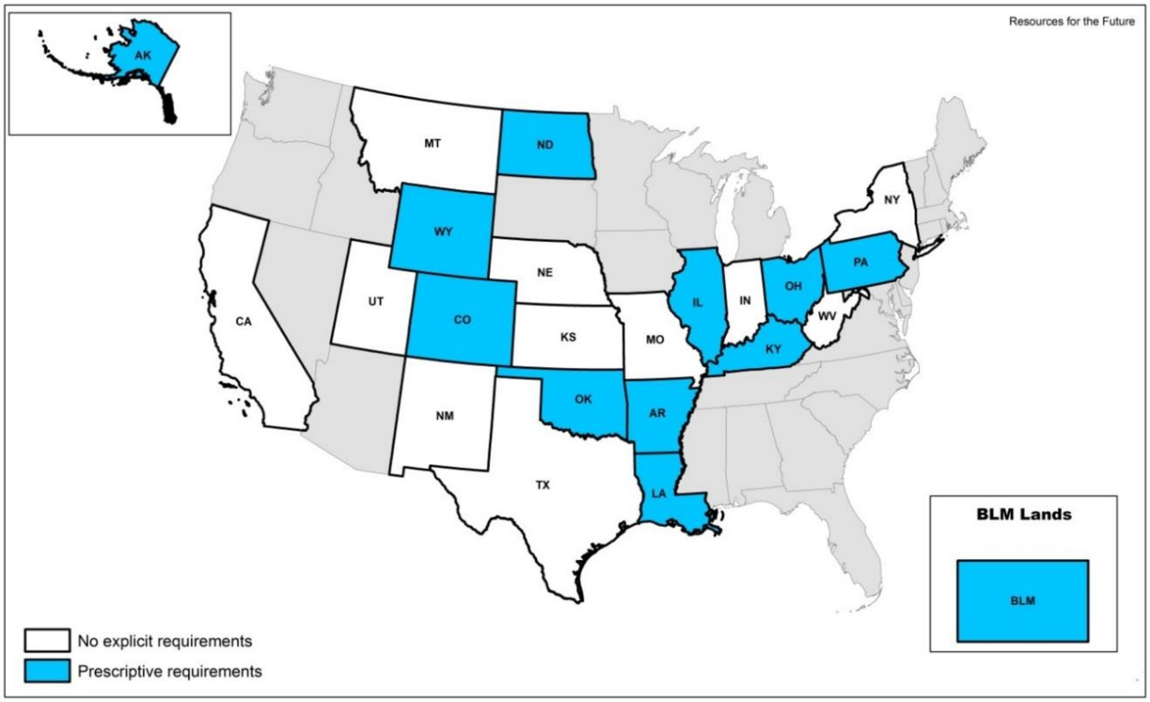
[30] ARM 36.22.1240; ARM 36.22.1303.

[31] ORC 1509.062.B.5

[32] 25 Pa. Code §78.102(4).

[33] 16 TAR 1.3.3.15.j.

MAP 8. SHUT-IN REQUIREMENTS DURING TEMPORARY ABANDONMENT



otherwise prescribe well closure in temporary abandonment status (Map 8). These 12 states require that operators cap the surface of the well (which would likely prevent air pollution emissions), place plugs in the well (which would help prevent water pollution) or both. Nearly all states require capping and most require plugging, with at least six states requiring both. Notably, Louisiana requires the same plugging requirements for temporary abandonment as it does for decommissioning a well—with the exception of installing a surface plug, a seemingly stringent regulation.[34] The states that do not require capping or plugging we judge to be at a higher risk for temporarily abandoned wells to cause environmental externalities.

The BLM rules contain a general clause that operators must isolate perforations in an acceptable manner, but do not offer any explicit requirements.

We use a binary and qualitative assessment when incorporating shut-in requirements into our stringency calculations for states. A state that imposes any such requirements (i.e., plug, cap, or both) receives a 1 while those that do not receive a 0.

Well Integrity Testing

Out of the 22 states we survey, 18 require well integrity tests before or during the period that a well has attained temporary abandonment status, and we could not find evidence that the remaining states in our survey impose

[34] LAC 43:XIX§137.H.

such requirements, although it may be incorporated into notification, approval, and inspection requirements. States may require testing either prior to entering temporary abandonment status or at specified intervals during temporary abandonment. At least four states require annual testing, and at least three states require testing every five years. At least three states stipulate different testing requirements after a period of time—Wyoming and Colorado after a temporary abandonment extension, and Texas after 25 years—and Colorado also gives regulator discretion at the time of temporary abandonment extension to require a well be switched from a blanket to individual bond.[35] Ohio requires the operator to inspect wells every six months and submit an inspection report within two weeks, a stringent outlier.[36] In addition, some states require that operators simply submit a report of results, whereas others require a witness to be present during testing. This element could confer large benefits on states by allowing regulators to catch problem wells before the environmental and fiscal costs become exceedingly large.

Plugging Requirements

A decommissioned well is one that is properly plugged and the surrounding site properly restored. Most state regulations we review contain a general phrase about the need to plug a well such that oil, gas, and water resources are contained to their original strata and to prevent any subsurface contamination. Beyond this, states show significant heterogeneity in how prescriptive they are in their regulations; for example, some states describe plugging materials, and the specific method of placing plugs of a certain length above or below various resources or strata of interest—whereas other states do not contain any such information. The lack of easily trackable regulatory elements on the specific plugging process may suggest that states approach each well on a case-by-case basis. Despite these difficulties, we can identify a handful of regulatory elements pertaining to plugging requirements that may decrease the likelihood of a well imposing environmental externalities.

Types of Plugs Required

An important part of the typical decommissioning process is placing plugs (usually made of cement) at the well bore's surface, bottom, and in regions in between. The purpose of these plugs is to prevent contamination between oil and gas strata and subsurface regions (e.g., freshwater zones) or the surface (e.g., methane or volatile organic compound emissions). Regulators take various approaches to plugging requirements, and they require operators to install a variety of types of plugs (if any at all). We expect that, in general and all else being equal, the more plugs that a regulator requires the less chance that a decommissioned well will create environmental externalities.

Of the 22 states we survey, 18 contain prescriptive regulations that describe the different types of plugs (i.e., surface, intermediate, and bottom) that operators must install and the required length of those plugs. The remaining four states (Montana, Nebraska, New Mexico, and North Dakota[37]) contain a general statement (i.e., a performance standard) about the need to decommission a well such that oil, gas, and water resources are contained to their original strata. Regulations in California and Texas contain such a phrase as well but also give prescriptive requirements, and Colorado uses a combination of prescriptive and performance

[35] WY Rule 3.16.c, d; 2 CCR-1-326.c; 16 TAR 1.3.15.l.

[36] ORC 1509.062.B.6; ORC 1509.062.C.

[37] ARM 36.22.1303; NAC Title 267 Chapter 3 028; NMC §19.15.25.10.A; NDAC 43-02-03-04.

standard approaches.[38] A handful of states (e.g., Colorado, Ohio, New Mexico, North Dakota, and Texas[39]) require that an operator's plugging plan be approved by the regulator.

The 18 states with prescriptive plugging regulations differ significantly in whether they contain prescriptive language requiring a surface, intermediate, and/or bottom plug—as displayed in Table 6. The blank rows indicate a state that relies on a general statement only.[40]

The BLM approves plugging plans for operators and does not require explicit provisions outside of this process.[41] We use a binary and qualitative assessment when incorporating the types of plugs required into our stringency calculations for states. States that explicitly impose prescriptive requirements and/or a performance standard receive a 1, while all others receive a 0.

Treatment of Wells with Different Casing Types

An active well requires different types of casings—steel tubing inside the well that helps the bore maintain its structure and protects the bore from contamination—including surface, intermediate, and production casings. The latter type of casing is perforated when a well is active, thus allowing oil and gas to seep through those perforations. Portions of well bores may not necessarily be cased and those that are cased may have portions that are not cemented. The extent to which a well is cased and the degree to which that casing is cemented therefore play a critical role in determining the potential environmental risk of the operation (Zirogiannis et al. 2016). Of the 22 states we survey, roughly three-quarters of states differentiate plugging requirements by whether certain casing types are present and/or whether casing is cemented. In general, these differentiations define different categories of wells and the prescriptive plugging methods that must be used.

Table 6. Prescriptive Requirements for Different Types of Plugs by State (and BLM)

State	Bottom	Intermediate	Surface
AK	X		
AR	X	X	
CA	X	X	X
CO	X	X	X
IL			X
IN	X		
KS	X	X	
KY		X	
LA		X	X
MO		X	
MT			
NE			
NM			
NY		X	
ND			
OH	X	X	X
OK			X
PA			X
TX			X
UT	X		X
WV		X	X
WY		X	X
BLM			

The regulatory element of casing type is closely linked by definition to a state's casing regulations, which was not in the current study scope (but was covered in Richardson et al. 2013). Additionally, casing conditions are part of many of the pre-plugging notices required by states, and thus may be individually tailored at this point through regulator discretion. If so, then regulations which specify different plug-

[38] CCR §1723, CPRC §3228; TAR 16-1-3-3.14(d)(2,3, and 8); 2 CCR-1-319.a.1.

[39] 2 CCR-1-311.a, 2 CCR-1-319.a.6; OAC 1501:9-11-02, OAC 1501:9-11-04; NMC §19.15.7.14.A(1e, 2); NDAC 42-02-03-33; TAR 16-1-3-3.15(l-m).

[40] While we treat prescriptive requirements as more stringent than general statements, note that a tightly monitored and enforced general statement that provides operators flexibility may be just as or even more protective than a less well enforced prescriptive approach—and potentially less costly.

[41] 43 CFR 3162.3-4.a.

ging regulations by casing type may simply be revealing a more prescriptive regulatory approach, and not necessarily guaranteeing higher environmental stringency.

However, the environmental risks mitigated by stringency in casing are potentially large. Watson and Bachu (2009) identified uncemented casing intervals as the source of the vast majority of contamination and gas leakage and Dusseault et al. (2000) recommend full cementation from the intermediate casing to the surface. Ingraffea et al. (2014) show that for wells drilled in Pennsylvania from 2000 to 2012, 6.2 percent of unconventional wells have casing and cementing issues, almost six times the rate of conventional wells. The implications of these studies on inactive wells is that monitoring, reporting, and verification of casing and cementing should be a high priority prior to entering temporary abandonment status or for final plugging.

Treatment of Casing Removal

When a well is being decommissioned, casing may be removed for a variety of reasons, including to create more favorable conditions for a plugging job or to capture any salvage value in the casing material itself.[42] As mentioned previously, some states have specific guidelines for how salvaging of well equipment may contribute to the state-run decommissioning of orphaned and noncompliant sites. The casing removal guidelines in technical plugging sections likely refer to both original and third-party operators who might remove well casing for salvage value. Some states explicitly ban the removal of any or certain types of casing, and others require approval prior to pulling. However, removing casing may increase the odds of contamination of the wellbore, specifically regarding pollution of groundwater and surface subsidence. We did not find evidence of any uniform rules on whether casing removal increases or decreases environmental risk, but in cases of collapsed, compromised, or uncemented casing, removal may lead to better long term environmental integrity. Of the 22 states we survey, approximately one-third do not have special instructions for removal, whereas the remaining two-thirds either require that the regulator approve the removal of certain types of casing or set prescriptive restrictions regarding removal of casing. Seven states require regulatory approval or prohibit pulling of casing, particularly surface casing. At least one state (Wyoming) incorporates a performance standard: any production casing left in place must pass a mechanical integrity test and—if it fails—must be cemented.[43] Oklahoma requires a license to pull casing, for which the company involved must show experience and financial responsibility.[44]

Treatment of Different Well Types

Different kinds of wells come with different environmental risk portfolios. Some states tailor requirements for decommissioning based on well characteristics including type (e.g., horizontal well) and subsurface geography (e.g., whether a well bore penetrates a coal seam, has hydrogen sulfide present, or is in a permafrost area). Of the 22 states we survey, 9 have special decommissioning requirements for well bores that pass through coal seams (related to environmental externalities, resource protection, and worker safety concerns) and 6 for horizontal wells (Table 7). California may require special procedures for fractured

[42] This section does not include cutting off of surface casing at plow depth, generally three feet below the surface, a common requirement to allow for continued surface use after decommissioning.

[43] WY Rule 3.18.b.iii.C.

[44] OAC 165:10-11-6.k.

TABLE 7. SPECIAL DECOMMISSIONING REQUIREMENTS

State	Horizontal Well	Coal Seam	Hydrogen Sulfide	Permafrost	Salt or Sand
AK				X	
AR	X		X		
CA					X
CO		X			
IL	X	X			
IN	X	X			
KS					X
KY		X			
LA					
MO	X				
MT					
NE					
NM					
NY					
ND					
OH		X			
OK		X	X		
PA		X			
TX	X				
UT					
WV		X			
WY	X	X			
BLM					

shale or schist, but not horizontal wells as a general category.[45]

Cement Specifications

The integrity of the cement used in securing the well bore and for plugs installed during decommissioning is crucial to limiting environmental externalities. In particular, one industry consultant claimed most decommissioned wells leak at some point due to cement shrinkage, and a report by Watson and Bachu (2009) finds that bridge plugs capped with cement plugs (the predominant plugging method used in Canada) result in leakage in 10 percent of decommissioned wells and recommends against using the bridge plug method.

We find that eight states include quantitative standards for cement requirements, expressed either in pounds per square inch over a certain length of time or pounds per gallon. Five states require or reference API and/or ASTM standards. Three states use the length of cement plug or other related factors as a standard, in addition to many states that stipulate plug length in the technical plugging section. Dusseault et al. (2000) cite previous studies that assert that more ductile, low compressive strength cements are less likely to crack under stress. Our analysis shows that states that used psi measurements as standards had a mode of 500 psi, with exceptions being Alaska (1500 psi or 0.25 psi/ft) and Colorado (800 psi

[45] CCR §1723.1.c.

after 72 hours).[46] Using a stringency metric of 1 for states with any quantitative cement requirements, and 0 for those with no evidence of quantitative requirements or a general requirement (e.g., Portland cement), 10 states receive a stringency rating of 0.

The use of cement additives is also addressed in some state regulations, either prohibiting their use or requiring regulatory approval. As Dusseault et al. (2000) note, additives can have either a positive or negative effect on cement quality but undergo little third-party verification. States also may regulate the materials that are used to fill the wellbore between plugs, and which can include performance standards for mud fluid or specifications on what non-mud materials may be used.

Because cement plugs and other materials are the primary barrier against wellbore contamination and leakage, they are critical to long-term wellbore integrity. However, the literature recommends that cement slurries and applications be tailored for individual wellbore conditions rather than be addressed in uniform standards, as factors such as temperature, pressure, and surrounding strata can all affect cementing quality. For this reason it is difficult, and perhaps not even recommended, to assess stringency of prescriptive cement standards. Rigorous monitoring and witnessing of cement jobs may be a more appropriate regulatory path to take.

Marking of Decommissioned Wells

State databases of inactive wells are likely incomplete. For example, nearly all of the wells in Pennsylvania tested by Kang et al. (2014) for methane emissions were not on Pennsylvania's list of inactive wells. Although a thorough review of the strategies that states take to identify inactive wells is beyond the scope of this paper, we do focus on one relevant regulatory element—whether a state requires decommissioned wells to be permanently marked. Whereas it is possible that the signs often required to be placed at the beginning of well construction are assumed to last past decommissioning, in our view this is not enough to assure proper identification. Unidentified wellbores complicate state identification of inactive wells and could result in incomplete information during surface purchases and other development decisions, and they could lead to environmental pollution or other externalities in the future. Of the 22 states we survey, 11 require operators to mark decommissioned wells in some fashion (Map 9). These 11 states typically require a permanent marker that is visible above ground or detectable below ground, if casing is cut off below plow depth. The BLM requires a permanent marker for decommissioned wells but the regulator can waive this requirement. We use a binary and qualitative assessment when incorporating marking of decommissioned wells into our stringency calculations. A state that explicitly requires marking of decommissioned wells receives a 1, whereas a state that does not have such requirements receives a 0.

Restoration Requirements

Requirement for restoring the well site (i.e., revegetation of surrounding areas and removal of equipment) is an area of significant heterogeneity among states and—as with regulations for plugging requirements—is difficult to compare across states. Surface disturbance by oil and gas activities—the well pad, the roads, the gathering lines, and the storage ponds—can leave a significant footprint that fragments habitat and exacerbates erosion and stormwater flows.

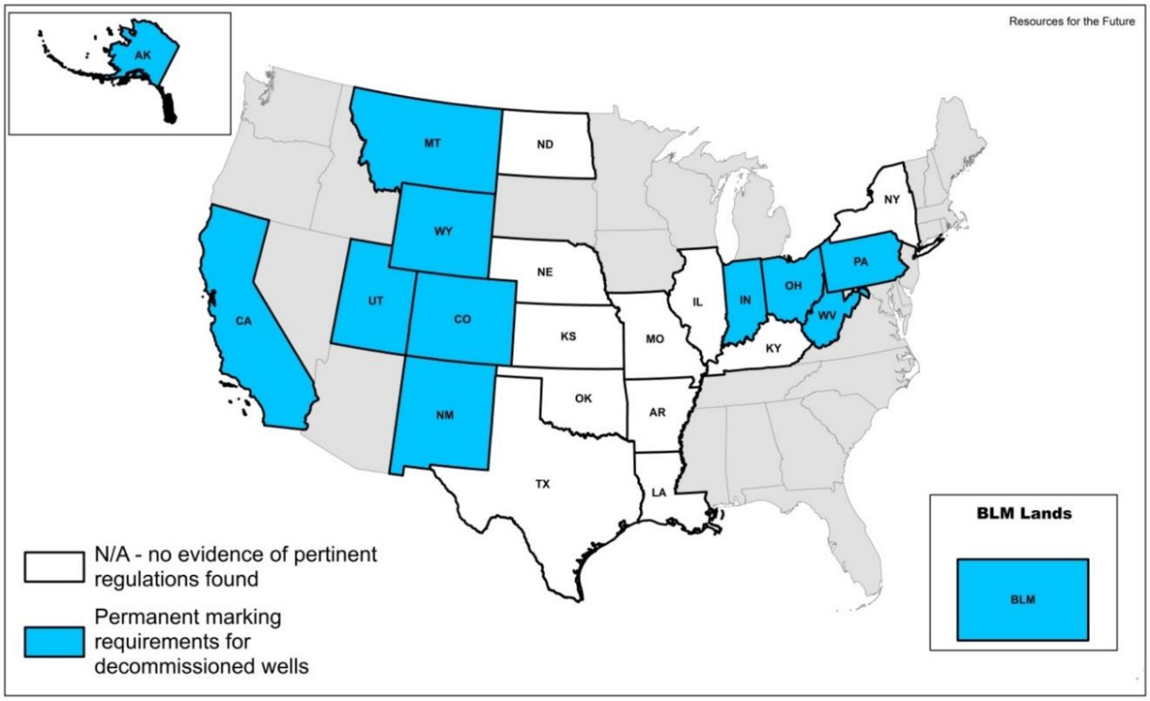
Restoration Requirements—Timing, Stringency, and Relationship to Bonding

General restoration requirements fall into three general categories, as displayed in Map 10. First, nearly one-third of states rely on a

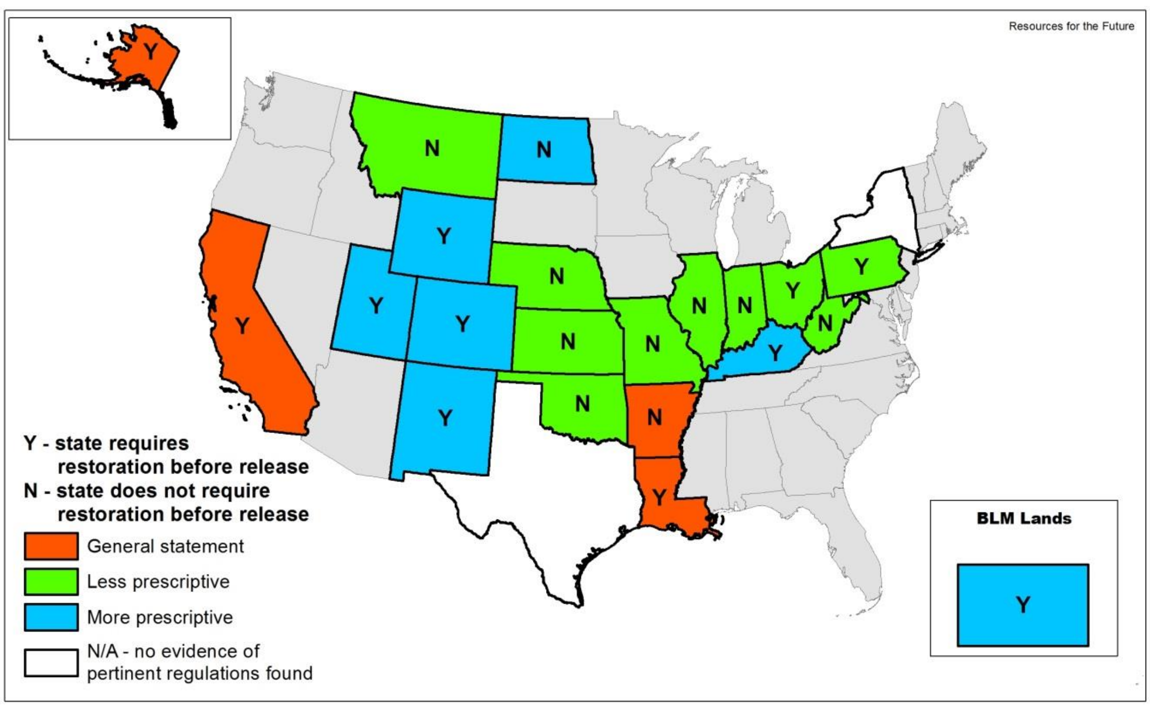
[46] 20 AAC 25.112.g; 2 CCR-1-319.a.1.

general clause that simply states that operators must restore the surface as near to the original state as possible. No further elaboration or specific requirements is detailed. The two remaining categories involve either a low or high amount of prescriptive restoration requirements, respectively. The "low" category typically includes regulations that describe a list of restoration procedures an operator must complete (e.g., remediate contaminated soils

MAP 9. MARKING REQUIREMENTS FOR DECOMMISSIONED WELLS



MAP 10. STRINGENCY OF RESTORATION REQUIREMENTS



and drain fluid storage ponds), whereas the "high" category can include highly prescriptive requirements such as specific seed composition and seeding schedules for revegetation. We generally favor a performance standard approach on cost grounds, but with regard to limiting damage, the most prescriptive is probably the most stringent. We use a binary and qualitative assessment when incorporating the stringency of restoration requirements into our stringency calculations. States that contain a general clause receive a 0 and those that offer some level of prescriptive requirements receive a 1.

States differ in how important restoration requirements are for the release of financial assurances. Of the 22 states we survey, only 10 require the regulator to inspect an operator's restored site before releasing the financial assurance associated with that well, which is displayed as a "yes" in Map 10. States also vary by when operators must complete restoration requirements (Map 11). Of the 22 states we survey, 14 explicitly require operators to complete restoration within a certain amount of time, whereas 8 do not.[47] Those 14 states require operators to complete restoration within a range of one month to one year—with a handful of states (Alaska, Colorado, Ohio, Oklahoma, and Pennsylvania) explicitly allowing for extensions.[48] Similar to well idle time, longer time periods reflect greater likelihood that environmental externalities continue occurring for a longer period of time—all else being equal. We use a continuous and quantitative variable when incorporating this element into our calculation of stringency across states. The highest value receives a 0 and the lowest a 1, with values between normalized.

Conversion to Freshwater Well

Some states allow an oil and gas well to be converted into a freshwater well, in which a bottom plug and a plug below the freshwater zone are placed. Of the 22 states we survey, 17 allow for the conversion of a well to a freshwater well. The states differ in the degree of regulator discretion and technical requirements associated with such conversion. Most states that allow conversion require a written statement that the landowner assumes all liability for the freshwater well and must receive approval of the plugging plan from the oil and gas regulator. Four states require approval from the relevant water regulatory body or groundwater rights holder.

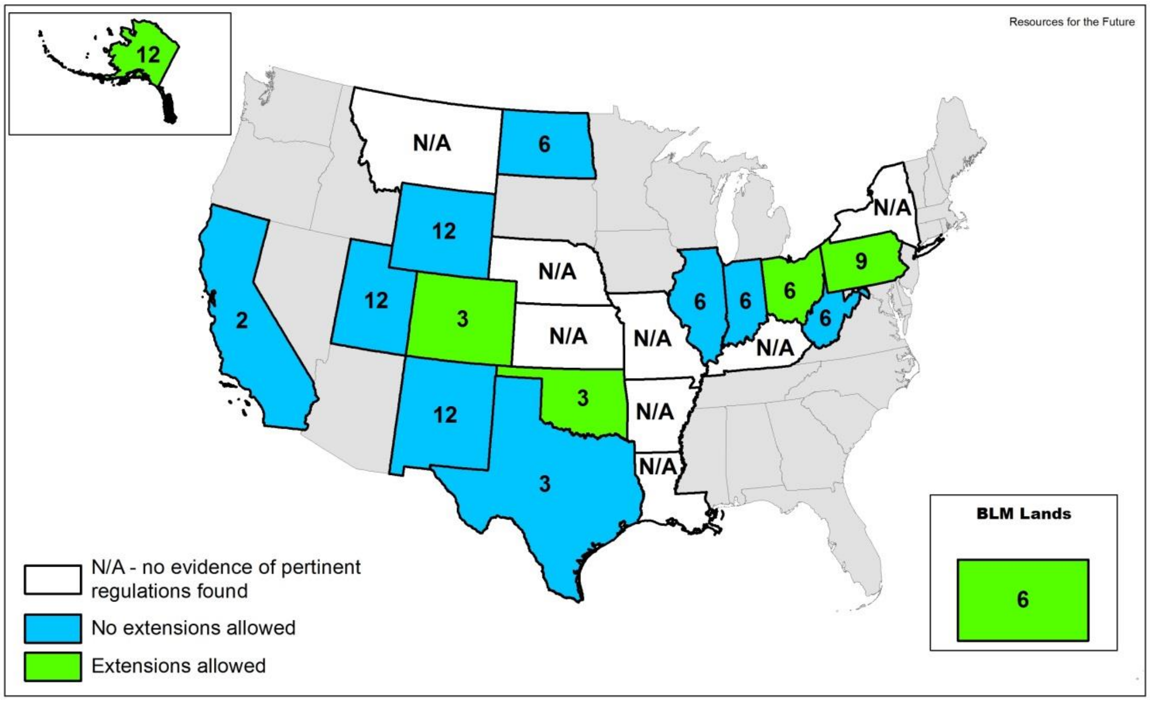
Regulator Involvement

The types of regulator involvement appearing in our survey are limited, and in general are difficult to measure in statutes and regulations. Our review covered only statutes and administrative rules and regulations, not permit documents or other sources, and cannot account for how the regulations are implemented nor many aspects of monitoring, review, and enforcement. Additionally, variance clauses and phrases like "regulator discretion"—for example, allowing time extensions, exemptions from prescribed technical requirements, and others—are found throughout all sections of the regulations surveyed. Although language to the effect of "to the satisfaction or approval of the Director" may seem similar to performance standards, such language lacks specificity as to goals. It does, however, insert some amount of flexibility into otherwise prescriptive command-and-control regulations that could account for well-by-well characteristics that characterize plugging costs and environmental risk.

[47] AR Rule B-9.e; 805 KAR 1:170; LAC 43:I§2101-3101; 10 CSR 50-2.060(3)(A)(1); ARM 36.22.1307; NAC Chapter 3 012.14-15, NAC Chapter 3 028.08.

[48] 20 AAC 25.170; 2 CCR-1-1000-1004; OAC 1509.072; OAC 165:10-3-17.n, §17-53.2.F; 58 Pa. Code §3216.

MAP 11 TIME LIMIT FOR RESTORATION (IN MONTHS)



Notification, Approval, and Inspection

A well's plugging plan may require notification, approval, and/or inspection. The specificity of the plugging plan varies on a state-by-state basis, but sometimes it includes proposed plugging methods and depth and length of plugs, as well as well casing information and well integrity test results. Given that GWPC (2014) identifies increasing reliance by regulators on plugging reports over in-person witnessing by a regulator as a possibly worrying trend, conditional inspection requirements might be improved by placing a default requirement on witnessing. Some states surveyed make an explicit statement on the right of the regulator to enter onto the well site and inspect at any time, which similarly gives regulators flexibility in choosing wells to prioritize for inspection. Such an option, depending on how it is applied by regulators, may help mitigate environmental and fiscal risk (especially in the case of orphaning).

All of the states in our survey require either notification or approval (and some require both) before and after decommissioning a well, but relatively few require inspection, as detailed in Table 8. The time by which post-plugging notice (generally in the form of a plugging report) is required is fairly uniform at 30 days, while pre-plugging notice is subject to greater variation; yet the impact of this variation on regulatory oversight and risk mitigation is unclear. One source of heterogeneity is whether parties other than the oil and gas regulator (e.g., surface owners or coal mine owners) must be notified. A process for comment by these parties on the proposed plugging plan is often included in this notice, and it partially addresses externalities relating to choice of plugging plan on other resources. This approach seems advisable, although the size of the transaction cost may be significant for some operators. Many states have a clause allowing emergency plugging with verbal or no prior approval. Notification is most common

TABLE 8. NUMBER OF STATES REQUIRING APPROVAL, INSPECTION, NOTIFICATION, AND REPORTING

	Approval	Inspection	Notification	Reporting
Pre-plugging	17	3	12	1
Post-plugging	2	1	15	6
Pre-restoration	2	1	1	0
Post-restoration	1	4	1	1

for post-plugging reports, whereas approval of an operator's plugging plan is most common for the pre-plugging stage. Another surprise in Table 8 is that the restoration phase has so few requirements across the states.

Ability for Regulator to Order Plugging or Replugging

Another regulatory power that some states make explicit is the ability of a regulator to order plugging or re-plugging of a well. Of the 22 states we survey, 17 give regulators this ability. In most cases, the order entails a notice and hearing or other appeals process available to the operator. Commonly cited reasons for allowing such an order include leaks and lack of compliance with notification requirements. Such authority relates to a previously discussed element: any outstanding liability or "statute of limitation clauses." Introduction of a quasi-CERCLA program, in which operator liability for a well extends beyond the time of bond return, could protect the state against environmental damages that do not appear until after well decommissioning and might deter some cases of operator orphaning. On the other hand, such extensive liability coverage might cause a short term increase in orphaning rates if smaller firms exit due to the increased regulatory burden. Establishing clear processes by which regulators may order re-plugging of a well is a middle-ground option.

Reporting Requirements of Operator or Regulator on Inactive Wells

State regulations often require that regulators and/or operators report the number of inactive wells, as displayed in Map 12. Of the 22 states we survey, we could not find any evidence of such requirements in five states (Arkansas, Illinois, Indiana, North Dakota, and Oklahoma, although even these may have reporting requirements outside of regulations). At least nine states require that operators file reports monthly, semiannually, or annually that detail certain types of inactive wells. At least five states require that regulators file the reports instead, either on a monthly or annual basis. Two states (California and Wyoming) require both.[49] We use a binary and qualitative assessment when incorporating this element into our stringency calculations for states. A state receives a 1 if it has explicit reporting requirements (for operators, regulators, or both) and a 0 if it does not.

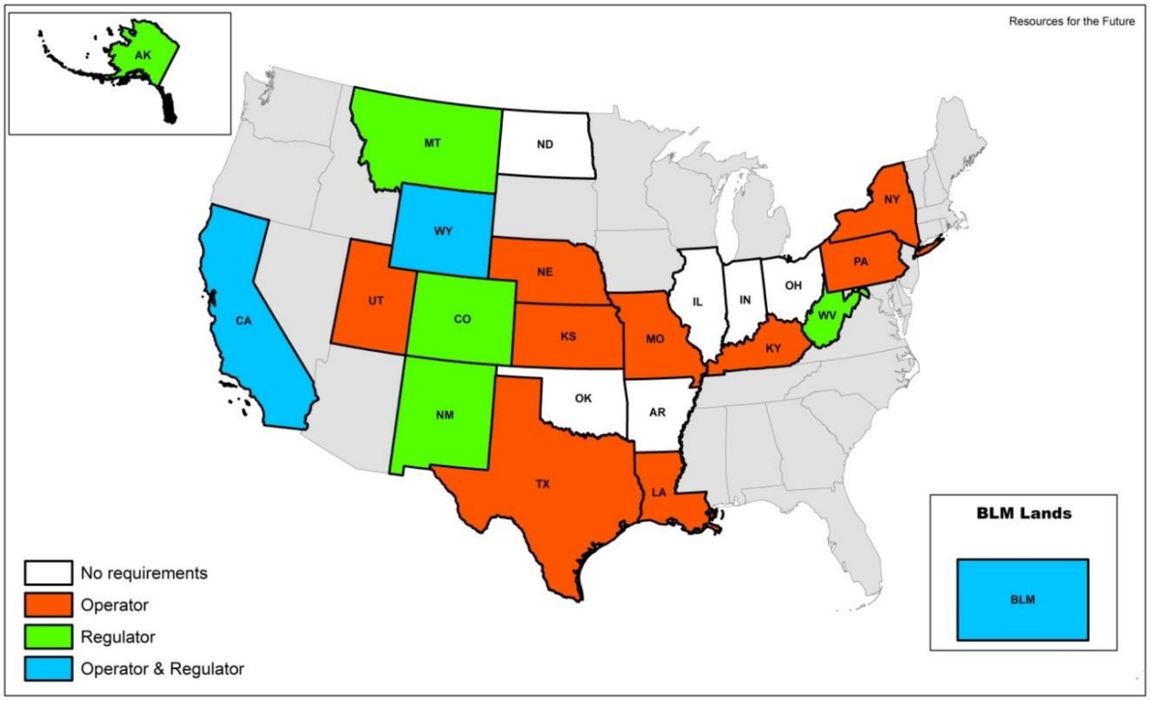
Consideration of Inactive Wells in New Well Permitting Processes

One environmental risk is that new drilling may unexpectedly cross an existing inactive well bore, whether plugged or not. Thus we examined whether states pay attention to the location of existing plugged and abandoned wells when permitting new wells. For the seven states that do require some notation on a well permit application of plugged wells in the area, three include it specifically for wells to be hydraulically fractured, two for disposal wells, and one for gas storage reservoirs. Arkansas is an interesting outlier in that it excludes plugged wells from consideration for fracturing permits.[50] The long-term risks of

[49] CPRC §3227.5; CPRC §3227.a.2; WY Rule 3.16.a.

[50] AR Rule B-5.g.1.A.

MAP 12. REQUIREMENTS TO REPORT INACTIVE WELLS



unconventional wells once decommissioned is still unknown, and the potential risk of fluid migration or other contamination due to unconventional wells in close proximity to decommissioned wells is one possible pathway that could arise.

Fugitive Methane

We found only a few references to fugitive methane monitoring requirements. By far the most noteworthy of these are Kentucky and West Virginia, which allow adjacent landowners to enter a noncompliant site or site where gas is leaking and plug the well. [51] Pennsylvania allows operators to vent gas to the atmosphere at inactive oil wells (or confine to the producing formation), but if this flow is over 5,000 cubic feet per day the regulator must be notified and remedial action taken.[52] Illinois requires plugging operations to be continuously monitored by a methane gas detector; if the methane concentration exceeds 3 percent, plugging must immediately cease.[53] Notably, all of these programs assume well ownership is known.

Policy Recommendations and Conclusions

In general, and echoing a recommendation by Richardson et al. (2013), it was very challenging to pull out regulations from some state codes, and the lack of information on use of field rules and permitting to adjust rules for individual cases is not well documented. Enforcement data are likewise difficult to find and process. Thus, we recommend that states do a better job in reporting these practices.

Our policy recommendations and conclusions are as follows. First, we echo recommen-

[51] KRS 353.140, 150, 160; WVC §22-6-31(b); WVC §22-6-32.

[52] 25 Pa. Code §78.102(3); §78.102(B)(2)(ii)(D).

[53] 62 IAC I.240.1140(e).

dations by Shih et al. (forthcoming) that states should require an amount of financial assurance that reflect real world plugging costs. Several states have completed reviews of their inactive well programs and have called for reviews of bonding amounts. Where states have not already revised their bonding amounts, we recommend they explore doing so based upon actual plugging costs among wells they have plugged. Where appropriate, differentiating bond amounts based on well characteristics or other driving factors of well plugging costs might provide better fiscal coverage, and provisions or special attention to operators with a history of noncompliance or a high share of inactive wells are featured by some states and seem advisable for all. Many states already make various adjustments of this type. Additionally, states should review the types of financial assurance offered, particularly those such as annual well fees, liens on equipment, and statements of financial health. These assurances, by design, do not require sufficient funds up front (irrespective of whether required financial assurances are set to cover well plugging and site restoration costs). In some cases, such as Oklahoma, these weak financial assurance measures are only available for operators with a good compliance history, whereas in other states they are specifically targeted at operators that may have trouble meeting the full bond amount.

States face an important question when setting bond amounts: how can states pool financial risk across operators, while not making financial assurance prohibitively expensive for some individual operators? One area of further research that could illuminate this question is the take-up rate and default rates for blanket versus individual bonds, and whether certain types of operators (e.g., small versus large, concentrated in one basin or spread throughout the state, new versus old) use blanket or individual bonds more. A system where industry contributes to a dedicated fund for plugging high-cost wells, in addition to standard financial assurance requirements, could provide an extra measure of protection for states while still allowing competitive financial assurance amounts.

Second, we observe that almost all states offer the option of blanket bonds, and these bonds feature quantity discounts over the number of wells covered. While individual well financial assurance requirements may be too low relative to plugging and site restoration costs for a sizable fraction of wells, as seen in Shih et al. (forthcoming), per-well coverage from blanket bonds is even considerably lower. Although blanket bonds may reduce administrative costs for state regulators, it is unclear whether the net benefit to the state of setting significant price discounts through blanket bonds is greater than the risk.

Third, our review of temporary abandonment practices finds that state well idle time and temporary abandonment time periods are generally well defined, although extensions and a few outliers (e.g., California) might allow for wells to be in an inactive state with no intention to return to active status. Requirements for temporary abandonment—including well testing and monitoring, proof of future economic viability, and mandated well closure requirements—are far less common in state regulations. Although these activities may be addressed during temporary abandonment approval proceedings (if approval is required), implementing systematic procedures for temporarily abandoned wells may greatly reduce the probability of future environmental damages or fiscal costs for the state. In particular, wells that have been inactive longer are likely to cause a greater risk. Thus, we recommend that states develop more stringent temporary abandonment requirements.

Fourth, well plugging and site restoration requirements vary greatly in the amount of detail set forth in regulations. This reflects both the different regulatory approaches taken by states, and the fact that well plugging and abandonment requirements may be dealt with on a case by case basis with a large amount of regulator discretion. In this case, ensuring a robust monitoring, review, and validation framework would be the most important regulatory element. We find that whereas most states require pre-approval of a plugging plan, relatively few require inspection after plugging and almost none inspect after site restoration is complete. Given that state resources are limited, the use of interested parties to inspect, such as surface and other resource owners, could provide additional monitoring capacity. In this regard, we note the use of surface damage agreements in a substantial number of states and their relevance for addressing some of the conflicts that arise in split estate cases. We recommend further study into how these agreements work in practice.

5. Conclusions, Recommendations and Future Research

This report has detailed the environmental and financial issues associated with inactive oil and gas wells. We considered the risk pathways and the number of such wells in a group of states, including orphaned wells that are the states' responsibility to clean up, surveyed the costs of decommissioning wells in a large group of states, and conducted a very detailed statistical analysis of the drivers of costs in decommissioning orphaned wells in Kansas. We then examined the regulations governing inactive wells across 22 states.

These analyses lead to the following conclusions. While we understand very well how inactive wells can harm the environment there are very few studies providing empirical information to show precisely how much these wells are affecting the environment or how much each factor contributes to environmental risk. However, the quality of well construction at the time it was drilled and the abandonment measures that have been taken on the well are two factors that stand out. Most disappointing, the empirical literature does not distinguish between the environmental damage caused by different types of inactive wells (e.g., temporarily abandoned vs. plugged and abandoned wells; historic wells vs. wells drilled more recently). As for the size of the inactive well burden, data from 13 states with significant oil and gas production show that about 12 percent of all inactive wells have not been decommissioned, but the percentage in each state varies considerably from one percent to 56 percent. Of course, the number of inactive wells reported here does not include wells that are simply missing from state records.

We find that decommissioning costs vary significantly, both within and across states, depending on a combination of factors, including the condition of the well, the quality of its original construction, well depth, market conditions in the production sector, and the market structure of the service provider industry. Average and median decommissioning costs exceed average bond amounts in most of the states studied here. Some wells are particularly expensive to decommission. The cost of decommissioning such wells could be covered by a pool of industry funds.

Regarding regulations, the individual states and the Bureau of Land Management take vastly different approaches to regulating the decommissioning of oil and gas wells, meaning that operators face wide heterogeneity in the rules they must follow when a well becomes inactive. This heterogeneity can be described in terms of the number of regulatory elements they regulate and their stringency. But many states offer only vague statements in support of some regulatory elements, while others are very specific.

Our most important findings about individual regulations are, for one, that state bonding requirements are set too low to cover decommissioning costs. Thus, when wells become orphaned, states and taxpayers will be on the hook for significant clean-up liabilities. We also found that states generally set bonding requirements that vary by at least one factor that affects costs, such as well depth. But the approaches are too simple to fully protect taxpayers even if the bonding amounts were larger.

Based on our findings, we highlight a number of priority areas for policy reform for state oil and gas agencies, BLM, and other relevant agencies to consider.

Bond Amounts

1. *Industry bonding requirements should be compared against decommissioning costs in each state and revised accordingly to cover more of the decommissioning costs.* Note, however, that the optimal amount of cost coverage that should be built into a bond is uncertain: while pegging bond amounts to the cost of the most expensive projects places an unreasonable burden on operators and can discourage drilling activity, too low a bond amount does not provide an adequate incentive for operators to decommission their wells.
2. *Bonding regulations should have provisions to ensure that states do not bear the cost of particularly expensive decommissioning projects.* For instance, a pool of funds could be provided by industry that could be drawn on if the cost of a project exceeds a certain threshold.
3. *Bond amounts should be calibrated to account for a variety of factors influencing cost.* At present, some states set bond amounts that vary by well depth, an important characteristic given that average well depths in the United States have been increasing. Some also set different bond amounts for specific districts, as several factors that affect costs vary spatially. Other factors that a few states consider include whether a well is horizontal or vertical, as well as operator characteristics such as compliance history and the number of wells the operator owns.
4. *Consider the use of surface damage agreements in addition to traditional plugging or plugging and restoration bonds.* We found that a number of states use some form of surface damage agreement or negotiation in cases where the surface and mineral estates are split. Although it is possible that these arrangements are common on an individual lease-by-lease basis, we view their inclusion in state regulatory programs as a potential way to limit externalities (e.g. crop damage, noise) of decommissioning to affected surface owners when secondary purchasers of the well go bankrupt. Relatedly, the very few states that inspect a site for the quality of its restoration before releasing financial assurances can serve as an example for other states.

Well Management and Monitoring

5. *The conditions under which wells are allowed to be transferred from one operator to another should be stricter.* Anecdotal insights have suggested that wells tend to be transferred from larger operators to smaller companies that purchase these wells for enhanced recovery or other operations. At present, well transfers are typically allowed as long as the buyer can cover the cost of the financial assurance attached to the bond. Regulators should ensure that the operator purchasing the well is financially stable and has a good track record of compliance with regulations. Alternatively, or in addition, states could hold the original owners at least partly liable for decomissioning their wells rather than trasnferring all liability to the new

owners, who are sometimes less financially secure

6. *Some states should tighten their requirements for maintaining temporary abandonment status.* Otherwise, operators may maintain their wells in this status for longer than appropriate to avoid or postpone decommissioning costs, raising environmental risks. Such measures could include well integrity demonstrations and inspections both prior to and at regular intervals during temporary abandonment, and requirements to demonstrate the future economic viability of a well (perhaps especially relevant during bust periods).
7. *States should conduct legislative audits to evaluate the stringency of their monitoring efforts and success of their plugging programs.* Regulatory capacity is a crucial factor that we do not evaluate in this study: a legislative audit in Louisiana found that the Office of Conservation did not issue compliance orders for 86 percent of the 482 wells that required them from 2008-2013. Audits should examine questions such as what percentage of the wells on their plugging lists states are able to decommission each year, whether inactive wells are consistently monitored, and what percentage of decommissioning costs have been covered by industry.

Inactive and Orphaned Well Programs

8. *States should develop more sustainable means of funding their orphaned well plugging programs.* At present, recovered bonds represent only a fraction of plugging revenues available for decommissioning orphaned wells in most states. States thus rely on a combination of legislative appropriations (public monies) and permit fees from industry, which are unreliable in times of low oil production. At a minimum, recovered bonds should cover a larger share of decommissioning costs.
9. *States need to do a better job in reporting information on numbers of inactive wells of various types and statuses, costs, and regulatory adjustments in the field and through permitting.* It was very difficult to find credible numbers of inactive wells and detailed data on orphaned well decomissioning costs. It was also very difficult to pull out regulations from some state codes, and there is a lack of information on how state rules are adjusted at the district level or for individual cases. Enforcement data are likewise difficult to find and process.
10. *Given the heterogeneity of state regulations, states should consider using the Regulatory Exchange (supported by the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission) or other bodies to share regulatory information and learn from one another.*

These recommendations obviously don’t apply to states (and the BLM) already adequately addressing them. And such states can serve as a model for others.

Finally, our study has revealed a number of areas for further research—both on the environmental risks of inactive wells and on the regulations governing these wells.

Environmental Risks of Inactive Wells

- *What is the magnitude of environmental risk posed by inactive wells with varying characteristics?* Our review of the literature and conflicting opinions from experts we spoke to revealed that there are limited empirical answers to this question and that this is an area in need of further research. For instance, to what extent do decommissioned wells plugged according to present-day regulatory standards still pose a risk of methane leakage or groundwater contamination? And how do such risks vary as the plug ages? How risky is a temporarily abandoned well as compared to a decommissioned well? What plugging technologies are most effective for minimizing leakage risk? What about the differences in risks posed by wells with modern well constructions, as opposed to historic wells? Understanding this heterogeneity in environmental threat has implications for how to cost-effectively target regulatory efforts.

Inactive Well Regulations and Programs

- *How do blanket bond amounts compare against decommissioning costs for groups of wells owned by a single operator, and to what extent do operators choose to post blanket bonds?* Our data only permitted us to compare bonds for individual wells against per-well costs. Operators are allowed the option of posting a blanket bond for all of their wells in a state. The blanket bond amount is lower on a per well basis than individual bonds, implying that the greater the extent that operators post blanket bonds, the more that plugging costs will exceed bond amounts.
- *What types of bonds do operators most often post?* In most states, operators may post either personal bonds, putting up their own assets as financial assurance, or surety bonds, in which case a third-party provider pays out the bond in the event that the operator is unable to decommission the well. There are other options as well. Research is needed on which types of bonds are more protective of the taxpayer and the environment.
- *To what extent do agencies evaluate the financial capacity of a new operator before they allow wells to be transferred from the primary operator?* If they do not, there is no guarantee that the new operator will have the financial means to bear the cost of decommissioning, making it more likely that the well will eventually become orphaned.
- *What are the characteristics of the operators that most commonly orphan their wells?* Smaller operators that are less financially stable may be more likely to default on their bonds. A systematic study of the data on this issue and other drivers of default and orphaning would suggest ways to better reform regulations. A related question is whether wells under blanket or individual bonds are more likely to be orphaned.
- *How are states financing their plugging programs?* A comprehensive review of state plugging revenues and expenditures could be conducted to assess the magnitude of the cost burden that is currently borne by the public. Such a review should also evaluate alternative financing options that would both increase available revenues and ensure that costs are internalized by industry.
- *Which states have been most successful at monitoring inactive wells and plugging orphaned wells?* A mixed-method study to identify “leadership states” and understand the factors behind their success could be very powerful in revealing best practices. Factors that could be examined include political and economic conditions in the state, bonding amounts, regulator capacity, plugging revenue sources, and degree of citizen involvement.

- *What are effective ways of identifying orphaned or abandoned wells not currently in state records?* Several states already have programs in place to locate and document orphaned wells, including Pennsylvania, Kansas, Colorado, and West Virginia. In some cases, the public can get involved in these efforts, submitting information about wells to the state website. A review can be done of various states' programs to identify the most effective identification methods. Another idea that can be considered is the creation of a mobile application that the public can use to report orphaned wells that they find, uploading the images and locations of orphaned wells into a national cloud database. This digitized information can be streamlined, ensuring good data quality, and then shared with state agencies.

Continued growth in wells drilled will eventually cause an increase in the number of inactive wells, and therefore a growth in the environmental threat and financial burden from these wells. Further research and regulatory reforms can help mitigate risks. Ultimately, developing effective policy recommendations will depend on a deeper understanding of where the environmental and financial risks are greatest, how operators are currently making decisions about temporary abandonment, well transfers, types of bonds, and permanent decommissioning, and how regulations can best be reformed. The challenge of ensuring that future environmental costs are borne by polluters is common to other sectors, such as mining and waste disposal, and lessons learned from this research will therefore have implications that reach beyond the oil and gas industry.

Appendix A. Average Well Depth and Associated Average Bond Amounts by State

Appendix A1. States Qualifying for our Regulatory Analysis of State Regulations on Inactive Wells

Number	State
1	Alaska
2	Arkansas
3	California
4	Colorado
5	Illinois
6	Indiana
7	Kansas
8	Kentucky
9	Louisiana
10	Mississippi
11	Missouri
12	Montana
13	New Mexico
14	New York
15	North Dakota
16	Ohio
17	Oklahoma
18	Pennsylvania
19	Texas
20	Utah
21	West Virginia
22	Wyoming

APPENDIX A2. THRESHOLD CRITERIA FOR INCLUDING STATES IN OUR REGULATORY ANALYSIS OF STATE REGULATIONS ON INACTIVE WELLS

PANEL A: NUMBER OF ORPHANED WELLS ON WAIT LIST IN 2006 AS REPORTED BY INTERSTATE OIL AND GAS COMPACT COMMISSION

Number	State	Number of Orphaned Wells on State's Wait List	Percent of Total	Included in Analysis?
1	Alabama	0	0.0	N
2	Alaska	15	0.0	N
3	Arkansas	577	1.0	Y
4	California	430	0.7	N
5	Colorado	45	0.1	N
6	Florida	17	0.0	N
7	Illinois	3900	6.6	Y
8	Indiana	598	1.0	Y
9	Kansas	7271	12.3	Y
10	Kentucky	10600	17.9	Y
11	Louisiana	3183	5.4	Y
12	Michigan	100	0.2	N
13	Mississippi	49	0.1	N
14	Missouri	2000	3.4	Y
15	Montana	90	0.2	N
16	Nebraska	6	0.0	N
17	New Mexico	134	0.2	N
18	New York	4800	8.1	Y
19	N Dakota	4	0.0	N
20	Ohio	2089	3.5	Y
21	Oklahoma	2089	3.5	Y
22	Pennsylvania	8700	14.7	Y
23	Texas	11220	18.9	Y
24	Utah	8	0.0	N
25	Virginia	37	0.1	N
26	West Virginia	1260	2.1	Y
	Total	***59222***	***100.0***	

PANEL B: HISTORICAL CRUDE OIL PRODUCTION BY STATE FROM 1981 TO 2014 AS REPORTED BY THE UNITED STATES ENERGY INFORMATION ADMINISTRATION

Number	State	Total Crude Oil Production (thousands of barrels)	Percent of Total	Included in Analysis?
1	Alabama	476828	0.7	N
2	Alaska	15436216	22.2	Y
3	Arizona	3479	0.0	N
4	Arkansas	338067	0.5	N
5	California	9611042	13.8	Y
6	Colorado	1054404	1.5	Y
7	Florida	234098	0.3	N
8	Illinois	551751	0.8	N
9	Indiana	97584	0.1	N
10	Kansas	1629315	2.3	Y
11	Kentucky	142549	0.2	N
12	Louisiana	4151638	6.0	Y
13	Michigan	479038	0.7	N
14	Mississippi	817398	1.2	Y
15	Missouri	4710	0.0	N
16	Montana	809190	1.2	Y
17	Nebraska	140859	0.2	N
18	Nevada	45851	0.1	N
19	New Mexico	2422916	3.5	Y
20	New York	14474	0.0	N
21	N Dakota	2378928	3.4	Y
22	Ohio	297293	0.4	N
23	Oklahoma	3374291	4.9	Y
24	Pennsylvania	101357	0.1	N
25	South Dakota	49448	0.1	N
26	Tennessee	15931	0.0	N
27	Texas	21102459	30.4	Y
28	Utah	829835	1.2	Y
29	Virginia	605	0.0	N
30	West Virginia	84458	0.1	N
31	Wyoming	2741437	3.9	Y
	Total	***69437449***	***100.0***	

Panel C: Historical Onshore Natural Gas Production from 1992 to 2014 as Reported by the United States Energy Information Administration

Number	State	Total Onshore Natural Gas Production (MMcf)	Percent of Total	Included in Analysis?
1	Alaska	69609461	15.2	Y
2	Arkansas	9740182	2.1	Y
3	California	6865283	1.5	Y
4	Colorado	23774320	5.2	Y
5	Kansas	10991955	2.4	Y
6	Louisiana	37126176	8.1	Y
7	Montana	1792136	0.4	N
8	New Mexico	35152190	7.7	Y
9	N Dakota	2466404	0.5	N
10	Ohio	2851044	0.6	N
11	Oklahoma	41483614	9.0	Y
12	Pennsylvania	14430793	3.1	Y
13	Texas	147884221	32.2	Y
14	Utah	8139257	1.8	Y
15	West Virginia	6620767	1.4	Y
16	Wyoming	39868485	8.7	Y
	Total	***458796288***	***100***	

Appendix B. State Oil and Gas Regulations

Alaska

Financial Assurance	
Individual Bond	20 AAC 25.025.b
Blanket Bond	20 AAC 25.025.b
Types of financial assurances allowed	20 AAC 25.025.a
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	No evidence found
Bond varies by well characteristics	20 AAC 25.025
Liens and/or special liability provisions	20 AAC 25.025.d; 20 AAC 25.026
Temporary Abandonment	
NAI TA	20 AAC 25.072.a
TA time limit	20 AAC 25.072.d
Well idle time limit	20 AAC 25.115
TA future economic viability requirement	20 AAC 25.110.a.2
TA technical shut-in requirement	20 AAC 25.110.c
TA well integrity demonstration	20 AAC 25.072.e
Plugging and Restoration	
Plugging requirements	20 AAC 25.112
Special treatment of casing removal	No evidence found
Special plugging requirements by well type	20 AAC 25.112.e
Cement standards	20 AAC 25.112.g
Conversion to freshwater wells	20 AAC 25.140
Marking after permanent abandonment	20 AAC 25.120
Restoration requirements	20 AAC 25.170
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	20 AAC 25.170.d
NAI pre plugging	20 AAC 25.105.e
NAI post plugging	20 AAC 25.070.3
Other	
Ability of regulator to order plugging	20 AAC 25.105.a
Reporting requirements of operator and/or regulator	20 AAC 25.115.a
Protection against fugitive methane at inactive sites	20 AAC 25.066
Consideration of inactive wells during new well permitting	20 AAC 25.283.a.10; 20 AAC 25.283.1.2.C.i

Note: AAC: Alaska Administrative Code

Arkansas

Financial Assurance	
Individual Bond	GRR B-2.f.1
Blanket Bond	GRR B-2.f.4
Types of financial assurances allowed	GRR B-2.d
Use of surface damage agreements	AC §15-72-203
Bond varies by operator characteristics	GRR B-2.g
Bond varies by well characteristics	GRR B-2.h; GRR B-2.f.4
Liens or special liability provisions	GRR G-3; GRR G-2
Temporary Abandonment	
NAI TA	GRR B-5.h
TA time limit	GRR B-5.h
Well idle time limit	GRR B-7.d; B-7.c
TA future economic viability requirement	No evidence found
TA technical shut-in requirement	GRR B-5.h.3
TA well integrity demonstration	GRR B-5.h.3.D.iv
Plugging and Restoration	
Plugging requirements	GRR B-8; GRR B-9
Special treatment of casing removal	No evidence found
Special plugging requirements by well type	GRR B-9.d
Cement standards	GRR B-9.a.2
Conversion to freshwater wells	GRR B-11
Marking after permanent abandonment	No evidence found
Restoration requirements	GRR B-9.e
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	GRR B-5.e-g
NAI post plugging	No evidence found
Other	
Ability of regulator to order plugging	GRR G-1.c-g; GRR B-5.c.3; GRR B-1.c.2; GRR B-26.l
Reporting requirements of operator and/or regulator	No evidence found
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	GRR B-5.g.1.A.

Notes: GRR: Arkansas Oil and Gas Commission, General Rules and Regulations; AC: Arkansas Code.

California

Financial Assurance	
Individual Bond	CPRC §3204
Blanket Bond	CPRC §3205
Types of financial assurances allowed	CCR §995.710-760; CPRC §3205.5
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	CPRC §3270.4; CCR §1722.8; CPRC §3202; CPRC §3206
Bond varies by well characteristics	CPRC §3204; CPRC §3205
Liens or special liability provisions	CPRC §3270.4.d; CPRC §3237
Temporary Abandonment	
NAI TA	No evidence found
TA time limit	CPRC §3008.d-e; CCR §1723.9
Well idle time limit	No evidence found
TA future economic viability requirement	No evidence found
TA technical shut-in requirement	No evidence found
TA well integrity demonstration	CCR 1723.9
Plugging and Restoration	
Plugging requirements	CCR §1723; CPRC §3228
Special treatment of casing removal	CCR §1723.6
Special plugging requirements by well type	CCR §1723.8; CCR §1723.1.c
Cement standards	CCR §1723.a
Conversion to freshwater wells	No evidence found
Marking after permanent abandonment	CCR §1723.5
Restoration requirements	CCR §1776
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	CPRC §3229-3230; CCR §1714
NAI post plugging	CPRC §3232; CPRC §3215.a; CCR §1724.1
Other	
Ability of regulator to order plugging	CPRC §3237.a.1; CPRC §3208.1; CPRC §3206.5
Reporting requirements of operator and/or regulator	CPRC §3227.5; CPRC §3227.a.2; CPRC §3260
Protection against fugitive methane at inactive sites	CPRC §3240-3241; CPRC §3850-3865
Consideration of inactive wells during new well permitting	CPRC §3160.d.1.E

Notes: CPRC: California Public Resources Code; CCR: California Code of Regulations.

Colorado

Financial Assurance	
Individual bond	2 CCR-1-706.a
Blanket bond	2 CCR-1-706-b
Types of financial assurances allowed	2 CCR-1-100; 2 CCR-1-702; C.R.S. §34-60-106(13)
Use of surface damage agreements	2 CCR-1-703
Bond varies by operator characteristics	2 CCR-1-707; 2 CCR-1-702.a
Bond varies by well characteristics	2 CCR-1-706
Liens or special liability provisions	2 CCR-1-708; 2 CCR-1-320
Temporary Abandonment	
NAI TA	2 CCR-1-319.b
TA time limit	2 CCR-1-319.b.1
Well idle time limit	No evidence found
TA future economic viability requirement	2 CCR-1-319.b.1
TA technical shut-in requirement	2 CCR-1-319.b.1
TA well integrity demonstration	2 CCR-1-326.c
Plugging and Restoration	
Plugging requirements	2 CCR-1-319.a.1
Special treatment of casing removal	2 CCR-1-319.a.4
Special plugging requirements by well type	2 CCR-1-209
Cement standards	2 CCR-1-319.a.1
Conversion to freshwater wells	2 CCR-1-319.a.7
Marking after permanent abandonment	2 CCR-1-319.a.5
Restoration requirements	2 CCR-1-1000-1004
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	2-CCR-1-1004.c
NAI pre plugging	2 CCR-1-311.a; 2 CCR-1-319.a.6
NAI post plugging	2-CCR-1-311.b; 2-CCR-1-319.a.3
Other	
Ability of regulator to order plugging	2 CCR-1-208
Reporting requirements of operator and/or regulator	2-CCR-1-308.B; 2-CCR-1-309
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	2 CCR-1-303.b.3.D; 2 CCR-1-608.a

Notes: CCR: Colorado Code of Regulations; CRS: Colorado Revised Statutes.

Illinois

Financial Assurance	
Individual Bond	62 IAC Chapter I Section 240.1500(a)(2)
Blanket Bond	62 IAC Chapter I Section 240.1500(a)(2)
Types of financial assurances allowed	62 IAC Chapter I Section 240.1510
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	62 IAC Chapter I Section 240.1500(a)(1)
Bond varies by well characteristics	62 IAC Chapter I Section 240.1500(a)(2)
Liens or special liability provisions	No evidence found
Temporary Abandonment	
NAI TA	62 IAC Chapter I Section 240.1130(c)
TA time limit	62 IAC Chapter I Section 240.1130(f)
Well idle time limit	62 IAC Chapter I Section 240.1120 and Section 240.1130(a-b)
TA future economic viability requirement	No evidence found
TA technical shut-in requirement	62 IAC Chapter I Section 240.1130(c)
TA well integrity demonstration	62 IAC Chapter I Section 240.1130(c)
Plugging and Restoration	
Plugging requirements	62 IAC Chapter I Section 240.1550
Special treatment of casing removal	62 IAC Chapter I Section 240.1150(d)
Special plugging requirements by well type	No evidence found
Cement standards	62 IAC Chapter I Section 240.1280(a-b)
Conversion to freshwater wells	62 IAC Chapter I Section 240.1280
Marking after permanent abandonment	No evidence found
Restoration requirements	62 IAC Chapter I Section 240.1160 and 240.1770
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	62 IAC Chapter I Section 240.1140 (a)
NAI post plugging	62 IAC Chapter I Section 240.1190
Other	
Ability of regulator to order plugging	62 IAC Chapter I Section 240.1610(a)
Reporting requirements of operator and/or regulator	No evidence found
Protection against fugitive methane at inactive sites	62 IAC Chapter I Section 240.1140(e)
Consideration of inactive wells during new well permitting	No evidence found

Note: IAC: Illinois Administrative Code

Indiana

Financial Assurance Requirements	
Individual Bond	312 IAC 16-4-2
Blanket Bond	312 IAC 16-4-2.a.5
Types of financial assurances allowed	312 IAC 16-4-2; IC 14-37-6-2; IC 14-37-6-4
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	312 IAC 16-4-1.a; 312 IAC 16-3-5-2
Bond varies by well characteristics	312 IAC 16-4-2
Liens or special liability provisions	IC 14-37-13-2
Temporary Abandonment	
NAI TA	TR Section 6; 312 IAC 16-5-20.b
TA time limit	312 IAC 16-5-20.b, e
Well idle time limit	312 IAC 16-5-20.b-c
TA future economic viability requirement	312 IAC 16-5-20.f.3
TA technical shut-in requirement	312 IAC 16-5-20.b, d
TA well integrity demonstration	312 IAC 16-5-20.d
Plugging Requirements	
Plugging requirements	TR Section 14, 15, 20, 1.13; 312 IAC 16-5-19
Special treatment of casing removal	No evidence found
Special plugging requirements by well type	TR Section 19
Cement standards	TR Section 3; 312 IAC 16-5-19.f
Conversion to freshwater wells	312 IAC 16-5-19(r)
Marking after permanent abandonment	TR Section 20.e
Restoration requirements	TR Section 23; 312 IAC 16-5-19.p-r
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	no evidence found
NAI pre plugging	TR Section 7, Section 8
NAI post plugging	TR Section 22, IC 14-37-8-4.4; 312 IAC 16-5-19(k-o)
Other	
Ability of regulator to order plugging	TR Section 10; IC 14-37-8-7, 12-15
Reporting requirements of operator and/or regulator	No evidence found
Protection against fugitive methane at inactive sites	IC 14-37-8-10
Consideration of inactive wells during new well permitting	IC 14-37-4-5

Notes: IC: Indiana Code; IAC: Indiana Administrative Code; TR: Temporary Rule

Kansas

Financial Assurance	
Individual Bond	KSA 55-155
Blanket Bond	KSA 55-155
Types of financial assurances allowed to be posted	KSA 55-155 and KAR-82-3-120(f)
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	KSA 55-155(d)(3)
Bond varies by well characteristics	KSA 55-155
Liens or special liability provisions	No evidence found
Temporary Abandonment	
NAI TA	No evidence found
TA time limit	KAR 82-3-111(b)(d)(e)
Well idle time limit	KAR 82-3-111(a)
TA future economic viability requirement	No evidence found
TA technical shut-in requirement	No evidence found
TA well integrity demonstration	KAR 82-3-111(b-c)
Plugging and Restoration	
Plugging requirements	KAR 82-3-114(a)(1-3), KAR 82-3-114(e)
Special treatment of casing removal	No evidence found
Special plugging requirements by well type	KAR 82-3-114(c), KAR 82-3-114(d)
Cement standards	KAR 82-3-114(e)
Conversion to freshwater wells	No evidence found
Marking after permanent abandonment	No evidence found
Restoration requirements	No evidence found
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	KAR 82-3-113(b)
NAI post plugging	KAR 82-33-111(c)
Other	
Ability of regulator to order plugging	KAR 82-3-112
Reporting requirements of operator and/or regulator	KAR 82-3-117, KAR 82-3-118
Protection against fugitive methane at inactive sites	KAR 82-3-1305
Consideration of inactive wells during new well permitting	No evidence found

Notes: KSA: Kansas Statute Annotated; KAR: Kansas Administrative Regulations.

Kentucky

Financial Assurance	
Individual Bond	KRS 353.590(7-9)
Blanket Bond	KRS 353.590(12, 13, 17)
Types of financial assurances allowed	KRS 353.590(18-22)
Use of surface damage agreements	805 KAR 1:170(2.3, 3, 4)
Bond varies by operator characteristics	KRS 353.590(12, 13)
Bond varies by well characteristics	KRS 353.590(7-9, 12, 17)
Liens or special liability provisions	805 KAR 1:050; 805 KAR 1:170reg(7); KRS 353.590(25)
Temporary Abandonment	
NAI TA	805 KAR 1:060(1)
TA time limit	805 KAR 1:060(1)
Well idle time limit	KRS 353.150(1)
TA future economic viability requirement	No evidence found
TA technical shut-in requirement	805 KAR 1:060(1)
TA well integrity demonstration	No evidence found
Plugging and Restoration	
Plugging requirements	805 KAR 1:060; 805 KAR 1:070
Special treatment of casing removal	No evidence found
Special plugging requirements by well type	805 KAR 1:070
Cement standards	805 KAR 1:070(6)
Conversion to freshwater wells	805 KAR 1:060(5)
Marking after permanent abandonment	No evidence found
Restoration requirements	805 KAR 1:170
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	805 KAR 1:170(6)
NAI pre plugging	805 KAR 1:060(2); 805 KAR 1:070(2); 805 KAR 1:080(5); 805 KAR 1:130reg
NAI post plugging	805 KAR 1:060(4)
Other	
Ability of regulator to order plugging	KRS 353.739; 805 KAR 1:070(1.2); 805 KAR 1:060(6); KRS 353.180
Reporting requirements of operator and/or regulator	KAR 1:180(i)
Protection against fugitive methane at inactive sites	KRS 353.140, 150, 160
Consideration of inactive wells during new well permitting	KAR 1:080

Notes: KRS: Kentucky Revised Statutes; KAR: Kentucky Administrative Regulations.

Louisiana

Financial Assurance	
Individual Bond	LAC 43:XIX§104.C.1.a; LAC 43:XIX§104.C.2.a
Blanket Bond	LAC 43:XIX§104.C.1.b; LAC 43:XIX§104.C.2.b
Types of financial assurances allowed	LAC 43:XIX§104.B
Use of surface damage agreements	LAC 43:I§3901
Bond varies by operator characteristics	LAC 43:XIX§703
Bond varies by well characteristics	LAC 43:XIX§104.C
Liens or special liability provisions	LAC 43:I§2701, 2703
Temporary Abandonment	
NAI TA	LAC 43:XIX§137.A.3.a; LAC 43:XIX§137.A.4
TA time limit	LAC 43:XIX§137.A.2
Well idle time limit	LAC 43:XIX§137.A.3.a
TA future economic viability requirement	LAC 43:XIX§137.A.3.b
TA technical shut-in requirement	LAC 43:XIX§137.H
TA well integrity demonstration	No evidence found
Plugging and Restoration	
Plugging requirements	LAC 43:XIX§137.F.3.a-f
Special treatment of casing removal	LAC 43:XIX§137.F.3.j
Special plugging requirements by well type	No evidence found
Cement standards	No evidence found
Conversion to freshwater wells	LAC 43:XIX§137.G
Marking after permanent abandonment	No evidence found
Restoration requirements	LAC 43:I§2101-3101
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	LAC 43:I§2503
NAI pre plugging	LAC 43:XIX§137.F.1, 2, 3k
NAI post plugging	LAC 43:XIX§137.F.4
Other	
Ability of regulator to order plugging	LAC 43:XIX§137.C; LAC 43:I§2501
Reporting requirements of operator and/or regulator	LAC 43:XIX§137.A.3.b,c
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Notes: LAC: Louisiana Administrative Code.

Missouri

Financial Assurance	
Individual Bond	10 CSR 50-2.020(1)
Blanket Bond	10 CSR 50-2.020(1)
Types of financial assurances allowed	10 CSR 50-2.020(2)
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	10 CSR 50-2.030(9); 10 CSR 50-2.020(1)(A)
Bond varies by well characteristics	10 CSR 50-2.020(1)
Liens or special liability provisions	No evidence found
Temporary Abandonment	
NAI TA	10 CSR 50-2.040(5)
TA time limit	10 CSR 50-2.040(5)
Well idle time limit	10 CSR 50-2.040(5)
TA future economic viability requirement	10 CSR 50-2.040(5)
TA technical shut-in requirements	10 CSR 50-2.040(5, 6)
TA well integrity demonstration	10 CSR 50-2.040(6)
Plugging and Restoration	
Plugging requirements	10 CSR 50-2.060(3)(C)
Special treatment of casing removal	10 CSR 50-2.060(3)(C)(4)
Special plugging requirements by well type	No evidence found
Cement standards	10 CSR 50-2.060(2, 4); 10 CSR 50-1.030(C)(3)
Conversion to freshwater wells	10 CSR 50-2.060(6)
Marking after permanent abandonment	No evidence found
Restoration requirements	10 CSR 50-2.060(3)(A)(1)
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	10 CSR 50-2.060(1, 2)
NAI post plugging	10 CSR 50-2.060(7)
Other	
Ability of regulator to order plugging	10 CSR 50-2.060(3)(A)(2, 4)
Reporting requirements of operator and/or regulator	10 CSR 50-2.080(2, 3)
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	10 CSR 50-1.030(1)(A)(3, 4); 10 CSR 50-2.030(2)

Note: CSR: Code of State Regulations.

Montana

Financial Assurance	
Individual Bond	ARM 36.22.1308.1.a
Blanket Bond	ARM 36.22.1308.1.b,c
Types of financial assurances allowed	ARM 36.22.1308.6,7
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	ARM 36.22.1308.3,5; MCA 82.10.402
Bond varies by well characteristics	ARM 36.22.1308
Liens or special liability provisions	No evidence found
Temporary Abandonment	
NAI TA	ARM 36.22.1240
TA time limit	ARM 36.22.1240; ARM 36.22.1303
Well idle time limit	ARM 36.22.1240
TA future economic viability requirement	ARM 36.22.1240; ARM 36.22.1303
TA technical shut-in requirement	No evidence found
TA well integrity demonstration	No evidence found
Plugging and Restoration	
Plugging requirements	ARM 36.22.1303
Special treatment of casing removal	ARM 36.22.1306
Special plugging requirements by well type	No evidence found
Cement standards	No evidence found
Conversion to freshwater wells	ARM 36.22.1305
Marking after permanent abandonment	ARM 36.22.1304
Restoration requirements	ARM 36.22.1307
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	ARM 36.22.1301; ARM 36.22.1302; MCA 82.10.401
NAI post plugging	ARM 36.22.1301; ARM 36.22.1309; ARM 36.22.1241
Other	
Ability of regulator to order plugging	No evidence found
Reporting requirements of operator and/or regulator	MCA 82.10.402
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Notes: ARM: Administrative Rules of Montana; MCA: Montana Code Annotated.

Nebraska

Financial Assurance	
Individual Bond	NAC Title 267 Chapter 3 004 Form 3A
Blanket Bond	NAC Title 267 Chapter 3 004 Form 3A
Types of financial assurances allowed	NAC Title 267 Chapter 3 004 Form 3A
Use of surface damage agreements	No evidence found
Bond varies by operator (bad, idle)	NAC Title 267 Chapter 3 004 Form 3A; NAC Title 267 Chapter 3 040.03
Bond varies by well charateristics	NAC Title 267 Chapter 3 004 Form 3A
Liens or special liability provisions	NAC Title 267 Chapter 3 030
Temporary Abandonment	
NAI TA	NAC Title 267 Chapter 3 040.02
TA time limit	NAC Title 267 Chapter 3 040.01
Well idle time limit	NAC Title 267 Chapter 3 040
TA future economic viability requirement	NAC Title 267 Chapter 3 040.01
TA technical shut-in requirement	No evidence found
TA well integrity demonstration	NAC Title 267 Chapter 3 040.01
Plugging and Restoration	
Plugging requirements	NAC Title 267 Chapter 3 028
Special treatment of casing removal	NAC Title 267 Chapter 3 028.04
Special plugging requirements by well type	No evidence found
Cement standards	NAC Title 267 Chapter 3 012.04
Conversion to freshwater wells	NAC Title 267 Chapter 2 007
Marking after permanent abandonment	No evidence found
Restoration requirements	NAC Title 267 Chapter 3 012.14-15; NAC Title 267 Chapter 3 028.08
Regulator Notification, Approval, and Inspection	
NAI post restoration	NAC Title 267 Chapter 3 028.08
NAI pre plugging	NAC Title 267 Chapter 3 028.06
NAI post plugging	NAC Title 267 Chapter 3 007 Form 6
Other	
Ability of regulator to order plugging	No evidence found
Reporting requirements of operator and/or regulator	No evidence found
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Note: NAC: Nebraska Administrative Code.

New Mexico

Financial Assurance	
Individual Bond	NMC §19.15.8.9D(2-4)
Blanket Bond	NMC §19.15.8.9D(1)
Types of financial assurances allowed	NMC §19.15.8.9A; NMC §19.15.10, 11, 15
Use of surface damage agreements	NMC §19.15.8.9B
Bond varies by operator characteristics	NMC §19.15.8.9C, D(5)
bond varies by well characteristics	NMC §19.15.8.9D
Liens or special liability provisions	No evidence found
Temporary Abandonment	
NAI TA	NMC §19.15.25.13; NMC §19.15.7.14.A(d)
TA time limit	NMC §19.15.25.12
Well idle time limit	NMC §19.15.25.8
TA future economic viability requirement	No evidence found
TA technical shut-in requirement	No evidence found
TA well integrity demonstration	NMC §19.15.25.14
Plugging and Restoration	
Plugging requirements	NMC §19.15.25.10.A
Special treatment of casing removal	No evidence found
Special plugging requirements by well type	No evidence found
Cement standards	No evidence found
Conversion to freshwater wells	NMC §19.15.25.15
Marking after permanent abandonment	NMC §19.15.25.10.B, C
Restoration requirements	NMC §19.15.25.10.D
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	NMC §19.15.25.10.F
NAI pre plugging	NMC §19.15.7.14.A(1e, 2)
NAI post plugging	NMC §19.15.7.14.E, F
Other	
Ability of regulator to order plugging	NMC §19.15.5.10.B(4, 7)
Reporting requirements of operator and/or regulator	NMC §19.15.5.9
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Note: NMC: New Mexico Code.

New York

Financial Assurance	
Individual Bond	6 CCR-NY 551.5.a.1.i; 6 CCR-NY 551.5.a.2.i
Blanket Bond	6 CCR-NY 551.5.a.1, 2
Types of financial assurances allowed	6 CCR-NY 551.4.b
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	No evidence found
Bond varies by well characteristics	6 CCR-NY 551.5; 6 CCR-NY 551.6
Liens or special liability provisions	11 CCR-NY 1101.3.e,f
Temporary Abandonment	
NAI TA	6 CCR-NY 555.3.b; 6 CCR-NY 555.2.a
TA time limit	6 CCR-NY 555.3.b; 6 CCR-NY 555.2.a
Well idle time limit	6 CCR-NY 555.3.a
TA future economic viability requirement	6 CCR-NY 555.3.b
TA technical shut-in requirement	No evidence found
TA well integrity demonstration	No evidence found
Plugging and Restoration	
Plugging requirements	6 CRR-NY 555.5
Special treatment of casing removal	6 CRR-NY 555.5
Special plugging requirements by well type	No evidence found
Cement standards	No evidence found
Conversion to freshwater wells	6 CRR-NY 555.6
Marking after permanent abandonment	No evidence found
Restoration requirements	No evidence found
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	6 CRR-NY 555.4
NAI post plugging	6 CRR-NY 555.5.d
Other	
Ability of regulator to order plugging	11 CCR-NY 1101.3.j
Reporting requirements of operator and/or regulator	No evidence found
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Note: CCR-NY: New York Codes, Rules and Regulations.

North Dakota

Financial Assurance	
Individual Bond	NDAC 42-02-03-15-2
Blanket Bond	NDAC 42-02-03-15-2
Types of financial assurances allowed	NDAC 43-02-03-15-1; NDAC 42-02-03-15-8
Use of surface damage assessments	No evidence found
Bond varies by operator characteristics	NDAC 42-03-03-13-2
Bond varies by well characteristics	No evidence found
Liens or special liability provisions	No evidence found
Temporary Abandonment	
NAI TA	NDAC 43-02-03-55
TA time limit	NDAC 43-02-03-55
Well idle time limit	NDAC 43-02-03-55
TA future economic viability requirement	No evidence found
TA technical shut-in requirement	NDAC 43-02-03-55
TA well integrity demonstration	NDAC 43-02-03-55
Plugging and Restoration	
Plugging requirements	NDAC 43-02-03-04
Special treatment of casing removal	NDAC 43-02-0
Special plugging requirements by well type	NDAC 43-02-03-24
Cement standards	NDAC 43-02-03-34
Conversion to freshwater wells	NDAC 43-02-03-35
Marking after permanent abandonment	No evidence found
Restoration requirements	NDAC 43-02-03-19
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	NDAC 42-02-03-13-7
NAI pre plugging	NDAC 42-02-03-33
NAI post plugging	NDAC 42-02-03-13-7
Other	
Ability of regulator to order plugging	No evidence found
Reporting requirements of operator and/or regulator	No evidence found
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	NDAC 43-02-03-15-2

Note: NDAC: North Dakota Administrative Code.

Ohio

Financial Assurance	
Individual Bond	OAC 1501:9-1-03(A)
Blanket Bond	OAC 1501:9-1-03(A)
Types of financial assurances allowed	OAC 1501:9-1-03(F)
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	No evidence found
Bond varies by well characteristics	No evidence found
Liens or liability provisions	ORC 1509.07(A)
Temporary Abandonment	
NAI TA	ORC 1509.062.C
TA time limit	ORC 1509.062.G
Well idle time limit	ORC 1509.062.A
TA future economic viability	ORC 1509.062.B.5
TA technical shut-in requirement	ORC 1509.062.C
TA well integrity demonstration	ORC 1509.062.B.6; ORC 1509.062.C
Plugging and Restoration	
Plugging requirements	OAC 1501:9-11-08; OAC 1501:9-11-09
Special treatment of casing removal	OAC 1501:9-11-06; OAC 1501:9-11-10; OAC 1501:9-11-08.F; OAC 1501:9-11-09.B
Special plugging requirements by well type	OAC 1501:9-11-08.A.6; ORC 1571.05
Cement standards	OAC 1501:9-11-01.M
Conversion to freshwater wells	OAC 1501:9-11-13
Marking after permanent abandonment	OAC 1501:9-11-10
Restoration requirements	OAC 1509.072; OAC 1501:9-1-02.B, C
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	OAC 1501:9-11-02; OAC 1501:9-11-04
NAI post plugging	OAC 1509.14
Other	
Ability of regulator to order plugging	ORC 1509.12; ORC 1509.04.C
Reporting requirements of operator and/or regulator	No evidence found
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Notes: OAC: Ohio Administrative Code; ORC: Ohio Revised Code.

Oklahoma

Financial Assurance	
Individual Bond	OS §17-518(A)
Blanket Bond	OS §17-518(A)
Types of financial assurances allowed	OAC 165:10-1-10-(a)(1), (b); OAC 165:10-1-11
Use of surface damage agreements	OS §17-519, 520
Bond varies by operator characteristics	OS §52-318.1(C); OAC 165-10-1-10(d)
Bond varies by well characteristics	OS §17-518(A)
Liens or special liability provisions	OAC 165:10-11-3(b)
Temporary Abandonment	
NAI TA	OAC 165:10-11-9
TA time limit	OAC 165:10-11-9.c.2
Well idle time limit	OS §68-1—1.F.2
TA future economic viability	No evidence found
TA technical shut-in requirement	OAC 165:10-11-9.d
TA well integrity demonstration	OAC 165:10-11-9.c.4
Plugging and Restoration	
Plugging requirements	OAC 165:10-11-6; OAC 165:10-11-3
Special treatment of casing removal	OAC 165:10-11-6.k
Special plugging requirements by well type	OS §52-308
Cement standards	No evidence found
Conversion to freshwater wells	OAC 165:10-11-6.p
Marking after permanent abandonment	OAC 165:10-3-4.f; OAC 165:10-3-17.j
Restoration requirements	OAC 165:10-3-17.k-n; OAC 165:10-7-2.d; OS §17-53.2
Regulator Notification, Approval, and Inspection	
NAI post restoration	No evidence found
NAI pre plugging	OAC 165:10-11-1, 2, 4
NAI post plugging	OAC 165:10-11-7
Other	
Ability of regulator to order plugging	OAC 165:10-1-10.g; OS §17-53; OAC 165:10-11-4; OS §52-309
Reporting requirements of operator and/or regulator	No evidence found
Protection against fugitive methane at inactive sites	OAC 165:10-12
Consideration of inactive wells during new well permitting	No evidence found

Notes: OS: Oklahoma Statues; OAC: Oklahoma Administrative Code.

Pennsylvania

Financial Assurance	
Individual bond	58 Pa. Code §3225(a)(1)
Blanket bond	58 Pa. Code §3225(a)(2):
Types of financial assurances allowed	25 Pa. Code §78.307-309; 58 Pa. Code §3225(a)(3); 58 Pa. Code §3225(d)(1)
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	No evidence found
Bond varies by well characteristics	58 Pa. Code §3225(a)(1, 2)
Liens or special liability provisions	58 Pa. Code §3225(a)(3); 58 Pa. Code §3220(a)
Temporary Abandonment	
NAI TA	58 Pa. Code §3214(a)
TA time limit	25 Pa. Code §78.104
Well idle time limit	No evidence found
TA future economic viability	25 Pa. Code §78.102(4)
TA technical shut-in requirement	25 Pa. Code §78.102(2)(C.)
TA well integrity demonstration	25 Pa. Code §78.103; 25 Pa. Code §78.102(2); 25 Pa. Code §78.903(8)
Plugging and Restoration	
Plugging requirements	25 Pa. Code §78.91, 92, 93, 94, 95
Special treatment of casing removal	25 Pa. Code §78.91(d)
Special plugging requirements by well type	25 Pa. Code §78.92-93; 58 Pa. Code §3220(b); 25 Pa. Code §78.91(g)
Cement standards	No evidence found
Conversion to freshwater wells	No evidence found
Marking after permanent abandonment	25 Pa. Code §78.96
Restoration requirements	58 Pa. Code §3216
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	25 Pa. Code §78.65; 25 Pa. Code §78.903(10); 25 Pa. Code §78.903(11)
NAI pre plugging	58 Pa. Code §3211(f)(2); 58 Pa. Code §3220(c, d); 25 Pa. Code §78.903(9)
NAI post plugging	25 Pa. Code §78.124
Other	
Ability of regulator to order plugging	58 Pa. Code §3214.e; 58 Pa. Code §3220(e.); 25 Pa. Code §78.13
Reporting requirements of operator and/or regulator	58 Pa. Code §3222
Protection against fugitive methane at inactive sites	25 Pa. Code §78.102(3); §78.102(B)(2)(ii)(D)
Consideration of inactive wells during new well permitting	No evidence found

Note: Pa. Code: Pennsylvania Code.

Texas

Financial Assurance	
Individual bond	TAR 16-1-3-3.78(g)
Blanket bond	TAR 16-1-3-3.78(g)
Types of financial assurances allowed	TAR 16-1-3-3.78(d-f)
Use of surface damage agreements	No evidence found
Bond varies by operator characteristics	TAR 16-1-3-3.78(b)(9)
Bond varies by well characteristics	TAR 16-1-3-3.78(g); TAR 16-1-3-3.78(b)
Liens or special liability provisions	TAR 16-1-3-3.78(k)
Temporary Abandonment	
NAI TA	No evidence found
TA time limit	TAR 16-1-3-3.15(d)(1); TAR 16-1-3-3.15(e)
Well idle time limit	TAR 16-1-3-3.14(b)(2)
TA future economic viability	TAR 16-1-3-3.15(j)
TA technical shut-in requirements	No evidence found
TA well integrity demonstration	TAR 16-1-3-15(l)
Plugging and Restoration	
Plugging requirements	TAR 16-1-3-3.14(d)(2,3, and 8)
Special treatment of casing removal	No evidence found
Special plugging requirements by well type	TAR 16-1-3-3.14(e-k)
Cement standards	TAR 16-1-3-3.14(d)(4 and 9)
Conversion to freshwater wells	TAR 16-1-3-3.14(a)(4)
Marking after permanent abandonment	No evidence found
Restoration requirements	TAR 16-1-3-3-.14(d)(12)
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	TAR 16-1-3-3.15(l-m)
NAI post plugging	TAR 16-1-3-3.14(b)(1)
Other	
Ability of regulator to order plugging	TAR 16-1-3-3.15(b)(3)
Reporting requirements of operator and/or regulator	TAR 16-1-3-3.15(i)(5)
Protection against fugitive methane at inactive sites	No evidence
Consideration of inactive wells during new well permitting	No evidence

Note: TAR: Texas Administrative Code.

Utah

Financial Assurance	
Individual bond	UAC R649-3-1-5.1-5.4
Blanket bond	UAC R649-3-1-6.2, 6.3
Types of financial assurances allowed	UAC R649-3-10
Use of surface damage agreements	UAC R649-3-38-6
Bond varies by operator characteristics	UAC R649-3-1-4.3, 4.4
Bond varies by well characteristics	UAC R649-3-1
Liens or special liability provisions	UAC R649-3-1-14
Temporary Abandonment	
NAI TA	UAC R649-3-36-2
TA time limit	UAC R649-3-36-3
Well idle time limit	UAC R649-3-36-1
TA future economic viability requirement	UAC R649-3-36-1.1
TA technical shut-in requirement	No evidence found
TA well integrity demonstration	UAC R649-3-36-1.3
Plugging and Restoration	
Plugging requirements	UAC R649-3-24-3
Special treatment of casing removal	UAC R649-3-24-5.3, 5.5, 8
Special plugging requirements by well type	UAC R649-3-28; UAC R649-3-31; UAC R649-3-30
Cement standards	No evidence found
Conversion to freshwater wells	UAC R649-3-24-6
Marking after permanent abandonment	UAC R649-3-24-7
Restoration requirements	UAC R649-3-34
Regulator Notification, Approval, and Inspection	
NAI post restoration	UAC R649-3-15; UAC R649-3-34-17
NAI pre plugging	UAC R649-3-24-1
NAI post plugging	UAC R649-3-24-5
Other	
Ability of regulator to order plugging	No evidence found
Reporting requirements of operator and/or regulator	UAC R649-3-6
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Note: UAC: Utah Administrative Code.

West Virginia

Financial Assurance	
Individual bond	WVC §22-6-26(b)
Blanket bond	WVC §22-6-26(c)
Types of financial assurances allowed	WVC S22-6-26(d)(e)
Use of surface damage agreements	WVC §22-6A-16; WVC §22-7
Bond varies by operator characteristics	WVC §22-6-6(h)
Bond varies by well characteristics	WVC §22-6-26; WVC §22-6A-7(g); WVC §22-6A-15
Liens or special liability provisions	WVC §22-10-7, 8, 9
Temporary Abandonment	
NAI TA	WVC §35-5-5.2
TA time limit	WVC §35-5-5.4
Well idle time limit	WVC §22-6-19; 35-5-2.2
TA future economic viability	WVC §22-6-19; 35-5-3, 4
TA technical shut-in requirement	No evidence found
TA well integrity demonstration	WVC §35-5-5.3
Plugging and Restoration	
Plugging requirements	WVC §22-6-24
Special treatment of casing removal	WVC §22-6-19
Special plugging requirements by casing type	WVC §22-6-24(b)(c)(d)(e.); WVC §22-6A-13
Cement standards	WVC §22-6-1(h)
Conversion to freshwater wells	No evidence found
Marking after permanent abandonment	No evidence found
Restoration requirements	WVC §22-6-30; WVC §22-6A-14
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	No evidence found
NAI pre plugging	WVC §22-6-6(c)(10); WVC §22-6-23
NAI post plugging	WVC §22-6-23
Other	
Ability of regulator to order plugging	WVC §22-6-26(e); WVC §22-6-14(d)
Reporting requirements of operator and/or regulator	WVC §22-6-29(b)
Protection against fugitive methane at inactive sites	WVC §22-6-31(b); WVC §22-6-32
Consideration of inactive wells during new well permitting	WVC §22-6-14(a)(1)

Note: WVC: West Virginia Code.

Wyoming

Financial Assurance	
Individual bond	Wyo. Stat. Ann. §30-5-404; Rule 3.4.a.i, ii
Blanket bond	Rule 3.4.a.iii
Types of financial assurances allowed	Rule 3.5, 3.6
Use of surface damage agreements	Wyo. Stat. Ann. §30-5-402(c, e); Wyo. Stat. Ann. §30-5-403; Wyo. Stat. Ann. §30-5-406(a); Rule 3.4.(i-k)
Bond varies by operator characteristics	Rule 3.4.(c-e)
Bond varies by well characteristics	Rule 3.4
Liens or special liability provisions	Rule 3.4.f; Rule 3.7; Rule 3.14
Temporary Abandonment	
NAI TA	Rule 3.16.a
TA time limit	Rule 3.16.b
Well idle time limit	No evidence found
TA future economic viability requirement	No evidence found
TA technical shut-in requirement	Rule 1.2.eee
TA well integrity demonstration	Rule 3.16.c, d
Plugging and Restoration	
Plugging requirements	Rule 3-18
Special treatment of casing removal	Rule 3.18.b.iii.C; Rule 3.18.b.iii.E
Special plugging requirements by well type	Rule 3.18.c; Rule 3.18.b.iv
Cement standards	Rule 3.18.b.i
Conversion to freshwater wells	Rule 3.15.b
Marking after permanent abandonment	Rule 3.19.a.5
Restoration requirements	Rule 3.17.b-d; Rule 3.7.a
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	Rule 3.17.c
NAI pre plugging	Rule 3.15
NAI post plugging	Rule 3.17.a
Other	
Ability of regulator to order plugging	Rule 3.36
Reporting requirements of operator and/or regulator	Rule 3.16.a;
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Notes: Wyo. Stat. Ann.: Wyoming Statutes Annotated; Rule: Wyoming Oil and Gas Conservation Commission Rules.

Bureau of Land Management

Financial Assurance	
Individual bond	43 CFR 3104.2
Blanket bond	43 CFR 3104.3
Types of financial assurances allowed	43 CFR 3104.1.b,c
Use of surface damage agreements	OOGO III.D.4; OOGO VI
Bond varies by operator characteristics	43 CFR 3104.5; OOGO III.D.5.a
Bond varies by well characteristics	43 CFR 3104.5; OOGO III.D.5.a
Liens or special liability provisions	No evidence found
Temporary Abandonment	
NAI TA	43 CFR 3162.3-4.c
TA time limit	43 CFR 3162.3-4.c
Well idle time limit	43 CFR 3162.3-4.c
TA future economic viability requirement	IM 2012-181
TA technical shut-in requirement	IM 2012-181
TA well integrity demonstration	IM 2012-181
Plugging and Restoration	
Plugging requirements	43 CFR 3162.3-4.a
Special treatment of casing removal	No evidence found
Special plugging requirements by well type	No evidence found
Cement standards	No evidence found
Conversion to freshwater wells	43 CFR 3162.3-4.b; OOGO IX.B
Marking after permanent abandonment	43 CFR 3162.6.d
Restoration requirements	OOGO II.4.D.j; OOGO XII.B
Regulator Notification, Approval, and Inspection (NAI)	
NAI post restoration	GAO 2011
NAI pre plugging	43 CFR 3162.3-4.a; OOGO XII.A
NAI post plugging	OOGO XII.A
Other	
Ability of regulator to order plugging	IM 2012-181
Reporting requirements of operator and/or regulator	43 CFR 3162.4-3; IM 2012-181
Protection against fugitive methane at inactive sites	No evidence found
Consideration of inactive wells during new well permitting	No evidence found

Notes: CFR: Code of Federal Regulations; IM: Instruction Memorandum; OOGO: Onshore Oil and Gas Order No. 1 (2007).

Acknowledgements

The authors would like to thank the Paul G. Allen Family Foundation for funding this project and, in particular, Courtney Blodgett for providing helpful and extensive comments on the draft. We also want to acknowledge the help of RFF's Jessica Chu, research associate; research assistants Elaine Swiedler and Alexandra Thompson; plus Jan Mares, senior policy advisor. We also thank Pat Payne (Alberta Orphan Well Association), Rod Smith (Schlumberger), Dale Kunz (Winterhawk, Inc.), John Reitsma (Bureau of Land Management National Operation Center), Patrick Shields (Kansas Corporation Commission) and Lane Palmateer (Kansas Corporation Commission). We offer special thanks to DrillingInfo for making its database available to us. Finally, we thank our many expert reviewers and state officials for their very helpful comments and suggestions.

References

API (American Petroleum Institute). 1993. Environmental Guidance Document: Well Abandonment and Inactive Well Practices for US Exploration and Production Operations. 31 Jan.

———. 2009. Environmental Protection for Onshore Oil and Gas Production Operations and Leases. July. http://www.api.org/~/media/Files/Policy/Exploration/API_RP_51R.pdf (accessed 23 Sept. 2015).

Bishop, Ronald E. 2013. "Historical analysis of oil and gas well plugging in New York: Is the regulatory system working?." *New Solutions: A Journal of Environmental and Occupational Health Policy* 23(1): 103–116.

Bonett, Art, and Demos Pafitis. 1996. "Getting to the root of gas migration." *Oilfield Review* 8(1): 36–49.

Boyer, Gerry. 2015. Vent Flow/Gas Migration Data Trends in the Western Provinces. Industry Operations Branch, Alberta Energy Regulator. May 13.

Brandt, A.R., G.A. Heath, E.A. Kort, F. O'Sullivan, G. Pétron, S.M. Jordaan, P. Tans, J. Wilcox, A.M. Gopstein, D. Arent, S. Wofsy, N.J. Brown, R. Bradley, G.D. Stucky, D. Eardley, and R. Harriss. 2014. "Methane Leaks from North American Natural Gas Systems." *Science* 343: 733–735.

Brown, Katie. 2014. "New Ingraffea Report: Same Old Tactics." Web log post. Energy in Depth, 10 July. http://energyindepth.org/national/new-ingraffea-report-same-old-tactics/ (accessed 15 Feb. 2015).

Calvert, D.G., and Dwight K. Smith.1994. "Issues and techniques of plugging and abandonment of oil and gas wells." SPE Annual Technical Conference and Exhibition. *Society of Petroleum Engineers.*

Chafin, Daniel T. 1994. Sources and Migration Pathways of Natural Gas in Near-Surface Ground Water Beneath the Animas River Valley, Colorado and New Mexico. No. 94-4006. US Geological Survey.

Davis, Lucas. 2015. "Bonding requirements for US natural gas producers." *Review of Environmental Economics and Policy* 9(1): 128–144.

Davies, Richard J., Sam Almond, Robert S. Ward, Robert B. Jackson, Charlotte Adams, Fred Worrall, Liam G. Herringshaw, Jon G. Gluyas, and Mark A. Whitehead. 2014. "Oil and gas wells and their integrity: implications for shale and unconventional resource exploitation." *Marine and Petroleum Geology* 56: 239–254.

Derksen, Cheyenne. 2015. "Deserted Wells Create Kansas Sinkholes." McPherson

Sentinel, 6 July. http://www.mcphersonsentinel.com/article/20150706/NEWS/150709731 (accessed 23 Sept. 2015).

DOI (US Department of the Interior). 2015. DOI (US Department of the Interior). 2015. *US Fish and Wildlife Service's Management of Oil and Gas Activities on Refuges.* Report No. CR-EV-FWS-0002-2014. Washington, DC: DOI. http://www.fws.gov/policy/ManagementofOilandGasActivitiesHandbook.pdf (accessed 24 Sept. 2015).

Drohan, P.J., M. Brittingham., J. Bishop, and K. Yoder. 2012. "Early trends in landcover change and forest fragmentation due to shale-gas development in Pennsylvania: a potential outcome for the Northcentral Appalachians." *Environmental Management* 49(5): 1061–1075.

Dusseault, Maurice, and Richard Jackson. 2014. "Seepage pathway assessment for natural gas to shallow groundwater during well stimulation, in production, and after abandonment." *Environmental Geosciences* 21(3): 107–126.

Dusseault, Maurice B., Malcolm N. Gray, and Pawel A. Nawrocki. 2000. "Why oilwells leak: cement behavior and long-term consequences." International Oil and Gas Conference and Exhibition in China. Society of Petroleum Engineers.

Dusterhoft, Dale, Greg Wilson, and Ken Newman. 2002. "Field study on the use of cement pulsation to control gas migration." SPE Gas Technology Symposium. Society of Petroleum Engineers.

EIA (US Energy Information Administration). 2015a. "Petroleum & Other Liquids: Crude Oil Production." https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm (accessed 15 Aug. 2015).

———. 2015b. "Natural Gas: Natural Gas Gross Withdrawals and Production." http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_m.htm (accessed 15 Aug. 2015).

Erno, B., and R. Schmitz. 1996. "Measurements of Soil Gas Migration Around Oil and Gas Wells in the Lloydminster Area." Journal of Canadian Petroleum Technology 35(7): 37–46.

Frosch, Dan, and Russell Gold. 2015. "How 'Orphan' Wells Leave States Holding the Cleanup Bag." Wall Street Journal, 25 Feb. http://www.wsj.com/articles/how-orphan-wells-leave-states-holding-the-cleanup-bag-1424921403 (accessed 23 Sept. 2015).

GAO (US Government Accountability Office). 2010. *Oil and Gas Bonds—Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells*. GAO-10-245. Washington, DC; GAO. http://www.gao.gov/assets/310/300218.pdf (accessed 24 Sept. 2015).

———. 2011. "Oil and Gas Bonds: BLM Needs a Comprehensive Strategy to Better Manage Potential Oil and Gas Well Liability." Feb 25. GAO-11-292. Washington, DC. http://www.gao.gov/new.items/d11292.pdf (accessed 24 Sept. 2015).

Gaspar, J., J. Mathieu, Y. Yang, R. Tomson, J.D. Leyris, K.B. Gregory, and P.J.J. Alvarez. 2014. "Microbial Dynamics and Control in Shale Gas Production." *Environmental Science and Technology Letters* 1: 465–473.

GWPC (Ground Water Protection Council). 2014. "State oil and natural gas regulations designed to protect water resources." *Prepared for the US Department of Energy, National Energy Technology Laboratory*.

Ingraffea, Anthony R., Martin T. Wells, Renee L. Santoro, and Seth B.C. Shonkoff. 2014. "Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pennsylvania, 2000–2012." *Proceedings of the National Academy of Sciences* 111(30): 10955–10960.

IOGCC (Interstate Oil and Gas Compact Commission) 2008. *Protecting Our Country's Resources: The States' Case*. http://iogcc.publishpath.com/Websites/iogcc/pdfs/2008-Protecting-Our-Country's-Resources-The-States'-Case.pdf (accessed May 2015). http://iogcc.publishpath.com/Websites/iogcc/pdfs/2008-Protecting-Our-Country's-Resources-The-States'-Case.pdf (accessed 12 May 2015).

Jackson, R.E., A.W. Gorody, B. Mayer, J.W. Roy, M.C. Ryan, and D.R. Van Stempvoort. 2013. "Groundwater Protection and Unconventional Gas Extraction: The Critical Need for Field-Based Hydrogeological Research." *Groundwater* 51(4): 488–510.

Kang, Mary, Cynthia M. Kanno, Matthew C. Reid, Xin Zhang, Denise L. Mauzerall, Michael A. Celia, Yuheng Chen, and Tullis C. Onstott. 2014. "Direct Measurements of Methane Emissions from Abandoned Oil and Gas Wells in Pennsylvania." *Proceedings of the National Academy of Sciences* 111(51): 18173–18177.

Kang, Mary, Ejeong Baik, Alana R. Miller, Karl W. Bandilla, and Michael A. Celia. 2015. "Effective Permeabilities of Abandoned Oil and Gas Wells: Analysis of Data from Pennsylvania." *Environmental Science & Technology* 49(7): 4757–4764.

KCC (Kansas Corporation Commission). 2015. *Abandoned Oil and Gas Well Status Report.* Topeka, KS: KCC.

Kell, Scott. 2011. State Oil and Gas Agency Groundwater Investigations and Their Role in Advancing Regulatory Reform; a Two-state Review, Ohio and Texas. Ground Water Protection Council.

King, George E., and Daniel E. King. 2013. "Environmental risk arising from well-construction failure—differences between barrier and well failure, and estimates of failure frequency across common well types, locations, and well age." *SPE Production & Operations* 28(4): 323–344.

King, George Everette, and Randy L. Valencia. 2014. "Environmental risk and well integrity of plugged and abandoned wells." SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers.

Krupnick, A., N. Richardson, and M. Gottlieb. 2015. "Heterogeneity of state shale gas regulations." *Economics of Energy & Environmental Policy* 4(1).

Kunz, Dale. 2015. Winterhawk, Inc., Calgary, Alberta, Canada. Personal Communication. 13 November.

Lattanzio, Richard K. 2013. Air Quality Issues in Natural Gas Systems. Congressional Research Service. March 4.

LLA (Louisiana Legislative Auditor). 2014. Regulation of Oil and Gas Wells and Management of Orphaned Wells. Office of Conservation—Department of Natural Resources. By Daryl G. Purpera, Paul E. Pendas, and Nicole B. Edmonson. N.p., 28 May. http://app.lla.state.la.us/PublicReports.nsf/0/D6A0EBE279B83B9F86257CE700506EAD/$FILE/000010BC.pdf (accessed 24 Sept. 2015).

Lyverse, Mark A., and Michael D. Unthank. 1988. Assessment of Ground-Water Contamination in the Alluvial Aquifer Near West Point, Kentucky. No. 88-4166. US Geological Survey.

Mitchell, Austin L., and Elizabeth A. Casman. 2011. "Economic incentives and regulatory framework for shale gas well site reclamation in Pennsylvania." *Environmental Science & Technology* 45(22): 9506–9514.

Muehlenbachs, Lucija. 2015. "A Dynamic Model of Cleanup: Estimating Sunk Costs in Oil and Gas Production." *International Economic Review* 56(1): 155–185.

NPC (National Petroleum Council). 2011. "Plugging and Abandonment of Oil and Gas Wells." Working Paper.

Railroad Commission of Texas. 2000. "Well Plugging Primer." January. http://www.rrc.state.tx.us/media/6358/plugprimer1.pdf (accessed Jun. 2015).

Richardson, N., M. Gottlieb, A. Krupnick, and H. Wiseman. 2013. *The State of State Shale Gas Regulation*. Washington, DC. Resources for the Future.

Shields, Patrick. 2015. Kansas Corporation Commission. Personal Communication. 6 July.

Shih, Jhih-Shyang, Jaqueline Ho, Lucija Muehlenbachs, Clayton Munnings, and Alan J. Krupnick. Forthcoming. The Costs and Fiscal Implications of Decommissioning Inactive Wells. RFF Discussion Paper. Washington, DC: Resources for the Future.

Smith, Rod. 2015. Schlumberger, Ltd. Personal Communication. 27 August.

Taylor, Michael (VP for Climate Policy Assurance, Alberta Energy Regulator, Alberta, Canada) 2016. Personal Communication. May 10.

Van Stempvoort, D.R., E.J. Jaworski, and M. Rieser. Canadian Association of Petroleum Producers. 1995. "Migration of methane into ground water from leaking production wells near Lloydminster. Report for Phase 2 (1995)." March.

Walls, Margaret, Carolyn Kousky, and Ziyan Chu. 2015. "Is what you see what you get? The value of natural landscape views." *Land Economics* 91(1): 1–19.

Watson, Theresa Lucy, and Stefan Bachu. 2009. "Evaluation of the potential for gas and CO_2 leakage along wellbores." E&P Environmental and Safety Conference. Society of Petroleum Engineers.

Zirogiannis, N., J. Alcorn, J. Rupp, S. Carley, and J.D. Graham. 2016. "State Regulation of Unconventional Gas Development in the US: An Empirical Evaluation." *Energy Research & Social Science* 11: 142–154.

RESOURCES
FOR THE FUTURE

Resources for the Future
1616 P St. NW
Washington, DC 20036
www.rff.org