RESOURCES
FOR THE FUTURE

A Review of Shale Gas Regulations by State

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Experts in RFF's Center for Energy Economics and Policy analyzed regulations and surveyed regulators in the 31 states that have significant shale gas reserves or where industry shows interest in shale gas development. The maps in this project show the results of these efforts for approximately 20 important regulatory elements in each state in the continental United States. The purpose of these maps is to provide an overview of the regulatory patterns, similarities, and differences among states—not to authoritatively compile any given state's regulations or fully analyze any specific regulation. The research team also examined the American Petroleum Institute's (API) best practices and included them in the maps where applicable because they may serve as guidelines for policymakers and industry operators.

To create the maps, RFF staff and outside experts reviewed state statutes, regulations, and documents, along with independent reports. When possible, state regulators reviewed the findings. The maps show regulations in force as of June 18, 2012, except for New York, which is treated as if the proposed rules in its 2011 Supplemental Generic Environmental Impact Statement were currently in place. As relevant regulations are passed, the maps will be updated accordingly. Note that some states regulate parts of the extraction process through case-by-case permitting or other means, which is not included in this study. The regulations included here are not necessarily specific to shale gas, but are applicable to shale gas. A list of technical definitions is provided below.

The maps are divided into six categories that include maps detailing the following:

- **Site Development and Preparation**, which includes: pre-drilling water well testing; water withdrawals; setback restrictions from residential and other buildings; and setback restrictions from municipal and other water sources. Site development and preparation begins before an operator selects an area for drilling. Many companies perform pre-drilling examinations such as seismic and water quality tests before finalizing the site choice. The operator must first ensure that the location adheres to siting rules, including any setback restrictions, which regulate the distance between wells and other entities like schools, homes, streams, and water wells that are thought to merit special protection. Most states have uniform well spacing requirements that limit the number of wells in an area, but these rules do not indicate how far wells must be from specific features. Thus, states enact setback restrictions to avoid environmental impacts and community disruption. Once a site has been selected, the land must be cleared—usually two acres, but up to twelve depending on the location and number of wells on the pad. All of the requisite equipment and materials are brought to the site at this time. An impoundment is often built to hold freshwater, which is either trucked or piped to the location in preparation for drilling.

- **Well Drilling and Production**, which includes: natural gas wells and shale gas production; cement type regulations; casing and cementing depth below water table; surface casing cement circulation regulations; intermediate casing cement circulation regulations; production casing cement circulation regulations; venting restrictions; flaring restrictions; and fracking fluid disclosure. After the site is prepared and the drilling rig is set up, drilling can begin. As the well is drilled, casing must be put in place and cemented. Poor casing and cementing can provide a potential conduit for groundwater contamination, and most states therefore have detailed casing and cementing regulations. Once the surface casing is set and cemented, the well is drilled deeper and an intermediate string of casing is often set and cemented. When the wellbore is just above the production zone, the drill turns and drills horizontally. The production casing is then set and cemented.

  To begin the hydraulic fracturing process, a fracture gun is detonated in the horizontal wellbore to create fractures in the casing, cementing, and rock, which are then propagated by the introduction of the fracturing fluid under high pressure. Fracturing fluid is composed of water, chemicals, and proppant (such as sand) that prop the fractures open to allow gas to flow up the wellbore. Before and during production, excess gas may be vented or flared if it cannot be stored or used commercially.

- **Wastewater Storage and Disposal**, which includes: fluid storage options; freeboard requirements; pit liner requirements; wastewater transportation tracking; and underground injection wells for flowback and produced water. During the fracturing process, between 1 and 7 million gallons of water per well is pumped down the wellbore, along with chemicals and proppant, to create the fractures from which the gas will flow. Although most of the water used remains underground, anywhere from 10 to 50 percent will flow back up and out of the wellbore. Flowback fluid and produced fluids, generally referred to as wastewater, require storage and disposal. Storage and disposal options vary by state and depend in large part on the chemical makeup of wastewater and geological conditions.

- **Well Plugging and Abandonment**, which includes: well idle time; and temporary abandonment. When a well is no longer producing, it must be permanently plugged and abandoned. However, many companies choose to temporarily abandon a well and bring it back into production when it is more economical to do so. Most states have detailed plugging and abandonment procedures to ensure that the well does not become a conduit for contamination through migration of fluids and gases from nearby wells being fractured.

- **Well Inspection and Enforcement**, which includes: number of wells per inspector; number of regulating state agencies; and accident reporting requirements. Well inspection and enforcement varies greatly by region. The degree to which an agency is effective in inspecting well sites can depend on the number of inspectors, the enforcement budget, and the level of voluntary reporting that is required in that state, among many factors.

- **Other**, which includes: state and local bans and moratoria; and severance taxes. This category includes maps showing state and local bans and moratoria as well as severance taxes in each state.

Pre-drilling Water Well Testing

Pre-drilling water well testing establishes the baseline water quality for an area prior to drilling activity. The majority of states' regulations do not mention baseline water well testing. However, states that regulate testing require that the area in which water wells are tested must be a specific distance from the proposed gas well, given as a radius from the wellhead (the average radius is about ½ mile). Most of these states require operators to test two wells within the specified radius. Colorado and Ohio have zone- or well-specific conditions for pre-drilling water well testing. For instance, the Wattenberg field in Colorado, which is part of the Niobrara play, is the only zone in Colorado that requires pre-drilling water well testing. Ohio, on the other hand, decides on a permit-specific basis whether or not pre-drilling water well testing is necessary. API best practice is to test water samples from any source of water located near the well (determined based on anticipated fracture length) before drilling, or before hydraulic fracturing.

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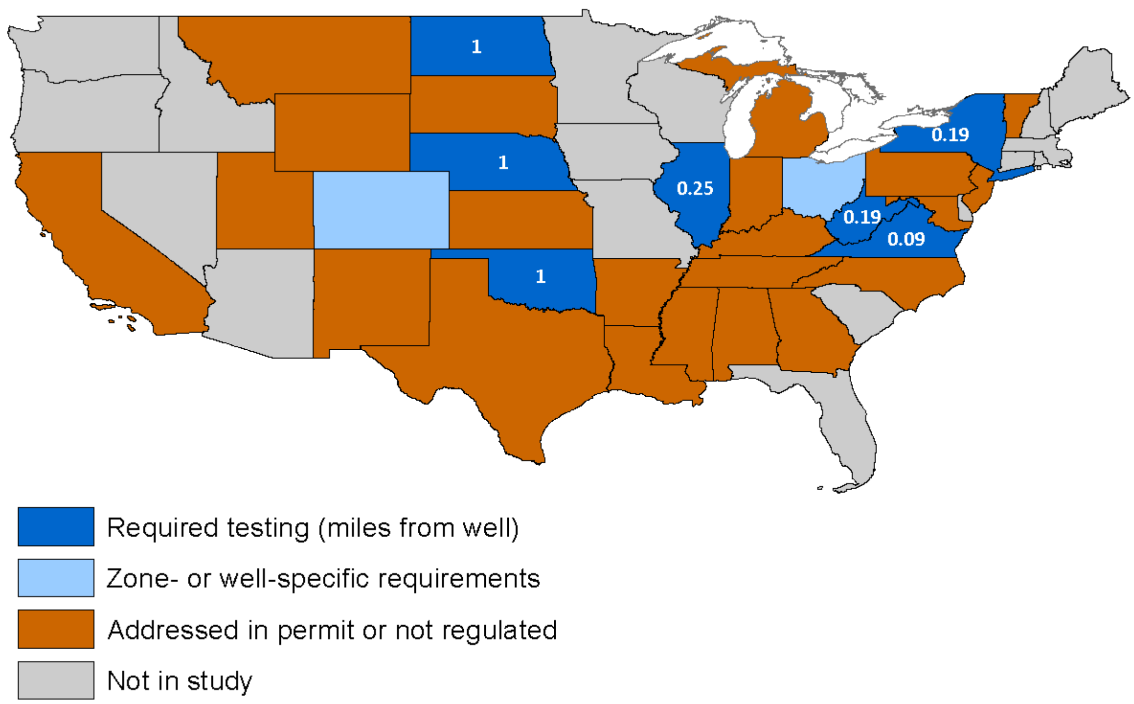

Water Withdrawals

Several states have discussed drafting rules about water withdrawal restrictions for the shale gas industry but none has yet passed such legislation. Water usage is particularly relevant in places where drought conditions often strictly limit water availability and appropriations. Most of the states surveyed (21) require general permits for surface and/or groundwater withdrawals. However, several states do not require permits for withdrawals below a certain threshold. Pennsylvania requires a water management plan covering the full lifecycle of the water used in shale gas production, including the location and amount of the withdrawal and an analysis of the impact of the withdrawal on the body of water from which it came. Louisiana recommends that groundwater used for drilling or fracturing be taken from the Red River Alluvial aquifer. Six states require water withdrawals to be registered and reported and three states require permits in addition to registration and reporting. Louisiana and Kentucky specifically exempt the oil and gas industry from water withdrawal requirements. The map shows water withdrawal thresholds in thousands of gallons per day (GPD). States without numbers require permits for all water withdrawals or do not specify a threshold. API best practice stipulates that "consultation with appropriate water management agencies is a must" and "whenever practicable operators should consider using non-potable water for drilling and hydraulic fracturing."

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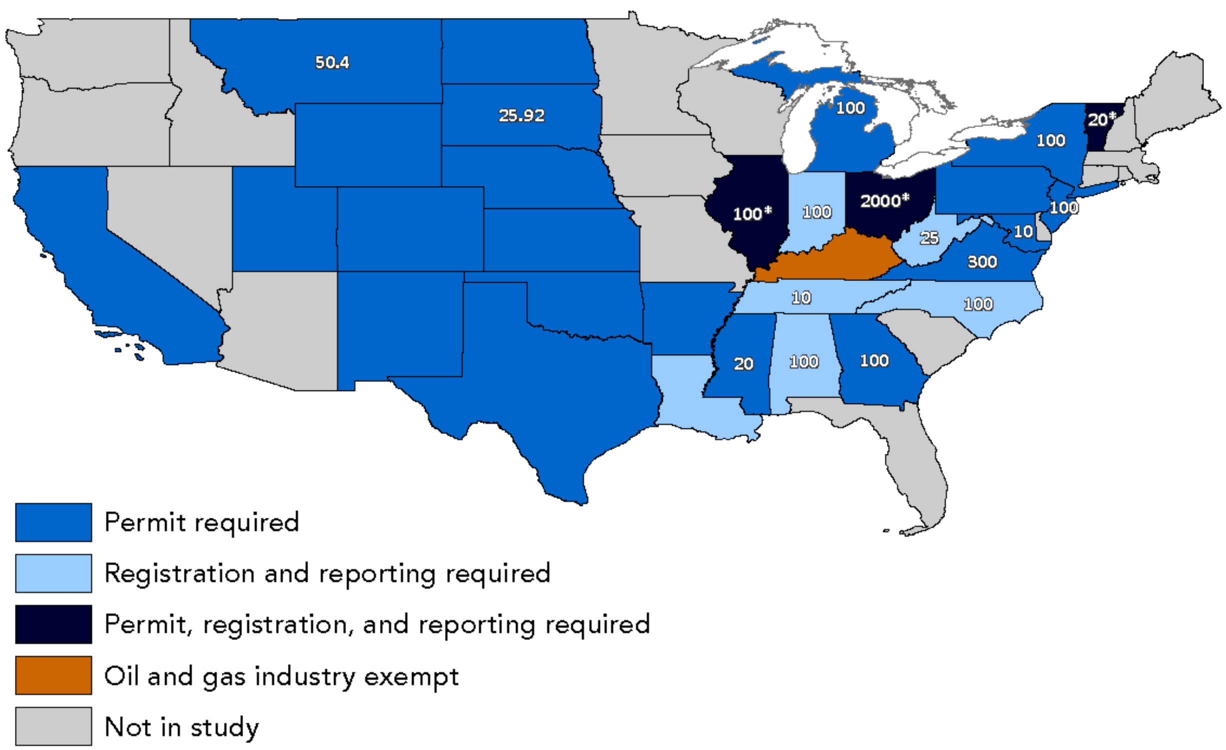

* All surface water withdrawals in IL require permits. OH also requires registering and reporting of water withdrawal over 100,000 gallons per day. VT requires permits for withdrawals of 57,600 gallons per day.

Setback Restrictions from Buildings

More than half of surveyed states (17) have building setback restrictions, ranging from 100 feet to 1,000 feet, with an average of 261 feet. In some states, these requirements apply to all "occupied dwellings," whereas in other states, the requirements pertain only to specific structures like schools, hospitals, and churches. In Ohio and Colorado, high density, or urbanized, areas tend to have higher setbacks. New Mexico and Arkansas measure setback restrictions from pits and tanks, respectively, but not from wells; California regulates the distance between wells and public streets, roads, or highways, but not buildings. In the map, "Other setback restrictions" refers to states that either have setback restrictions from structures other than residential and other buildings, or states that measure setbacks from equipment other than the wellhead. API best practice is "when feasible, the wellsite and access road should be located as far as practical from occupied structures and places of assembly."

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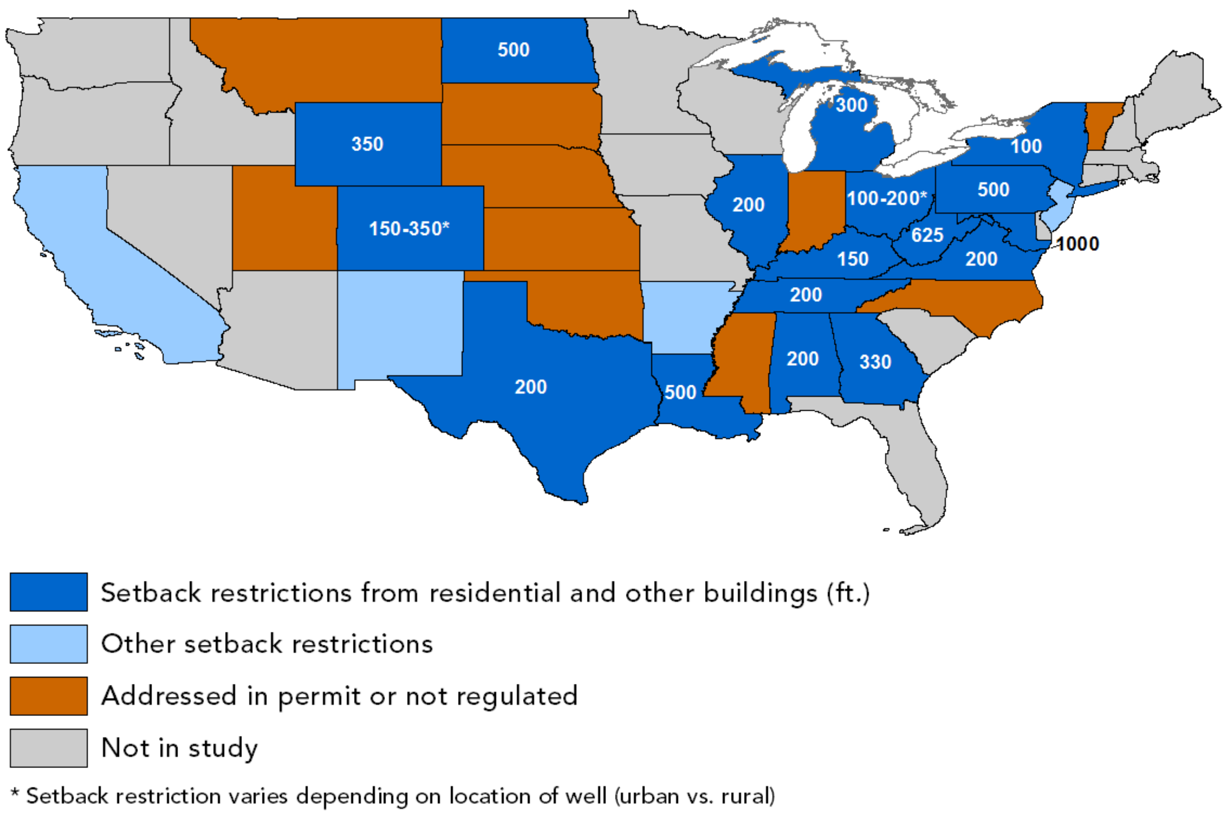

Setback Restrictions from Water Sources

Almost a third of states surveyed (9) have setback restrictions from some body of water or water supply source; six of those have setback restrictions from municipal water supplies (measured from the well) ranging from 350 feet to 2,000 feet, with an average of 885 feet. Michigan also has setback restrictions from municipal water sources that are measured from other pieces of equipment such as well separators and storage tanks, but not from the well, and vary depending on the type of water supply. Kansas, New York, Pennsylvania, and Ohio have additional setback restrictions from other water sources such as lakes, streams, and private water wells. New Mexico and Arkansas measure setback restrictions from pits and tanks, respectively, but not from wells. In the map, "Other setback restrictions" refers to states that either have setback restrictions from entities other than municipal or other water sources, or states that measure setbacks from equipment other than the wellhead. API best practice is to, where feasible, locate sites away from sensitive areas such as surface waters and freshwater wells. Also, that "pits used for long term storage of fluids should be placed an appropriate distance from surface water to prevent unlikely overflows from reaching the surface water."

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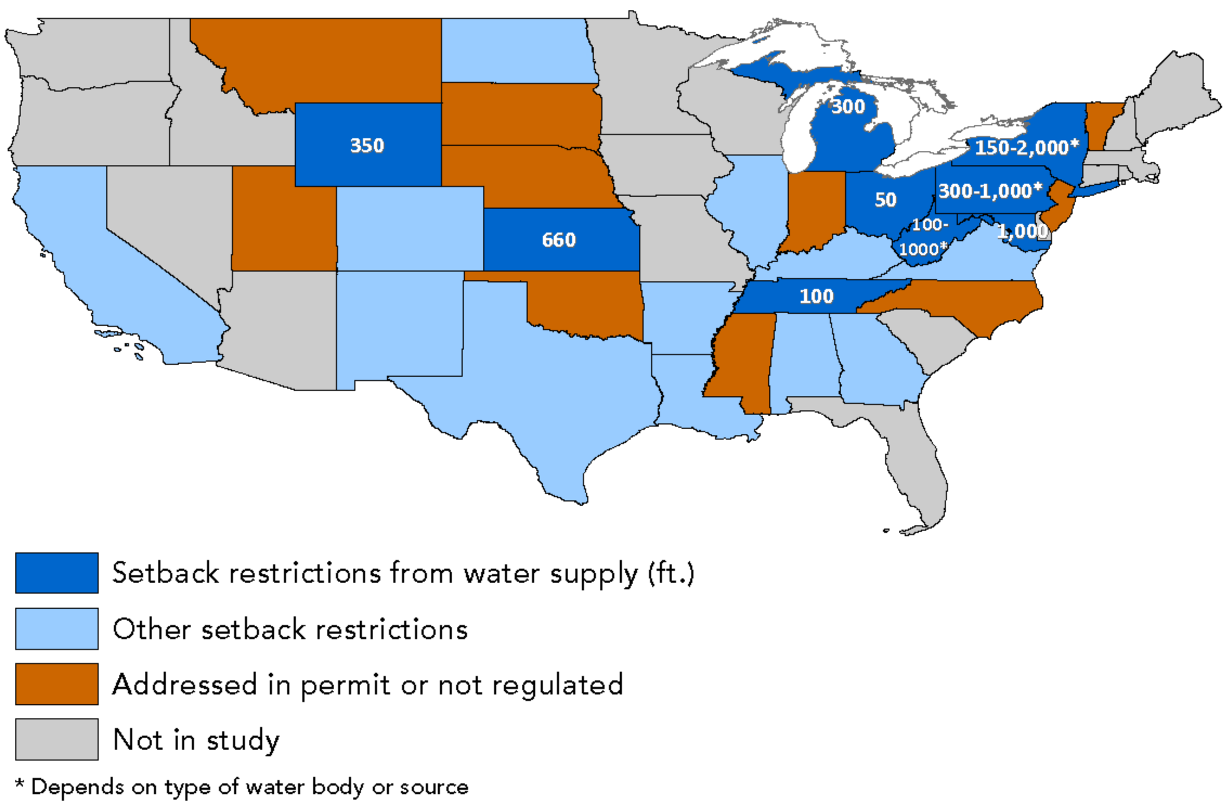

Natural Gas Wells and Shale Gas Production

This map shows natural gas production by state. The shading indicates the number of producing natural gas wells (shale or conventional) in the state in 2010. The size of the red circles indicates the amount of shale gas production in 2009. Production is measured in thousand cubic feet (MCF). Because the data for the number of wells are from 2010 and include all natural gas wells, and the shale gas production data are from 2009, it appears that some wells are operating with zero production in several states. However, they may be producing other kinds of natural gas (but are not producing shale gas). Note that some states' shale gas production increased significantly between 2009 and 2010. Table 1 showing the number of wells by state in 2010 and shale gas production by state in 2009 is available below.

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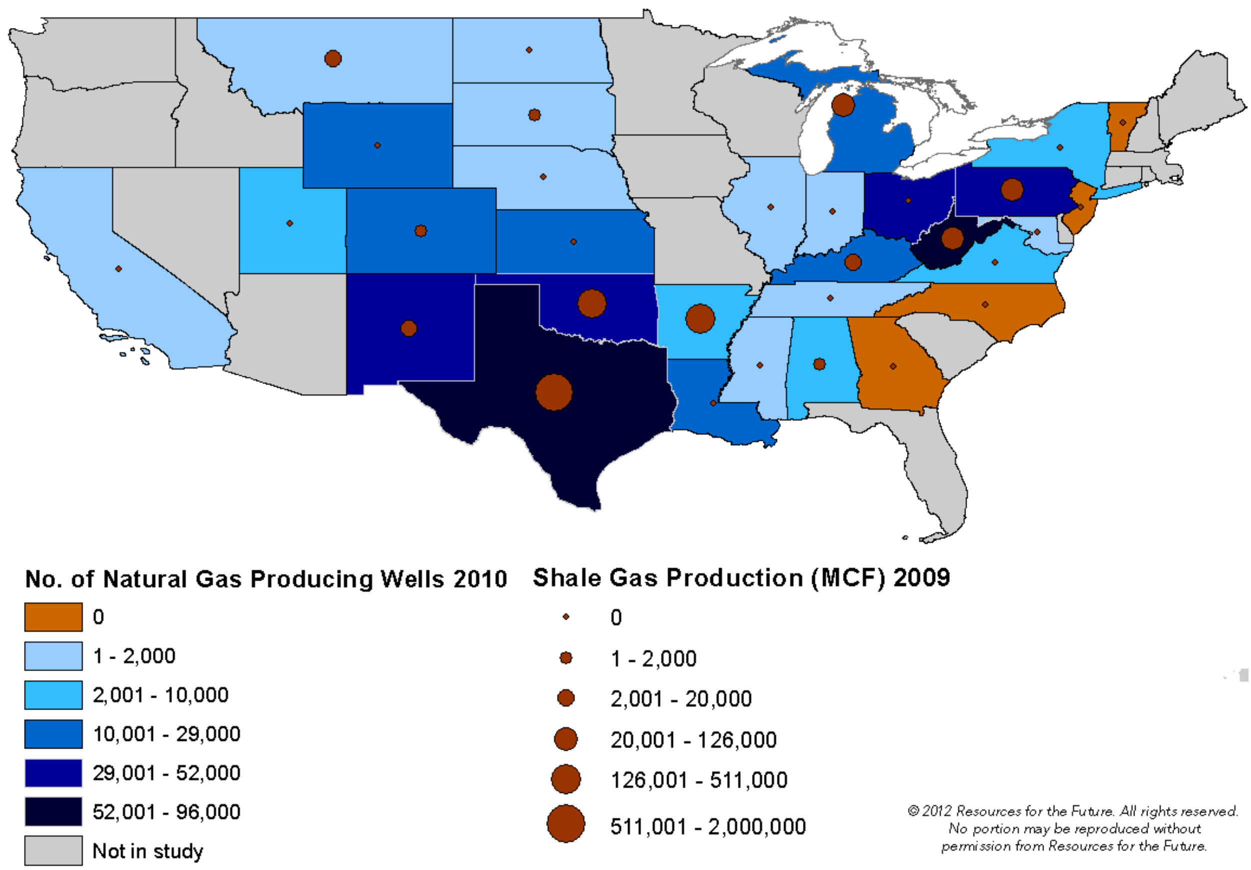

Table 1: Natural Gas Wells and Shale Gas Production

	Natural gas producing wells 2010	Shale gas production (MCF) 2009
Alabama	7,026	93
Arkansas	7,397	510,897
California	1,580	0
Colorado	28,813	1,000
Georgia	0	0
Illinois	50	0
Indiana	620	0
Kansas	22,145	0
Kentucky	17,670	5,000
Louisiana	19,137	0
Maryland	7	0
Michigan	10,100	125,562
Mississippi	1,979	0
Montana	6,059	7,000
North Carolina	NA	0
North Dakota	188	0
Nebraska	276	0
New Jersey	NA	0
New Mexico	44,748	2,040
New York	6,736	0
Ohio	34,931	0
Oklahoma	44,000	301,028
Pennsylvania	44,500	79,000
South Dakota	102	1,561
Tennessee	230	0
Texas	95,014	1,893,711
Utah	6,075	0
Virginia	7,470	0
Vermont	0	0
West Virginia	52,498	0
Wyoming	26,124	0

Cement Type Regulations

Class A Portland cement is the most commonly used type of cement for setting casing in place. Cement types vary by well and operator, and 10 states surveyed mandate specific types of cement that must be used. Several states, including Michigan, require the cement mixture to be of a specific composition and volume that must be approved by the supervisor of the regulating agency. New York's proposed legislation specifically mandates that cement would have to conform to API Specification 10A and would have to contain a gas-block additive. API best practice is that appropriate API standards should be consulted in selection of cement and "selected cements, additives, and mixing fluid should be laboratory tested in advance to ensure they meet the requirements of the well design."

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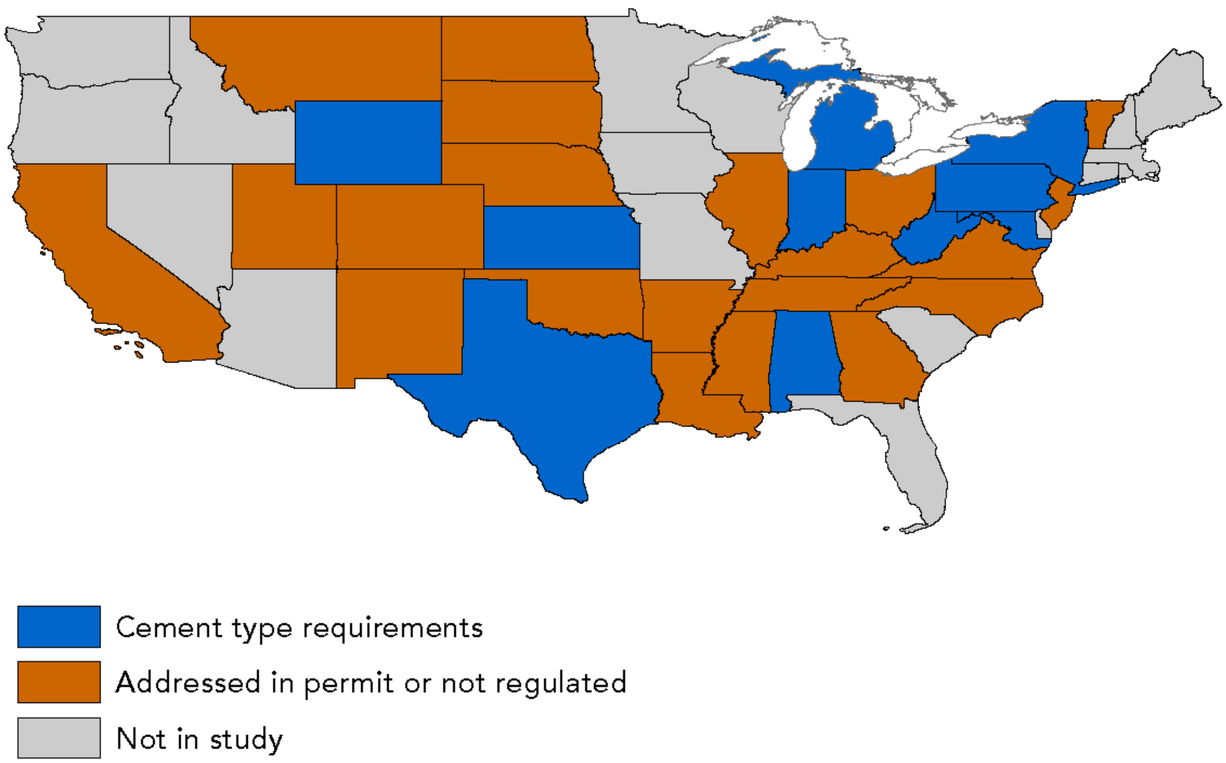

Casing and Cementing Depth

Casing and cementing regulations vary widely across states, including the depth to which the casing must be set and cemented. Some states (13) set the regulation based on depth below the water table. Among these, the average required depth below the water table is about 66 feet, with a range of 30 to 120 feet. Ten of the states surveyed rely on well-specific determinations. In these instances, instead of a specific mandate, regulations often read as "casing must be set and cemented to protect all freshwater bearing zones." In Kansas, casing and cementing depth below the water table is determined by county, but the state requires at least 50 feet of surface casing. Alabama, California, Louisiana, Mississippi, and South Dakota regulate the minimum number of feet of casing that must be used, but not the depth below the water table. Virginia does not have regulations for casing and cementing depth. API best practice is a casing and cementing depth of 100 feet below the deepest underground source of drinking water encountered while drilling the well.

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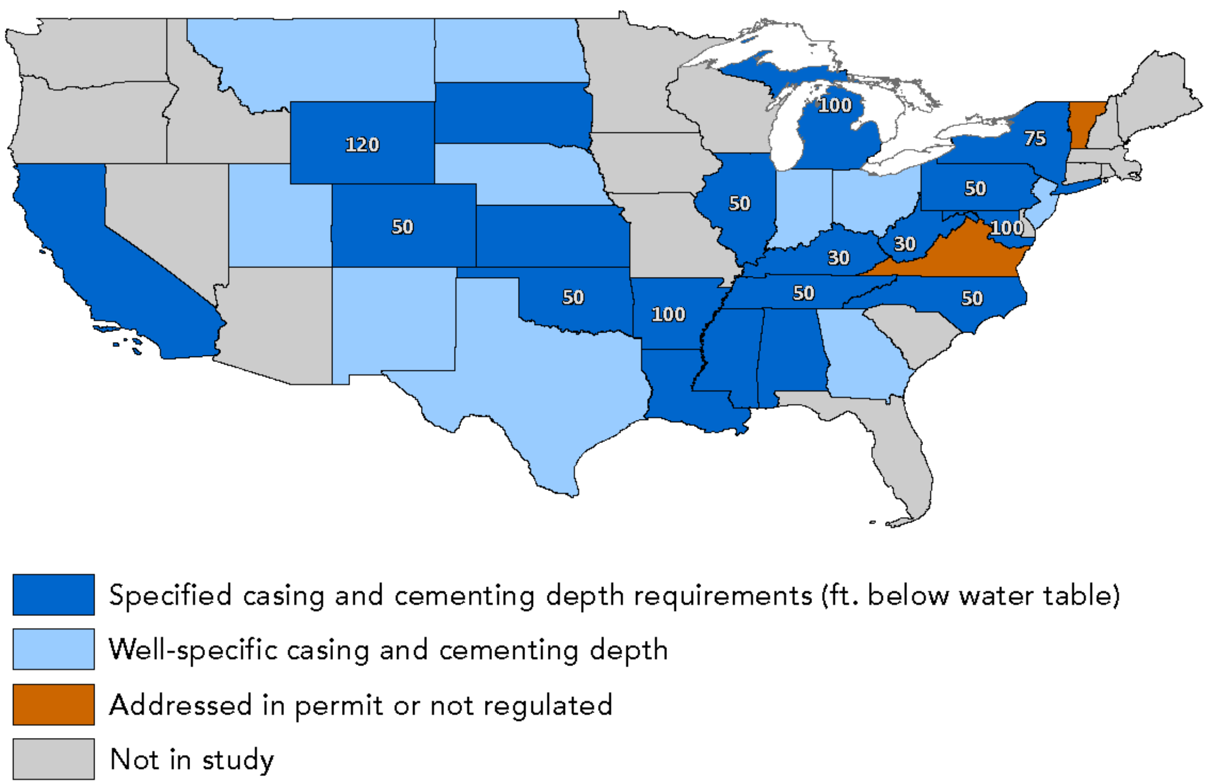

Surface Casing Cement Circulation Regulations

Cementing practices may be regulated in terms of compressive strength, type of cement, or circulation around casing. Circulation around casing refers to the process by which cement is pumped down the wellbore and up through the annulus on the outside of the casing, cementing it in place. Geology and state law help determine how high cement must be circulated around the casing. This map shows that 27 states surveyed require surface casing to be cemented through the length of the annular space to the surface. Ohio has a performance-based standard where operators are directed to circulate sufficient cement to isolate and protect all freshwater and hydrocarbon zones. API best practice is "that the surface casing be cemented from the bottom to the top," but where that is not possible, cementing across all underground sources of drinking water is recommended.

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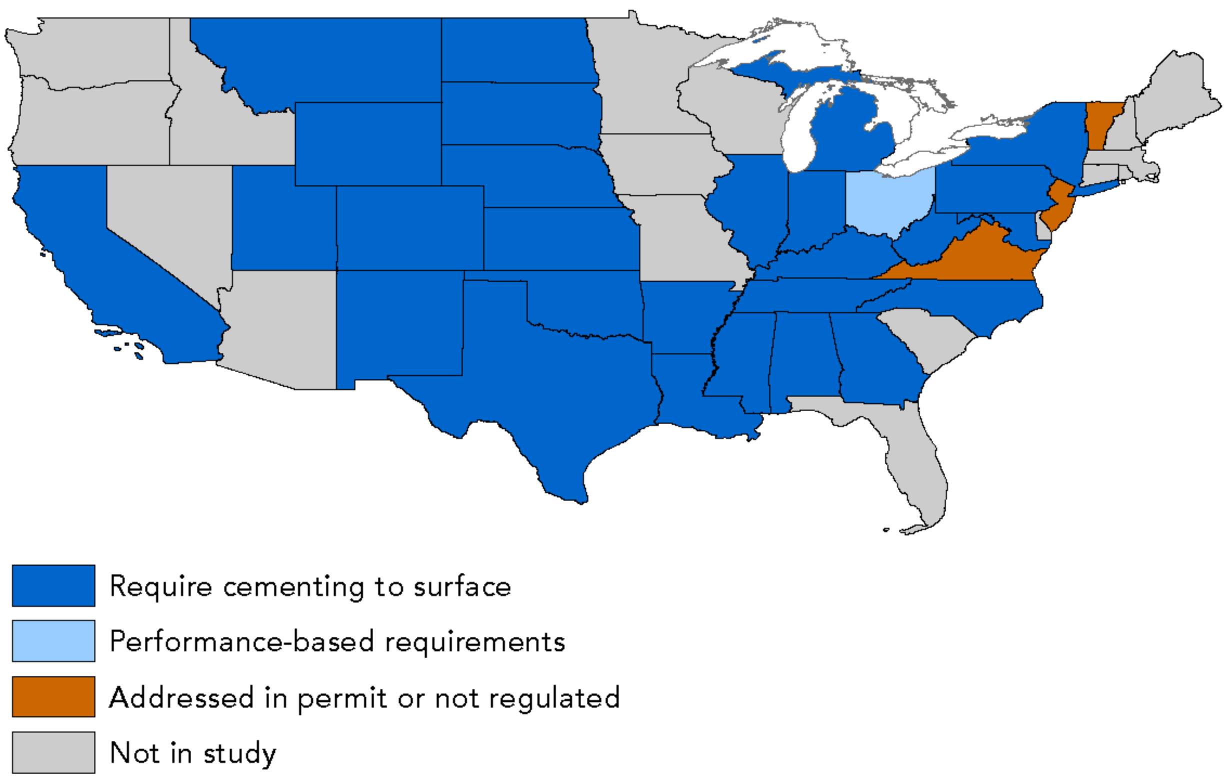

Intermediate Casing Cement Circulation Regulations

After the surface casing is set and cemented, an intermediate casing is often set and cemented as well. This map illustrates which portions of the intermediate casing must be cemented—that is, how high the cement must be circulated in the annulus. Only four states require cement to be circulated to the surface of the intermediate casing, and five states have performance-based standards (where operators are directed to isolate and protect groundwater or hydrocarbon zones, but are not told exactly how far cement must be circulated to achieve that). Six states have specific regulations for how high cement must be circulated above the shoe or uppermost hydrocarbon zone. California and Louisiana stipulate that cement must reach 500 feet above the uppermost hydrocarbon zone; Colorado and Oklahoma mandate 200 feet above the uppermost hydrocarbon zone; and Wyoming specifies 200 feet above the trona interval. Texas requires cement to reach 600 feet above the shoe. API recommends that sufficient cement be circulated around the intermediate casing to isolate all underground sources of drinking water and hydrocarbon zones. API best practice is "if the intermediate casing is not cemented to the surface, at a minimum the cement should extend above any exposed underground sources of drinking water or any hydrocarbon bearing zone."

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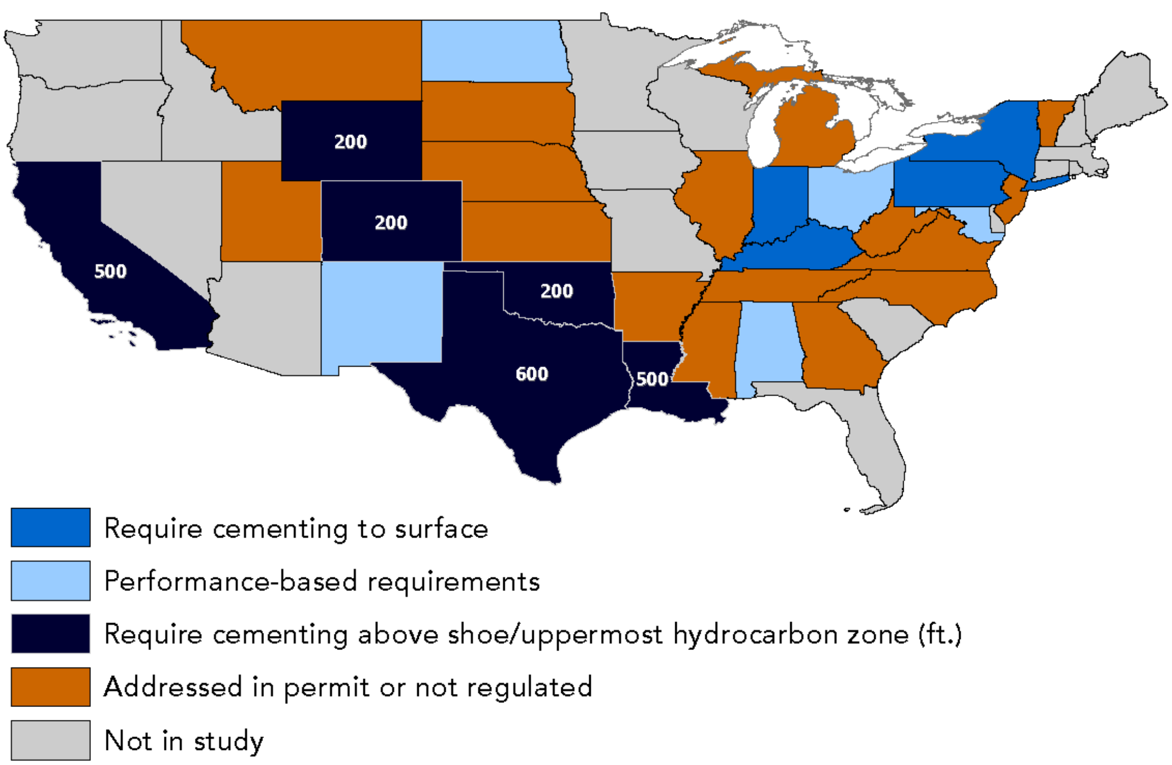

Production Casing Cement Circulation Regulations

This map shows which portions of the production casing must be cemented. Only two states require cement to be circulated to the surface, and seven states have performance-based standards (meaning that operators are directed to isolate and protect groundwater or hydrocarbon zones, but are not told exactly how far cement must be circulated to achieve that). Eleven states have specific regulations for how high cement must be circulated above the shoe, true vertical depth, or uppermost hydrocarbon zone. Alabama, California, Georgia, and Louisiana stipulate that cement must reach 500 feet above the uppermost hydrocarbon zone; Colorado and Illinois mandate 200 and 250 feet, respectively, above the uppermost hydrocarbon zone; and Wyoming specifies 200 feet above the trona interval. Mississippi and North Carolina require cement to reach 500 feet above the shoe, and Texas requires cement to reach 600 feet above the shoe. Pennsylvania mandates cement circulation 500 feet from the true vertical depth. API states that best practice is to cement production casing to "at least 500 ft. above the highest formation where hydraulic fracturing will be performed."

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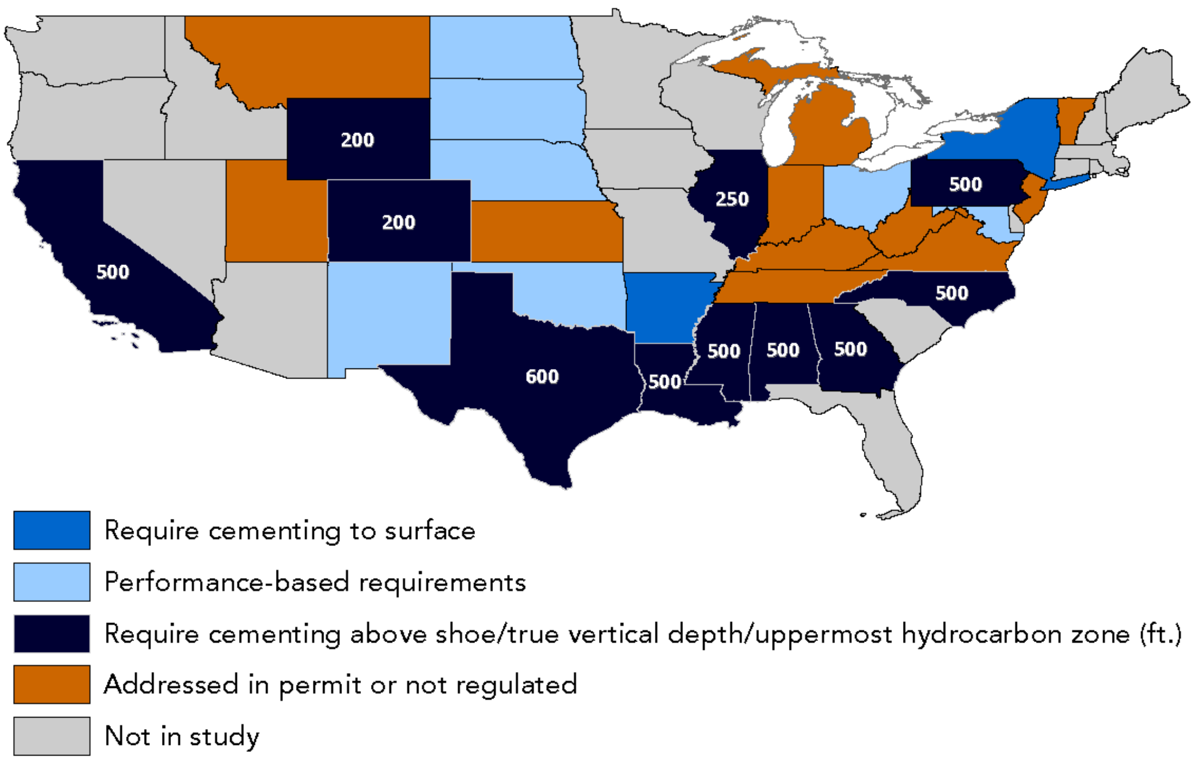

Venting Regulations

Venting occurs when gas escapes from the wellbore into the atmosphere. More than half of states surveyed (22) have some form of venting regulations, though these vary greatly across states. Some states have specific restrictions such as the number of days that venting may occur, the amount of gas that may be vented, or the development phases during which gas may be vented. That is, some states specify that venting may be allowed during well cleanup, well testing, and emergencies, but at no other time. Some states have "aspirational standards," which require operators to minimize gas waste or not to harm public health, but impose no effective requirement or standard. Louisiana prohibits venting unless it can be shown that the prohibition causes economic hardship. API suggests that all gas resources of value that cannot be captured and sold should be flared, but that any venting be restricted to a safe location and oriented downwind considering the prevailing wind direction at the site.

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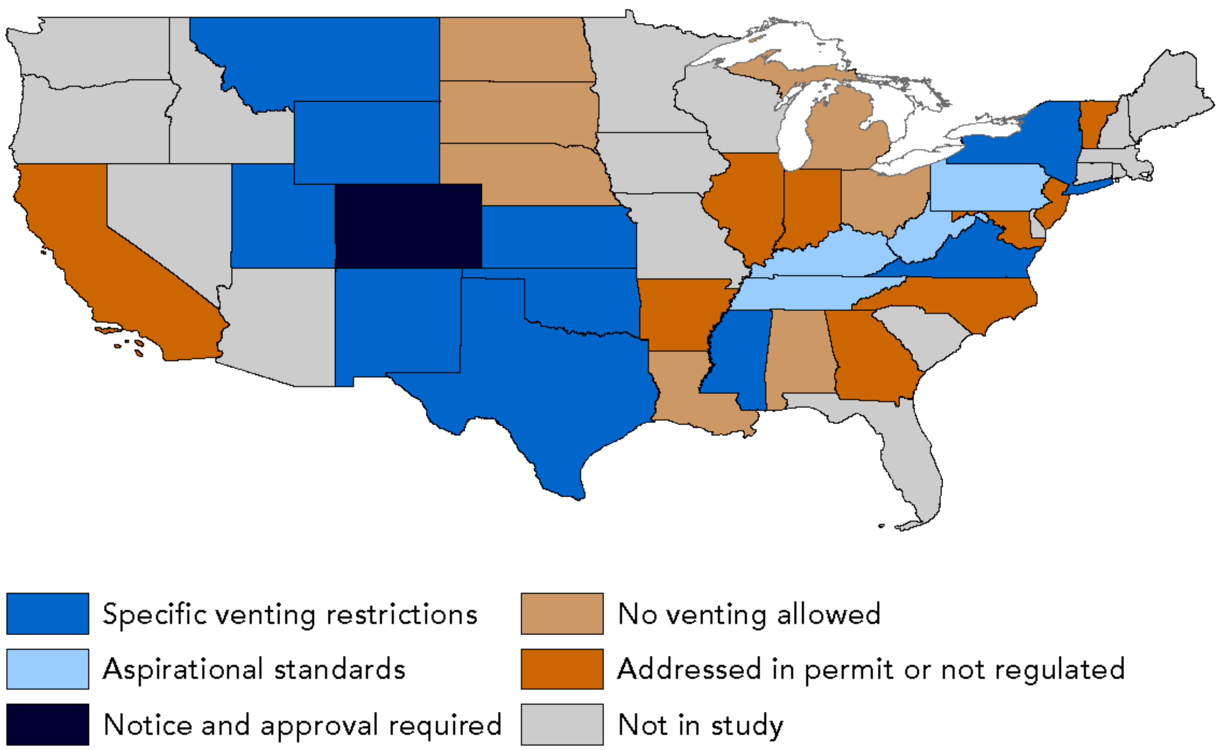

Flaring Regulations

Flaring is the process by which excess gas is burned off in stacks or flares. The majority of states surveyed (23) have some flaring regulations, though these vary greatly across states. Some states restrict the amount of gas that may be flared, the location of flares, or the development phases during which gas may be flared. That is, some states specify that flaring may be used during well cleanup, well testing, and emergencies, but at no other time. Several states mandate that gas be flared as opposed to vented. API suggests that all gas resources of value that cannot be captured and sold should be flared and recommends that flares be restricted to a safe location and oriented downwind considering the prevailing wind direction at the site.

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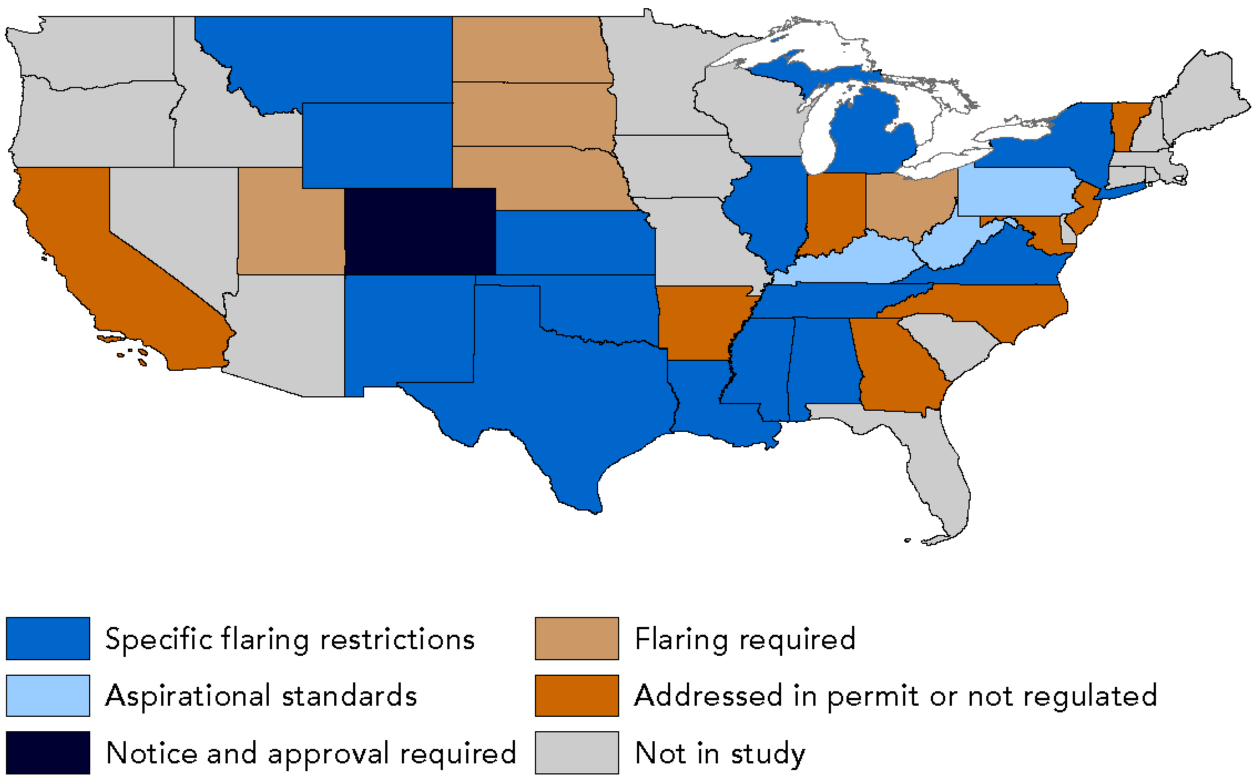

Fracking Fluid Disclosure

At the federal level, hydraulic fracturing is exempt from disclosure that would otherwise be required by the Safe Drinking Water Act, though the Department of the Interior recently passed rules requiring frack fluid disclosure for wells drilled on public lands. Less than half of states surveyed (14) require disclosure of fluids used in the fracturing process. At least three states have proposed rules, and two states have some form of fluid disclosure regulations but it is unclear if they pertain to hydraulic fracturing. Illinois' proposal would strengthen existing disclosure rules. The level of disclosure detail required also differs across states. Few states require disclosure of all chemicals used; even fewer states require disclosure of additive volume and concentration. Pennsylvania, for example, requires the disclosure of percent by volume of each additive in the stimulation fluid, whereas Arkansas requires additives to be expressed as a percent by volume of the total hydraulic fracturing fluids, *and* of the total additives used. All states with chemical disclosure requirements provide trade secret exemptions for chemicals considered "confidential business information." Wyoming requires prior approval for use of benzene, toluene, ethylbenzene, and xylene (BTEX) compounds. API suggests that operators be prepared to disclose information on chemical additives and their ingredients and that "the best practice is to use additives that pose minimal risk of possible adverse human health effects to the extent possible in delivering needed fracture effectiveness."

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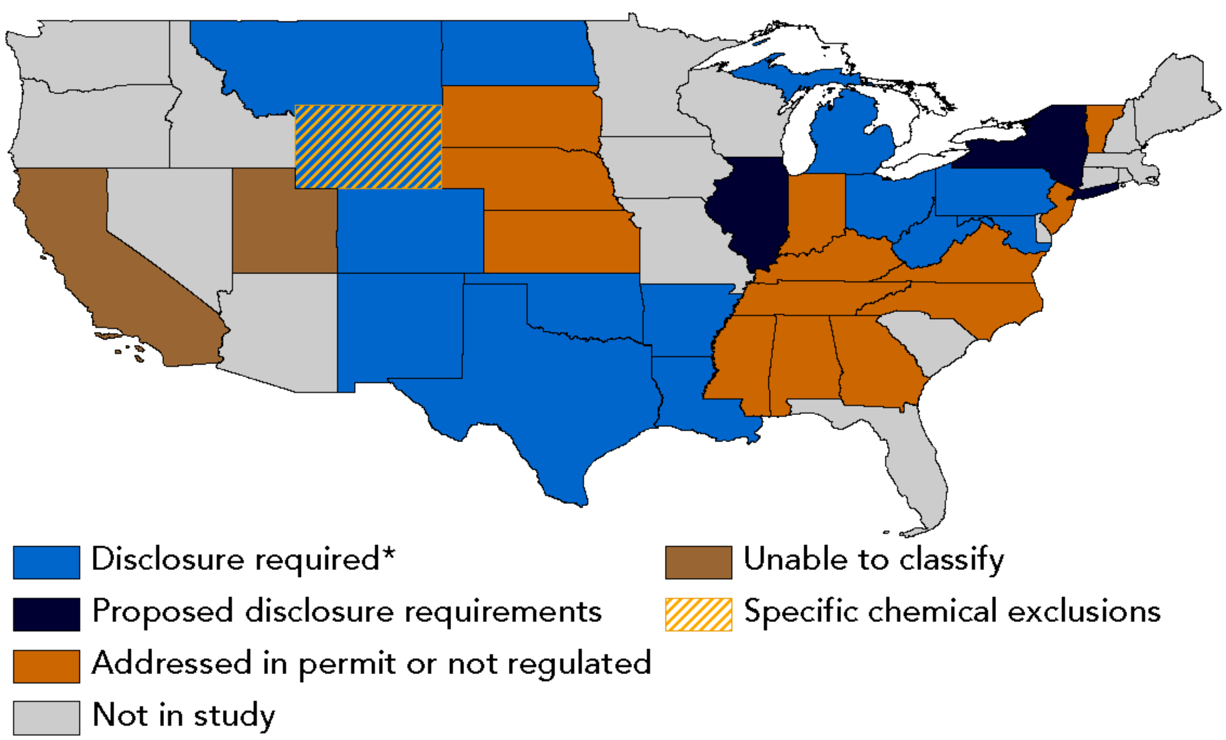

* Require volume disclosure: MD, MI, NM, OH, OK. Concentration disclosure: WY. Volume and concentration: AR, LA, MT, PA

Fluid Storage Options

Fluid storage needs vary over the course of the shale gas development process. Fracking fluids must be stored before being used, and the post-fracturing wastewater, including flowback fluids and produced fluids, must also be stored before disposal. There are many different types of pits, including permanent and temporary pits, and different pits have distinct specifications, such as whether or not they require lining. Fluids are most commonly stored in pits and tanks; 9 surveyed states only specifically address pit storage and 19 specifically mention pits and tanks in their regulations. The map displays the storage information explicitly stated in a state's regulations. If a state does not mention tank storage for example, it would be categorized as "pits only," though storage may be addressed otherwise in the permit. California mandates a closed-loop systems in which fluids are not exposed to the elements at any point. Michigan only allows pits to be used for drilling fluids, muds, and cuttings; tanks must be used for produced water, completion fluids, and other liquid wastes, and in all areas zoned residential. Other storage options include ponds, sumps, containers, impoundments, and ditches. API best practice stipulates that "completion brines and other potential pollutants should be kept in lined pits, steel pits, or storage tanks."

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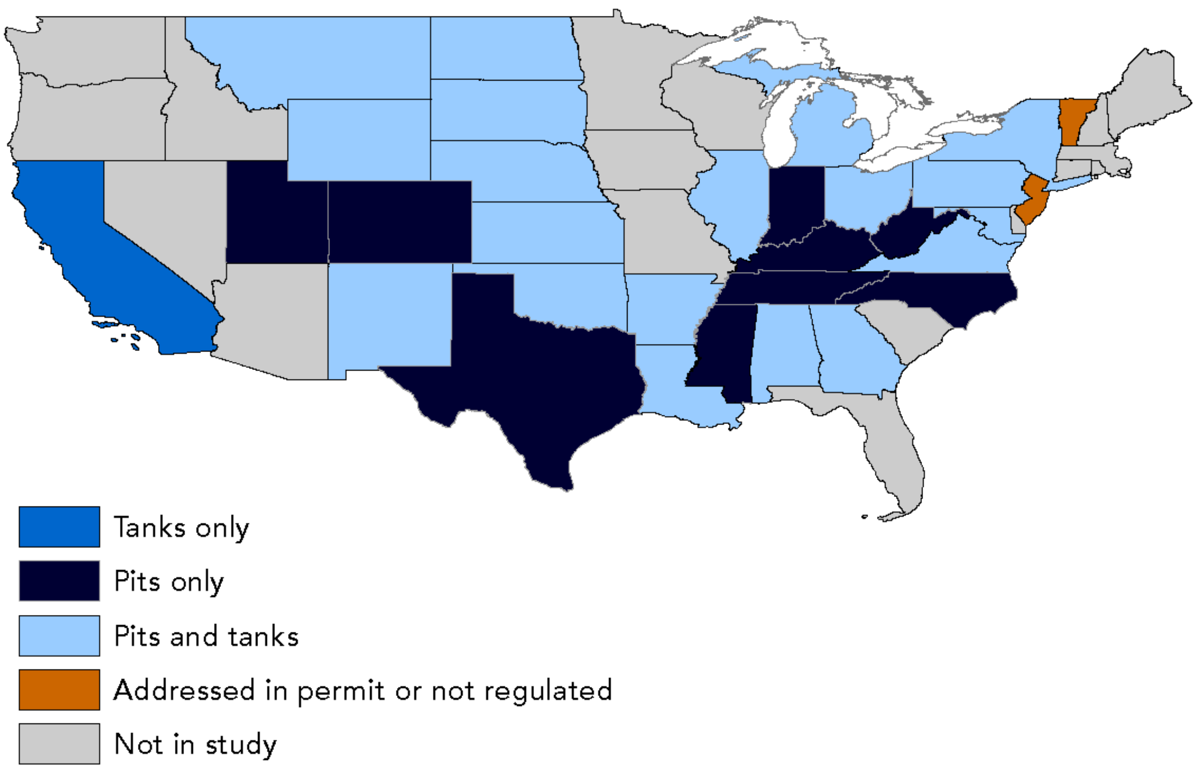

Freeboard Requirements

Most states that allow fluid storage in pits have a variety of specifications that must be met, including freeboard requirements—that is, the amount of space in the pit between the maximum water level and the top of the pit. Freeboard is important for preventing overflow of fluids, particularly during and after intense rain. Of the 27 states that allow storage of fluids in pits, 16 have freeboard regulations, ranging from 1 foot to 3 feet. New Mexico differentiates between permanent pits and temporary pits in the amount of freeboard required, 3 feet and 2 feet, respectively. Oklahoma requires 1.5 feet of freeboard for temporary pits, 2 feet of freeboard for noncommercial pits, and 3 feet of freeboard for pits capable of holding more than 50,000 barrels. Montana's requirements only apply to earthen pits or ponds that receive produced water containing more than 15,000 ppm total dissolved solids in amounts greater than five barrels per day on a monthly basis. California does not allow the use of pits for fluid storage, thus freeboard requirements are not applicable. API best practice is that pits should be constructed with sufficient freeboard "to prevent overflow under maximum anticipated operating requirements and precipitation."

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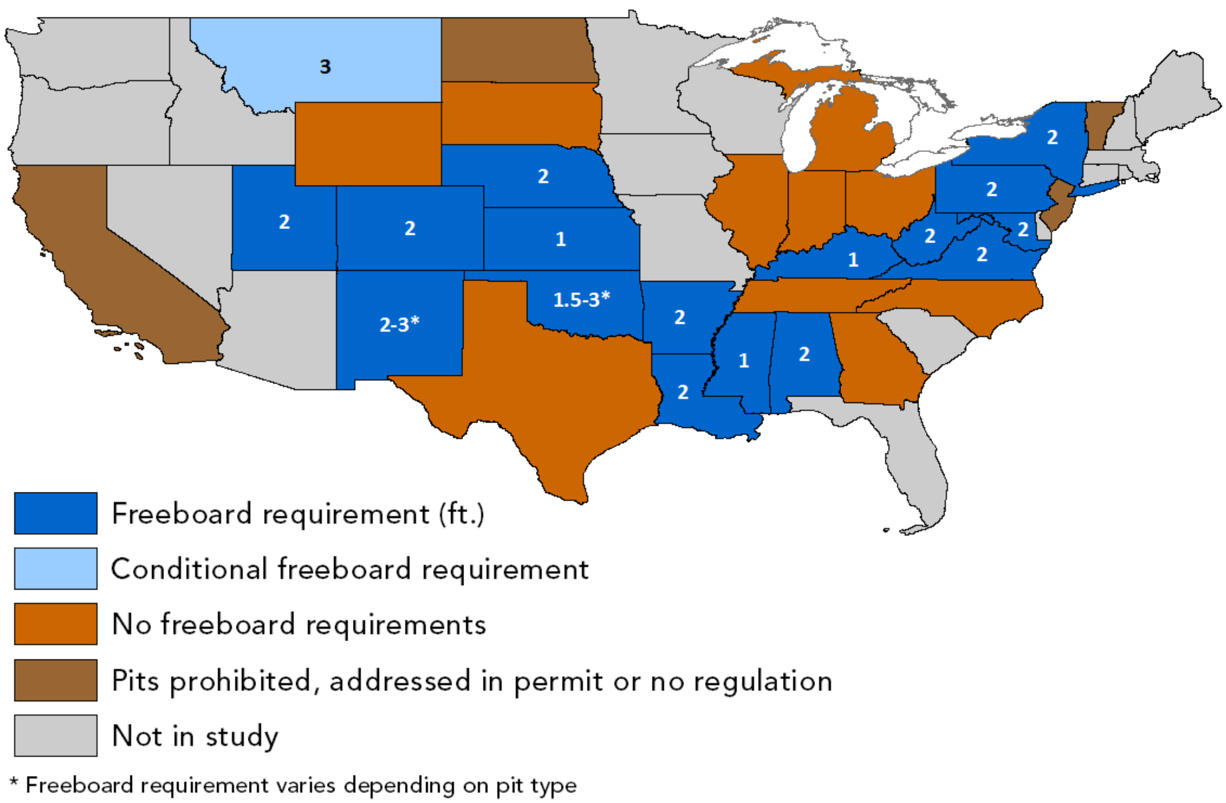

Pit Liner Requirements

Pit liners prevent fluids from seeping into the ground and potentially contaminating groundwater. Most of the states surveyed that allow fluid storage in pits (18) require pit liners. Of those states, 11 have specific regulations about the thickness of the liners and several states have other regulations such as permissible liner materials (for example. re-compacted clay liners, soil mixture liners, and synthetic liners). Alabama, Montana, and Wyoming all have conditional requirements for pit liners, such as Alabama's rule that liners are only required if the bottom of the pit is not above the seasonal high water table. Wyoming requires them only if it is "necessary" to prevent contamination of surrounding ecosystems. California does not allow the use of pits for fluid storage, thus pit liner requirements are not applicable. API best practice is that "depending upon the fluids being placed in the impoundment, the duration of the storage and the soil conditions, an impound lining may be necessary to prevent infiltration of fluids into the subsurface."

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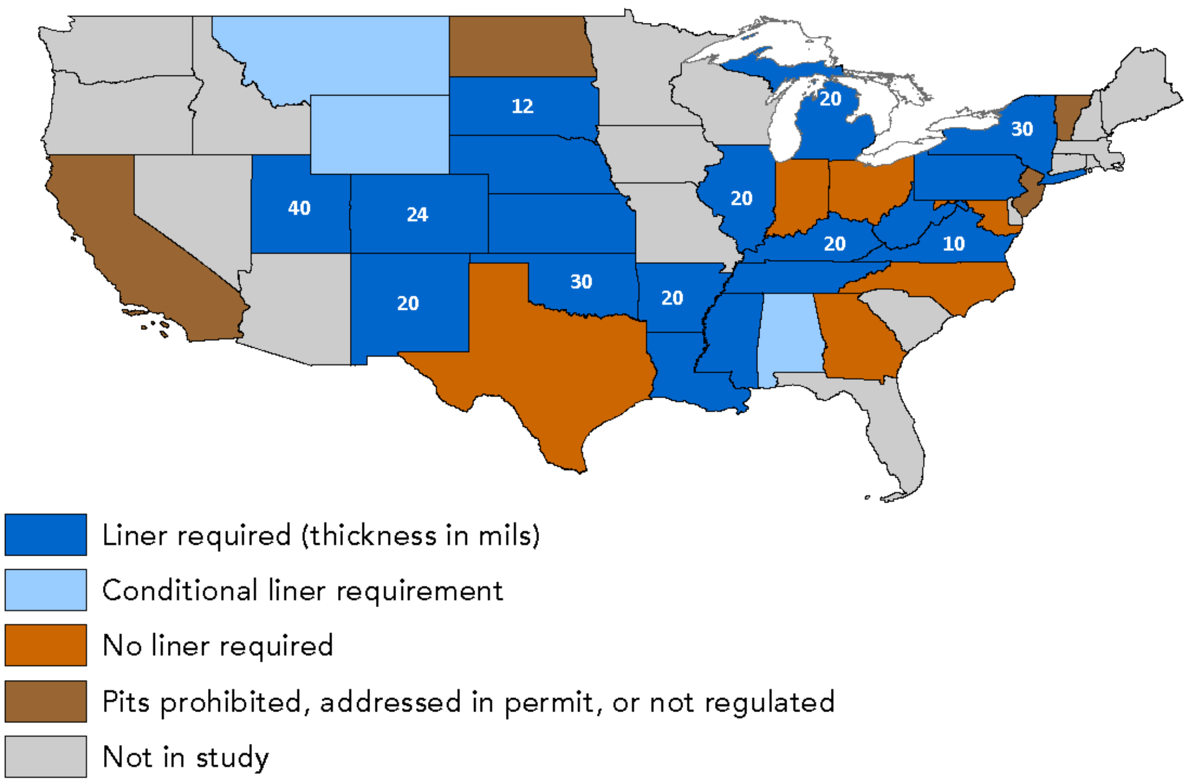

Wastewater Transportation Tracking

Wastewater that is not reused, recycled, or disposed of on-site is transported off-site, usually in trucks. The tracking of transported wastewater can be enforced either by requiring transporters to have permits, by requiring detailed recordkeeping of shipments, or both. Recordkeeping requirements often include the names of the operator and transporter, the date the wastewater was picked up, the location at which it was picked up, the location of the disposal facility or destination of the shipment, the type of fluid being transported, and the volume. Many states also stipulate the number of years that such records must be kept available to inspectors. Slightly less than half of the states surveyed (15) do not require tracking of transported wastewater. The rest (16) use permits, recordkeeping, or both to track transported wastewater. Colorado and Kansas require records to be kept of wastewater shipments but do not require transporters to be approved or permitted. In some cases, the onus is placed on the operator to ensure that all information is tracked and reported, whereas in other cases, the burden is on the transporter to do so. API best practice is that wastewater is transported "in enclosed tanks aboard DOT compliant tanker trucks or a dedicated pipeline system."

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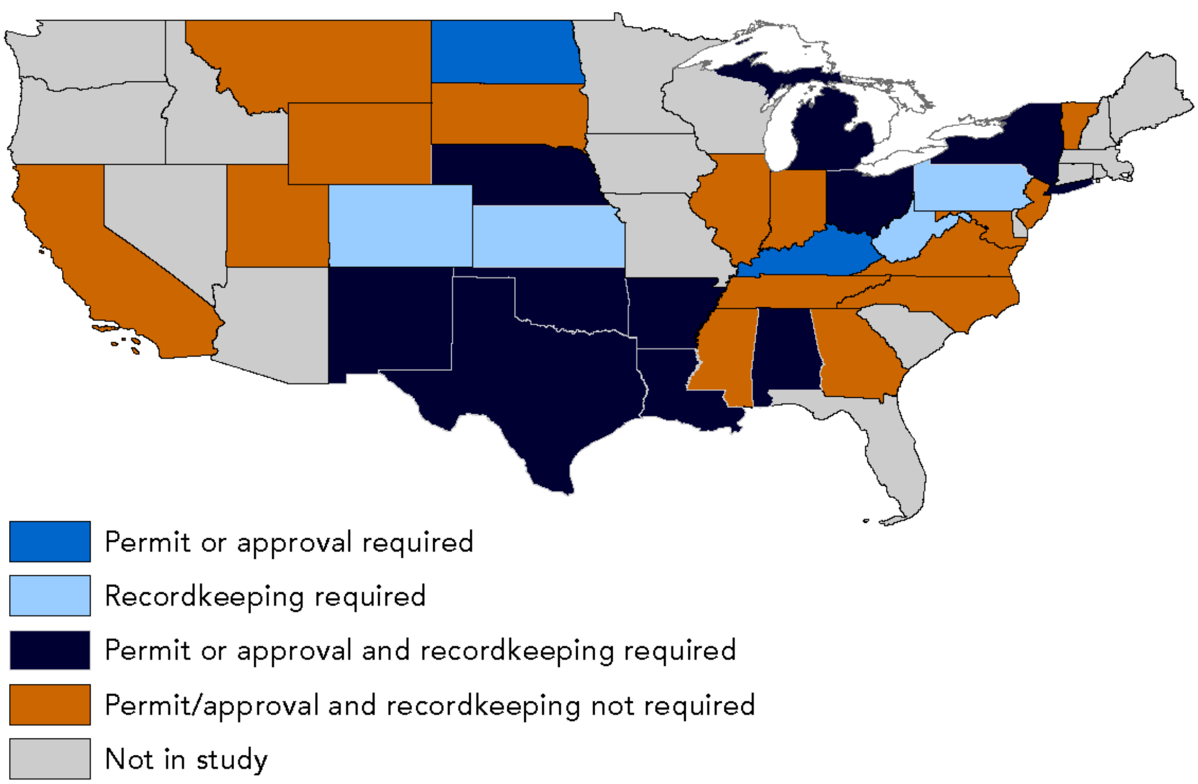

Underground Injection Wells for Flowback and Produced Water

Arkansas, Colorado, Ohio, Oklahoma, and Texas have recently experienced an increase in seismic activity near deep underground injection sites. As a result, many deep injection wells have been closed while further research is conducted. Almost all of the states surveyed (30) allow deep well injection as a form of wastewater disposal. North Carolina prohibits underground injection of fluids produced in the extraction of oil and gas wells. Arkansas has a moratorium on deep injection in a 600-square-mile area of the state where there is a fault that may have been activated by wastewater injections in the area. Ohio has recently followed a similar course of action, temporarily closing down several injection wells in an area where seismic activity has occurred. Fort Worth, Texas, has a moratorium on deep injection wells. API best practice is that "disposal of flow back fluids through injection, where an injection zone is available, is widely recognized as being environmentally sound, is well regulated, and has been proven effective." For more information on other disposal options, see Table 2: Wastewater Disposal Options.

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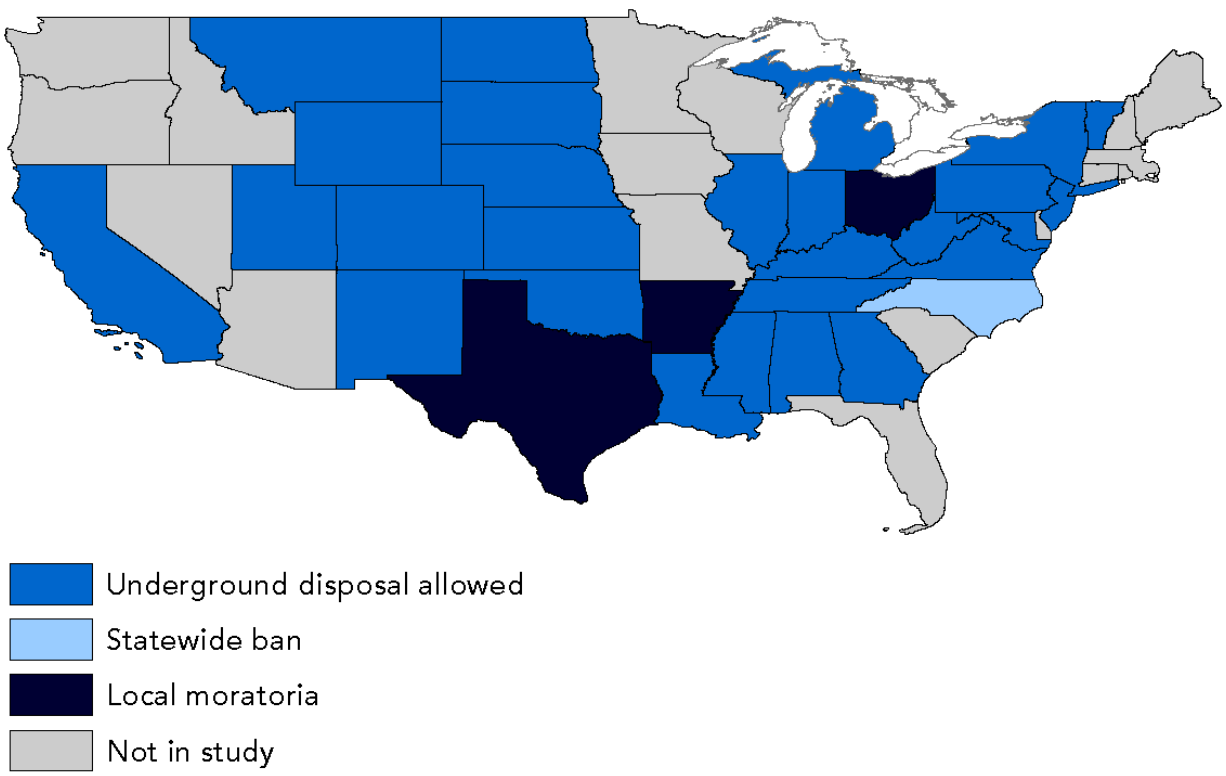

Table 2: Wastewater Disposal Options

States offer a variety of disposal options for wastewater, and most states allow more than one option. Underground injection is the most common disposal method (30 of the surveyed states allow underground injection), and 13 states directly discuss fluid disposal at a disposal facility in their regulations, making it the second most common form of disposal allowed. A few states have specific regulations for wastewater reuse though it is not mandatory in any surveyed state. It is possible that some states do allow other disposal options beyond what is directly stated in their regulations, but only that which is explicitly stated in the regulations is captured here. API best practice is that "operators should consider options for the recycling of fracture treatment flowback fluid" and that disposal options include landspreading, roadspreading, on-site burial, on-site pits, annular injection, underground injection wells, regulated and permitted discharge of fluid, incineration, and off-site commercial facilities.

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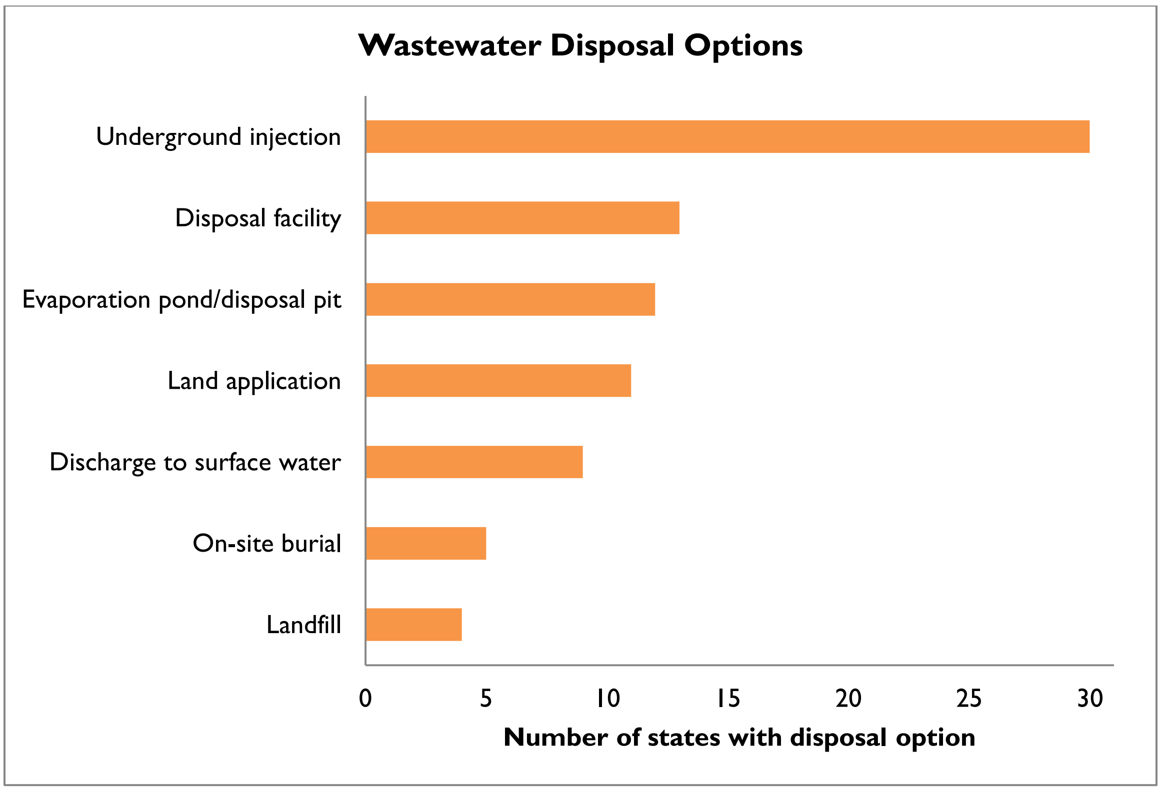
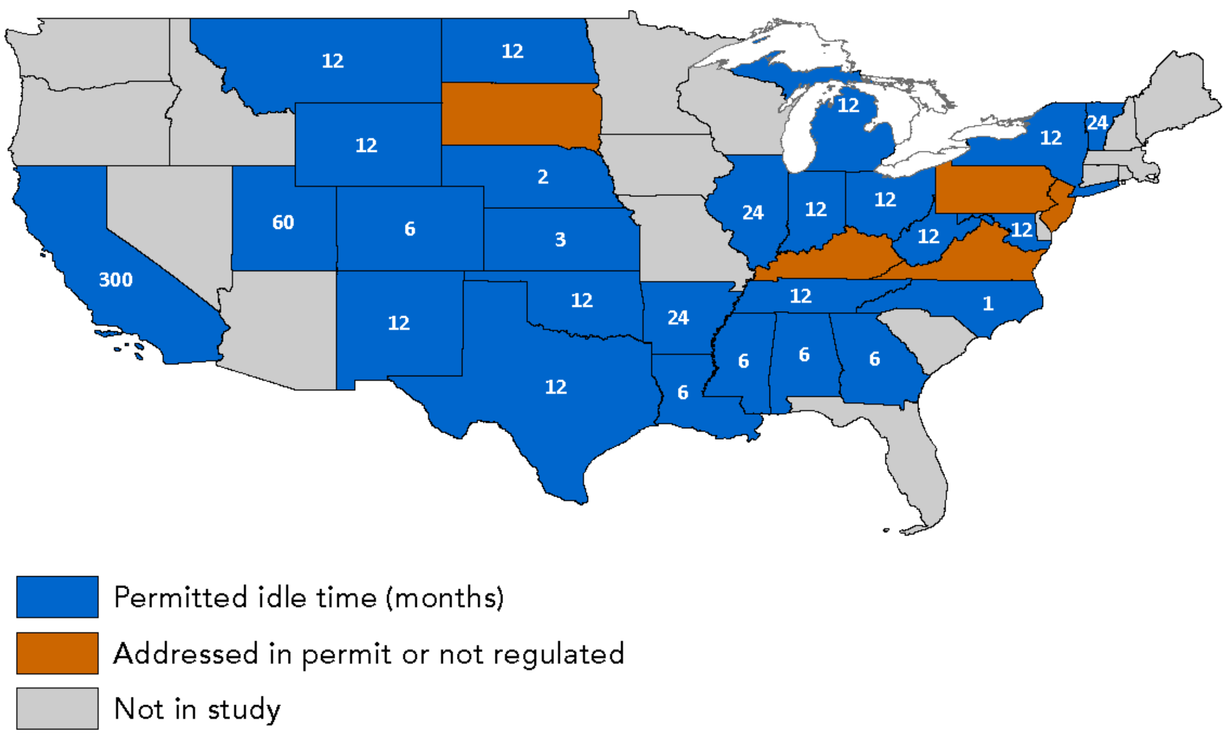


Well Idle Time

An idle well is one which is not currently producing oil or gas. Most states (26) regulate the amount of time that a well is allowed to sit idle before it must receive official temporary abandonment status or be permanently plugged and abandoned, or brought back into production. The time ranges from 1 month to 300 months, with an average of 24 months. Several states have a range of permitted idle times depending on whether the well is a productive well or a nonproductive well, or depending on the casing installed in the well. Oklahoma, for example, specifies that wells that only have a surface casing must be plugged within 90 days, whereas a well that was completed with production casing may remain inactive for 12 months. API does not have a recommended best practice for well idle time.

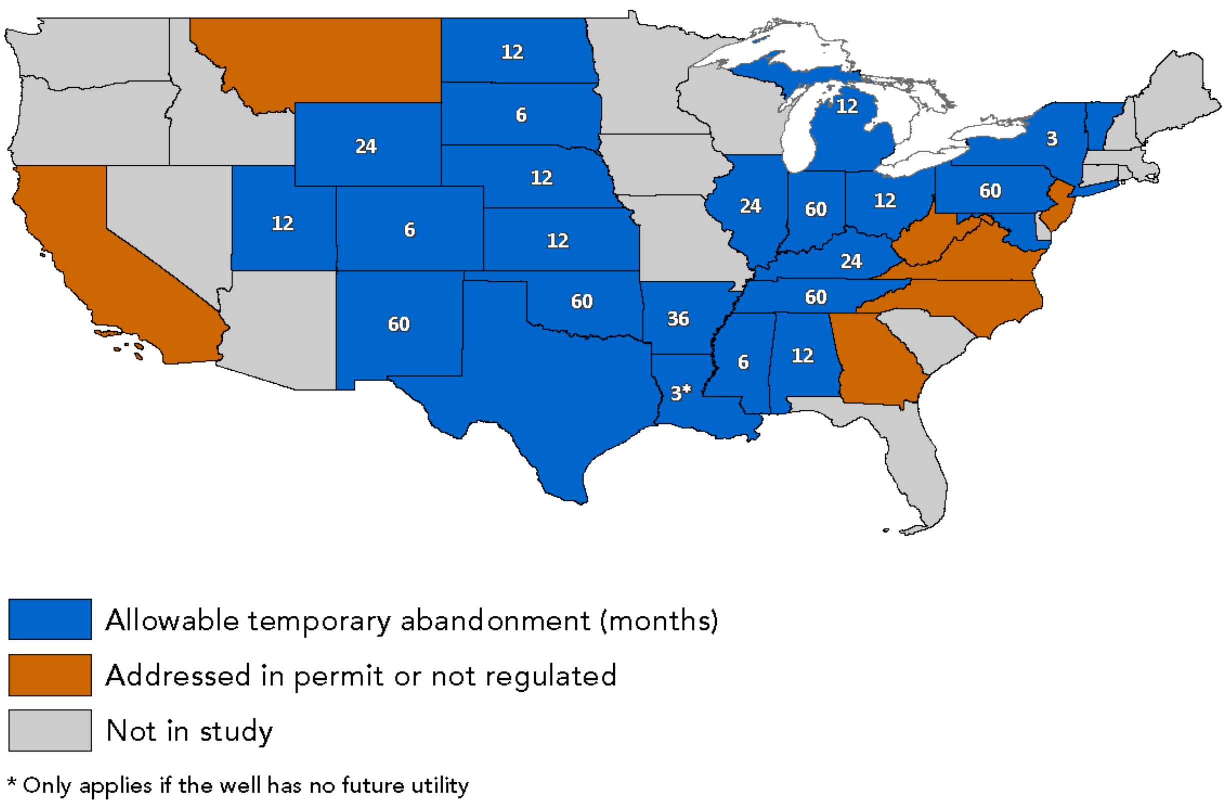
Last updated July 9, 2012



Temporary Abandonment

When a well is no longer producing at an economical rate, an operator may choose to stop production, but not permanently plug the well. Temporary abandonment is a formalized way of leaving a well idle. Most of the states surveyed (24) have temporary abandonment regulations and, typically, operators have to apply for a permit to temporarily abandon a well. In addition, states have a time limit attached to the temporary abandonment permit or approval, ranging from 3 months to 60 months, with an average of 25 months. Operators can often apply for extensions, which also have an expiration date and can have renewal limits. Kansas, for example, will renew a temporary abandonment permit for up to 10 years. When a temporary abandonment permit expires, the well must either be permanently plugged and abandoned or brought back into production. This map displays the *initial* duration of the temporary abandonment permit. API best practice is that when a well is temporarily abandoned it "must be maintained in a condition where routine workover operations can restore a wellbore to service."

Last updated July 9, 2012



Number of Wells per Inspector

Inspections are one way for agencies to verify that well operators are following the rules. This map shows the number of wells per inspector in each state—that is, the number of wells that one inspector is responsible for on average. Note that well data are from 2010 but inspector data are generally more recent; given the speed of shale gas expansion, this mismatch means these ratios should be taken as estimates only. States with no oil and gas development at this time, such as New Jersey, may have zero inspectors because there are no wells to inspect. Many states are proposing to hire more inspectors, and some states, like Arkansas, are in danger of losing inspectors due to lack of funding. API best practice is that "appropriate equipment should be used for all operations, and inspections/maintenance performed according to design and manufacturer's requirements," and that "pipelines should be tested for integrity after installation and inspected as appropriate to ensure they are not leaking."

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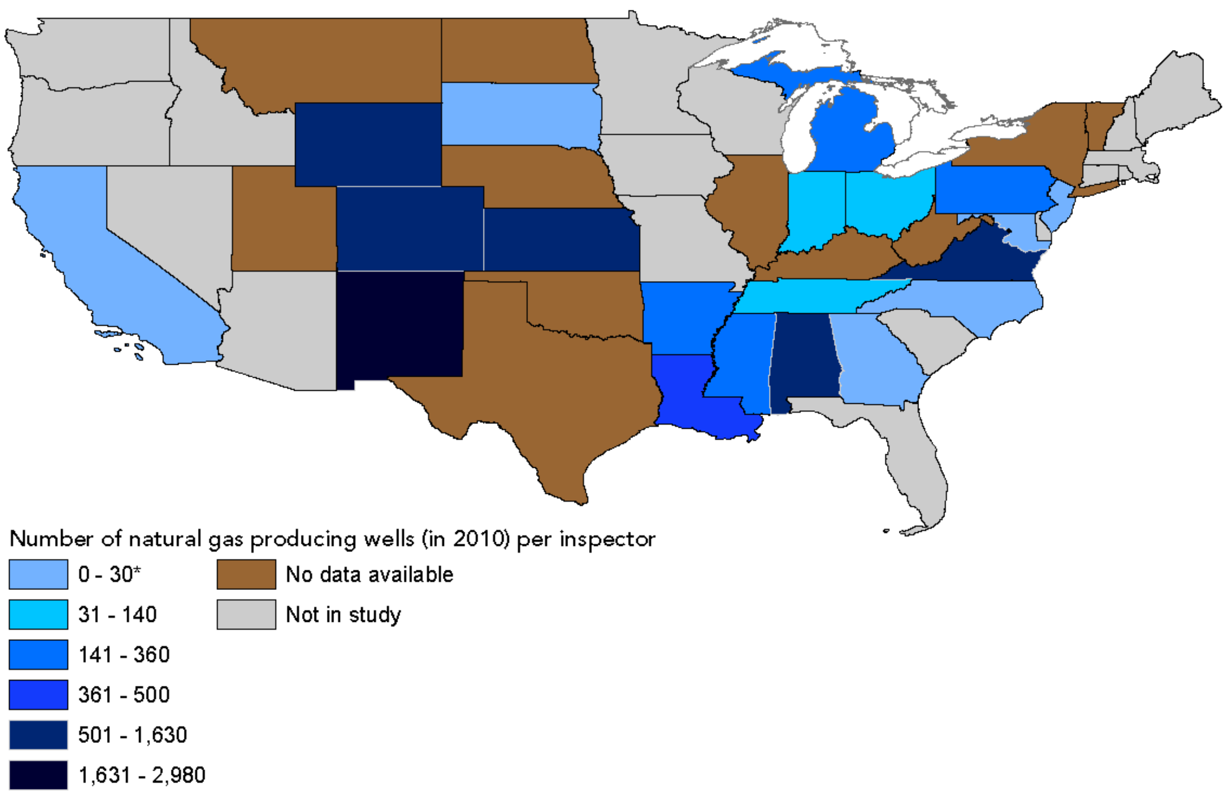

* No designated inspectors in SD. Inspections conducted by other Department of Environment and Natural Resources employees.

Number of Regulating State Agencies

Shale gas regulation is complex because multiple state agencies, often with overlapping jurisdiction, are involved—along with federal agencies, river basin commissions, and municipal governments. Natural resource or environmental agencies are often the main regulators, but other agencies are often involved. This map shows the number of state agencies that are responsible for overseeing various parts of the shale gas development process. New Jersey currently has a one-year moratorium on hydraulic fracturing and has not yet designated an agency to be responsible for regulating shale gas extraction in the event that it is legalized. The average number of state agencies is two, with a range of zero to six.

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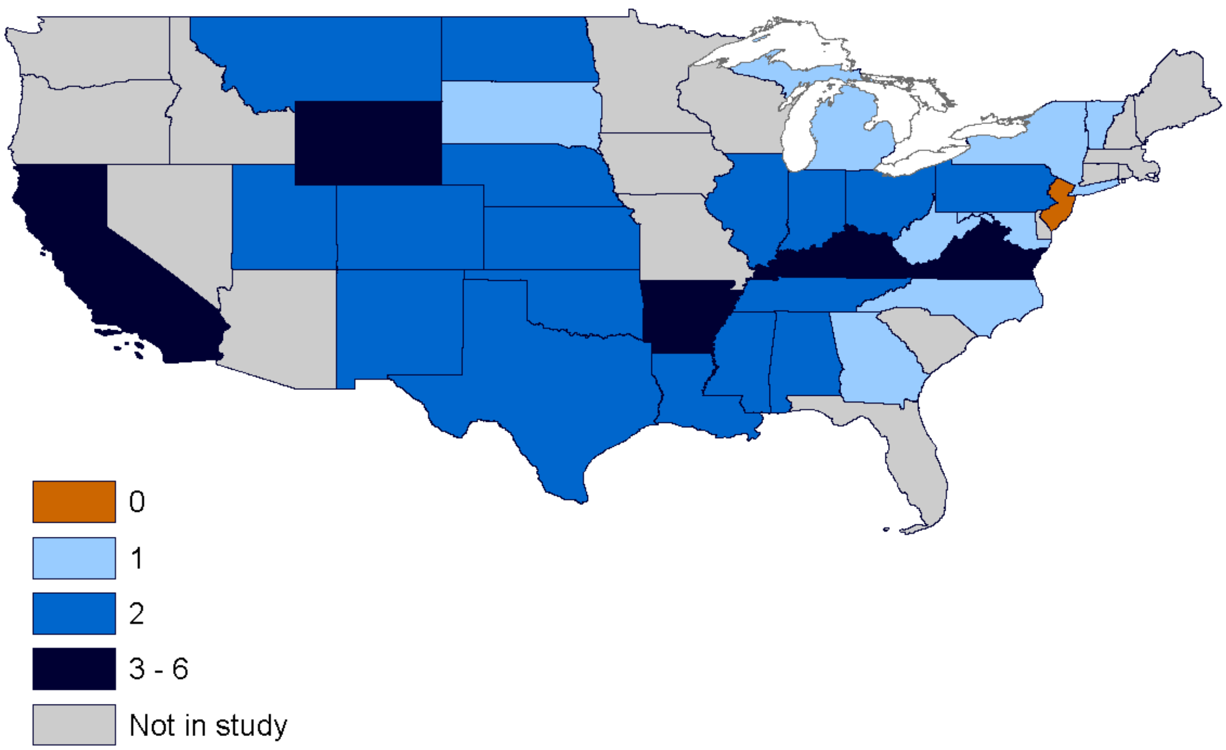

Accident Reporting Requirements

Most of the states surveyed (26) have regulations that require reporting of accidents (such as spills, leaks, and fires). The rest do not mention reporting requirements in their regulations but may stipulate such requirements in permits. The map shows the specific time or range of times in which accidents must be reported, which averages 14 hours. Several states offer different timelines depending on the severity of the spill. Louisiana and Virginia, for example, set a 24-hour timeline for spills that are not categorized as “emergencies.” New Jersey has a 2-hour reporting requirement if potable water supplies are affected and a 24-hour requirement if an underground source of drinking water is impacted. West Virginia does not provide a timeline but states that in case of an accident the operator must give notice to the district oil and gas inspector or the chief. Typically, operators are then given a specific number of days thereafter to file a written report detailing the accident. On the map, a zero indicates that accidents must be reported immediately. API best practice is that “a spill or leak should be promptly reported.”

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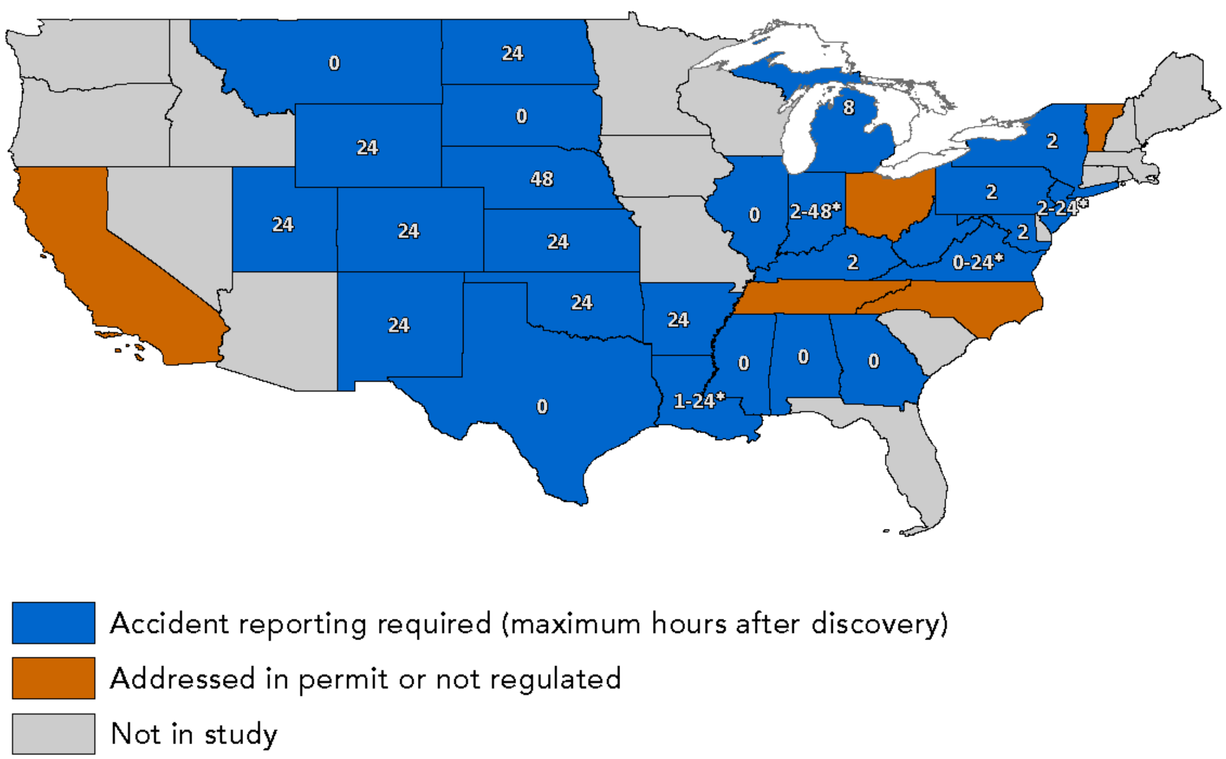
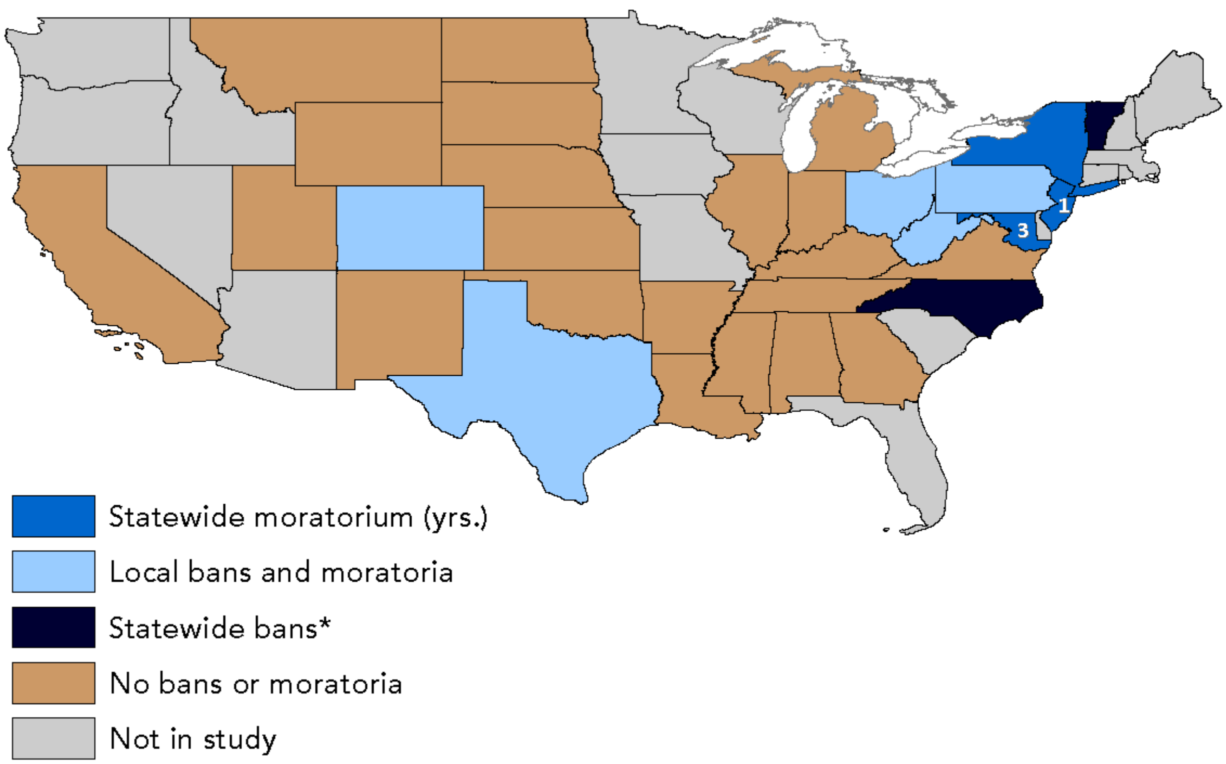


* Required reporting time varies depending on the severity of the accident.

State and Local Bans and Moratoria

Several state and local governments have passed bans and moratoria on various parts of the horizontal drilling and hydraulic fracturing process. New York State, in addition to a statewide moratorium, has more than fifty local bans and moratoria. Several states with local or municipal bans are currently in litigation over the legality of local regulation of shale gas extraction. Two New York judges recently upheld local ordinances banning the practice, whereas a judge in West Virginia ruled a local ordinance unconstitutional and unenforceable. Texas and Colorado do not allow local or municipal bans, but several local governments in these states have passed moratoria on the shale gas development process. On the map, the New Jersey and Maryland numbers indicate the number of years the moratoria are set to run, beginning in January 2012 and June 2011, respectively. As of June 2012 New Jersey has six months remaining and Maryland has two years.

Last updated July 9, 2012



* NC prohibits horizontal drilling and hydraulic fracturing under the 1945 Oil and Gas Conservation Act.

Severance Tax Calculation Method

Severance taxes are taxes imposed on gas production. Each state has a different rate, and states use one of two methods to calculate the tax—either a percentage of the market value of the gas extracted or a fixed dollar amount per quantity extracted. Some states use a hybrid approach in which the percentage tax varies between different levels based on the gas price. Rates may also vary based on production, well vintage, or other factors. This map indicates the predominant calculation method used by each state.

Note that some states have severance taxes that vary based on production levels, well characteristics, or other factors. For example, in Montana, the tax rate is 0.5 percent for the first 18 months of a well's operation (compared to 9 percent thereafter). In Utah, if the price of gas is below $1.51 per MCF the tax rate is 3 percent, and in Colorado the tax rate is set based on total net gross income, with the lowest rate (2 percent) pertaining to total net gross income less than $25,000 and the highest (5 percent) pertaining to total net gross income greater than or equal to $300,000.

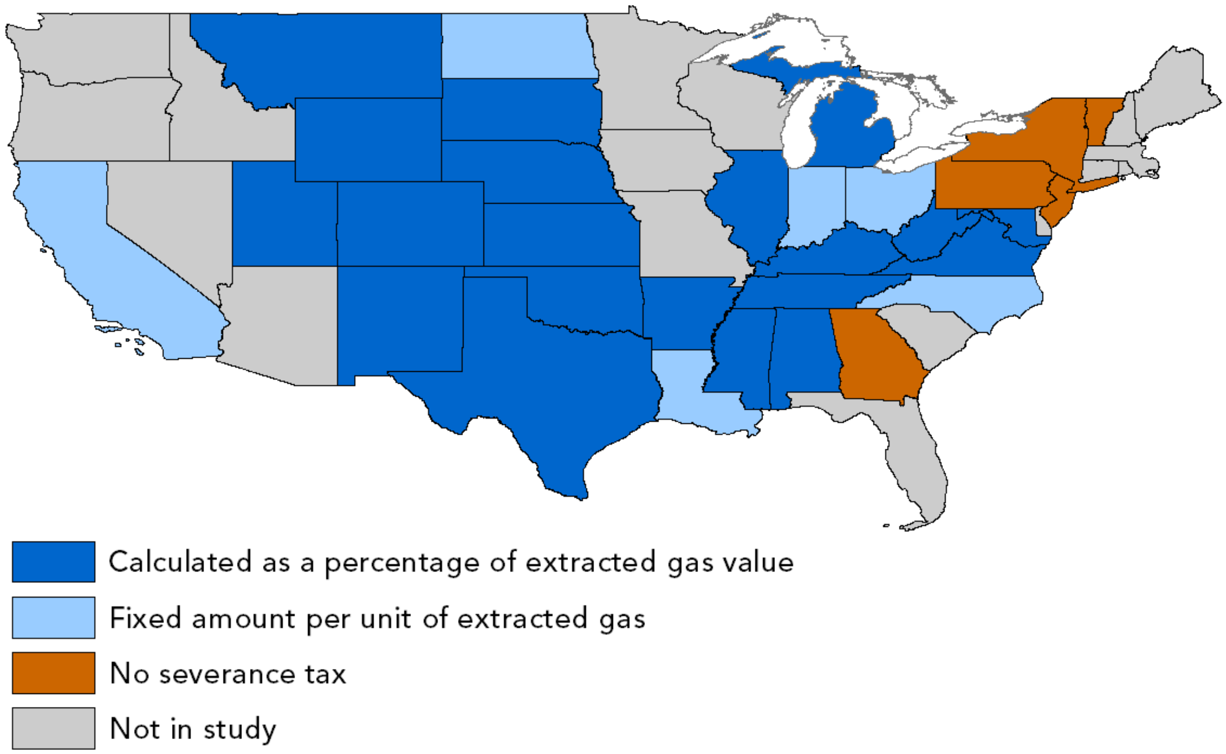
Some states (such as Maryland and Virginia) leave the question of severance taxes to local governments, though Maryland is debating a 4.5 percent statewide severance tax which would be imposed on top of any local taxes (currently Allegany County's 7 percent and Garrett County's 5.5 percent tax). Virginia limits local severance taxes to 1 percent.

Several states offer incentive programs that can reduce severance tax burdens. Louisiana, for instance, offers discounts for "incapable" wells; Montana offers a decreased rate for "nonworking interests;" Oklahoma lowers the tax according to the price of gas at market; and Texas can lower taxes for high-cost wells and inactive wells.

Pennsylvania recently passed an "impact fee" that provides funds to the communities where drilling is occurring to alleviate the cost of burdens, such as road repairs, environmental damages, and other issues. Georgia and Vermont do not have severance taxes but that is not surprising since they do not have production.

(Map on next page.)

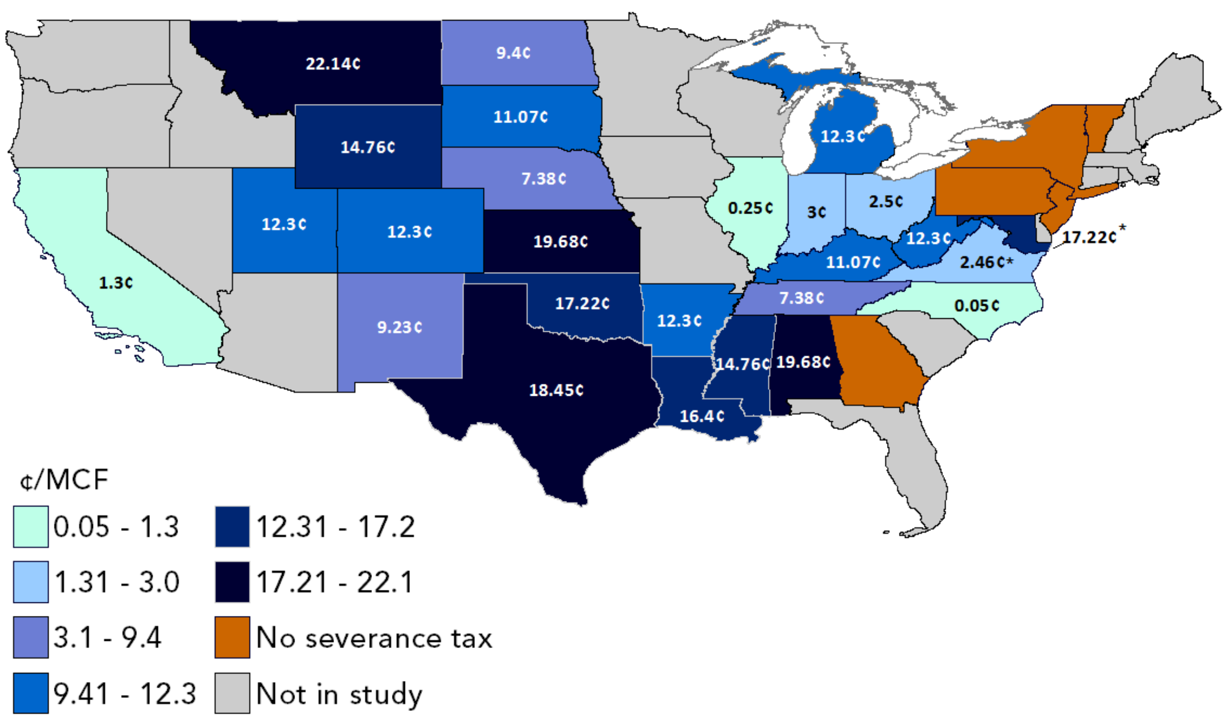
Last updated July 9, 2012



Severance Tax Rates in ₵/MCF

This map compares state severance tax rates. Since states use different methods to calculate their taxes, it is necessary to convert percentage-based taxes into fixed dollar amounts (or vice-versa—see "Severance Tax Rates in Percentage Terms") to compare rates across states. This map shows tax rates in cents/MCF. Tax rates for states with percentage-based severance taxes were converted into ¢/MCF based on the current gas price of $2.46 per MCF. For example, if a given state had a 1 percent severance tax, its tax in dollar terms would be 2.46 ¢/MCF. Based on this conversion, we find that the national average tax is about 11¢/MCF. Because the current gas price is low by historical standards, one would expect the states with fixed-dollar taxes to have relatively high taxes in percentage terms when compared to other states. But this is not the case—the average percentage basis tax in fixed-dollar-tax states is more than 2 percentage points *lower* than the national average.

Last updated July 9, 2012

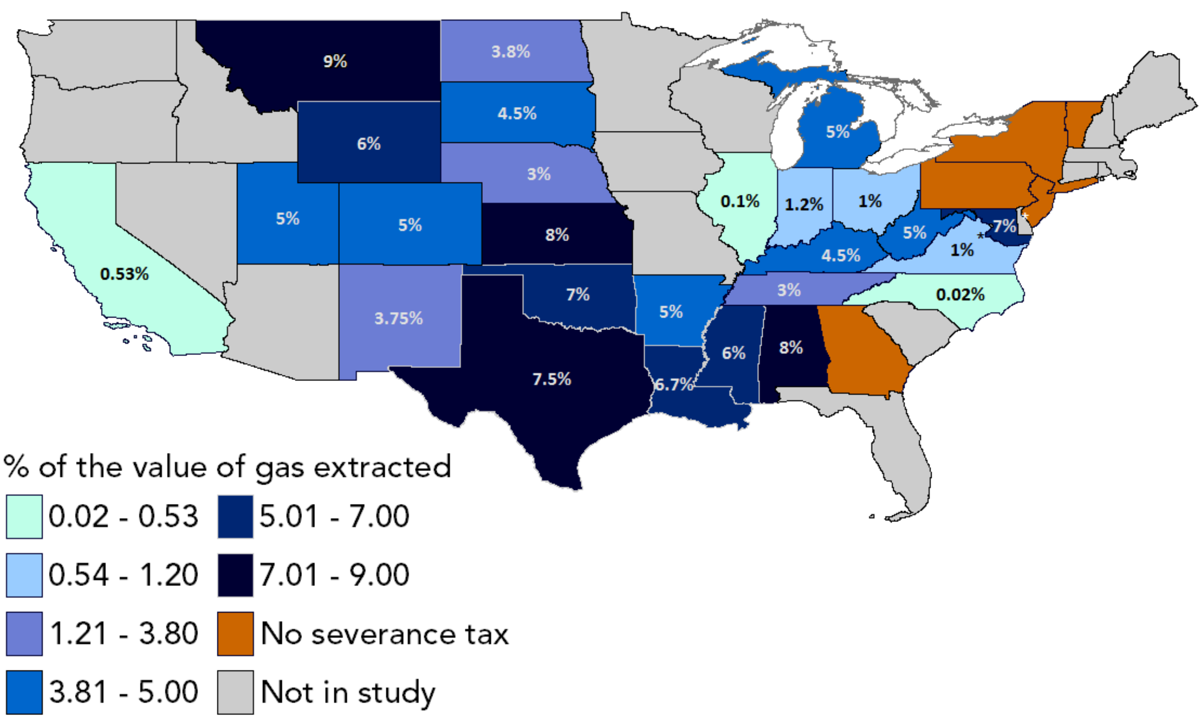


* MD and VA severance taxes are set at the local level. MD tax shown is highest in any county (Garrett). VA limits local taxes to 1%

Severance Tax Rates in Percentage Terms

This map compares state severance tax rates. Because states use different methods to calculate their taxes, it is necessary to convert fixed dollar amount taxes into percentage terms (or vice-versa—see "Severance Tax Rates in ₵/MCF") to compare rates across states. This map shows tax rates as a percentage of the value of gas produced. Tax rates were converted into percentages based on the current gas price of $2.46 per MCF. For example, if a given state had a 5¢/MCF severance tax, it would effectively tax production at 2 percent at current gas prices. Based on this conversion we find that the national average tax is 4.5 percent. Because the current gas price is low by historical standards, one would expect those states with percentage taxes to have relatively low taxes in dollar terms compared to other states. But this is not the case—the average per-MCF tax in percentage-tax states is more than 1.5¢/MCF *greater* than the national average.

Last updated July 9, 2012



* MD and VA severance taxes are set at the local level. MD tax shown is highest in any county (Garrett). VA limits local taxes to 1%.

Definitions of Shale Gas Terms

annular space (annulus): openings or voids found around the casing of a well

***casing (string)*:** a steel or plastic pipe that serves as the lining of a well

***casing shoe (shoe)*:** a cylinder or ring of steel with a cutting edge attached to the bottom of a string of well casing

cementing: the process of placing a cement sheath around casing strings

closed-loop system: A system that uses aboveground steel tanks for the management of drilling or other fluids without using below-grade tanks or pits

containers: any portable device used to accumulate, store, or transport industrial wastewater, except mobile tanks

disposal facility: an injection well, pit, treatment facility, or combination thereof that receives exploration and production (E&P) wastes for the purpose of disposal

disposal pit: a lined or unlined pit approved for the disposal and/or storage of exploration and production (E&P) wastes

ditches: a narrow channel dug in the ground used to temporarily store saltwater

evaporation pond: a lined retention facility with a large surface area designed to efficiently evaporate liquids

***fracture fluid*:** a mixture of water, sand, and chemicals that is pumped down the wellbore to stimulate and prop open the fractures

***flowback fluid*:** the return flow of water and formation and fracture fluids recovered from the wellbore of an unconventional natural gas or hydrocarbon development well within 30 days following the release of pressures induced as part of the hydraulic fracturing process, or until the well is placed into production, whichever occurs first

gas-block additive: a chemical added to the cement mixture that provides very low fluid-loss values by developing an impermeable filter

hydrocarbon zone: a layer of rock containing a naturally occurring organic compound comprising hydrogen and carbon

impoundments: a depression, excavation, or facility situated in or upon the ground used to store wastewater

incapable well: A well which is unable to produce at least an average of 250,000 cubic feet of gas per day

injection or disposal well: a well used for the injection of air, gas, water, or other substance into any underground stratum

landspreading: The discharge of wastewater on, above, or into the surface of the ground

MCF: 1,000 cubic feet, a unit of measure in the natural gas industry

mils: a thousandth of an inch

noncommercial pits: An earthen pit that is located either on-site or off-site and is used for the handling, storage, or disposal of harmful substances or soils contaminated by harmful substances produced, obtained, or used in connection with the drilling and/or operation of a well or wells, and is operated by the generator of the waste

on-site burial: the burial of cuttings and drilling muds in on-site pits and ditches

permanent pit: a pit, including a pit used for collection, retention, or storage of produced water or brine, that is constructed with the conditions and for the duration provided in its permit

pit: an earthen surface impoundment constructed to retain fluids and other wastes

***plug (or plugged)*:** the closing off of all oil, gas, and water-bearing formations in any producing or nonproducing wellbore before such well is abandoned

***produced fluid*:** water or formation fluids recovered at the wellhead of a producing hydrocarbon well as a by-product of the production activity

roadspreading: the disposal of wastewater by spreading on roads for dust control and road stabilization

***severance tax*:** a tax imposed on the extraction (or severance) of natural resources

sumps: pits or hollows in which liquid collects

***temporary pit*:** a pit, including a drilling or workover pit, which is constructed with the intent that the pit will hold liquids for less than six months and will be closed in less than one year

trona interval: a natural soda ash mineral layer found in Wyoming that is 70 percent sodium carbonate

true vertical depth: the vertical depth of the wellbore independent of its path measured as the vertical distance from the final depth (end of the wellbore) to a point at the surface

underground injection: the permanent placement of fluids underground in wells

underground source of drinking water (USDW): an aquifer or part of an aquifer that supplies any public water system or contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contains fewer than 10,000 mg/L of total dissolved solids (TDS)

urbanized area: an area where a well or production facilities of a well are located within a municipal corporation or within a township that has an unincorporated population of more than five thousand in the most recent federal decennial census prior to the issuance of the permit for the well or production facilities.

***wastewater*:** tophole water, spent drilling fluids, and flowback and produced water generated during development and operation of a well