RFF REPORT

Attaining Sustainable Development of Oil and Gas in North America

Appendix: US Policy Briefs

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JUNE 2014

RESOURCES FOR THE FUTURE

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ATTAINING SUSTAINABLE DEVELOPMENT OF OIL AND GAS IN NORTH AMERICA

APPENDIX: US POLICY BRIEFS

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Introduction

The following set of policy descriptions was put together by researchers at Resources for the Future as part of an international review of environmental policies governing oil and gas development in Canada, Mexico, and the United States. The policy briefs presented here cover the United States, with Canada and Mexico covered in companion appendices. The broader set is reflected in a summary report covering all three countries: *Attaining Sustainable Development of Oil and Gas in North America: A Review of the Environmental Regulatory Landscape*.

This document includes brief descriptions of policies governing the oil and gas production process, from extraction (well-site permitting onward) to end use in the transportation and electricity sectors. Each description provides context, the current state of regulation and best practice, and commentary options for reform and, in some cases, harmonization.

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Well-site Permitting

Context

- State agencies are in charge of permitting drilling on state and private lands, and the federal Bureau of Land Management (BLM) issues permits for well sites on federal lands.
- States are considered to issue permits much faster than BLM, but often are not transparent about the metrics used in assessing permits.
- According to the federal Government Accountability Office (GAO), BLM received half as many applications to drill in 2012 as it had in 2007 [1].
- In 2013, BLM reported that it had been unable to process completed applications to drill within the 30-day deadline required by the Energy Policy Act of 2005 [1].

Current Policy

- States
    - Regulations vary significantly. Some states require little information beyond the location of the proposed well and what it will be drilled for, and others require detailed information, such as proximity to buildings and waterways, type of fluids that will be used to fracture the well, etc.
- BLM
    - BLM is required by law to ensure that applications comply with all pertinent rules and regulations. It must also review lease requirements or stipulations and conditions of approval (such as wildlife habitat protections or well control equipment testing).

Commentary

- GAO recommends that BLM keep better notes of its permitting so that the process can be more effectively reviewed. GAO also recommends that BLM increase its staffing to allow for more efficient, faster permit review [1].
- For states, it might be helpful to have a guidance document for the kinds of information that states should be collecting, and what process they should use to review that information. All of this should be publicly available.
- There is a research need as to whether states that take longer to provide permits are seeing less drilling activity on nonfederal lands, other things equal.
- In general, the responsible government agency should be charging permit application fees commensurate with providing efficient and thorough service.

Performance Bonds

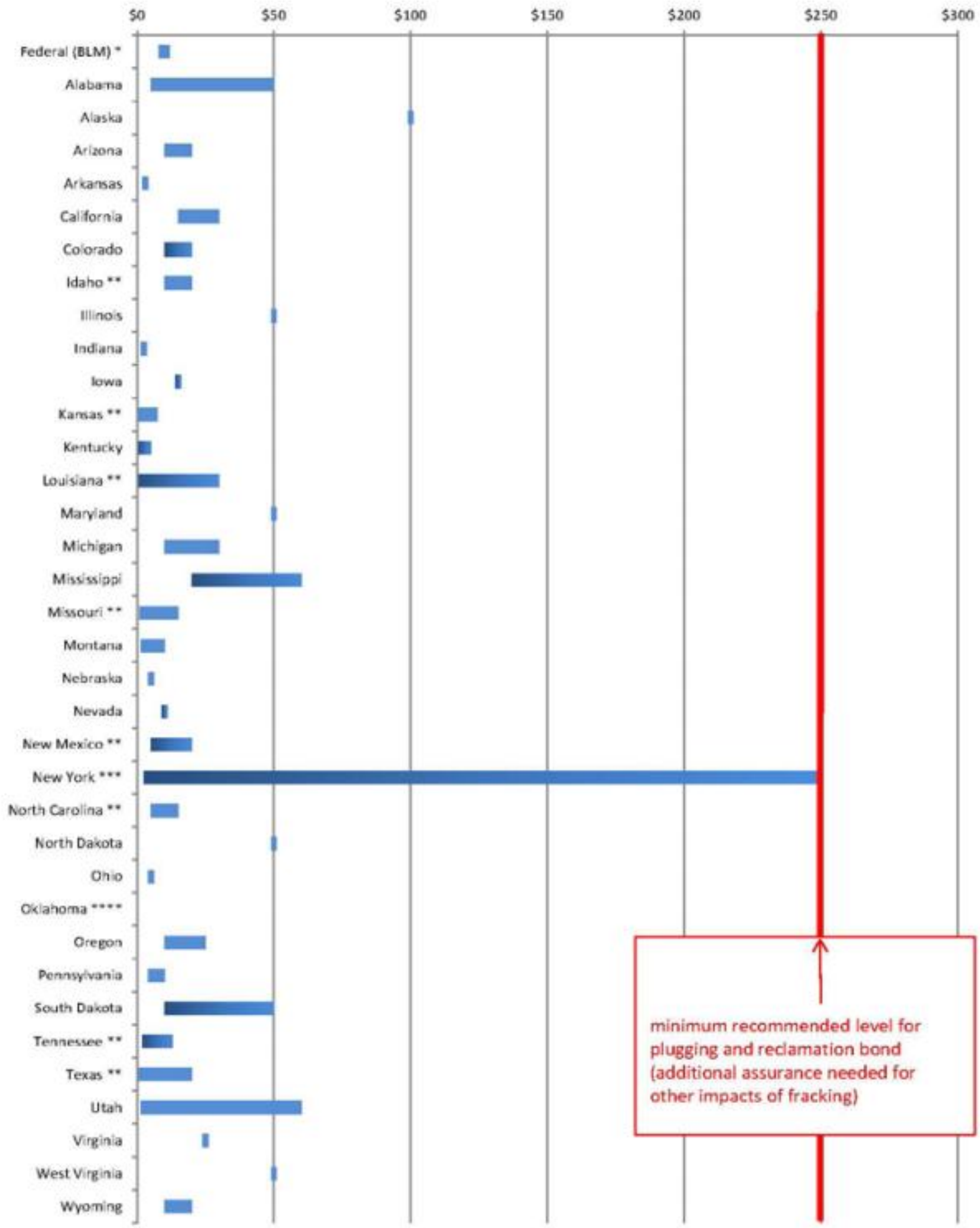
Context

- Federal and state governments have policies to protect the public interest in cleaning up abandoned wells, well pads, and other infrastructure. Federal and state governments use performance bonds to provide for this cleanup.
- BLM's bond adequacy policy is intended to ensure that BLM field offices conduct regular reviews of active bonds.
    - GAO found that between 2005 and 2009, 13 of the 33 BLM field office survey respondents had not conducted bond reviews or were unsure of the number of bond reviews that had been conducted [2].
        - Field office officials cited lack of resources and higher priorities as reasons for the lack of follow-up. Two BLM state offices and 22 field offices reported that they have not yet developed action plans for reviewing bond adequacy, as BLM policies require [2].
    - GAO found that BLM state offices did not consistently interpret BLM's regulations on increasing bond amounts [2].
- As of 2006, more than 59,000 orphan oil and gas wells were on state waiting lists for plugging and remediation, the costs of which are estimated to exceed $760 million [3].

Current Policy

- The Mineral Leasing Act of 1920 (with later amendments) requires federal regulations to establish adequate bonds before operators begin drilling, to ensure proper reclamation.
- BLM requires operators to carry individual lease bonds, statewide bonds, or nationwide bonds and accepts either surety bonds or personal bonds.
    - BLM is required to increase the bond amount when an operator that did not previously plug a well or reclaim land appropriately applies for a drilling permit.
    - BLM is also authorized to increase bond amounts for any operator considered "risky."
- Minimum bond requirements have not been updated since the 1950s [3].
- Most states require bonds to cover the costs of plugging a well and reclaiming the site and do not require financial assurance after a well has been plugged and the site reclaimed.
    - Only eight states require bonds of $50,000 or more for plugging and reclamation (costs to plug hydraulically fractured wells can be as high as $700,000). See Figure 1.
    - Most states have "blanket bond" options, which can reduce the amount of financial assurance required to less than $100 per well [3].
    - Some states excuse operators from bonding requirements if they can demonstrate financial health [3].

Figure 1. Pre-Well Bonding Amount (thousands of dollars)



Source: Dutzik et al., *Who Pays the Costs of Fracking?: Weak Bonding Rules for Oil and Gas Drilling Leave the Public at Risk.*

Commentary

- Any issues with environmental protection through performance bonding are likely to grow as more wells are drilled and existing wells are repurposed for extracting deeper shales or refracking, which likely raises the number of times well ownership changes and makes responsible parties harder to track.

- We agree with GAO, which recommends significant increases in minimum bond requirements (currently $10,000 for individual bond, $25,000 for statewide bonds, and $150,000 for national bonds), given information that reclamation of a site would cost around $100,000 [2].
    - GAO also recommends increasing resources for bond reviews [2].
- PennEnvironment suggests that bonds cover a wider range of activities and potential damages, that minimum bond requirements be increased to at least $250,000 per well, and that exemptions and blanket bonding be eliminated [3].
- Carnegie Mellon researchers found that the cost of plugging a well and reclaiming the site is approximately $100,000 and bond requirements should be increased significantly to account for those high costs. They also assert that blanket bonds should not be permitted unless that bond requirement is similarly increased.

Silica Sand Mining

Context

- Silica sand, commonly used as a proppant for hydraulic fracturing, is being heavily mined in Minnesota, Wisconsin, and Iowa because of this sand's perfect crystalline structure.
- The oil and gas industry used 56.3 billion pounds of sand in 2013, which represents a 25 percent increase since 2011, with a projected 20 percent continued increase in the next two years [4].
    - During the first nine months of 2013, the energy industry bought $245 million worth of sand, 62 percent of US silica sales (up from 53 percent during the same period of 2012, and up from 33 percent during the same time period in 2011) [4].
- Residents in areas with sand mining have complained of airborne particulate matter, and some scientists are concerned about the potential for diseases like silicosis [4].

Current Policy and Best Practice

- Sand mining is currently regulated like other nonmetallic mining in Minnesota, Wisconsin, and Iowa.
    - Wisconsin Administrative Code Section NR 415.075(2) requires a fugitive dust control plan before operations begin.
- In 2013, Minnesota passed a suite of laws requiring special permits for silica sand mining within one mile of a trout stream. It recently passed a series of optional standards that build on the 2013 regulations [5].
    - The rule, HF 976, tasked the state's Department of Natural Resources with creating rules for site reclamation, the Department of Health with creating air quality rules for silica, and the Pollution Control Agency with developing regulations for particulate emissions.

        - The Department of Health established a silica health-based value of 3 micrograms/square meter.
        - The other two departments have yet to promulgate rules.
- To minimize local exposure to silica dust, mining operators can store sand indoors, use tarps, cover trucks and rail cars, apply water or other dust-suppressing sprays, and use other mechanical control devices [6].
- Engineered proppants like ceramic and resin avoid many of the environmental issues associated with silica sand mining. Ceramic and resin proppants currently account for 10 percent each (20 percent total) of the proppant market in the United States. Silica sand is still much cheaper but producers expect ceramic proppants to continue to grow in market share [7].

Freshwater Withdrawals

Context

- Each horizontally drilled, hydraulically fractured well requires about 5 million gallons of water, a relatively small amount compared with other industrial water uses, but the time and place of the extraction may change its overall impact.
- Ambiguity in some states' rules has caused local governments to step in to regulate water withdrawals.
    - For instance, in Karnes County, Texas, in the Eagle Ford shale play, oil and gas drillers must apply for a permit from the local groundwater authority, which limits how much water can be withdrawn and requires companies to report how much they use. In neighboring Dimmit County, drillers can pump as much water as they want and no permit is required [8].
    - Texas does not allow groundwater districts to require permits for water for oil and gas well "drilling and exploration operations," though some localities argue that fracking is a production process [8].

Current Policy and Best Practice

- The Susquehanna River Basin Commission regulates water withdrawals in its river basin, which runs through New York, Maryland, and Pennsylvania.
    - In October 2008, the commission began requiring natural gas producers to apply for a permit for a water withdrawal of any size.
    - In each of its approvals, commission reviews the timing, location, and amount of withdrawals and sets a maximum withdrawal quantity. Approval does not necessarily guarantee that the approved quantity will always be available for withdrawal, since withdrawals must be temporarily halted at a prescribed "low flow."
- State-of-the-art best practice is for government to use ecosystem-based models to determine the impacts of various water withdrawals.

- Every state regulates industrial water withdrawals generally, but very few have regulations pertaining specifically to oil and gas development.
    - A few states make judgments on environmental damages and then deny or limit permits accordingly.
    - Most require permits for withdrawals over a minimum threshold, and a few require registration and reporting of withdrawals over the minimum (but approval is not necessary).
- Industry is moving to reduce freshwater use by recycling produced water and adopting fracking fluid technologies requiring lower water volumes.

Commentary

- Incentives, such as water withdrawal fees, can reduce water use. Such incentives could be design to vary with season, location, and amount withdrawn.
- The Susquehanna River Basin Commission system could be adopted by other states.
- A number of studies have compared water stressed areas around the United States with oil and gas fracking areas. The resulting maps show places with significant overlap, but overlap does not mean that the oil and gas operations are the primary cause of water stress, or that further regulation in these areas will reduce stress. For instance, oil and gas companies can be using salt water rather than freshwater, and agricultural water use can completely dominate oil and gas freshwater use.

Setback Restrictions

Context

- Proximity of well pads to buildings and water sources (and even forest habitat) could pose accident and pollution risks to people and the environment if a well site is located too close to a fragile ecosystem or human settlement.
    - For instance, in 2013, a spill at a well site in Kentucky caused massive fish kills, including kills of a threatened species, and in 2009, a spill of 8,000 gallons of frack fluids near Dimock, Pennsylvania, caused another fish kill [9].
    - Researchers in Colorado examined surface water in drilling areas where spills had occurred and found endocrine-disrupting chemicals that can cause reproductive, metabolic, neurological, and other diseases, especially in children [10].

Current Policy and Best Practice

- State regulations generally take a command-and-control approach but vary widely in specific distances from homes, schools, hospitals, rivers, lakes, etc.
    - More than half of the states currently developing oil and gas have setback restrictions from buildings (ranging from 100 to 1,000 feet), but less than half have setback restrictions from water bodies (also ranging from 100 to 1,000 feet). See Figure 2.

Figure 2. Setback restrictions from buildings

Source: Richardson, Nathan, Madeline Gottlieb, Alan J. Krupnick, and Hannah Wiseman. 2013. *The State of State Shale Gas Regulation*. Washington, DC: Resources for the Future.

Commentary

- The Nature Conservancy is developing a model to aid in well pad placement. An optimal model would trade off the costs of deviating from the economically most advantageous site within a leased area against the value of the expected environmental, property, and human health damage.
- States without setback restrictions should justify why they are not needed.
- Performance standards would be more flexible than the dominant command-and-control approach but require greater regulatory capacity.

Casing and Cementing

Context

- Poor casing and cementing have allegedly contaminated water in several instances around the country.
  - In 2011, the US Environmental Protection Agency (EPA) announced that fracking fluids had contaminated water in Pavillion, Wyoming; however, the investigation was dropped.
  - A series of studies by Duke researchers, published in the *Proceedings of the National Academy of Sciences,* found that shale gas development had contaminated groundwater in Pennsylvania [11, 12]. These studies have been challenged by other experts.
- A 2012 study by hydrogeologist Tom Myers, published in *Ground Water,* found that fracking fluids can migrate through the wellbore to the surface in the Marcellus play inless than a decade [13].
- Industry-sponsored reports show that they expect anywhere from 18 to 45 percent of wells to have well integrity issues (which could potentially allow for fluid or gas migration) [14, 15].
- Nondisclosure agreements with affected landowners prevent research and understanding of actual risks.

Current Policy and Best Practice

- Regulations vary across states, with some requiring a specific number of casing layers (from one to four), set to a specific depth below the water table (from 30 to 100 feet) and cemented to a specific height within the wellbore (above the shoe, to the surface, etc.); others simply require a casing to be used and provide no specifications.
  - Most state regulations are command-and-control, though there are a few performance standards that require operators to "protect all fresh water."
- Many innovations in drilling techniques and fluids are being made to reduce leak risks.
- Independent best practice suggests that casing should be set and cemented below the water table, and multiple layers of casing are generally considered superior to fewer.

Commentary

- Data collection and reporting systems need to be developed to enable regulators and researchers to assess the risks of groundwater contamination from faulty cementing and casing operation, over space and over well lifetime, and the factors that can reduce risks.
- Pennsylvania's presumptive liability rule is potentially a good model for other states to follow. This rule holds operators responsible for any contamination that occurs within 12 months of the beginning of unconventional oil and gas operations within a 2,500-foot radius

of the well site; one of the defenses against the presumption is a predrilling baseline groundwater testing survey.

Liquids Handling

Context

- Frack fluids pose different risks at different points in the development process, and little is known in the public domain about the composition and quantities of produced water, partly because it is thought to be so heterogeneous across wells, even in the same play.
- Work in progress at RFF shows that produced water concentrations of many hazardous substances exceed drinking water and even in-stream standards. But these liquid wastes are not supposed to be released to the environment untreated.
- Unless mitigation measures are taken, openly storing fluids in pits and ponds creates potential for spills and threatens wildlife from drowning or ingestion of toxic fluids.
- Ultimately, some liquid wastes need to be treated and released or permanently disposed of. Research at RFF on the routes being taken by trucks suggests that most Marcellus wastes are going to commercial waste treatment facilities, some hundreds of miles from the well site. Few shipments in our sample are going to Ohio deep injection wells.

Current Policy and Best Practice

- No states require recycling and no states require the elimination of pits and ponds to store flowback and produced water, though some states limit which substances can be stored in pits or ponds and which substances need to be stored in closed tanks.
- Best practice is to reuse liquids to frack additional wells, reducing freshwater and ultimate disposal costs. Best practice is also to have closed-loop systems for drilling, flowback, and produced water [16]. Only 25 percent of drilling rigs offer closed-loop drilling fluid systems.

Commentary

- Several states are beginning to implement water-cycle planning, in which operators must detail how they will handle and treat water from start to finish, approaching it as a holistic system instead of piecemeal.
- There are several options for improving liquids handling from start to finish:
    - Recycle and reuse produced water
    - Use low-toxicity additives
    - Employ closed-loop storage options
- Greater understanding of industry liquid-handling economics and the influence of regulation is needed.

Wastewater Treatment Facilities

Context

- Anywhere from 10 to 50 percent of the fracturing fluid used to fracture a well will flow back up and out of the wellbore and need to be either reused or disposed of [18].
    - Wastewater can be disposed of many ways, including treatment and discharge at publicly owned treatment works (POTWs) or centralized waste treatment facilities (CWTs).
- Research has shown that not all wastewater treatment plants are equipped to properly treat shale gas wastewater.
    - RFF's water quality study found that treatment of shale gas wastewater by POTWs in a watershed raises downstream chloride concentrations.

Current Policy and Best Practice

- In 2010 Pennsylvania asked operators to voluntarily stop bringing wastewater to POTWs for disposal and within several months had achieved high compliance [19].
- Indirect discharges of unconventional oil and gas wastewater via POTWs are subject to EPA's General Pretreatment regulations.
    - EPA is proposing to amend the Effluent Limitation Guidelines for shale oil and gas wastewater to ensure that CWTs are adequately treating such waste before disposing of it; the amendments are scheduled to be posted in 2014.
- State policies on wastewater disposal vary; several states require applications or permits to discharge wastewater to surface waters, and some operate on a case-by-case basis.
- The American Petroleum Institute (API) suggests that operators consult local regulations to determine whether POTWs and CWTs are viable disposal options and that operators may need to disclose chemical compositions to be allowed to deposit wastes at those facilities [16].

Commentary

- API posits that future disposal needs are unlikely to be met by POTWs because of regulatory and other challenges and therefore suggests investing in private or industry-owned treatment facilities. Further, API says that an evolving practice in active drilling areas is to set up temporary treatment facilities to treat waste on site, thus reducing transportation needs [16].
- The Natural Resources Defense Council recommends that states and/or the federal government develop pretreatment standards and set a total maximum volume of wastewater that POTWs are allowed to accept. It points to Pennsylvania's standard of 500 mg/L total dissolved solids and 250 mg/L chlorides as a sufficiently stringent example for others to follow [19].
    - The Natural Resources Defense Council also recommends that EPA update the Effluent Limitation Guidelines to limit discharges of naturally occurring radioactive

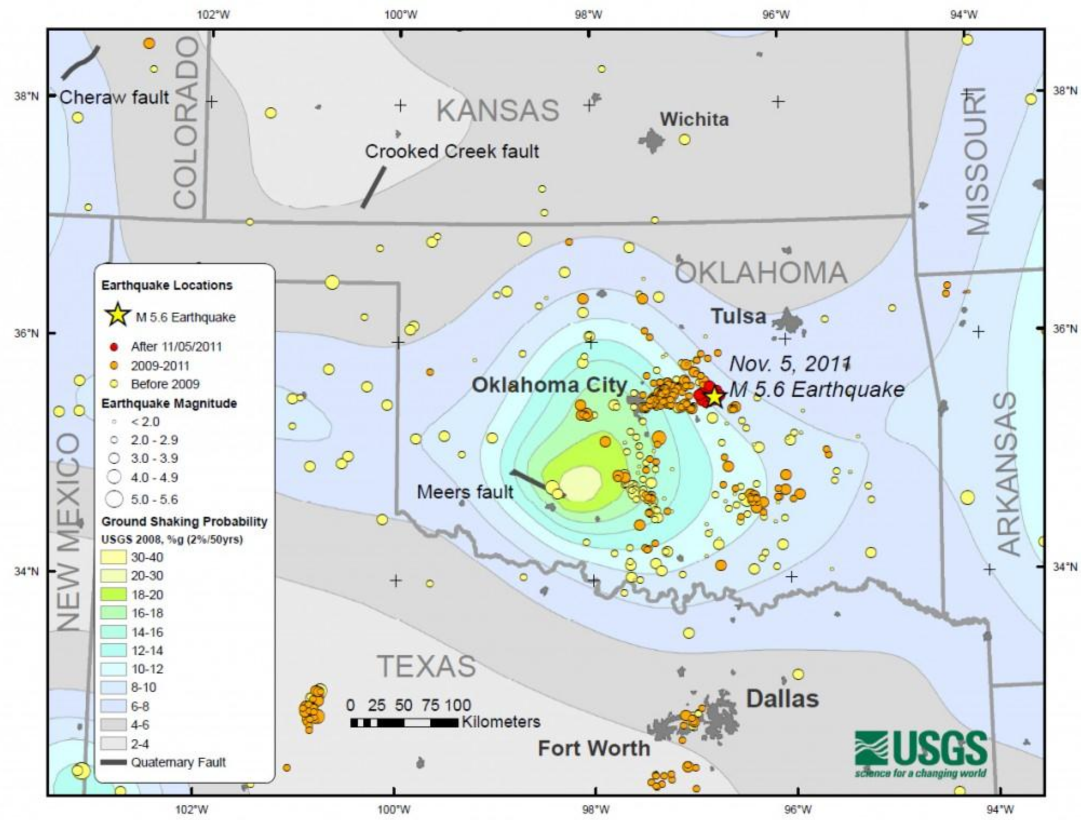
material (NORM), total dissolved solids, and bromides, which were not considered in the original guidelines [19].

Underground Injection Control

Context

- Underground injection has become a common form of wastewater disposal. Texas alone has 8,000 disposal wells, and the amount of wastewater injected underground increased from 46 million barrels in 2005 to 3.5 billion barrels in 2011 [20].
    - According to EPA, about 28,000 Class II injection wells are being used for wastewater disposal in the United States [21].
- Recent studies have linked seismic activity in numerous states to underground wastewater injection wells.
    - Scientists concluded that a series of earthquakes (reaching magnitude 3.9) in Youngstown, Ohio, were caused by the local wastewater injection well [22].
    - A recent US Geological Survey (USGS) study found that a magnitude 5.0 earthquake in Prague, Oklahoma, was caused by fluid injection [23]. See Figure 3.
    - In 2013 USGS researchers concluded that an earthquake swarm in New Mexico and Colorado along the Raton Basin was caused by underground wastewater injection [25].

Figure 3. USGS map of earthquake swarm in Oklahoma



Source: USGS, "Oklahoma Struck by Series of Quakes," Nov. 2011.

Current Policy and Best Practice

- EPA oversees underground wastewater injection, but states can apply for supremacy (39 states have primary authority).
    - The application for a permit to drill an injection well must include the location and depth of the proposed well.
    - After receiving a permit, the operators must observe, record, and report the injection pressure, flow rate, and cumulative volume each month; they must also conduct mechanical integrity tests on the wells at least once every five years.
- All states allow, and some even encourage, underground injection of wastewater.
    - In light of recent seismic events, some states have begun enacting rules about where injection wells can be located, and many local bans on injection wells have been enacted, such as in Arkansas, Ohio, and Texas.

    - Though Pennsylvania does not formally ban underground injection of wastewater, the state Department of Environmental Protection says that the geology generally does not allow for it, so wastewater is often shipped to Ohio or West Virginia for injection. Nevertheless, several new injection wells are opening in Pennsylvania this year.
- Industry best practice is to reduce throughput, thus reducing the volume of wastewater [16].

Commentary

- Underground injection is considered by many, including API, to be the best option for wastewater disposal, if done properly [16].
- Mark Zoback, of Stanford University, suggests several steps that operators can use to minimize seismicity impacts from injections [24]:
    - Use seismic imaging to ensure that the injection site is not located near an active fault line.
    - Minimize the volume of fluid injected.
    - Utilize highly permeable regional saline aquifers.
    - Install local seismic monitoring arrays.
    - Establish modification protocols in advance (so that operators have a predetermined system for halting injections as necessary).

Fugitive Methane Standards

Context

- According to EPA's 2012 CO_2 Emissions Inventory, about 2 percent of US CO_2-equivalent (CO_2e) emissions are from fugitive methane, though other estimates have a wider range and some scientists argue that even with fugitive methane releases, oil and gas are still "cleaner" than coal or diesel. Others argue the reverse.
- A study by the Environmental Defense Fund found that about half of the 40 percent reductions that are currently possible are no-cost reductions [26].

Current Policy

- EPA's Green completion standards go into full effect in January 2015.
    - Phase one requires combustion devices (flares) be used until operators are able to implement green completions, which are required beginning in 2015.
    - These regulations ostensibly were designed to target volatile organic compounds (VOCs), not methane, but have the ancillary benefit of reducing methane emissions.
    - API says the rule will cost $780 million over four years, but EPA contends it should save the industry $11 million to $19 million over the same timeframe [27, 28].

- Colorado recently passed the first state rules to directly reduce methane and VOCs from oil and gas development. Violations of ozone standards in the state were a key driver.
    - The rules will reduce annual emissions of VOCs by 90,000 tons and methane by 100,000 tons; the rules also contain the nation's strongest leak detection and repair regulations, including requirements for monthly inspections at the largest sources [29].
- In March 2014, EPA proposed a rule requiring oil and gas operators to report greenhouse gas emissions from their operations.

Commentary

- We are skeptical that many fugitive methane emissions reductions are "free," as suggested by the Environmental Defense Fund study.
- The continuing debate about the percentage of production leaking and the unfavorable comparisons of natural gas to coal on CO_2e grounds are harming industry's license to operate.
- Some natural gas operating companies are beginning to organize efforts to pledge to reduce methane emissions and ultimately create a tradable methane credit market.
- EPA is expanding its voluntary Gas Star program to include a GOLD designation that rewards companies for reducing methane emissions. So far the program has reportedly been effective and could be a good carrot to complement EPA's sticks.
- A carbon-pricing regime that incorporated fugitive methane emissions would do much to efficiently reduce CO_2e mitigation costs.

Fluid Disclosure

Context

- Industry and environmental and health groups have been arguing about the appropriate trade-off between secrecy in tracking fluid formulations (for competitive reasons and to stimulate innovation) and the public's right and need to know what is in these fluids (for public and environmental health reasons).
- Transparency improved when the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission created FracFocus, a website where oil and gas companies can voluntarily disclose their fluid mixtures.
    - FracFocus has been criticized for being voluntary (calling into question the accuracy and completeness of information provided) and difficult to use (because the data cannot be downloaded and are thus difficult to analyze).
    - The US Department of Energy has provided support for the website.

Current Policy and Best Practice

- Requirements are highly varied across states, with most states now requiring some form of disclosure.

    - About half of the states with disclosure rules require mandatory disclosure to doctors, though doctors are often required to sign nondisclosure agreements.
    - All states allow for trade secret exemptions, though some states require a justification of this designation for each chemical and some do not.
- BLM's revised proposed Hydraulic Fracturing on Indian and Federal Lands Act includes disclosure requirements, using FracFocus as the mode of reporting. BLM's rules require postfracturing disclosure and provide exemptions for trade secrets.
- One best practice from the major fracking fluid suppliers is that set by Schlumberger for the state of Wyoming four years ago: to provide each chemical's name, mass, and concentration to its operating company clients, which then decide on their own whether to disclose the information or follow regulations to make the information available to the state and/or to FracFocus. What is not being disclosed is the recipes for making company products. Baker-Hughes just announced it will adopt the same company policy as Schlumberger. Schlumberger argues that for all practical purposes, it is making full disclosure. Company calculations from FracFocus show that trade secrets claims appear in less than 5 percent of FracFocus records for wells fracked by Schlumberger.
- On the fluids themselves, industry best practice is moving to use lower concentrations of and less toxic chemicals.

Commentary

- Disclosure is important for determining sources of groundwater contamination, treating people who have been exposed to chemicals in accidents, and making a holistic assessment of the industry's impact.
- Required full adoption of the Schlumberger disclosure model and mandatory disclosure in state and federal rules would go a long way to addressing public concerns.

Truck Traffic

Context

- Oil and gas development has moved into rural and suburban neighborhoods unaccustomed to such industrial activity, causing a backlash in some areas.
- Fracturing a single well requires between 2,300 and 4,000 truck trips (considerably more than conventional drilling) for delivery of water and other inputs, which can add to road congestion, road damage, and traffic accidents [30].
- US census data in six drilling states show that in some areas, traffic fatalities have more than quadrupled since 2004, even as most American roads have become safer [30].
    - In North Dakota drilling counties, the population has increased 43 percent while traffic fatalities have increased 350 percent [30].
    - RFF analyses of drilling and truck accident statistics since 2004 in Pennsylvania suggest that each additional well drilled per month per county results in a 2 percent increase in heavy-duty truck accidents [31].

Current Policy and Best Practice

- To try to minimize community disturbances, some local governments have begun to pass rules limiting which roads trucks can use, but these rules are sparse and often ineffective.
- North Dakota is adding turning and climbing lanes to give drivers a safe way to pass trucks and is also widening a stretch of heavily used Route 85 [32].
- Pennsylvania and Texas transportation departments have launched safe driving campaigns aimed at minimizing such accidents [32].
- Federal rules limit the amount of time that truck drivers can spend on the road, but these regulations are less stringent for drivers in the oil and gas industry [32].
- Industry is trying to limit freshwater needs and use pipelines to reduce trips [32].

Commentary

- Increased accident rates are a consequence of industrial activity, so no special blame falls on the industry. RFF's expert survey showed that industry is quite aware and concerned about this problem, suggesting that it has been internalizing the costs.
- To the extent road damage, inadequate signage, a lack of enforcement, and other inadequacies of local and state funding are the problem, new revenue streams and greater accountability are needed. Severance taxes and Pennsylvania's impact fee system are not the best approach because they are not based on damages (see "Compensation for Damages," below).

Compensation for Damages

Context

- Economic efficiency in the presence of externalities suggests that mechanisms be in place for oil and gas operators to internalize damages they do to communities. This internalization should come ex ante, through regulatory activities, but it may also come ex post, through compensation for damages. Because activities are repetitive over time, damage compensation can be seen as a deterrent to future externality-causing behavior. Nevertheless, there are no institutionalized compensation schemes at the state or local level, the closest being Pennsylvania's impact fee system. Any aggrieved party can seek compensation through the liability system, however.

Current Policy

- Pennsylvania's impact fee system was passed in 2012 as a substitute for severance taxes.
    - Fee is per well. It begins at $40,000 per year (assuming gas prices are less than $2.25/mcf) and is reduced each year for three years, then stays at $10,000 per year from year 4 to year 10 [33].

    - It has generated an average of more than $200 million per year in revenues, though estimates show that only 50 percent of the collected fee actually reaches the affected areas.
- Pennsylvania's impact fee is not tied to actual impacts but rather is a schedule over time that depends partly on natural gas prices (like some state severance taxes); only a fraction of the collected revenue goes to communities and none to individuals. Thus internalization of damages is not occurring.

Commentary

- Better instrument design is needed so that community impacts are taken into account when the fee is set.

Deepwater Drilling

Context

- Deepwater drilling in the Gulf of Mexico alone produces 1.6 million barrels of oil per day (70 percent of the Gulf's oil production, and 23 percent of total US crude oil production), more than a fifth of the world's offshore drilling units, and 7 percent of total US natural gas production [34, 35].
- The 2010 BP *Deepwater Horizon* oil spill raised awareness of the growing number of offshore accidents.
    - In the first 10 months of 2010, the Gulf of Mexico alone saw seven incidents in which the drilling crew lost control of a well [36].
    - RFF research shows a strong statistical relationship between well depth and the probability of a significant accident.

Current Policy

- In 2012 the Bureau of Safety and Environmental Enforcement enacted new safety rules for offshore drilling, with the following purposes:
    - To define testing requirements for cement
    - To clarify requirements for dual mechanical barriers
    - To extend requirements for blow-out preventers and well-control fluids to well completions, workovers, and decommissioning operations
- In 2013, Congress approved the RESTORE Act to allocate 80 percent of Clean Water Act fines to ecosystem restoration in the Gulf.
- The Department of the Interior (DOI) restructured its oil and gas organization to clarify and separate the missions of the former Minerals Management Service into three separate agencies, each with its own focus and resources.

Commentary

- President Obama's Oil Spill Commission writes annual "report cards" addressing the progress made on its recommendations. The commission also believes that DOI's changes to regulations were less extensive than they should have been. For example, it would like to see the following reforms [36]:
    - Extend the period for approving exploration plans from 30 to 60 days
    - Provide protection for whistleblowers
    - Substantially increase liability cap and financial responsibility limits (currently $75 million)
    - Increase the existing $1 billion per incident limit on payouts from Oil Spill Liability Trust Fund
    - Fund the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM) with user fees
- One of the more interesting reforms planned by DOI is adoption of a "near miss" reporting system, similar to that used by the Federal Aviation Administration, to aid in developing measures to avoid future accidents.
- Donald Boesch, who served as commissioner of the National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling, recommends advancing various measures to create more certainty and improve environmental oversight [36]:
    - Congress and DOI should create a Leasing and Environmental Science office to foster environmentally responsible and efficient development.
    - Congress should provide mandatory funding (not tied to annual appropriations) for oil spill research and development, in addition to a tax credit for research and development, to encourage private investment in response technology.
    - Congress should maintain its risk awareness by appointing a subcommittee to oversee offshore safety and environmental risk, require annual reports from DOI on risks, and require oversight hearings on the state of technology and safety.

Bans and Moratoriums

Context

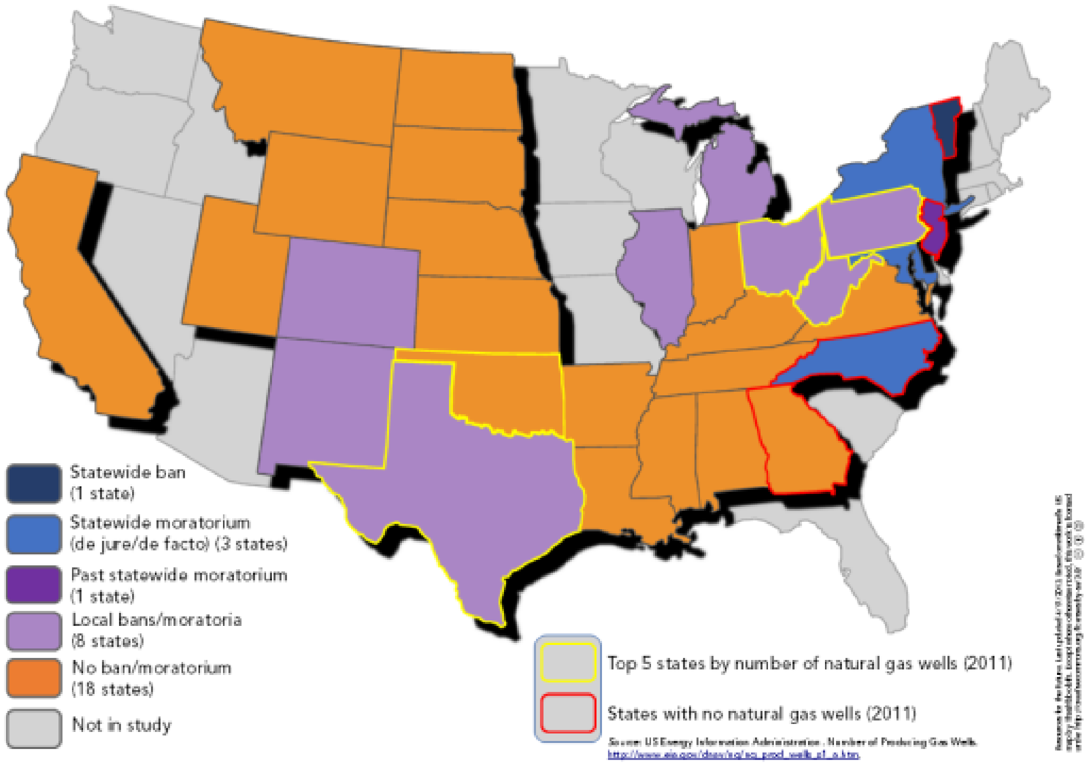
- Federalism issues have arisen as local governments have asserted themselves in the regulation of shale gas development; some states have chosen to support local regulations, and some states have passed legislation to preempt local regulation.
- Local bans can effectively render drilling uneconomical in large regions if enough of the shale is off limits.

Current Policy

- Vermont is the only state with a statewide ban on fracking, but New York and other states have moratoriums, and several states have local bans. See Figure 4.

- State courts in New York and Colorado upheld local bans, but a precedent-setting case in state court in West Virginia struck down a ban in Morgantown, and the Pennsylvania supreme court threw out this attempt to preempt local bans and regulatory efforts by the state.
- Colorado is seeking to define power-sharing arrangements between local government and the states to enhance use of memoranda of understanding that locals use with operators to gain agreements on acceptable behavior, short of rulemakings [37].

Figure 4. Bans and Moratoriums



Source: Richardson, Nathan, Madeline Gottlieb, Alan J. Krupnick, and Hannah Wiseman. 2013. *The State of State Shale Gas Regulation*. Washington, DC: Resources for the Future.

Commentary

- A ban is a very blunt instrument. It eliminates risks to the local community rather than managing the risks and reaping the economic benefits. But a local community may have preferences different from those of the state government, and those preferences need to be respected and taken into account.
- Bans may cause more intense development elsewhere, thereby relocating risks rather than limiting them.
- Moratoriums allow states and localities time to learn more about the extraction process and proper regulations before drilling proceeds; they are viewed by some as a smart way to

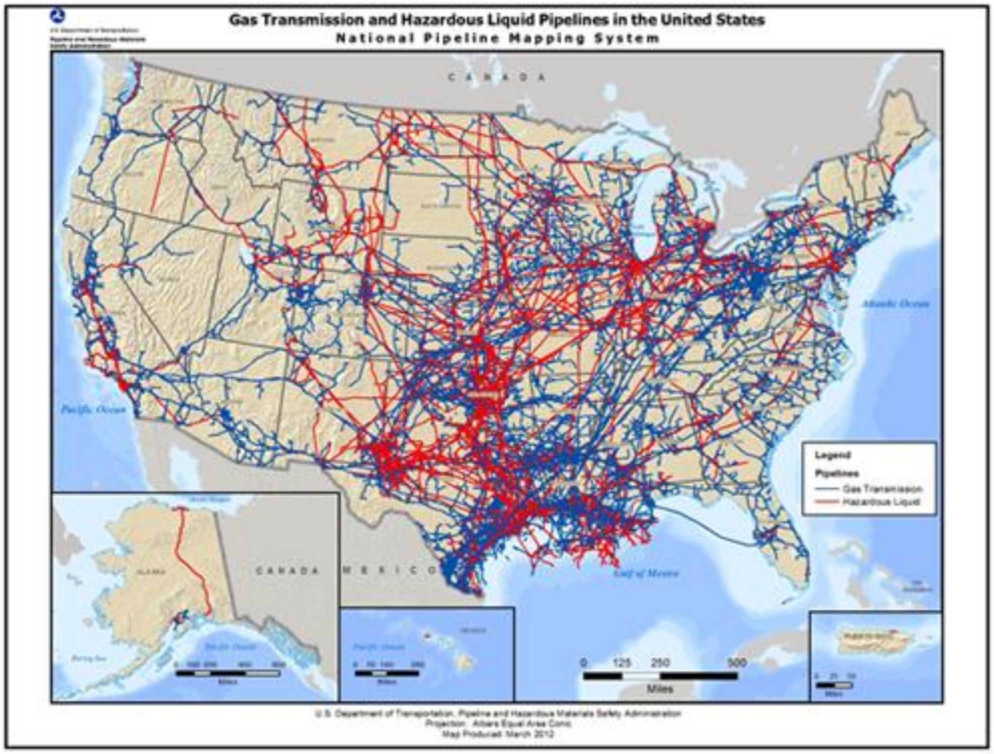
approach sustainable development, but by others as an indefinite postponement of the time when the jurisdiction can realize the economic benefits of drilling.

Pipeline Safety Act 2011

Context

- The United States currently has 2.5 million miles of pipelines carrying oil and gas around the country [38]. See Figure 5.
- Pipelines are generally considered a safe mode of transport for oil and gas: based on fatality data from 2005 to 2009, pipelines are 70 times safer than trucks (which transported less fuel but killed four times the number of people) [38].
- Recent accidents like the 2010 explosion in San Bruno that left 8 people dead and the 2010 accident in Michigan that spilled 840,000 gallons of crude into the Kalamazoo River (at $800 million, the most expensive pipeline accident in US history) have raised public awareness and concern about pipeline safety [38].
- Underground pipelines can remain in operation for decades, even up to a century; currently, more than half of the nation's pipelines are at least 50 years old [38].
    - Corrosion has caused 15 to 20 percent of all reported "significant incidents." [38]

Figure 5. Gas Transmission and Hazardous Liquids Pipelines in the US, 2012



Source: US Department of Transportation, Pipeline and Hazardous Materials Safety Administration, "Gathering Pipelines: Frequently Asked Questions."

Current Policy

- Under current regulations of the Pipeline and Hazardous Materials Safety Administration (PHMSA), only 7 percent of natural gas lines and 44 percent of hazardous liquid lines are subject to rigorous and frequent inspections, and of the roughly 240,000 miles of gathering pipelines in the US, PHMSA regulates only about 24,000 [38].
- Passed in January 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act ("Pipeline Safety Act") has many components, including an increase in civil penalties for violations of US Department of Transportation (DOT) safety and compliance regulations. The act also mandated the following tasks:
    - DOT must prepare a report on existing integrity management requirements and leak detection systems to determine whether expanded or enhanced requirements are necessary.
    - The secretary of DOT must decide whether to require the use of automatic or remote-controlled shut-off valves, as well as the use of excess flow valves.

  - The secretary must evaluate whether integrity management system requirements, which currently apply only to high-density population areas (and other high-consequence areas) should be expanded to other areas.
  - The secretary must report on pipeline leak detection systems and whether new standards and technology should be employed.

Commentary

- As pipelines age, it becomes increasingly more important to monitor and upgrade them as necessary to prevent leaks and ruptures.
- A Congressional Research Service report found that PHMSA lacks sufficient inspectors to adequately monitor the millions of pipelines it is charged with overseeing. The report also said that replacing manual shut-off valves with automatic ones would cost the industry hundreds of millions of dollars [39].

Pipeline Siting Requirements

Context

- Laying new pipelines requires some temporary and some permanent land disturbance that may disrupt habitats and, if close to dwellings or taken by eminent domain, humans.
- Once a route has been decided on, the company must receive permission to cross each part of land that the route encounters. This can be done by purchasing an easement from the landowner in a voluntary contract, or by the power of eminent domain.
- Under federal law, interstate natural gas pipelines have the right to use eminent domain once a permit has been issued by the Federal Energy Regulatory Commission (FERC); other pipelines must rely on state law for eminent domain, and state regulations vary widely.

Current Policy

- FERC is responsible for permitting pipeline siting. Before granting a permit, FERC conducts a thorough environmental review, which often necessitates an environmental impact statement (and sometimes changes in routes and other operational details).
- Depending on the proposed pipeline route, various other federal regulations come into play, including the Clean Water Act, National Pollutant Discharge Elimination System permitting, dredge and fill permits from the Army Corps of Engineers, the Coastal Zone Management Act, the Endangered Species Act, and the Historic Preservation Act.
- There is no federal permitting process for interstate hazardous liquids pipelines (approval falls to the individual states involved), and the federal government has no role in permitting an intrastate pipeline of any kind. International pipelines do necessitate a federal permit, called a Presidential Permit.
- State rules for new pipelines vary significantly: some identify areas to exclude or avoid, some develop alternative routes, and some have no regulations at all.

- If a state has no agency in charge of pipeline permitting, then permitting falls to the land-use authority of the local governments along the proposed route.

Commentary

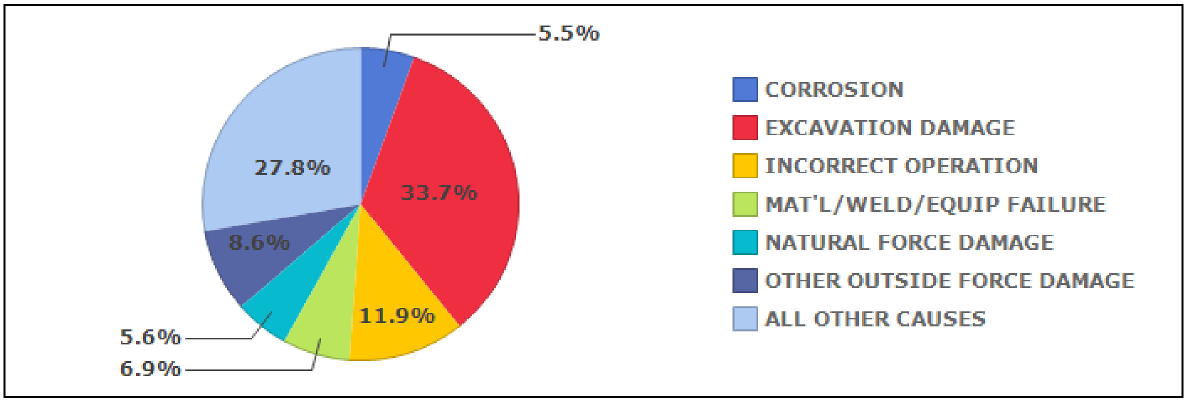
- The Pipeline Safety Trust found that FERC rarely rejected pipeline siting permits and therefore questioned its due diligence on the safety of these sitings [40].
- The Interstate Natural Gas Association of America (INGAA) suggests that operators engage in presiting communications modeling with local communities and in pipeline leadership to cultivate relationships with local regulators.
- To obtain a Presidential Permit for an international pipeline, the State Department must show that the pipeline serves the "national interest," but the term is not defined by federal law, leaving much room for dissent in the determination process (which includes a full environmental impact statement). A clear definition of the term may help simplify the permitting process in cases like Keystone XL.
- During the Keystone XL controversy, many new rules were proposed to switch the permitting authority to other agencies (e.g., FERC), to limit the allowed application approval time, and eliminate Presidential Permit requirements. None of these bills passed, but they indicate how Congress could circumvent or alter current regulations to allow pipeline sitings [41].

Pipeline Excavation Damage Prevention

Context

- According to DOT, one of the greatest challenges to safe pipeline operation is avoiding accidental damage caused by digging into a buried pipeline [42].
    - Damage is caused by many routine operations, including road and highway maintenance, general construction, farming activities, new home construction, and homeowner activities [42].
- In one year alone (2002–2003), 15 percent of incidents for hazardous liquids pipelines and 18 percent of incidents for natural gas transmission pipelines were due to excavation damage (see Figure 6.) [42].
    - Excavation damage can cause catastrophic pipeline failure with environmental and human health repercussions, as well as loss of oil or gas.

Figure 6. Serious Incident Cause Breakdown, National, All Pipeline Systems, 1994–2013



Source: PHMSA Significant Incident Files, May 7, 2014

Current Policy and Best Practice

- Every state has a "One-Call" center for businesses and individuals to call and report excavations so that pipeline operators have a chance to mark their pipelines before construction begins. It is illegal to dig without calling a One-Call center first.
- PHMSA proposed a rule to oversee state excavation damage prevention laws and establish federal backstop requirements. Specifically, it will accomplish the following:
    - Establish an administrative process for making adequacy determinations
    - Establish the federal requirements that PHMSA will enforce in states with inadequate law enforcement programs to prevent excavation damage
    - Establish the adjudication process for administrative enforcement proceedings against excavators where federal authority is exercised
- INGAA's Trenching and Excavation Safety Document CS-S-12 includes numerous suggestions for improving excavation safety, such as the following [43]:
    - Develop a work plan and ensure that proper equipment is being used
    - Install high-visibility markings of underground structures and crossroads
    - Use protective systems like shoring, sloping or benching, trench boxes, or the equivalent

Commentary

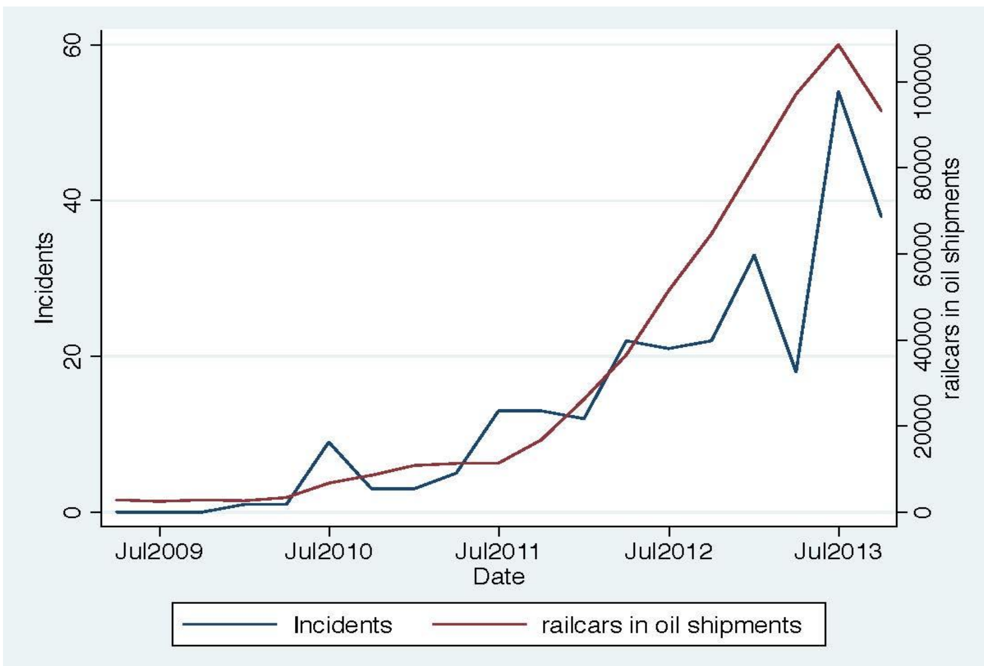
- PHMSA recommends that industry educate the community and excavators about pipeline awareness, and it encourages the general public to be aware of nearby pipelines and report any concerns to the local One-Call center [42].
- The Congressional Research Service says that some policymakers have proposed establishing federal civil penalties for violations of state One-Call rules; other stakeholders have argued that such enforcement is best performed by state regulators unless federal regulators determine that state rules are insufficient [44].

Track Safety Standards (improving rail integrity)

Context

- Railroads are now transporting 11 percent of crude oil, up from 1 percent just five years ago [45].
- Rail operators are responsible for moving the crude and maintaining tracks and other infrastructure, but they do not own the crude oil itself or the tank cars in which it is carried.
    - Whoever owns the crude oil typically owns or leases the tank cars used to carry it.
- Since July 2013, there have been six major accidents across North America involving trains moving crude oil, one of which resulted in 47 deaths [45]. See Figure 7 for more information on incidents in the US.

Figure 7. Number of incidents versus number of railcars used for oil shipments



Source: Calculations from Charles Mason, Department of Economics, University of Wyoming, and Visiting Fellow, Resources for the Future.

Current Policy

- Within DOT, the Federal Railroad Administration (FRA) and PHMSA both regulate the rail industry.
    - FRA oversees safety and compliance generally, while PHMSA oversees safety specifically when hazardous materials are involved.
- As of March 2014, a new FRA rule seeks to improve rail integrity by addressing defective rails, rail inspections, inspection records, and qualified operators.
    - The final rule provides a four-hour window for verification of suspected rail defects.

    - It requires track owners to have no more than 0.09 service failures per year per mile of track for Class 3, 4, and 5 tracks that carry hazardous materials.
    - It also requires internal rail inspections on Class 3, 4, and 5 tracks that carry hazardous materials every 370 days or 30 million gross tons, whichever is less.
    - Every rail flaw detection provider must have a training program in place; for a rail flaw detection test to be valid, it must be performed by a qualified operator who is subject to minimum training.
    - Rail inspection records must include date, track identification and milepost, type of defect found, defect size (if not removed prior to traffic), and initial remedial action.

Commentary

- The government could codify commitments and recommendations made by the American Association of Railroads (AAR) such as analyzing routes for safety potential, restricting speed for crude oil trains, performing at least one more inspection than required, and installing wayside defective bearing detectors [46].
- The National Transportation Safety Board (NTSB) recommends that PHMSA expand hazardous materials route planning and, where possible, reroute to avoid transporting hazardous materials through populated or sensitive areas [47].
    - NTSB further recommends that FRA revise its track safety standards to inspect each main track by foot or vehicle at least once every two weeks and to inspect each siding by vehicle or foot at least once a month [48].

Tank Car Requirements

Context

- Rail operators do not own the tank cars in which oil is carried; whoever owns the crude oil typically owns or leases the tank cars used to carry it.
- Crude oil is generally transported in an unpressurized tank car, model DOT-111.
- An NTSB study found that 54 percent of DOT-111s involved in accidents released fluids they were carrying—a significantly higher rate than pressurized tank cars like DOT-105 and DOT-106 [45].

Current Policy

- Within DOT, FRA and PHMSA both regulate the rail industry.
    - FRA oversees safety and compliance generally, while PHMSA oversees safety specifically when hazardous materials are involved.
- In September 2013 PHMSA issued an advanced notice of proposed rulemaking that covers upgrades to DOT-111s.
- DOT issued an emergency order in February 2014, requiring railroads carrying more than 1,000,000 gallons of Bakken crude oil to notify state emergency response commissions of estimated volume, frequency of anticipated traffic, and route.

- FRA and PHMSA also issued a joint safety advisory recommending the use of tank cars with the highest level of integrity for transporting Bakken crude (and cautioning against the use of DOT-111 cars).
- NTSB suggests equipping DOT-111s with enhanced shell puncture and tank head systems and top fitting protection. It also recommends requiring bottom outlet valves designed to stay closed during accidents and requiring center sill or draft sill attachments, like those recommended by AAR in its 2011 tank car specifications [45].
- AAR has designed a new DOT-111, the CPC-1232, which is made of thicker and stronger materials. The association recommends such materials for every new tank car and asks that PHMSA make them mandatory [45].

Commentary

- PHMSA notes three issues with the new rules [45]:
    - Whether to require upgrades beyond the scope of AAR's 2011 recommendations
    - Whether to retrofit tank cars that do not meet the new standards
    - What timeline to enforce for phaseouts and retrofits

Tank Car Staff

Context

- Rail operators do not own the tank cars in which oil is carried; whoever owns the crude oil typically owns or leases the tank cars used to carry it.
- Since July 2013, there have been six major accidents across North America involving trains moving crude oil, one of which resulted in 47 deaths [45].
- Accidents have occurred because operators have fallen asleep or been distracted (i.e., by texting) while operating trains without a second-in-command [49].

Current Policy and Best Practice

- Within DOT, FRA and PHMSA both regulate the rail industry.
    - FRA oversees safety and compliance generally, while PHMSA oversees safety specifically when hazardous materials are involved.
- In April 2014, FRA proposed a rule that would require two-person crews on trains carrying crude.
- Current industry best practice is to have two-person crews for over-the-road operations; industry recommends that this be expanded to all rail operations [50].

Commentary

- AAR president and CEO Edward Hamberger said that there has been no evidence shown that two-person crews are safer; API, on the other hand, supports the regulation (supposedly because accidents look bad for the industry but the energy companies do not control the rail operations) [50].

- Canadian Pacific Railway already operates all its freight trains with two-person crews and is a major carrier of crude oil from the Bakken oil patch to the Port of Albany [49].

Crude Oil Classification

Context

- Proper classification is critical because it ensures that materials are appropriately packaged and that emergency responders know what protocols to follow in the event of an accident.
- All crude oil is classified as hazard Class 3 and then into three packing groups: I, II, and III, with III being the least dangerous [45].
- Recent evidence has shown that "unsafe practices related to the classification and packaging of petroleum crude oil, are causing or otherwise constitute an imminent hazard to the safe transportation of … Petroleum crude oil" (Docket No. DOT-OST-2014-0025) [51].
    - FRA audits revealed that shipments were being classified based solely on material safety data sheets and not on testing the crude itself [51].

Current Policy

- Within DOT, FRA and PHMSA both regulate the rail industry.
    - FRA oversees safety and compliance generally, while PHMSA oversees safety specifically when hazardous materials are involved.
- In February 2014, DOT issued an emergency order that would accomplish the following:
    - Require that crude oil be properly tested with sufficient frequency and quality and classified accordingly
    - Require that crude oil be treated as Packing Group I or II hazardous material
    - Prohibit reclassifying crude oil to circumvent the rules
- API has voluntarily agreed to provide expertise and testing information to FRA regarding Bakken crude, including identifying best practices regarding testing and classification [45].
    - In addition, API pledged to develop a standard for testing, classification, loading, and unloading of crude [45].

Commentary

- There is a need to properly balance packaging requirements with the degree of hazard posed by various materials. Misclassification of materials, whether intentional or not, can result in improper packaging and shipping.
- The Center for Strategic & International Studies suggests that new regulations could require further testing or processing before shipment and says that the industry is expected to release a study of crude oil characteristics at the end of May 2014 [45].

Maximum Achievable Control Technology (MACT I and II) Applied to Refineries

Context

- Emissions come from refineries' operational activities (filling, additive blending, tank cleaning, and degassing); combustion of fuels to generate power, heat, and steam; flue gas; venting; flaring; and fugitive emissions.
- Refinery emissions that cause cancer, birth defects, and respiratory problems include the following:
    - Criteria air pollutants (like sulfur dioxide, carbon monoxide, and particulate matter)
    - Volatile organic compounds (VOCs)
    - Hazardous air pollutants (HAPs)
    - Greenhouse gases (refineries are the second-largest industrial source) and hydrogen sulfide

Current Policy

- Section 112(d) of the Clean Air Act requires the US Environmental Protection Agency (EPA) to set emission standards for HAPs emitted by major stationary sources based on the performance of the maximum achievable control technology (MACT) and to conduct two sets of reviews (followed by updates to the existing standards as necessary):
    - Residual risk assessment, a one-time review to determine whether additional emission reductions are needed to protect human health or the environment
    - Technology reviews, required every eight years to determine whether better emissions control approaches, practices, or processes are available
- EPA is proposing new MACT rules that it says will reduce emissions of BTEX gases (benzene, toluene, ethylbenzenes and xylenes) by 5,600 tons per year and VOCs by 52,000 tons per year, at a cost of about $40 million per year plus a $240 million capital cost. The rules include the following [52]:
    - Adding MACT standards for delayed coking unit decoking operations
    - Revising the catalytic reforming units purge vent pressure exemption
    - Adding operational requirements for flares used as air pollution control devices in Refinery MACT 1 and 2
    - Adding requirements and clarifications for vent control bypasses in Refinery MACT 1

Commentary

- API says companies need a minimum of three years to comply with the new law and predicts that it will cost upwards of $100 million per year. It argues that the high costs do not justify the small emissions reduction potential [53].

New Source Performance Standards for Refinery Flares

Context

- Refinery flares are combustion devices designed to prevent the release of gases to the atmosphere, but incorrect operation can lead to toxic releases, wasted energy, and greenhouse gas emission releases.
    - In addition, flares produce noise and light pollution.

Current Policy

- Section 111(b) of the Clean Air Act requires EPA to periodically review and set emission standards for new sources of criteria air pollutants, VOCs, and other pollutants.
    - EPA's proposed updates to the New Source Performance Standards for refinery flares will reduce HAPs by 3,800 tons per year and VOCs by 33,000 tons per year.
- Current law prohibits visual emissions (except five minutes every two hours), requires a pilot flame to be present, and sets a minimum heat value and a maximum exit velocity.
- In a 2012 consent decree with BP, EPA required use of compressors to divert waste gas from flares back into the plant for use as fuel.
- In other consent decrees, EPA has also required use of "steaming" to improve flare efficiency.

Commentary

- Though small refineries are still being proposed to be built, the rate of new refinery building has been slowing because of slack demand for refined products. Existing refinery operators will be under continuing pressure to reduce HAPS and criteria air pollutants, and refineries are up next for CO_2 controls under Section 111(d) of the Clean Air Act.

Refinery Wastewater

Context

- Wastewater arises from several sources:
    - Tank bottom draining
    - Tanker vehicle cleaning
    - Vapor recovery processes
    - Contaminated stormwater runoff
    - Leaks and spills
- There is potential for contamination of water bodies from wastewater runoff in addition to potential dermal contact and inhalation from spills and leaks.

Current Policy and Best Practice

- EPA currently defines the normal effluent discharge limit as 10 mg/L (average per month; or 15 mg/L daily maximum) for oil and grease by concentration.
- Best practices suggest [54] the following:
    - Oily water should be passed through interceptors to separate some oils and fuels from water
    - Steam and sour water strippers should be used to remove hydrocarbons and ammonia
    - Stripped phenolic sour water should replace fresh water as wash water in desalters
    - Desalter pH should be monitored and stay around 6–7
    - Adequate piping and valves should be used to fully drain tanks
    - Cooling tower blowdown should be routed separately, not through the sewer or directly to the secondary oil/water separation equipment
    - The otal volume of condensate blowdown should be less than 10 percent of total flow of wastewater from refinery

Commentary

- A lack of research makes it difficult to comment on the efficacy of current refinery wastewater operations. However, the current regulations have been in place since the 1970s with apparently very few updates since then, suggesting that it would be prudent to revisit those regulations to determine whether they are still adequate.

Proposed Carbon Pollution Standard for New Power Plants

Context

- In 2012, the electric power sector accounted 38 percent of all US energy-related CO_2 emissions [55].
- Following a Supreme Court ruling in 2009, the US Environmental Protection Agency (EPA) was obligated to promulgate standards restricting levels of CO_2 emissions from new power plants, as well as other sources of CO_2 emissions. EPA elected to address power plant emissions first [56].

Current Policy and Best Practice

- Proposed carbon pollution standards for new and existing power plants fall under Section 111(b) of the Clean Air Act. As noted on the EPA website, "Section 111 (b) is the federal program to address new, modified and reconstructed sources by establishing standards" [57].
- Proposed performance standards for new facilities were released by EPA in April 2012, later withdrawn, and then rereleased on September 20, 2013.
- In the 2013 proposed rule, EPA set separate standards for natural gas-fired turbines and coal-fired units. This represents a key distinction from the original proposed rule.

- Large natural gas–fired plants would be required to use combined cycle technology and limit emissions to 1,000 pounds of CO_2 per megawatt-hour (MWh). Smaller units (used less often) would be required to attain a slightly less stringent standard.
- New coal units would be required to fit carbon capture technology to lower their allowed emissions to 1,000–1,100 pounds of CO_2 per MWh.

Commentary

- EPA's proposed new source rule is expected to be finalized in June 2014 and track the proposed rule closely.
- Carbon capture technology is just now being constructed at commercial scale, and operating performance data are not available.
- Captured carbon dioxide must be stored. Use of captured CO_2 for enhanced oil recovery is one storage option but is limited in magnitude. Regulations, transportation, and social acceptance of large-scale storage have not been developed.
- Given uncertainty about the performance characteristics of capture technology and the equally uncertain state of large-scale storage options, it is likely that the EPA regulations will effectively eliminate all future coal facilities, at least until capture and storage uncertainty is reduced, and accelerate the deployment of new combined cycle gas plants.

Proposed Carbon Pollution Standard for Existing Power Plants

Context

- In 2012, the electric power sector accounted 38 percent of all US energy-related CO_2 emissions [55].
- Following a Supreme Court ruling in 2009 stating that EPA has the authority to regulate CO_2 emissions under the Clean Air Act, EPA began to issue regulations to limit CO_2 from the electric power sector [56].
- EPA first issued regulations for new coal and gas power plants (September 2013) and in June 2014 will issue regulations for existing coal and gas power plants.

Current Policy and Best Practice

- EPA has been developing regulations for CO_2 emissions under Section 111(d) of the Clean Air Act since fall 2013.
- A proposed rule was released June 2, 2014. The timeline given by the Obama administration specifies release of final regulations by June 2015, and receipt of proposed state implementation plans by June 2016 [58].
- The proposed rule requires states to develop implementation plans that in the aggregate will lead to electricity sector reductions in CO_2 emissions of 30 percent by 2030 (from a 2005 baseline). EPA provided each state with a performance standard (pounds of CO_2 per MWh) tailored to the state's generation mix and ability to reduce emissions. The proposed

regulations give the states significant flexibility in implementation and allow for regional cooperation and crediting of existing emissions reductions efforts, including the Northeast's Regional Greenhouse Gas Initiative and California's AB32.

Commentary

- Compared with the CO_2 regulations for new sources, the regulations for existing sources will have a much greater impact on electric utilities, bulk electricity markets, retail electricity prices, the demand for gas, and CO_2 emissions from the sector.
- If EPA issues separate performance standards for coal and gas plants (as it did in the rules for new plants), it will diminish the incentive for coal-to-gas switching and thereby lead to a diminished demand for gas vis-à-vis a rule that sets one performance standard for both coal and gas.
- EPA could give the states considerable flexibility and allow actions beyond the designated source categories (coal and gas) to count toward emission reductions. These "beyond-the-fence line" activities could include energy efficiency and renewables. To the extent these are allowed, they could diminish the demand for gas compared with the case of a single performance standard for coal and gas and no credit for beyond-the-fence-line activities.

Renewable Portfolio Standards (RPS)

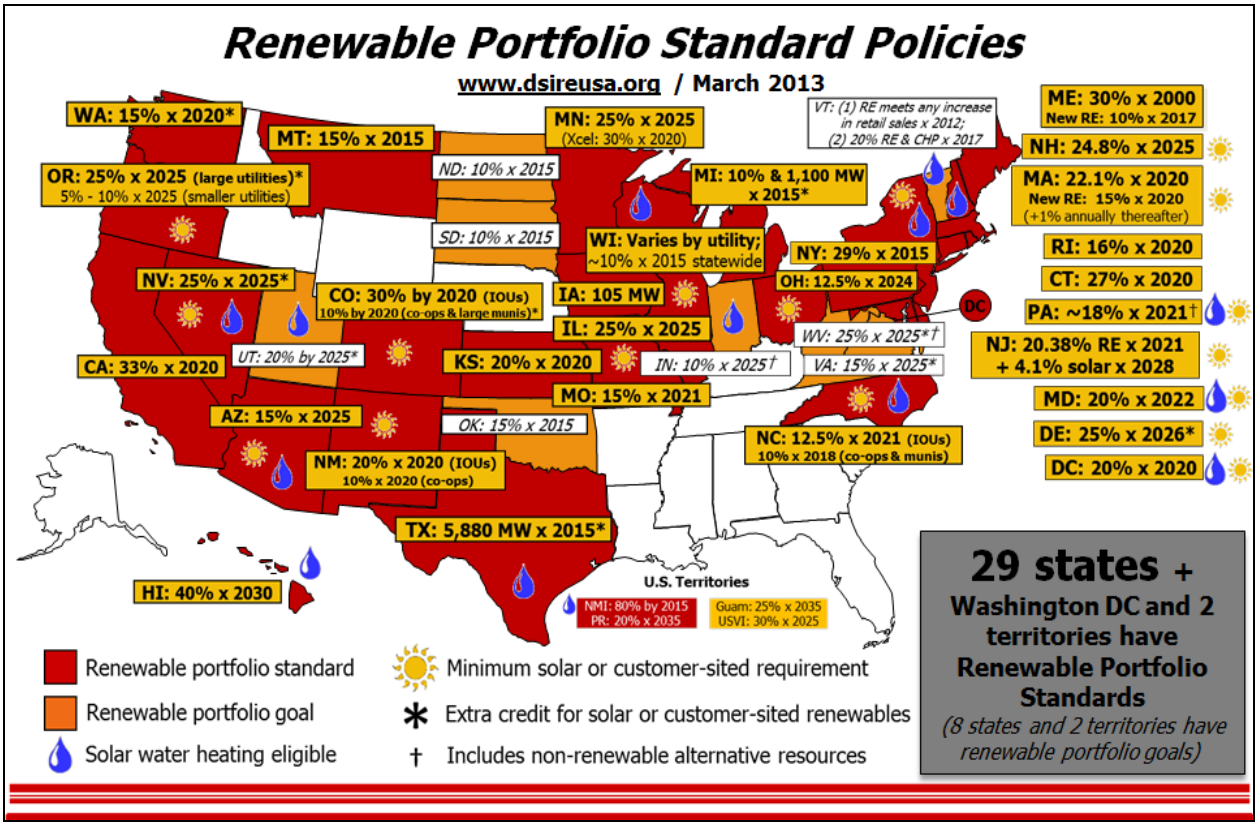
Context

- Twenty-nine states and the District of Columbia have renewable portfolio standards (RPS), which are designed to encourage the deployment of low-carbon electricity generation technologies. See Figure 8.
- The stringency of the RPS in terms of the percentage of generation or percentage of generation capacity from low-carbon technologies varies considerably among the states.
- The generation technologies that are deemed "renewable" under an RPS also vary. For example, nuclear is rarely an eligible technology even though it is carbon free.
- Despite some attempts to develop a federal RPS, no such policies have been adopted.

Current Policy and Best Practice

- States with RPS regulations have seen increases in the percentage of generation from eligible technologies, but so too have states that do not have RPS regulations.
- In many states, RPS requirements are beginning to bind on utilities and thereby forcing them to add more renewable capacity than they would do given market conditions.

Figure 8. Renewable Portfolio Standard Policies



Source: Database of State Incentives for Renewables and Efficiency (DSIRE), http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf

Commentary

- If the motivation behind RPS was reduction in CO_2 emissions, state-level cap-and-trade programs or carbon taxes would be more economically efficient and would also incentivize energy efficiency.
- As RPS regulations begin to bind in many states, they will force utilities to add eligible technologies. In many cases, given market conditions, utilities would rather add gas. Thus binding RPS regulations could mean more gas demand.
- Given binding RPS regulations, eligible technologies could be intermittent and require rapid-cycling gas backup, adding to gas demand.
- The interaction between binding RPS regulations and new regulations developed by EPA for existing coal and gas plants under Section 111(d) of the Clean Air Act is at present unknown.

Regional Greenhouse Gas Initiative and California Global Warming Solutions Act

Context

- As the world's largest historical emitter of greenhouse gases (recently overtaken by China) the United States is under significant pressure from the global community to take the lead on emissions reduction, particularly after having refused to ratify the Kyoto Protocol after signing on in 1998.
- Climate legislation has repeatedly stalled at the federal level; the American Clean Energy and Security Act (Waxman-Markey bill) of 2009 was probably the closest the United States has come to passing federal climate change legislation.

Current Policy

- The Regional Greenhouse Gas Initiative (RGGI) began in 2008 as a partnership among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont (New Jersey subsequently withdrew). It is the first market-based program to reduce greenhouse gas emissions in the United States.
    - The new 2014 cap is 91 million short tons of carbon dioxide (from the power sector) with a scheduled decrease of 2.5 percent each year from 2015 through 2020.
    - Each state has its own budget trading program regulations based on the model rule.
- The California Global Warming Solutions Act (AB 32) was signed into law in 2006 and required the California Air Resources Board (CARB) to develop actions to meet the 2020 emissions reduction goal of 427 million metric tons of (carbon dioxide equivalent) greenhouse gases.
    - In 2011 CARB, adopted a cap-and-trade program covering the largest emitters in the state, including power plants, refineries, industrial facilities, and transportation fuels. The cap was set in 2013 at 2 percent below 2012 emissions, with plans to decrease the cap by 2 percent in 2014 and 3 percent each year from 2015 through 2020.
    - Beginning January 2014, CARB officially linked its cap-and-trade program with the government of Quebec's cap-and-trade system, such that auctions are held jointly and operators can purchase allowances from either system [59].

Commentary

- California's system, seen by many as an example of how to "do it right," is earning the highest carbon price of any cap-and-trade market—$11 per ton—with most of that money being funneled into clean energy projects.
- Learning from the European system, California spent years collecting emissions data before beginning and set a de facto price floor and ceiling to avoid the price volatility experienced in Europe. California has also allowed offset projects as a means of creating credits and has imposed a strict and thus far successful monitoring and enforcement program [60].

- The recent linking with Quebec's cap-and-trade system may set the stage for other such linkages in the future; according to the *New York Times,* California and Europe have both begun discussions of linking their systems with China [60].
- RGGI's performance initially invited skepticism as prices hovered around $2 per ton for several years, but recent data show that the system has effectively reduced emissions and generated more than $1.7 billion for clean energy projects in the nine states. In addition, the recent 45 percent cut to the emissions cap has doubled carbon prices to $4 per ton and is expected to catalyze greater investment in renewable technologies [60].
- June 2014, President Obama is expected to unveil a plan that would require states to reduce their power plant emissions. Analysts expect that plan to encourage states to adopt cap-and-trade systems like California's [60].

Corporate Average Fuel Economy Standards for Light-Duty Vehicles

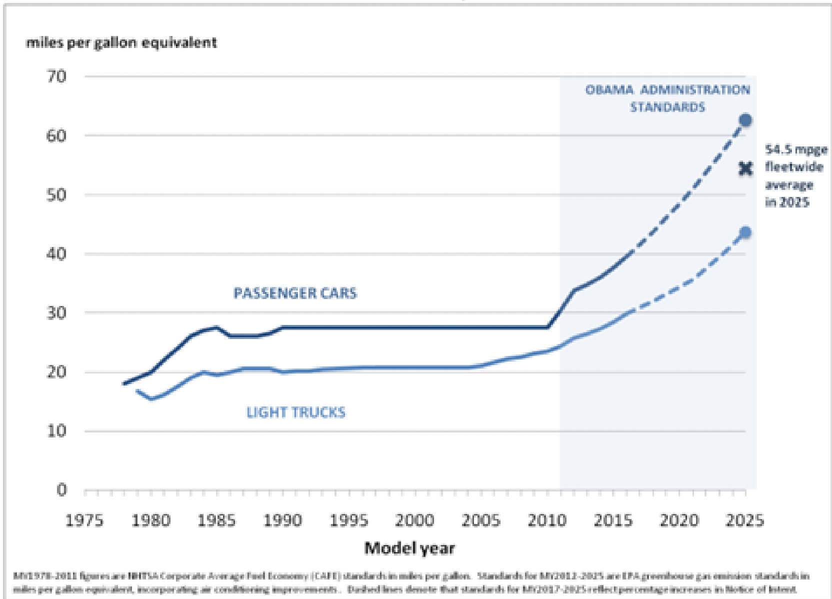
Context

- The United States is home to one-third of the world's automobiles, and 71 percent of all petroleum products (28 percent of total energy) used in the US goes to the transportation sector [61].
- A number of policies and planning decisions affect overall demand for fuel in the transportation sector, but the centerpiece of US efforts to reduce oil use and greenhouse gas (GHG) emissions from the sector are the corporate average fuel economy (CAFE)/GHG emissions rate standards, commonly referred to simply as CAFE standards.

Current Policy and Best Practice

- CAFE standards for light-duty vehicles were first enacted by Congress in 1975 and have stayed constant for more than two decades.
- In 2012, the two lead agencies, EPA and the Department of Transportation's National Highway Safety Administration (NHTSA), set much stricter CAFE standards each year to 2025. (See Figure 9.) Both agencies have committed to conduct a midterm evaluation of the later years of the standards. Specifically, the agencies will complete a technical assessment report of the appropriateness of the 2022–2025 standards by November 15, 2017, and make final decisions based on the evaluation by April 1, 2018.

Figure 9. Light-Duty Vehicle Fuel Economy Standards, 1978–2025



Source: Driving Efficiency: Cutting Costs for Families at the Pump and Slashing Dependence on Oil, http://www.whitehouse.gov/sites/default/files/fuel_economy_report.pdf.

Commentary

Changes in the US population and culture and previous fuel economy regulations are leading to a predicted slowing of passenger vehicle driving increases and reductions in net oil demand, even as trucking ton-miles are on the upswing. Thus, the rationale for improving fuel economy has shifted away from energy security and toward CO_2 emissions reductions.

Many observers expect a battle over this major federal regulatory effort, with the vehicle manufacturing sector saying the standards will be too expensive and the agencies (EPA and NHTSA) defending them on grounds of air quality, CO_2, and energy security benefits, as well as fuel cost savings. RFF researchers have noted numerous questions [62] to be answered about consumer and manufacturer responses to the regulations and how the costs and benefits should be estimated before these issues can be decided.

Phase II Fuel Efficiency/GHG Emissions Standards for Heavy-Duty Trucks

Context

- The first ever (Phase I) CAFE/GHG emissions standards for heavy-duty trucks were finalized in 2011 for implementation through 2016, when Phase II regulations are to be approved. The trucking industry worked closely with EPA and NHTSA to define what was reasonable during Phase I.
- Work at EPA and RFF shows that these standards will not be very costly, although the benefits depend heavily on how estimated fuel savings are calculated, just as for light-duty vehicles [63].
- With diesel currently making up 98 percent of truck fuel, meeting these standards will reduce oil use by 530 million barrels and CO_2 emissions by 270 million metric tons [63].
- With natural gas so cheap, it is making inroads into the trucking sector. Its penetration will depend on several facets of government policy, including how this fuel is treated in the Phase I and II regulations.

Current Policy and Best Practice

- The Phase I regulations will have relatively minor effects on the trucking sector and demand for oil and natural gas.
- The Phase I regulations credited natural gas with CO_2 emissions reductions but based this on volume, not on energy content, which would have given natural gas more credit. The natural gas industry wants this provision changed.
- Truck manufacturers have been innovating and selling trucks fueled by liquefied natural gas (LNG), in some cases without government subsidies; for trash trucks in particular, LNG has captured the new-truck market.
- Some natural gas operating companies and LNG providers, along with Clean Fuels, Inc., have partnered to help solve the "chicken and egg" problem by building LNG refueling stations on the interstate network and LNG corridors in various parts of the country in advance of truck sales to support this investment.

Commentary

- The Phase II truck standards, coming in 2016, are expected to be much more costly than those in Phase I because the "easy" fuel economy improvements have already been accomplished.
- Flexibility in the application of these standards, such as implementation of a trading program, would help keep costs in check.
- For making confident decisions about how tight the standards should be, policymakers need research on why this industry has been so reluctant to purchase more fuel-efficient trucks, given engineering estimates of their fuel savings and rapid payback periods.

Renewable Fuel Standard

Context

- Before the shale gas and tight oil revolutions, energy security concerns loomed large in the United States. Against this backdrop, in 2005 the federal government enacted a renewable fuel standard that mandates that specific quantities of renewable fuels (on a percentage basis) be blended into gasoline—and later, diesel—by certain years. The types of fuels covered by the renewable fuel standard (RFS) include cellulosic biofuels, biomass-based diesel, and advanced biofuels. EPA qualified something as a renewable fuel if its life-cycle greenhouse gas emissions reductions were at least 20 percent lower than the baseline petroleum fuel it would replace. The agency continues to update its life-cycle analyses.

Current Policy

- The original RFS program (RFS1) was created under the Energy Policy Act of 2005 and later expanded under the Energy Independence and Security Act (EISA) of 2007. This second iteration (RFS2) was finalized by EPA in 2010.
- Among other changes, RFS2 covered diesel as well as gasoline. It also revised upward the quantities of renewable fuels required, starting at 9 billion gallons in 2008 and growing to 36 billion gallons by 2022.
- Each year, EPA must evaluate whether the mandated amounts included in EISA are, in fact, achievable. In particular, "If the projected available volume of cellulosic biofuel is less than the required volume specified in the statute, EPA must lower the required volume used to set the annual cellulosic biofuel percentage standard to the projected available volume. EPA must also determine whether the advanced biofuel and/or total renewable fuel volumes should be reduced by the same or a lesser amount" [64].
    - This guidance for any given year must be released by EPA by November 30 of the preceding year.

Commentary

- The biofuels program has proven to be a disappointment and serves as a warning that mandating market changes doesn't necessarily make it so. Cellulosic biofuels production has consistently been insufficient to meet the program's goals for renewable fuels. Most recently, EPA again reset the yearly target to equal production to avoid levying fines on refineries for fuel that was not actually available for blending with gasoline and diesel.
- One related event was elimination of the ethanol subsidy where it is used to blend with gasoline in the summer. Most economists found this subsidy to be unjustified on economic efficiency grounds. Some observers pointed to the rise in corn and related food prices, as well as Midwest agricultural land prices, as unfortunate consequences of this policy.

- Finally, a Congressional Research Service report notes that “considerable uncertainty remains regarding the development of the infrastructure capacity (e.g., trucks, pipelines, pumps, etc.) needed to deliver the expanding biofuels mandate to consumers” [65].

LNG Export Terminal Siting

Context

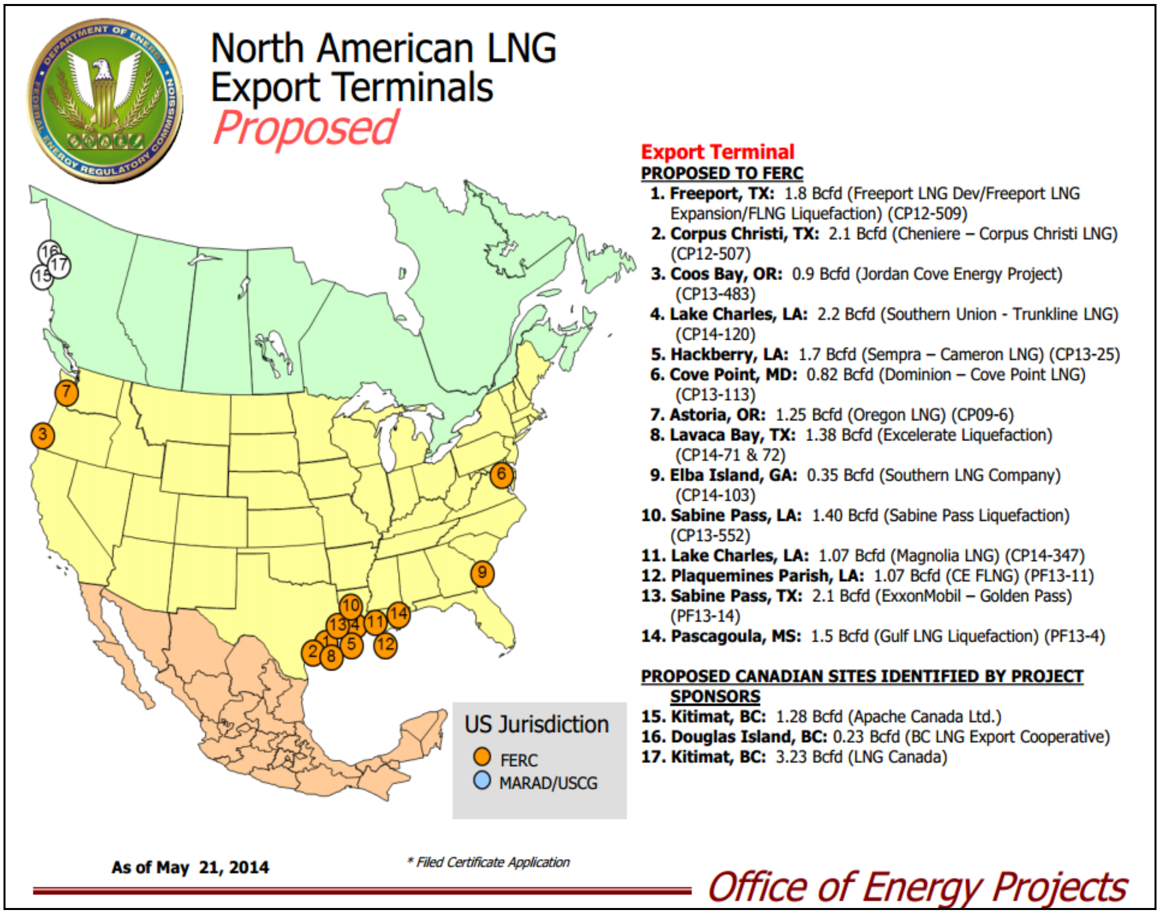
- As of April 2014, the US Department of Energy had received 43 requests for permits to export liquefied natural gas (LNG) in the lower 48 states. [66]
- If these permits are granted, companies must request separate permits to construct and/or operate LNG export terminals, requiring an extensive environmental impact statement (EIS).
- LNG export terminal siting permits for onshore facilities are issued by the Federal Energy Regulatory Commission (FERC). FERC’s authority to issue such permits is captured in Section 3 of the Natural Gas Act, although that was only codified as part of revisions under the Energy Policy Act of 2005.
- An important issue is whether the proposed site is a brownfield (basically a repurposing of an existing LNG import terminal, such as that for Cove Point, Maryland) or a greenfield.

Current Policy and Best Practice

13 requests for siting permits have currently been proposed to FERC (see Figure 10 below). Only Sabine Pass, on the Gulf coast, has been fully approved, with construction well underway.

- Criticisms of the current permitting process include the length of time needed to secure a permit, as well as the cost of completing regulatory requirements. A memorandum from the Congressional Research Service, for example, notes that the FERC approval for the Sabine Pass LNG export terminal took 441 days from application filing [67].
- The memorandum also estimates that “once a company enters the filing phase, there will be more significant costs associated with the required documentation, estimated to be approximately $100 million for engineering reports, environmental analysis, market studies, and other application requirements.”

Figure 10. North American LNG Export Terminals, Proposed



Source: Federal Energy Regulatory Commission, http://www.ferc.gov/industries/gas/indus-act/lng.asp

Commentary

- There may be a relatively short time frame in which the US gas industry can profitably sell LNG to Asian and other markets. Thus, delays in approval are more relevant.
- The EIS process for these approvals has become wrapped in the environmental movement to "keep fossil fuels in the ground." In at least one sense, this is unfortunate because in many cases, the carbon footprint of exported gas that substitutes for coal is probably smaller.
- One such case is Cove Point in Maryland, which is selling LNG to India. This suggests that net CO_2 benefits world-wide should be a component of the EIS.
- The above-noted distinction between greenfield and brownfield plants (the latter being repurposed from import terminals for LNG) should matter for the EIS as well, with a streamlined process for brownfields.

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