THE UNSEEN COSTS OF NATURAL GAS-GENERATED ELECTRICITY

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THE UNSEEN COSTS OF NATURAL GAS-GENERATED ELECTRICITY

“In the economic sphere an act, a habit, an institution, a law produces not only one effect, but a series of effects. Of these effects, the first alone is immediate; it appears simultaneously with its cause; it is seen. The other effects emerge only subsequently; they are not seen; we are fortunate if we foresee them.” -- Frederic Bastiat, 1848

EXECUTIVE SUMMARY

This report identifies and analyzes both explicit and implicit factors that influence the cost of producing electricity from natural gas. Implicit and explicit cost factors include both costs to retail electricity consumers as well as the indirect expenses paid by taxpayers to finance government interventions in the electricity market. Although this report does not estimate an actual value for the cost of producing electricity from natural gas, it examines the factors that policymakers should consider when making decisions about energy policy.

This report begins by discussing the explicit, or seen costs of natural gas-generated electricity. These costs include components such as power plant development and construction, operation & maintenance, and transmission infrastructure expenses. The report then explores the implicit costs of electricity generated from natural gas, which stem from social costs, government subsidies, mandates, and regulations. Government intervention distorts the electricity market, but the implicit costs of subsidies, mandates, and regulations are often overlooked. As such, implicit costs are the primary focus of this report.

A key contributor to increasing the implicit costs of natural gas is government intervention in the electricity market. Federal and state policies distort the cost of natural gas electricity by transferring wealth and market share to natural gas electricity producers and by imposing costly regulations on natural gas electricity producers. Both policies that encourage natural gas development and those that discourage it distort energy markets, ultimately forcing consumers to pay more for electricity than they otherwise would and often increasing the burden on US taxpayers.

Today, much of the regulation of natural gas production in the US occurs at the state level. Some states have even gone so far as to enact state-wide bans on hydraulic fracturing, a key production technology for the industry. These policies increase the cost of natural gas-generated electricity by restricting supply and preventing local communities located near shale gas resources from taking advantage of the economic benefits of producing natural gas. States have also enacted impact fees and severances taxes in an effort to counteract the heavy wear on roads caused by traffic related to natural gas production. These policies should also be considered an unseen cost of natural gas-generated electricity.
Government support and impediments increase the unseen costs of natural gas-generated electricity by preventing the market from efficiently allocating resources. These policies burden US taxpayers and electricity consumers with unwanted costs, and discourage innovation in energy technology. The importance of low energy costs to a healthy economy make it a crucial policy goal. If US policymakers were to leave financial resources to market forces instead of attempting to anticipate America’s energy needs, taxpayers and electricity consumers alike would benefit.

**NATURAL GAS IN THE U.S. ENERGY MARKET**

Natural gas-generated electricity is produced primarily through two methods: combined cycle and combustion turbine. Combined cycle plants heat natural gas and combine it with compressed air. The mixture moves through a gas turbine to generate energy. Exhaust heat is captured and used to generate steam in a boiler, and the steam powers a turbine, generating additional electricity.¹

Similarly, combustion turbine technology generates electricity by pumping compressed air into a chamber that is heated by burning natural gas. As the air heats up, it expands and is directed to a turbine. The heated air spins the turbine blades, which in turn spin the electric generator.²

Though coal still generates the largest percentage of electricity of any energy source, its market share of total US electricity is falling, while electricity produced from natural gas has been increasing since the early 2000’s.³ In the 25 years prior to 2004, natural gas increased its share of electricity production by just over 2 percent. From 2004 to 2014, widespread implementation of horizontal drilling and hydraulic fracturing allowed electricity production from natural gas to grow by 9.5 percentage points, reaching 27.4 percent of total US electricity production.⁴ Figure 1 shows natural gas and coal as a percentage of total US generation from 1949 to 2014.⁵

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Natural gas has become a major player in the US electricity market despite receiving fewer subsidies than many sources of energy. In 2013, natural gas generated 28 percent of US electricity, but received only four percent of federal subsidies for electricity generation. In contrast, wind power received 37 percent of federal subsidies, but generated only 4.1 percent of total US electricity.\(^7\)

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METHODS OF NATURAL GAS EXTRACTION

New technology has driven the growth of natural gas. Hydraulic fracturing, or fracking, is a technology that cracks open geological formations to extract fossil fuels. The most commonly drilled source is shale, a sedimentary rock layer that often contains deposits of natural gas. Shale rock layers, called shale plays, are usually hundreds of miles wide and are located several thousand feet underground. To release natural gas, a high-pressure mixture of water, sand, and chemicals is injected through concrete wells, fracturing the shale. These fractures allow trapped natural gas to flow out of the rock and into wells, where it can be collected and transported for consumer use.9

Despite common beliefs that hydraulic fracturing is a new practice, it actually has a long history of use and development in the United States. Earlier forms of the technology have been in use since 1865.10 Hydraulic fracturing did not make natural gas competitive with coal until producers paired hydraulic fracturing with horizontal drilling in the 1980s.11 A horizontal drill enters vertically into the earth until it approaches the shale rock layer. Once the drill reaches the shale rock layer, it then rotates roughly 90 degrees and continues until the desired length is drilled. The advantage of horizontal drilling over vertical drilling is that it allows producers to drill multiple horizontal shafts into the shale rock from a single vertical well.12

Due to improvements in hydraulic fracturing methods, seismic imaging technology, and other aspects of shale production, energy producers are able to access far more oil and natural gas than they could before at a lower production cost.13 The Energy Information Administration (EIA) estimates that the addition of shale gas and shale oil

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8 Energy Information Administration (EIA). 2015, March. “Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013.” Pg. xix and xxi. Retrieved from: http://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf. The data for this chart were taken from Table ES4 and Table ES5. The numbers may not sum to 100 percent because of independent rounding.
has increased attainable U.S. reserves by 38 percent and world reserves by 47 percent over previous estimates.\textsuperscript{14} Catherine Hausman and Ryan Kellogg, from the University of Michigan, estimate that the boom in natural gas supply “lowered wholesale prices [of natural gas] by $3.45 per [thousand cubic feet].”\textsuperscript{15} As the price of natural gas drops to be competitive with coal prices, natural gas continues to gain market share.

**EXPLICIT (SEEN) COST FACTORS**

There are four main explicit cost factors for producing electricity from natural gas. Capital costs and operations and maintenance (O&M) costs are the two largest cost components of natural gas. The third is natural gas’ capacity factor, which is a measurement of how much electricity a natural gas plant generates as a percentage of its theoretical maximum annual output capability.\textsuperscript{16} Finally, the cost of electricity generated from natural gas is also affected by transmission costs. To understand these factors, the overall explicit cost of electricity, also known as the levelized cost of electricity, must be understood.

**LEVELIZED COST OF ELECTRICITY**

A common metric for comparing the cost of electricity from different technologies and fuels is the levelized cost of electricity (LCOE). The LCOE is the cost of “building and operating a generating plant over an assumed financial life and duty cycle” and includes capital costs, operations and maintenance costs, and transmission investment costs.\textsuperscript{17} These costs are distributed over the estimated lifetime of an energy plant and are related in terms of dollars per megawatt-hour.\textsuperscript{18} Of the major studies on the cost of electricity, the most commonly referenced study is the Energy Information Administration’s (EIA) *Annual Energy Outlook*. The EIA estimates the LCOE of new combined cycle natural gas at $75.2 per megawatt-hour, and the more efficient advanced combined cycle at $72.6 per megawatt-hour (2013 $/MWh), making it one of the cheapest available options for energy production from newly constructed power plants.\textsuperscript{19} Advanced combustion turbine technology, estimated at $113.5 per megawatt-hour, is used mainly to meet short-term peak demand.\textsuperscript{20} Table 1 presents the EIA’s estimated LCOE for natural gas, coal, wind, and solar.

\textsuperscript{16} The capacity factor used in calculating cost estimates has a strong effect on how affordable a given energy technology appears to be.
\textsuperscript{20} U.S. Energy Information Administration. 2013, October 1. “Natural gas-fired combustion turbines are generally used to meet peak electricity load.” Retrieved from: http://www.eia.gov/todayinenergy/detail.cfm?id=13191
The Unseen Costs of Natural Gas-Generated Electricity

Table 1: EIA Annual Energy Outlook 2015

<table>
<thead>
<tr>
<th>Source</th>
<th>LCOE ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advanced Combined Cycle (Natural Gas)</td>
<td>72.6</td>
</tr>
<tr>
<td>Advanced Combustion Turbine (Natural Gas)</td>
<td>113.5</td>
</tr>
<tr>
<td>Coal</td>
<td>95.1</td>
</tr>
<tr>
<td>Wind</td>
<td>73.6</td>
</tr>
<tr>
<td>Solar PV</td>
<td>125.3</td>
</tr>
</tbody>
</table>

The EIA approach to estimating energy costs has different goals than this study. The EIA estimates the cost of producing electricity from various sources in the future, and assumes government interventions in the energy market. This report, on the other hand, seeks to identify factors involved in the cost of generating electricity from natural gas. Policymakers should be concerned with both present and future costs, and how their policies will affect those costs. These factors should include the market-distorting effects of government intervention in the energy market and the cost of these policies borne by taxpayers and electricity consumers.

Electricity production from dispatchable sources, such as coal and natural gas, can be scaled up or down to meet demand. Production from non-dispatchable energy sources, such as wind and solar, cannot be increased relative to demand. Therefore, as the EIA notes in the AEO report, the levelized costs of dispatchable and non-dispatchable technologies are not directly comparable.

Wind and solar cannot increase production of electricity on demand because optimal sunlight and wind are not consistently available nor are they controllable. If the transmission system is not fed with a steady and controllable supply of electricity, instability can occur. To avoid electricity shortages, there must be enough dispatchable power plants, like natural gas, to provide electricity to cover shortages left by solar and wind energy.

The LCOE does not accurately portray the distorting effects of most subsidies. Subsidies do not reduce costs, but simply transfer part of the cost of energy production from producers to taxpayers. Government support to the energy industry may lower production costs, but it Increases the cost of energy to society by increasing the taxpayer burden and raising electricity rates.

George Taylor and Thomas Stacy’s IER report The Levelized Cost of Electricity from Existing Energy Resources (2015) investigates another aspect of the EIA’s method of calculating electricity cost. The EIA estimates the cost of electricity from new power plants coming on line five years into the future, but does not compare the cost of electricity from prospective new power plants to the cost of generating electricity from existing resources.

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22 As “Advanced Combustion Turbine”
23 The EIA notes in the AEO report that the LCOE for fossil fuels (dispatchable sources) cannot be directly compared with the LCOE for non-dispatchable sources like wind and solar.
24 The levelized fixed costs assigned to non-dispatchable technologies are not 1:1 substitutes for the levelized fixed cost of dispatchable technologies. Rather, the more non-dispatchable electricity that is produced, the higher the levelized fixed cost of the dispatchable sources from which the non-dispatchable sources derive market share. U.S. Energy Information Administration. 2015, June 3. “Annual Energy Outlook 2015: Levelized cost and levelized avoided cost of new generation resources in the Annual Energy Outlook 2015.” Retrieved from: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm
EIA’s predictive estimates are misleading when used as justification for policies dictating subsidies or mandates for renewables because they ignore the fact that generating electricity from existing plants is much cheaper than electricity from any new source. Stacy and Taylor find the cost of electricity from existing combined cycle generation is $24.5 per megawatt-hour cheaper than the EIA estimate for new combined cycle generation. Stacy and Taylor also find the cost of electricity from existing combustion turbine generation to be $219.3 per megawatt-hour cheaper than the EIA estimate for new combustion turbine generation at equivalent real world capacity factors.\(^\text{26}\)

**CAPITAL COSTS**

The capital costs of natural gas plants are the costs paid by the producer to bring a plant to commercially active status. These costs include the cost of purchasing the land to build the plant, the cost of obtaining building permits, the cost of connecting to the transmission system, and the cost of building the plant itself.\(^\text{27}\) The levelized capital cost for natural gas is fairly low, at $15.9 per megawatt-hour for combined cycle and $27.8 per megawatt-hour for combustion turbine, as seen below in Table 2.\(^\text{28}\) The capital cost in dollars per megawatt-hour is obtained by taking the total capital cost and dividing that by the amount of electricity, in megawatt-hours, that the plant is expected to produce over a lifespan of thirty years.

**Table 2: EIA capital costs\(^\text{29}\)**

<table>
<thead>
<tr>
<th></th>
<th>(Natural Gas) Advanced Combined Cycle</th>
<th>(Natural Gas) Combustion Turbine</th>
<th>Coal</th>
<th>Wind</th>
<th>Solar PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital costs (2013 $/MWh)</td>
<td>15.9</td>
<td>27.8</td>
<td>60.4</td>
<td>57.7</td>
<td>109.8</td>
</tr>
</tbody>
</table>

**OPERATIONS & MAINTENANCE COSTS**

Operations and maintenance (O&M) costs are split into fixed and variable costs. Annual fixed O&M expenses are expenses unaffected by how much energy is produced. Fixed O&M costs are primarily made up of scheduled upkeep and maintenance costs and the cost of full-time employees. Both combined cycle and combustion turbines have low levelized fixed O&M costs, at $2.0 per megawatt-hour for combined cycle (at 87 percent capacity factor) and $2.7 per megawatt-hour for combustion turbine (at 30 percent capacity factor) according to the EIA.\(^\text{30}\)

Variable O&M costs vary annually depending on how much energy is produced. Likewise, levelized variable costs only change if the cost of a variable input (such as fuel cost) changes. Conventional power plants have high variable O&M when compared to renewable energies with no fuel costs. The EIA’s estimates for natural gas’s variable O&M costs

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are $53.6 per megawatt-hour for advanced combined cycle and are higher than variable O&M for coal at $29.4 per megawatt-hour. Low capital costs and decreasing fuel costs, however, make investment in new combined cycle gas facilities more attractive than investment in new coal plants in most locations and therefore increase the competitiveness of natural gas-generated electricity. Table 3 shows both fixed and variable O&M costs estimated by the EIA.

Table 3: EIA operations & maintenance costs

<table>
<thead>
<tr>
<th></th>
<th>(Natural Gas) Advanced Combined Cycle</th>
<th>(Natural Gas) Combustion Turbine</th>
<th>Coal</th>
<th>Wind</th>
<th>Solar PV</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fixed O&amp;M</strong></td>
<td>2.0</td>
<td>2.7</td>
<td>4.2</td>
<td>12.8</td>
<td>11.4</td>
</tr>
<tr>
<td>(2013 $/MWh)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Variable O&amp;M</strong></td>
<td>53.6</td>
<td>79.6</td>
<td>29.4</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>(2013 $/MWh)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**CAPACITY FACTOR**

The capacity factor of a power plant is its annual utilization rate, which is a measurement of how much electricity the plant generates in a year as a percentage of how much electricity it would generate if it could run at full capacity for the entire year. In its AEO report, the EIA notes that the “LCOE values [for wind and solar] are not directly comparable to [the LCOE estimates] for other technologies (even where the average annual capacity factor may be similar).” The technologies cannot be directly compared because the capacity factor of dispatchable technologies can be operator controlled while the capacity factor of wind and solar is outside the realm of human control (i.e., the wind doesn’t blow, blows too forcefully or not at all; sunlight is blocked by clouds or is unavailable at night). Table 4 shows the capacity factor of natural gas combined cycle, natural gas combustion turbine, coal, wind, and solar technologies.

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34 As “Advanced Combustion Turbine”
35 U.S. Energy Information Administration. n.d. “Glossary.” Retrieved from:http://www.eia.gov/tools/glossary/index.cfm?id=C. The capacity factor used in calculating cost estimates has a strong effect on how affordable a given energy technology appears to be. For example, say the levelized fixed costs of a power plant are calculated to be $30 per MWh at a 90 percent capacity factor. If the plant utilization rate turns out to be only half of what was projected—resulting in a capacity factor of 45 percent—the levelized fixed cost doubles to $60 per MWh. Counterintuitively, levelized variable costs do not vary with capacity factor but levelized fixed costs vary inversely with change in capacity factor.
Table 4: EIA Theoretical Maximum Capacity Factors

<table>
<thead>
<tr>
<th>Energy Source</th>
<th>Combined Cycle</th>
<th>Combustion Turbine</th>
<th>Coal</th>
<th>Wind</th>
<th>Photovoltaic Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity Factor (%)</td>
<td>87</td>
<td>30</td>
<td>85</td>
<td>36</td>
<td>25</td>
</tr>
</tbody>
</table>

To estimate the LCOE of different energy sources, the EIA uses theoretical maximum estimates of capacity factors. Combined cycle natural gas energy’s capacity factor is one of the highest among electricity-generating technologies, with estimates falling around 87 percent. As a baseload energy provider with a high capacity factor, that means that a high level of reliable electricity can be produced for an extended period of time.

The EIA estimates combustion turbine natural gas’ capacity factor at 30 percent. Because of their quick ramping ability, high levelized variable cost, and resulting lower capacity factor, combustion turbine natural gas is primarily used as a peaking power source when electricity demand is highest or to quickly replace a large power plant that goes offline unexpectedly.

Stacy and Taylor caution that the capacity factors used by EIA to calculate levelized fixed costs of new generating resources are far higher than have been historically achieved from a given energy technology. Table 5 compares actual recorded capacity factors to those used by the EIA in LCOE calculations.
Table 5: Real-World vs. EIA Theoretical Maximum Capacity Factors

<table>
<thead>
<tr>
<th></th>
<th>Average Capacity Factors for Existing Resources</th>
<th>Best-Case Capacity Factor from EIA LCOE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Cycle Gas</td>
<td>47.8</td>
<td>87</td>
</tr>
<tr>
<td>Combustion Turbine Gas</td>
<td>4.8</td>
<td>30</td>
</tr>
<tr>
<td>Conventional Coal</td>
<td>60.9</td>
<td>85</td>
</tr>
<tr>
<td>Wind</td>
<td>33.9</td>
<td>35</td>
</tr>
</tbody>
</table>

TRANSMISSION COSTS

Many fossil fuel power plants minimize transmission costs by building near existing power lines and centers of electricity demand. Renewable resources like wind and solar, however, tend to be most plentiful in remote locations far from population centers. As Table 6 shows, the EIA estimates transmission costs for combined cycle natural gas at $1.2 per megawatt-hour, significantly lower than wind or solar power.

Table 6: EIA Transmission Costs

<table>
<thead>
<tr>
<th></th>
<th>Combined Cycle</th>
<th>Combustion Turbine</th>
<th>Coal</th>
<th>Wind</th>
<th>Solar PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>$/MWh</td>
<td>1.2</td>
<td>3.5</td>
<td>1.2</td>
<td>3.1</td>
<td>4.1</td>
</tr>
</tbody>
</table>

IMPLICIT (UNSEEN) COSTS FACTORS

In analyzing all of the costs of natural gas, implicit costs must also be considered. Though often more difficult to quantify than explicit costs like O&M, implicit costs help provide a more complete estimate of the cost of natural gas-generated electricity. These costs include less apparent factors driving the cost of natural gas, such as the costs of

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46 Utility scale solar.
complying with state and federal regulations for natural gas extraction, delivery, and natural gas-fired power plant emissions.

Modern energy policy favors renewable sources of electricity like wind and solar over conventional sources such as coal and natural gas. Appendix A provides an overview of U.S. tax incentives across the energy sector. Our analysis here focuses on the most influential policies that affect natural gas producers today. We analyze the most impactful of both federal and state policies in the following sections.

**FEDERAL NATURAL GAS POLICIES**

Federal natural gas policies affect the cost of natural gas-generated electricity by distorting the energy market. These policies include both regulations and subsidies. In this section, we identify some of the reasons these policies are enacted as well as their effects on the cost of natural gas-generated electricity paid by both electricity consumers and taxpayers.

The federal government has regulated the natural gas industry since the early 1900s when interstate pipelines were built to transport natural gas across municipal and state borders. Some federal regulations were enacted to correct problems created by previous legislation. Price ceilings instituted in 1954, for example, led to nationwide natural gas shortages in the 1970s. As a response, Congress passed the Natural Gas Policy Act (NGPA) in 1978, which began the process of deregulating natural gas prices.47

The Federal Energy Regulatory Commission (FERC) is the main federal agency that oversees the natural gas industry.48 In addition to regulating interstate sales, FERC oversees interstate natural gas transportation including pipeline construction and environmental matters, and the enforcement of regulatory requirements.49

Although the natural gas industry has grown rapidly, with a 64 percent increase in the number of wells fracked from 2011 to 2014, delays in acquiring permits for natural gas pipelines present significant regulatory hurdles that increase the cost of natural gas.50 A 2013 report by the Government Accountability Office (GAO) found that, on average, the time from pre-filing to certification for natural gas pipelines was 558 days (18.6 months). Projects that chose to skip pre-filing, the process where a company alerts relevant stakeholders to the company’s plans and provides a forum for discussion, and began at the application phase had to wait an average of 225 days (7.5 months) to be reviewed.51 The process of acquiring a permit can increase the transportation costs of natural gas and adversely affect the economy by preventing producers from building new pipelines quickly enough to keep pace with production.

The regulatory burden of complying with pipeline permitting requirements represents another unseen cost of natural gas-generated electricity. According to Jason Thomas, managing director of the Carlyle Group, when an additional permitting delay of a year and a half is added to a project, the internal rate of return declines by 36 percent.52 While

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48 Ibid.
proper precautions are necessary for public safety, these permitting delays can transform an attractive investment opportunity into an undesirable option for investors if it does not meet minimum return specifications.

Delays and postponements increase costs for producers, which in turn increases the cost of natural gas-generated electricity for consumers. Excess delays prevent pipelines from transporting the natural gas being produced. Such delays constrict the natural gas supply, which can lead to supply shortages and increased prices. Consumers in New England experienced these impacts first-hand when, during the winter of 2014, natural gas shortages, and other causal factors like the polar vortex, contributed to a 20-fold increase in natural gas prices according to a Forbes report.53

Oil and natural gas companies are also required to pay federal royalties for the extraction of oil and gas on public lands. These federal royalties, however, have not increased at the same rate as similar fees charged for the use of state lands. The onshore oil and gas royalty rate on US public lands, according to the Center for Western Priorities, has not been updated in almost 100 years. Outdated royalty rates, the Center reports, cost taxpayers between $490 million and $730 million in annual revenue and increase the burden on US taxpayers who must bear the costs of upgrading and repairing transportation infrastructure worn out during the extraction process.54

SOCIAL AND ENVIRONMENTAL COSTS

One of the key justifications for government intervention in the electricity market is to address social and environmental costs. An accurate estimate of the cost of producing electricity should include health and environmental costs imposed on society that are not borne by producers or consumers, often known as externalities. Social and environmental costs include potential health problems that power plants create for the nearby population, negative effects of energy production on the environment, and effects on global climate change.

Analysts have attempted to price carbon emissions based on their social and environmental effects. Estimates for the proper tax on carbon emissions vary widely—from $5 to more than $100 per ton—while estimates for the damages caused by carbon dioxide range from $5 to $35 per ton.55

The high degree of uncertainty involved in the calculation of social and environmental costs of carbon makes them difficult to precisely quantify. Economist Robert Pindyck, a professor at the Massachusetts Institute of Technology, notes that economists have attempted to quantify the social cost of carbon by developing integrated assessment models. Pindyck notes, “these models have crucial flaws that make them close to useless as tools for policy analysis.”56 The difficulty and imprecision of quantifying the cost, however, does not imply that there is no cost, just that we do not know what that cost is.57

CARBON CAPTURE AND STORAGE TECHNOLOGY

One method electricity producers can use to reduce carbon emissions is carbon capture and storage technology (CCS), which the EPA estimates could reduce emissions from fossil fuel burning power plants by 80 to 90 percent.58
plants and industrial users of natural gas can capture carbon dioxide, transport it to a storage site, and store it deep underground so that it is not released into the atmosphere.

Adapting a natural gas power plant to meet carbon-capture goals is an expensive process. According to the EIA, CCS increases costs by $27.6 per megawatt-hour.59 Generation capacity is required to run CCS technology. The extra demand can reduce output of power plants by up to 30 percent.60 Table 7 shows the EIA’s estimates for the increased costs of carbon capture and storage technology applied to natural gas combined cycle generation.

Table 7: Natural Gas LCOE61

<table>
<thead>
<tr>
<th></th>
<th>Total LCOE</th>
<th>Capital</th>
<th>Fixed</th>
<th>Variable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Cycle</td>
<td>72.6</td>
<td>15.9</td>
<td>2.0</td>
<td>53.6</td>
</tr>
<tr>
<td>Combined Cycle with Carbon Capture and Storage</td>
<td>100.2</td>
<td>30.1</td>
<td>4.2</td>
<td>64.7</td>
</tr>
<tr>
<td>Increase due to Carbon Capture and Storage</td>
<td>27.6</td>
<td>14.2</td>
<td>2.2</td>
<td>11.1</td>
</tr>
</tbody>
</table>

THE CLEAN POWER PLAN

In 2009, the EPA determined that regulating carbon dioxide emissions was necessary to protect human health and the environment. According to the EPA, “unchecked carbon pollution leads to long-lasting changes in our climate... [that] threaten America’s health and welfare for current and future generations.”62 The agency also claims that threats from carbon dioxide-induced climate change will include heat waves, drought, smog, extreme weather events, and an increase in the range of disease-spreading ticks and mosquitos.63

Under the authority of Section 111(d) of the Clean Air Act (CAA), in August 2015 the EPA established carbon emission standards for power plants, which emit 32 percent of total U.S. greenhouse gas emissions.64 The EPA’s new regulation,

http://www.epa.gov/climatechange/ccs/#ref1
64 Environmental Protection Agency (EPA). 2015, August 3. “Learn About Carbon Pollution From Power Plants.” Retrieved from:
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Known as the Clean Power Plan (CPP), requires states to reduce carbon emissions to 32 percent below 2005 levels by 2030.65

Predicting the economic effects of the Clean Power Plan is difficult and estimates vary. A U.S. Chamber of Commerce analysis of the draft CPP, as proposed by the EPA in June 2014, concluded that the CPP may “suppress average annual U.S. [GDP] by $51 billion and lead to an average of 224,000 fewer U.S. jobs every year through 2030.”66 A study of the finalized CPP, as announced by the EPA on August 3, 2015, by the Electric Reliability Council of Texas concluded that “energy costs for customers may increase by up to 16 percent by 2030 due to the CPP alone, without accounting for the associated costs [that will result from compliance with the CPP].”67 The EPA estimates, however, predict that the CPP will result in “net benefits of $26-$45 billion.”68 The wide range in findings of these studies demonstrate the high level of uncertainty regarding what the economic effects of the CPP will actually be.

Although the CPP focuses mainly on coal, it will have an impact on the energy sector that reaches much further than coal power alone. The plan calls for a switch to natural gas and renewable energy sources in order to cover the loss of production from reducing the amount of coal-generated electricity.69 A NERA study of the draft CPP, as announced in June 2014, estimated that the increased demand for natural gas caused by the CPP will increase nationwide consumption from 6 to 64 percent.70 The EIA also estimated the increased demand for natural gas in a report released in May 2015 using an analysis from the Annual Energy Outlook 2015. The EIA estimates that by 2030, which is the EPA’s target year of compliance with the CPP, the share of total electricity generation from natural gas may increase between 5 and 23 percent from 2010 generation levels.71 Growth in demand for natural gas will require increases in or realignment of transportation infrastructure.72 By altering the energy market and artificially increasing the demand for natural gas, the CPP creates unseen costs that should be considered in the actual cost of natural gas-generated electricity.

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70 NERA Economic Consulting. 2014, October. “Potential Energy Impacts of the EPA Proposed Clean Power Plan.” Pg. 23. Retrieved from: http://www.nera.com/content/dam/nera/publications/2014/NERA_ACCCE_CPP_Final_10.17.2014.pdf. Note that this estimate is based on the proposed CPP, which had a Best System of Emissions Reduction (BSER) determined by four building blocks. The final version of the CPP eliminated the fourth building block (energy efficiency) and retained blocks one through three (improved heat rate for coal plants, increased natural gas use, and increased renewable energy use).
71 Energy Information Administration (EIA). 2015, May 27. “Under the proposed clean power plan, natural gas, then renewables, gain generation share.” Retrieved from: http://www.eia.gov/todayinenergy/detail.cfm?id=21392. These numbers were obtained from the second graph on the web page, using the Clean Power Plan Base Policy as the 5% increase from 2010 generation percentages and the CPP + High Oil and Gas Resource estimates as the 23% increase.
METHANE EMISSIONS

The EPA has also released new standards for regulating methane emissions from well sites as well as small leaks in the transmission and distribution pipeline systems.\textsuperscript{73} These new standards will impact the cost of generating electricity from natural gas. Natural gas is made of methane gas, a hydrocarbon that is more than 20 times more potent a greenhouse gas than carbon dioxide.\textsuperscript{74} Natural gas and petroleum systems in the United States account for 29 percent of methane emissions produced nationwide from 1990 to 2013, making natural gas the largest source of methane emissions in the United States. Total methane emissions, however, fell by 15 percent during that same 23-year period. Further, during those 23 years “emissions decreased from sources associated with the exploration and production of natural gas and petroleum products.”\textsuperscript{75} Figure 3 displays the largest contributors to methane emissions in 2013.

Two weeks after unveiling the CPP, the EPA announced new standards of methane regulation. The new standards are intended to help the Obama administration reach its goal of reducing methane emissions by at least 40 percent of 2012 levels by 2025.\textsuperscript{77} The EPA estimates that it will cost $150 to $170 million in 2020 and $320 to $420 million in 2025 to...

\textsuperscript{73} U.S. Environmental Protection Agency (EPA). 2015, November 5. “Oil and Natural Gas Air Pollution Standards.” Retrieved from: http://www3.epa.gov/airquality/oilandgas/
\textsuperscript{77} Environmental Protection Agency (EPA). 2015, August 18. “EPA Proposes New Commonsense Measures to Cut Methane Emissions from the Oil and Gas Sector/Proposal Cuts GHG Emissions, Reduces Smog-Forming Air Pollution and Provides Certainty for Industry.” Retrieved from: http://yosemite.epa.gov/opa/admpress.nsf/bd4379a92ceceea8525735900400c27/e5f2425e2e668a2b85257ea5005176fa1OpenDocument
comply with these new standards. While the EPA does claim the standards will have a positive net benefit for the climate, these standards will also have real compliance costs that will likely be passed on to consumers.  

Some companies in the natural gas industry have already voluntarily implemented technology to reduce methane emissions, as lost methane reduces profitability. In fact, methane emissions from hydraulically fractured wells have been reduced by 79 percent since 2005. Lost methane is lost fuel, and the EPA notes that a portion of these reductions in methane emissions have resulted from voluntary implementation of new technologies by the natural gas industry.

**FEDERAL SUPPORT**

The federal government provides various forms of financial support for the natural gas industry. Support generally takes one of two forms: tax expenditures, which reduce the amount of taxes an organization or individual pays; and direct expenditures, which include direct cash payments to energy producers and consumers, support given to the natural gas industry in the form of loans and loan guarantees, electricity production subsidies, and funding for research and development.

Historically, fossil fuels have been the largest beneficiaries of federal energy incentives. The federal government spent $837 billion dollars, as measured in 2010 dollars, to subsidize energy between 1950 and 2010. Of that sum, fossil fuels claimed 70 percent, or 594 billion dollars. Natural gas received 14 percent of all federal energy incentives over the same time period, totaling approximately 121 billion dollars. The majority of the incentives were preferential tax policies. Since 2005, however, renewable energy technology has been heavily favored by the federal government and support for fossil fuels, including natural gas, has stayed roughly constant. While many renewable energy subsidies have expirations, and are not permanent, most subsidies for fossil fuels are permanent and do not have to be renewed by Congress.

The three largest forms of federal support for the natural gas industry from 1950 to 2010 included preferential tax policy (87.6 percent), research and development (5.8 percent), and exemptions from regulations, as well as regulations that cost the federal government tax dollars to enforce, but are not recouped through fees charged to the regulated energy producer (3.3 percent). Table 7 breaks down the forms of federal support for the natural gas industry from 1950 to 2010. Market activity and government services each make up only 1.7 percent of the total federal support. Market activity, as defined by the Management Information Services, Inc., encompasses the "planning, leasing, and resource development.

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management” done by the Bureau of Land Management. Government services are defined as federal support like roads, ports, and inland waterways.\textsuperscript{87}

Table 8: Form of Federal Expenditures for Natural Gas from 1950 to 2010\textsuperscript{88}

<table>
<thead>
<tr>
<th>Type of Federal Support for Natural Gas</th>
<th>Tax Policy</th>
<th>Research and Development</th>
<th>Regulation</th>
<th>Market Activity</th>
<th>Government Services</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage of Total Support for Natural Gas from 1950-2010</td>
<td>87.6%</td>
<td>5.8%</td>
<td>3.3%</td>
<td>1.7%</td>
<td>1.7%</td>
</tr>
</tbody>
</table>

**TAX EXPENDITURES**

Preferential tax policies made up about 87 percent of the federal expenditures for natural gas, compared to almost 60 percent for renewables and 33 percent for coal.\textsuperscript{89}

Tax deductions lessen a company’s tax burden by reducing the amount they must pay if they meet specific standards. Deductions allow companies to retain possession of a larger portion of their profits, creating a net revenue loss for the government but imposing no immediate burden on taxpayers. This presents an unseen cost because preferential tax deductions for one energy source distort the market by encouraging the use of the sources favored and made artificially cheap by the unequal tax policy. As Figure 4 shows, the natural gas industry receives an overwhelming share of its total subsidies in the form of tax expenditures.\textsuperscript{90}


As Figure 5 shows, preferential tax policies favored fossil fuels heavily until 2008, when tax preferences shifted in favor of renewables. According to the EIA, tax expenditures for natural gas and petroleum fell from $2.7 billion in 2010 to $2.3 billion in 2013. In addition, the Department of Energy’s budget for fiscal year 2015 rescinded tax policies worth more than four billion dollars per year that had previously gone to all fossil fuels producers, not only natural gas and petroleum.

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In fiscal year 2013, natural gas and petroleum liquids received a total of $2.346 billion in subsidies and support. Of that sum, $2.25 billion—or about 96 percent of the subsidies and support—was from tax expenditures. The Obama Administration calculates that repealing tax preferences for oil and natural gas in the 2016 budget proposal would decrease the federal deficit by $26.2 billion between 2016 and 2020 and $45.5 billion from 2016 to 2025. Of course, such estimates assume that producers will not engage in other tax-avoiding behavior.

**DIRECT EXPENDITURES, LOAN GUARANTEES, AND R&D**

The EIA defines direct expenditures as "federal programs that provide direct cash outlays which provide a financial benefit to producers or consumers of energy." Table 9 displays federal support in fiscal years 2010 and 2013 by the type of support.

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Table 9: Types of Federal Support for Natural Gas and Petroleum Liquids in Fiscal Years 2010 and 2013 (million 2013 dollars)\textsuperscript{99}

<table>
<thead>
<tr>
<th>Fiscal Year</th>
<th>Direct Expenditures</th>
<th>Tax Expenditures</th>
<th>Research and Development</th>
<th>Federal and RUS Electricity Support</th>
<th>Total (million 2013 dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>$80</td>
<td>$2,752</td>
<td>$9</td>
<td>$77</td>
<td>$2,918</td>
</tr>
<tr>
<td>2013</td>
<td>$62</td>
<td>$2,250</td>
<td>$34</td>
<td>-</td>
<td>$2,346</td>
</tr>
</tbody>
</table>

As Table 9 shows, federal spending on direct expenditures for natural gas and petroleum products decreased by 18 million dollars from 2010 to 2013.\textsuperscript{100} Spending on research and development, however, increased from $9 million to $34 million over the same period.\textsuperscript{101} In 2010, the U.S. Department of Agriculture’s Rural Utilities Service provided $77 million in loan guarantees and loans to the natural gas and petroleum liquids industries.\textsuperscript{102}

Together, producers of electricity from natural gas and petroleum liquids received four percent of total electricity production subsidies and support from the federal government in 2013, a total of around $690 million. Tax expenditures make up about 96 percent of the federal support, or about $662 million of the total $690 million.\textsuperscript{103} In 2013, the only electricity producers that received less federal support than natural gas and petroleum liquids were geothermal, biomass, and hydropower. Wind and solar received the greatest support at 37 and 27 percent, respectively. Coal, with six percent, received more support than natural gas.\textsuperscript{104} Table 10 displays the percentage of federal support for major sources of electricity.


The Unseen Costs of Natural Gas-Generated Electricity
Table 10: Federal Support and Subsidies for Electricity Production by Source in Fiscal Year 2013

<table>
<thead>
<tr>
<th>Fuel Source</th>
<th>Fossil Fuels (10%)</th>
<th>Renewables (72%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Coal</td>
<td>Natural Gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>and Petroleum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Liquids</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Nuclear</td>
</tr>
<tr>
<td></td>
<td>Biomass</td>
<td>Geothermal</td>
</tr>
<tr>
<td></td>
<td>Hydropower</td>
<td>Solar</td>
</tr>
<tr>
<td></td>
<td>Wind</td>
<td>Other</td>
</tr>
<tr>
<td>Percentage</td>
<td>6%</td>
<td>4%</td>
</tr>
<tr>
<td>of total f</td>
<td>10%</td>
<td>1%</td>
</tr>
<tr>
<td>federal support</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>received in FY 2013</td>
<td>27%</td>
<td>37%</td>
</tr>
<tr>
<td></td>
<td>4%</td>
<td></td>
</tr>
</tbody>
</table>

THE UNSEEN COSTS OF FEDERAL ENERGY POLICY

Market distortions caused by federal support for electricity production from natural gas are smaller than other energy sources, like wind and solar, because relatively less federal support exists. In free markets, the production of natural gas, and the electricity generated by natural gas, is determined by the laws of supply and demand. Prices convey information to consumers about the affordability of electricity, and tell suppliers there is profit to be made by producing it with natural gas. Government intervention, in terms of financial support for the natural gas industry, distort the proper market signals that producers and consumers rely on to determine efficient allocation of resources.

A 2013 study from the International Monetary Fund (IMF) suggests that energy subsidies impose substantial costs on consumers. For example, energy subsidies for natural gas discourage private investment in renewable energy technologies, and cause resource misallocation throughout the economy. Further, the IMF concludes there are substantial negative externalities caused by energy subsidies because they facilitate the overconsumption and overproduction of the energy products they incentivize. According to the IMF’s calculations, there could also be significant health benefits if fossil fuel energy prices truly reflected supply and demand rather than being kept artificially low by subsidies. These gains would occur due the accompanying decrease in emissions of SO2 and other pollutants as the higher cost of fossil fuels directs individuals to alternative fuel sources and lower consumption.

Other forms of support, like loan guarantee programs, also create poor incentives because developers do not bear the financial burden if the investments fail. Loan guarantees encourage moral hazard, where individuals engage in riskier

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The Unseen Costs of Natural Gas-Generated Electricity
behavior than they otherwise would because they know they are insulated from loss. These moral hazards, and the extra risks they entail, represent an unseen cost of federal support for the natural gas industry.

The federal government has enacted large subsidies for renewable energy to encourage the use of resources like wind and solar. Regardless of which type of energy receives subsidies, federal interference distorts the energy market. Whether aimed at fossil fuels or renewables, federal support incentivizes production of one energy resource over others and misallocates resources. Instead of resources being used by the individuals who value them the most, they are assigned to private interests via the political system.

**STATE NATURAL GAS POLICIES**

In addition to federal policies, the cost of natural gas-generated electricity is also impacted by state-level regulations, mandates, and other policies. As a result of the growth in hydraulic fracturing since the early 2000s, state officials are taking steps to increase regulation of the industry. In some states, like New York, policymakers have enacted statewide hydraulic fracturing bans. Other states, like Texas, have outlawed local hydraulic fracturing bans, ensuring continued natural gas production. Most states, however, employ more moderate policies like natural gas residential programs, hydraulic fracturing disclosure laws, impact fees, and severance taxes. These policies, which are examined in the following section, affect the costs of electricity paid by taxpayers and ratepayers.

**STATE REGULATION OF HYDRAULIC FRACTURING**

Federal legislation has removed many federal regulatory standards for natural gas producers, leaving the regulation of hydraulic fracturing largely to the states. The 2005 Energy Policy Act eliminated federal oversight of hydraulic fracturing under the Safe Water Drinking Act of 1974 and amended the Clean Water Act to exempt oil and gas construction from runoff regulations. The 2005 Energy Policy Act also exempted gas drilling from many regulatory standards created by the National Environmental Policy Act (NEPA) and the Clean Air Act. Despite these federal exemptions, with hydraulic fracturing at the forefront of many environmental and economic debates, states have taken a number of different approaches to regulating the fracking industry. These policies have had various economic impacts on natural gas production, from booming growth in Texas to outright bans in New York.

The recent growth in hydraulic fracturing has led to significant economic benefits in the United States. A study published by the Brookings Institute in March 2015 provided estimates of the wide-scale impact hydraulic fracturing has had on the economy. The report estimates that the boom in natural gas production from hydraulic fracturing has caused the price of natural gas across the U.S. to fall 47 percent below what it would have otherwise been in 2013. Brookings estimates that translates to a $13 billion per year decrease in the overall price of residential gas bills from 2007 to 2013. Brookings also found that over that same period, increased production from hydraulic fracturing increased consumer welfare by $74 billion because of lower natural gas prices. The decreased price of natural gas did lower producer surplus by $26 billion, but that still translates to a net benefit of $48 billion, or about $150 per capita. This

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number, as the authors stress, ignores possible environmental damages.\textsuperscript{113} Another report from Reuters found that, since 2008, the natural gas boom increased US Gross Domestic Product (GDP) from manufacturing by 15 percent. In 2013 alone, the natural gas industry brought in $2.08 trillion for the U.S. manufacturing sector.\textsuperscript{114}

While many economic benefits are already being realized from the shale boom, the environmental impacts of hydraulic fracturing are still difficult to measure and heavily debated. One major environmental concern with hydraulic fracturing is the storage and disposal of wastewater. Each time a well is fracked, between one and five million gallons of water are used.\textsuperscript{115} Disposing of wastewater can be difficult because municipal and private water treatment facilities are not always capable of treating wastewater properly.\textsuperscript{116}

Natural gas producers have turned to other methods of wastewater disposal. One of the most common methods of water disposal involves injecting water into disposal wells deep underground. This practice, however, may lubricate faults and create tremors.\textsuperscript{117} For example, areas in Oklahoma have experienced an increase in geological activity that scientists are attributing not to hydraulic fracturing, but to improper wastewater disposal practices.\textsuperscript{118} For now, improvements to wastewater recycling and green completion technology, which captures gas and fluids from wells during post-drilling operations, can provide alternatives to using disposal wells to get rid of hydraulic fracturing wastewater.\textsuperscript{119}

Some have also raised concerns that hydraulic fracturing can lead to groundwater contamination. For example, one study by a researcher at Duke University “found methane in 115 of 141 shallow, residential drinking-water wells” and higher concentrations of methane in homes that were within a mile of a fracking well than those more than a mile away.\textsuperscript{120} In response to these concerns, the EPA conducted an investigation of the widespread effects of hydraulic fracturing on drinking water resources. The findings of the draft study, which were released in June 2015, stated:

“From our assessment, we conclude there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. These mechanisms include water withdrawals in times of, or in areas with, low water availability; spills of hydraulic fracturing fluids and produced water; fracturing directly into underground drinking water resources; below ground migration of liquids and gases; and inadequate treatment and discharge of wastewater. We did not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States.”


The EPA went on to state that “the number of identified cases where drinking water resources were impacted are small relative to the number of hydraulically fractured wells.”

Thirty-three states produced natural gas in 2014 with Texas, Pennsylvania, Louisiana, Oklahoma, and Wyoming as the top producers. Many of these states sit above shale gas reserves. The largest reserves include the Marcellus shale play in parts of New York, Pennsylvania, Ohio, and West Virginia, the Haynesville in Louisiana, and the Barnett in Texas. Recent growth in hydraulic fracturing in many of these areas has prompted varying levels of regulatory responses from state governments.

Three states have banned hydraulic fracturing altogether, but 31 states have considered legislation to create bans. Policymakers in Vermont and New York have enacted statewide bans on hydraulic fracturing. Maryland has enacted a ban that lasts until 2017 at which time the state’s environmental agency is to have designed appropriate rules to govern fracking. In 2012, Vermont’s Governor Peter Shumlin signed the first statewide hydraulic fracturing ban into law. At the time, however, Vermont had no natural gas drilling projects or underground reserves. The governor announced the law as a measure to protect Vermont’s groundwater against the possibility of the discovery of shale gas in Vermont.

Because Vermont does not produce natural gas, and because Vermont is the second smallest consumer of natural gas in the United States, the ban is not likely to have an effect on gas and electricity prices within the state. It did, however, affect natural gas policies in other states by placing political pressure on other state policymakers, especially New York, to enact their own bans.

In June of 2015, the New York Department of Environmental Conservation released its conclusions following a seven-year review of the health effects of hydraulic fracturing. The review, titled the State Environmental Quality Review Findings Statement, concluded that hydraulic fracturing should be banned until the impacts of hydraulic fracturing can be sufficiently determined through research. New York policymakers responded by enacting a statewide hydraulic fracturing ban, despite the fact that natural gas supplies the majority of New York’s electricity.

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Due to New York’s reliance on natural gas, and unless demand for electricity suddenly falls, the ban will force state energy suppliers to either increase the production and importation of electricity from other energy sources or increase imports of natural gas from other states.\(^{130}\) Imports will likely be more expensive than natural gas produced in the state because of the increased transportation costs associated with bringing natural gas from other states rather than producing it locally. Higher costs for producers ultimately means higher energy prices for consumers.

The ban also prevents New York citizens from profiting on resources held on their privately-owned land. Towns in upstate New York are upset over the announced ban because they live on the Marcellus Shale play where drilling operations would provide job opportunities and economic development for the area.\(^{131}\)

Maryland’s legislators, much like New York and Vermont, have also resisted the growth of hydraulic fracturing along the Marcellus shale play. In May of 2015, as a response to residents’ fears that hydraulic fracturing would hurt tourism, farming, and water systems, Maryland policymakers enacted a temporary ban on hydraulic fracturing which expires in October of 2017. The same legislation requires the Maryland Department of Environment to adopt regulations for hydraulic fracturing in preparation for future natural gas production.\(^{132}\) This legislative action came following the recommendation of Maryland environmental officials that “shale gas drilling be allowed using best practices, following a three-year review of potential risks.”\(^{133}\) If Maryland policymakers allow hydraulic fracturing in the future, the incorporation of strict regulations from the state Department of Environment may still discourage gas companies from drilling in Maryland.\(^{134}\)

Policymakers in Texas have taken a different approach to managing hydraulic fracturing by limiting the authority of local governments to ban hydraulic fracturing. In 2015, Texas’s legislators gave themselves sole regulatory authority over the oil and gas industry to prevent patchwork regulation from being created.\(^{135}\) Patchwork regulation can discourage industry development by creating uncertainty for producers and increasing the time and effort necessary to comply with a variety of different regulatory standards across a state.\(^{136}\) Forbidding local governments from regulating fracking, however, does not mean natural gas producers can drill anywhere they like. Natural gas developers are still required to make arrangements with city officials to drill within city borders.\(^{137}\)

Texas accounts for one-seventh of the United States’ natural gas consumption and relies heavily on natural gas as a fuel source.\(^{138}\) Hydraulic fracturing bans would necessitate large volume imports of natural gas and inevitable price increases if the ban forces Texas to increase energy procurements from other states.\(^{139}\) Due to New York’s reliance on natural gas, and unless demand for electricity suddenly falls, the ban will force state energy suppliers to either increase the production and importation of electricity from other energy sources or increase imports of natural gas from other states.\(^{130}\) Imports will likely be more expensive than natural gas produced in the state because of the increased transportation costs associated with bringing natural gas from other states rather than producing it locally. Higher costs for producers ultimately means higher energy prices for consumers.


\(^{136}\) Miller, Craig. 2015, January 2. Interior Secretary: Local Fracking Bans Are Wrong Way To Go. KQED, Science. Retrieved from: http://www2.kqed.org/science/2015/01/02/interior-secretary-local-fracking-bans-are-wrong-way-to-go/


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jumps for Texas consumers. Texas’s policy preventing bans on fracking helps prevent these price fluctuations and the added costs of natural gas shortages and transportation costs.

Following Texas policymakers’ example, Oklahoma legislators passed a law that limits local regulation of hydraulic fracturing to areas such as traffic, noise, and odors, but prohibits local authorities from banning hydraulic fracturing outright. Governor Mary Fallin introduced the bill as a means to avoid a situation of legislative patchwork bans, saying that such regulatory patchwork “could arbitrarily ban exploration and damage the state’s largest industry, largest employers and largest taxpayers.” Limiting local authority to ban hydraulic fracturing eliminates uncertainty for producers and allows unhampered production, which keeps prices low for consumers.

HYDRAULIC FRACTURING DISCLOSURE LAWS

Many people who oppose hydraulic fracturing fear the environmental impacts of chemicals used in the hydraulic fracturing process. Hydraulic fracturing disclosure laws are enacted to address this concern by requiring that each well operator publically disclose information about the chemical composition and volume of hydraulic fracturing fluid used. Of the thirty-three states that produce natural gas, 29 had enacted chemical disclosure laws and two were considering disclosure requirements as of April 2015, as Figure 6 shows. Chemicals generally constitute 0.5-2 percent of hydraulic fracturing fluids. Because disclosure laws require that each company’s fluid composition is public knowledge, disclosure laws are intended to hold producers accountable for any environmental damage that may occur.

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The Railroad Commission of Texas estimated that compliance with the law would add costs of $50 to 100 per well.\textsuperscript{145} Compared to the total cost of a new well undergoing hydraulic fracturing, which can cost about $8 million, or the cost of re-fracking, which is about $2 million, these compliance costs are relatively low.\textsuperscript{146}

More controversial than these compliance costs is the requirement that producers disclose the chemical makeup of their fracking fluids, which are often considered trade secrets.\textsuperscript{147} Disclosure requirements must be balanced with trade secret exemptions and patents.\textsuperscript{148} Applying for an exemption is sometimes costly. According to the Texas Registry, applying for a trade secret protection can cost between $1,000 and $5,000.\textsuperscript{149} In addition, state attorney generals may

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure6}
\caption{Map of states requiring chemical disclosure}\textsuperscript{144}
\end{figure}

\begin{flushright}
\textsuperscript{145} Texas Secretary of State. Texas Register. 2011, September. Texas Register. Volume 36, Number 36, Pg. 5767. Retrieved from: http://texashistory.unt.edu/ark:/67531/metapth190847/m1/14/?q=disclosure
\textsuperscript{149} Texas Secretary of State. 2011, September. Texas Register. Volume 36, Number 36, Pg. 5768. Retrieved from: http://texashistory.unt.edu/ark:/67531/metapth190847/m1/15/?q=trade%20secret%20$1,000
\end{flushright}
contest exemptions, forcing producers to pay for costly legal defense. An appeal of the decision to grant trade secret protection can cost from $5,000 to $25,000.150

Fracking disclosure laws may increase the cost of producing natural gas, and those increased costs are likely passed on to consumers. The public access to information, however, may be worth the investment because consumers can better keep the companies in check by holding them responsible for any environmental damages they cause by fracking.

NATURAL GAS RESIDENTIAL PROGRAMS

In 1996, state and local policymakers began implementing natural gas residential programs—also known as customer choice or unbundling programs.151 These policies enable residents and small commercial gas consumers to buy natural gas from providers other than their utility companies, allowing for more competitive pricing in the industry. As of 2009, twenty-one states had customer choice programs in at least the pilot stages.152

Consumer savings have increased in many states with customer choice programs. According to a 1999 General Accounting Office survey, consumers in Ohio were already reporting savings from 3-30 percent in gas prices, depending on their supplier and location.153 Pennsylvania consumers reported average savings of 8 percent compared to gas costs with the traditional utility company.154

Customer choice programs weaken the monopolies held by utility companies, increasing competition, and driving down electricity prices. By increasing the number of available suppliers—even marginally—customer choice programs facilitate a more competitive natural gas market. Customer choice programs encourage natural gas production and decrease the cost of natural gas-generated electricity for consumers.

SEVERANCE TAXES AND IMPACT FEES

Although natural gas production likely has net economic benefits, it also imposes costs on the local communities where it occurs in the form of noise pollution and wear and tear on roads. In order for natural gas production to occur, massive amounts of water and heavy machinery are moved in and out of production sites using large trucks. These trucks wear down roadways, decreasing their useful lifecycle and increasing costs for road maintenance and repair.

A study conducted by RAND Corporation researchers and published by Carnegie Mellon University estimated the costs of heavy truck traffic on Pennsylvania roads caused by shale gas production in the Marcellus Shale region. The study found that for 2011 alone, the costs of heavy truck traffic on all state roads ranged from $13,000 to $23,000 per well.155 Policymakers have enacted both severance taxes and impact fees in an effort to make up for these unintended consequences of natural gas production.

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150 Texas Secretary of State. 2011, September. Texas Register. Volume 36, Number 36, Pg. 5768. Retrieved from: http://texashistory.unt.edu/ark:/67531/metaph190847/m1/15/?q=trade%20secret%20$1,000
To address increased wear on roads and the forfeiture of natural resources, states impose taxes on natural gas production. These taxes are known as severance taxes because they apply to the removal or “severance” of a nonrenewable resource. The type and scope of severance taxes varies from state to state, with some taxes based on the volume of gas produced, some on the value of the natural gas extracted, and some using a mixture of the two. Natural gas production occurs in thirty-two states. Of those, only New York, Pennsylvania, and Maryland do not have a severance tax in place.

In place of a severance tax, Pennsylvania uses an impact fee to recoup some of the unintended costs of natural gas production. Pennsylvania’s impact fee is tied to the average annual price of natural gas. In 2015, discussions between Pennsylvania Governor Tom Wolf and the state legislature about replacing the impact fee with a severance tax are ongoing. If enacted, the severance tax would increase the rate natural gas producers pay to the highest of any natural gas producing state. This would increase the cost of producing natural gas in the Pennsylvania, and potentially make the state less competitive for natural gas production. A report by Timothy Considine, a professor of energy economics at the University of Wyoming, estimates the impacts of Pennsylvania’s proposed severance tax. Considine estimates the severance tax would lead to an estimated loss of 18,000 jobs over ten years due to reduced productivity for the natural gas sector.

RENEWABLE PORTFOLIO STANDARDS

One of the most common state policies for encouraging renewable energy use is known as Renewable Portfolio Standards (RPS). These programs mandate that a specific percentage of a state’s electricity be generated from renewables by a given date. Twenty-nine states, the District of Columbia, and three territories have adopted RPS. Eight states and one territory have renewable portfolio goals, which are not mandatory. Figure 7 shows US states with RPS in place.
RPS have succeeded in increasing renewable energy use, but they have also increased unemployment, slowed job growth, and increased electricity prices. A recent study by the Institute for Political Economy at Utah State University found that North Carolina’s RPS resulted in 23,769 foregone jobs and $3,870 of foregone household income per family in 2013 alone. Likewise, the effect of RPS on Ohio was a loss of 29,366 jobs and a loss of $3,842 per household. The study found no evidence of a net increase in job production or a net savings in income per household as a result of RPS in any of the states examined.

Renewable Portfolio Standards can also lead to higher electricity prices because they require the use of more expensive renewables instead of conventional sources of electricity. In 2010, the Institute for Energy Research (IER) found that states with RPS had electricity rates 38 percent higher than states without. A 2012 study by the Manhattan Institute found “a pattern of mostly higher costs in states with RPS mandates,” in which 8 out of 10 states with the highest electricity rates had RPS in place. The report is clear, however, that RPS requirements are not the only reason for rising prices, but that the standards play a role in increasing prices. Although these studies fall short of proving causation, the theory is intuitive: mandating the use of more expensive sources of energy will increase the cost of electricity.

Using renewables is cost-effective in some locations. For example, in 2013 Idaho generated 58 percent of its net electricity from hydropower while enjoying the fourth lowest electricity rates in the nation.\textsuperscript{168} Though Idaho does not have an RPS, the state still illustrates that there are certainly cases where renewables make economic sense. Areas with abundant renewable resources may find economical uses of renewable energy, but places that do not are unable to take advantage of renewables in an economically feasible way. Unique conditions exist where renewables are the most economical option, but they are not the norm. Not all places have exploitable renewable resources. Thus, blanket laws enacted without regard to the specific capabilities of states may increase electricity rates.

**STATE ENERGY POLICY AND THE IMPLICIT COSTS OF NATURAL GAS**

The state-level regulatory environment for natural gas is highly varied. The unseen costs of natural gas are affected by interactions between the availability of in-state natural gas, public perception, and regulation, especially of fracking. Outright hydraulic fracturing bans in states like Vermont, New York, and Maryland increase the unseen cost of natural gas by preventing profitable development of natural resources and requiring additional transportation expenses. Prohibiting local bans on hydraulic fracturing, as Texas and Oklahoma have done, avoids limiting beneficial expansions in the natural gas market, which reduces the cost to consumers of natural gas. Removing regulatory burdens and costs on producers would reduce the unseen cost of natural gas for consumers and encourage more natural gas production.

**KEY FINDINGS**

Natural gas is quickly becoming a dominant source of electricity production in the US due to innovation in extraction technology, as well as regulation of coal—natural gas' main competitor. Today, natural gas still enjoys a relatively favorable regulatory environment at the federal level, however, both federal- and state-level regulation of natural gas is increasing. These policies are often enacted without consideration of the negative economic consequences they will have on American taxpayers and electricity consumers. The implicit, or unseen, costs of policies meant to encourage and discourage production of electricity from natural gas must be included in the cost of natural gas energy.

- Federal support for natural gas, mostly in the form of preferential tax policy, distorts the energy market. Direct expenditures and preferential tax policies cost billions of dollars in estimated federal revenue losses and increase the burden on US taxpayers.
- Natural gas produces about half as much CO2 emissions as coal, but produces methane, which has a greenhouse gas effect 20 times stronger than CO2. The EPA has announced new emissions limits for methane, adding compliance costs that will likely be passed on to consumers.
- In response to fears about environmental impacts, states have enacted bans on hydraulic fracturing that prevent economic growth in communities with natural gas resources.
- State policies that restrict or even prevent natural gas production altogether raise the burden on taxpayers, while states that allow more customer choice have lower gas prices and more competitive natural gas markets.
- Long permitting processes for natural gas pipelines prevent producers from building new pipelines quickly enough to keep pace with production, restricting supply and increasing the cost of electricity generated from natural gas.

CONCLUSION

Natural gas is one of the least expensive and most reliable methods of generating electricity today. Federal and state policies are enacted to both incentivize and disincentivize natural gas. Government support and impediments increase the unseen costs of natural gas-generated electricity by preventing the market from efficiently allocating resources. These policies burden U.S. taxpayers and electricity consumers with unwanted costs, and discourage innovation in energy technology. Further, because electricity costs are vital for a vibrant economy it is critical that policies foster low cost electricity. If US policymakers were to leave financial resources to market forces instead of attempting to anticipate America’s energy needs, taxpayers and electricity consumers alike would benefit.
APPENDIX A:
COMPARATIVE ANALYSIS OF TAX CODE PROVISIONS RELATED TO ENERGY PRODUCTION
By: Jonathan E. Jenkins, JD, LLM

1. ABSTRACT
This note aggregates sections of the Internal Revenue Code and comparative studies of federal tax policy towards energy production, and answers the question about whether tax policy treats equally all sources of energy production (coal, oil, natural gas, wind, solar, etc.). Tax policy does not treat all energy sources equally, but instead, during the past ten years, federal tax policy has shifted to give greater tax preferences to renewable energy sources over fossil fuels. Congressional Budget Office (CBO) estimates show significantly more tax expenditures for renewable energy than for fossil fuels during the years 2008-2011, by ratio of approximately four to five times greater. A graph prepared by the CBO illustrates the estimated tax expenditures/preference by the type of fuel or technology (see the CBO graph attached at the end of this note as Exhibit A).

2. BRIEF HISTORY OF TAX INCENTIVES FOR ENERGY PRODUCTION
"The Internal Revenue Code (I.R.C.) has been intimately linked to tax subsidies for investment, development, and production of American energy sources for much of this nation's history. The same year that Congress adopted the federal income tax in 1913, it also passed legislation permitting oil companies to receive a subsidy for depleting an oil-based resource."170

"In contrast to the first traditional energy tax subsidies in 1913, Congress passed the first renewable energy tax credits in 1978,171 likely as a response to the energy crisis of the late 1970s.172 From 1978 until 2015, Congress created new incentives, extended existing incentives, and renewed expired incentives for renewable energy."173 In December 2015, as part of the spending bill for the 2016 federal budget, Republicans in Congress agreed to extend the tax incentives for renewable energy, which would lapse, in exchange for an agreement with the Obama Administration and Democrats to end the four decade long ban on the export of US produced crude oil.174 This note does not identify or discuss special appropriations or spending measures made by Congress (i.e., "pork"), because those are beyond the practical spoke of

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172 See Hymel, supra note 2, at 160.
this note. For example, part of the $1.1 trillion spending bill to fund the federal government for the 2016 budget included a provision, at the request of Senator Thad Cochran (Republican, Mississippi), for an appropriation of "at least $160 million to a financially troubled ‘clean coal’ power plant” located in Kemper County, Mississippi. Identifying all such special appropriations is not feasible.

Most subsidies to fossil fuels were written into the U.S. Tax Code long ago as permanent provisions, while subsidies for renewables are time-limited initiatives implemented through energy bills that have set expiration dates. The expiration dates built into short term renewable subsidies, lasting one or two years, and this short term expirations create an unstable investment environment for renewable energy. The short term nature of these subsidies has the effect of discouraging long term investment into renewable energy.

An overlap of tax incentives exists among fossil fuels, and also among renewable energies, so it is not always possible to allocate the value of the annual subsidy for a specific energy industry, such as coal or wind. Some subsidies though are industry specific, and are noted below.

3. COAL

3.1 CREDIT FOR PRODUCTION OF NONCONVENTIONAL FUELS

(annual subsidy: $14 billion)

I.R.C. Section 45K. This provision provides a tax credit for the production of certain fuels. Qualifying fuels include: oil from shale, tar sands; gas from geopressurized brine, Devonian shale, coal seams, tight formations, biomass, and coal-based synthetic fuels. This credit has historically primarily benefited coal producers.

3.2 CHARACTERIZING COAL ROYALTY PAYMENTS AS CAPITAL GAINS

(annual subsidy: $986 million)

I.R.C. Section 631(c). Income from the sale of coal under royalty contract may be treated as a capital gain rather than ordinary income for qualifying individuals.

3.3 EXCLUSION OF ALTERNATIVE FUELS FROM FUEL EXCISE TAX

(annual subsidy: $343 million)

I.R.C. Section 6426(d). This section applies to liquified petroleum gas (LPG), P-series fuels (defined at 42 U.S.C. 13211(2)), compressed natural gas (CNG), liquefied natural gas (LNG), liquefied hydrogen, liquid coal, and liquid hydrocarbon from biomass.

175 Id.
176 See Harrison, supra note 2, at 861-66.
181 Id.
3.4 OTHER-FUEL EXPLORATION & DEVELOPMENT EXPENSING

(annual subsidy: $342 million)

I.R.C. Section 617. Identical provisions as applied to oil and gas (above). Including, for example, the costs of surface stripping, and construction of shafts and tunnels. 182

3.5 OTHER-FUEL EXCESS OF PERCENTAGE OVER COST DEPLETION

(annual subsidy: $323 million)

I.R.C. Section 613. Taxpayers may deduct 10 percent of gross income from coal production. 183

3.6 CREDIT FOR CLEAN COAL INVESTMENT

(annual subsidy $186 million)

I.R.C. Sections 48A and 48B. Available for 20 percent of the basis of integrated gasification combined cycle property and 15 percent of the basis for other advanced coal-based generation technologies. 184

3.7 SPECIAL RULES FOR MINING RECLAMATION RESERVES

(annual subsidy $159 million)

I.R.C. Section 468. This deduction is available for early payments into reserve trusts, with eligibility determined by the Surface Mining Control and Reclamation Act and the Solid Waste Management Act. The amounts attributable to mines rather than solid-waste facilities are conservatively assumed to be one-half of the total. 185

3.8 CARBON DIOXIDE (CO2) SEQUESTRATION CREDIT

($0 in 2009, $60 million in 2013, for both coal and oil combined)

Tax credit of $20 per ton of CO2 sequestered (largely from coal plants); $10 per ton for CO2 used for enhanced oil recovery. 186
3.9 BLACK LUNG DISABILITY TRUST FUND
(total subsidy $1 billion)

Pays health benefits to coal miners afflicted with pneumoconiosis, a long-term degenerative disease from constant inhalation of coal dust, also known as “black lung.” Created in 1978, it is funded through an excise tax on coal to support a trust fund covering health costs of affected workers, however the tax is not sufficient to cover all costs, and the BLDTF was given “indefinite authority to borrow” from the U.S. General Fund. By the end of FY 2008, the BLDTF had accrued nearly $13 billion in debt. In 2008, Congress partially “bailed out” the BLDTF, which the Environmental Law Institute (ELI) tabulated as a subsidy to coal.187

3.10 EXCLUSION OF BENEFIT PAYMENTS TO DISABLED MINERS
(annual subsidy: $438 million)

30 U.S.C. 922(c). Disability payments out of the Black Lung Disability Trust Fund are not treated as income to the recipients.188

4. OIL AND NATURAL GAS

Estimates for annual tax expenditures for oil and natural gas production are often grouped together, since those tax expenditures come from the same sections of the I.R.C., and because the extraction methods are similar. Total oil and gas subsidies are estimated at $5.3 billion in 2009, and $10.5 billion in 2013.189

4.1 MASTER LIMITED PARTNERSHIPS (MLP)
($2.3 billion in 2009, and $3.9 billion in 2012)

More than three-quarters of MLPs are fossil fuel companies.190 The MLP is a complicated and creative tax avoidance structure.191 “[The MLP] ‘is a business structure that is taxed as a partnership, but whose ownership interests are traded on a market like corporate stock.’”192 Instead of a typical corporate structure - investors, managers, and officers - an MLP’s members resemble more closely a partnership and are split into two categories: limited partners, who usually hold ninety-eight percent of the enterprise but have no control in the MLP’s operation, and general partners,
who hold a two percent ownership stake in the enterprise and oversee the MLP’s operation. Similar to forming one’s business as a corporation, an MLP seeks investors and promises to reward them with dividends from the company’s profits following investment. Unlike a corporation, however, if particular conditions are met, then the MLP is be treated as a partnership instead of a corporation. This means that the entity’s income is only taxed once, on the dividends it gives out to its investors. Thus, MLPs provide many of the same benefits of incorporation without the added double tax liability. The result is more money saved and, thus, more money for an MLP’s investors in the form of dividends. Only businesses that fall under a categorical exception may take advantage of all that an MLP structure provides. The default position of the I.R.C. is to treat MLPs as corporations. However, if ninety percent of an MLP’s gross income comes from a qualifying source, the I.R.C. treats the MLP as a partnership. Qualifying sources include interest-based income, real property rents, and, most importantly, income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource. Ultimately, if an oil and gas producing taxpayer structures its business as an MLP, the taxpayer may avoid corporate double taxation and instead give that money to its investors. The current market capitalization of MLPs is nearly $490 billion.

4.2 INTANGIBLE DRILLING COSTS (IDC)

(Estimated between $43 billion and $55 billion during 1968–2000, $1.6 billion in 2009, $3.5 billion in 2013)

This expenditure provides a 100% tax deduction for costs not directly part of the final operating oil or gas well (such as labor costs, survey work, and ground clearing, including oil and gas exploration and development costs). The value of the IDC between 1968 and 2000 was between forty-three and fifty-five billion dollars in lost revenue.

4.3 ENHANCED OIL RECOVERY CREDIT (EORC)

($1 billion between 1990 and 2000)

“...This subsidy covers expenses related to oil and gas in hard-to-drill areas and nearly dry wells in addition to oil and gas wells that are particularly difficult to drill. As a result, the EORC ‘encourages oil companies to go after reserves that are more expensive to extract, like those that have been nearly depleted or that contain especially thick crude oil.’ The EORC awards taxpayers a credit for any taxable year in an amount equal to fifteen percent of the taxpayer’s

193 See I.R.C. § 701 (2012) (stating that, in partnerships, partners owe taxes in their individual capacities, not the partnerships in their capacities as entities).
194 See I.R.C. § 7704(a) (2012).
195 See I.R.C. § 7704(c) (2012).
197 Id.
201 Id.
202 Id.
205 Id.
206 Id.
qualified enhanced oil recovery costs for such taxable year.\textsuperscript{207} Qualified costs include the IDC costs detailed above, expenses exceeding those costs that are integral parts of the project incurred in an attempt to extract more oil (tertiary injectant expenses), and depreciation of tangible property.\textsuperscript{208} Certain restrictions and limitations apply to the EORC as well,\textsuperscript{209} and the EORC is only available to parties who have an operating mineral interest in the property.”\textsuperscript{210}

\section*{4.4 Nonconventional Source Credit (NSC)}

\((\$11\text{ billion between 1980 and 2000})\textsuperscript{211}\)

“In general,\textsuperscript{212} the NSC provides an incentive for taxpayers to produce oil and gas domestically from sources that typically require more investment to extract oil and gas.\textsuperscript{213} The difficult-to-drill sources include “oil from shale and tar sands, gas from geopressured brine, Devonian shale, coal seams, [and] tight formations.”\textsuperscript{214} The NSC gives a three dollar-per-barrel credit, which is adjusted for inflation and may be reduced if the market cost of oil per barrel increases above a predetermined price.

\section*{4.5 Lost/Reduced Royalties from Leasing}

\((\$2.2\text{ billion in 2009, and again in 2013})\)

Lost/reduced royalties from leasing of federal lands for onshore and offshore drilling.\textsuperscript{215}

\section*{4.6 Percentage Depletion Allowance}

\((\$340\text{ million in 2009, }\$900\text{ million in 2013})\)

Independent producers can deduct 14-15\% of large investment costs from income taxes. “Percentage depletion allows the firm to deduct a fraction of the revenue arising from sale of the resource. Historic percentage depletion rates have been as high as 27.5\%. Currently percentage depletion is allowed for independent producers at a 15\% rate for oil and gas and 10\% for coal.\textsuperscript{216} Percentage depletion is allowed on production up to 1,000 barrels of average daily production of oil (or its equivalent for natural gas). In addition, the depletion allowance cannot exceed 100\% of taxable income

\begin{footnotes}
\item [207] I.R.C. § 43(a) (2012).
\item [209] I.R.C. § 43(b) (2012) (detailing a pro-rated credit if the price of the oil is above a certain price per barrel); I.R.C. §§43(c)(2)(A) (2012) (detailing that a party must domestically produce a significant increase in amount of crude oil recovery), 43(d) (detailing that a taxpayer must also reduce the otherwise deductible or capitalizable costs).
\item [214] In determining what constitutes taxable income, the I.R.C.’s congressional underpinnings play a large part in what amounts to a series of political, accounting, economic, and social considerations. See Boris I. Bittker & Lawrence Lokken, Federal Taxation of Income, Estates and Gifts §§ 2.1, 27.6. (2012) (“The statutory base is ‘taxable income,’ a term whose content not only reflects accounting principles and economic concepts but also embodies numerous legislative judgments about fairness, administrative convenience, and the desirability of encouraging or not impeding a host of social, personal, and business activities.”).
\item [216] Id. “Independent producers are defined as producers who do not engage in refining or retail operations. EPACT increased the amount of oil a company could refine before it was deemed to engage in refining for this purpose from 50,000 to 75,000 barrels per day.”
\end{footnotes}
from the property (50% for coal) and 65% of taxable income from all sources. Despite the curtailed availability of percentage depletion, it continues to be a significant energy tax expenditure, costing $3.2 billion over five years in the federal budget.  

4.7 DOMESTIC MANUFACTURING DEDUCTION

($605 million in 2009, $574 million in 2013)

Allows oil producers to claim a tax break intended for U.S. manufacturers to prevent job outsourcing.

4.8 EXEMPTION FROM PASSIVE LOSS LIMITATION

($20 million in 2009, $20 million in 2013)

Exempts investors from limits on deductions of losses from oil and gas activities in which they are not directly involved.

4.9 DEDUCTION FOR TERTIARY INJECTANTS

($0 in 2009, $7 million in 2013)

Allows companies to deduct the costs of fluids, gases, and other chemicals used for enhanced oil recovery from existing wells.

4.10 DEEP GAS AND DEEP WATER PRODUCTION ROYALTY RELIEF

($1 million in 2009, $1 million in 2013)

Suspension of royalty payments for deepwater oil and gas production.

4.11 DEDUCTION FOR OIL SPILL REMEDIATION COSTS

($679 million in 2011, with a spike of $9.9 billion in 2010)

This deduction allows companies to deduct from tax payments the costs associated from cleaning up oil spills. In 2010, an extraordinary spike occurred with the claim of this deduction, because of the British Petroleum Deepwater Horizon oil spill in the Gulf of Mexico.

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217 Id. “Amounts in excess of the 65% rule can be carried forward to subsequent tax years. The net income limitation has been suspended in years past but the suspension lapsed as of this year.”
220 Id.
221 Id.
222 Id.
4.12 THE LOW INCOME HOME ENERGY ASSISTANCE PROGRAM

(annual subsidy $6.3 billion)

“The main structure of the program is to provide low-income households with the means to make their utility payments, the vast majority of which is energy generated by fossil fuels [mostly natural gas]. The U.S. Department of Health and Human Services has tabulated the percentage of households using fossil versus non-fossil heating fuels in 2001, and ELI used the percentage as a proxy for fossil versus non-fossil expenditures for 2002-2008.”

5. WIND AND SOLAR

Estimates for annual tax expenditures for wind and solar renewable energy production are often grouped together, since those tax expenditures come for the same sections of the I.R.C.

5.1 MODIFIED ACCELERATED COST-RECOVERY SYSTEM (MACRS)

I.R.C. Section 168. This incentive, 225 “permits businesses to recover investments in certain property through depreciation deductions at a faster rate than otherwise permissible under the IRC’s standard depreciation deduction.” 226 The relevant qualifying properties include a variety of solar technologies and small-scale wind turbines. 227 For example, the MACRS allowance permits a business to purchase solar or small-scale wind technology that would normally depreciate over a lifetime of five to ten years, and instead deduct its depreciation over five years. 228 Additionally, the 2012 extension of the MACRS deduction extends a bonus depreciation, which “allows industrial and commercial businesses to recover investment in, among other renewables, solar and wind and deduct a depreciation allowance up to 50 percent in the first year that the equipment is purchased and placed into service,” 229 as long as it was purchased between 2008 and 2012.

5.2 PRODUCTION TAX CREDIT

($18 billion between 1992 and 2015) 230

I.R.C. Section 45. This incentive, 231 “allows taxpayers to receive a credit on their taxes for the electricity that they produce from qualifying renewable energy technology and sell to unrelated parties. 232 It is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during

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224 Id.
228 Id.
229 Id.
234 I.R.C. § 45.
the taxable year. Unlike the MACRS, which primarily allows a party to deduct the purchased renewable energy technology’s depreciated value from their taxes and thus pay fewer taxes on the technology, the PTC benefits parties who produce and sell electricity with their renewable energy technology by giving the taxpayer a credit on their income taxes. The PTC is available for any scale wind project, but not for solar energy production. This restriction against solar panels may be due to the disturbance that a production tax credit’s application could have on a taxpayer’s income tax burden as well as on the utility industry. Because residential scale solar energy production is becoming increasingly feasible and popular across the country, tax credits for electricity production by owners of small-scale solar panels would disadvantage utility competitors and reduce individual homeowners’ income tax burdens. A taxpayer who wishes to produce and receive a tax credit for wind power must follow certain conditions. First, according to the most recent legislation passed in January 2013, a wind developer must begin construction on the project prior to January 1, 2014 in order to receive a tax credit. Second, a PTC-eligible facility only qualifies if it is within its first ten years of operation. If a wind farm meets both conditions, once the wind farm begins to produce wind energy, the taxpayer is eligible for a tax credit - currently 2.2 cents per kilowatt-hour - for each kilowatt of electricity the facility delivers to the grid.

5.3 THE RENEWABLE ENERGY INVESTMENT TAX CREDIT (ITC)

($2.7 billion between 2011 to 2015)

I.R.C. Section 48. This incentive is smaller than PTC. The ITC permits “businesses and energy producers to deduct up to thirty percent of the cost of purchasing solar and small-scale wind technology (less than 100kW), but not large-scale wind technology. The ITC historically represented a smaller loss of tax revenue, compared to the PTC. […] Although some of these parties would be glad to receive a tax credit for potential investments in large-scale wind, the thought of making it easier for competitors to enter the electricity market would result in significant pushback from utilities and the producers of traditional energy sources. Although the ITC does not apply to the full range of renewable energy technology, its benefits are numerous. Unlike the PTC, the ITC does not require the purchaser to produce any electricity to earn the credit. Additionally, the Tax Code does not limit how many credits a taxpayer may receive in a taxable year for purchasing solar and wind technology. However, the ITC has its disadvantages. For example, it explicitly disallows companies to elect the ITC for property for which, in the same taxable year or in prior taxable years,

242 I.R.C. § 48. See generally DSIRE.
243 I.R.C.§48(a)(1)(A) (2012) (percentage deduction and duration of credit); I.R.C. § 48(a)(3)(A)(i) (2012) (solar energy); I.R.C. § 48(a)(3)(A)(vi) (2012) (small wind energy). Large-scale wind investment is likely not included in the ITC for political and economic reasons. It is unlikely that coal and gas companies would permit Congress to heavily subsidize investments in large-scale wind technology because more investment in wind technology would lead to less coal and gas investment. In addition, large-scale wind technology paired with the PTC makes wind technology investments cost competitive with subsidized natural gas. But, in line with the Note’s central theme, wind technology being cost competitive is insufficient because it does not fully incentivize the adoption of renewable energy.
245 See DSIRE.
they elected the PTC. In other words, for renewable energy technology that produces electricity, a party cannot in the same year deduct the cost of purchasing the technology and receive a tax credit for producing renewable energy. The qualifying investments under the ITC include costs such as “installation costs and the cost for freight incurred in construction of the specified energy property.” Absent an exemption from the restriction on deducting capital expenditures, however, the ITC does not include all potential project costs such as the cost of land, buildings, certain land improvements, siting the technology, and connecting transmission lines to the grid.

6. QUANTITATIVELY DE MINIMIS TAX EXPENDITURES

The following tax provisions are viewed as tax expenditures by the staff of the United States Congress, Joint Committee on Taxation, but these expenditures are not itemized or quantified in federal reports, because the estimated revenue losses for fiscal years 2013 through 2017 are below the de minimis amount ($50 million/year):

- Credit for producing oil and gas from marginal wells (I.R.C. 45I)
- Credit for producing fuels from a nonconventional source (I.R.C. 45K)
- Seven-year MACRS Alaska natural gas pipeline (I.R.C. 168(e)(3)(C))
- 50-percent expensing of cellulosic biofuel plant property (I.R.C. 168(1))
- Partial expensing of investments in advanced mine safety equipment (I.R.C. 179E)
- Expensing of tertiary injectants (I.R.C. 193)

246 “Such term shall not include any property which is part of a facility the production from which is allowed as a credit under section 45 for the taxable year or any prior taxable year.” I.R.C. § 48(a)(3).
248 Id.
250 Compare I.R.C. §§ 48(a)(3)(A)-(B), referring only to equipment technology and construction, with the interpretation of intangible drilling costs to include all costs reasonably related to drilling wells.
EXHIBIT A

Cost of Energy-Related Tax Preferences, by Type of Fuel or Technology

(Billions of 2013 dollars)


Note: The estimates of costs resulting from individual tax preferences do not account for any potential interactions between preferences and do not include tax provisions estimated to cost less than $50 million. Nor do they reflect the budgetary effects of eliminating those preferences and of taxpayers’ adjusting their activities in response to those changes.