Carbon Capture and Storage (Sequestration)

by Arnold W. Reitze Jr.

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Carbon dioxide (CO_2) is an end product created by the combustion of carbon-based fuel.[1] It is usually released to the atmosphere, and most scientists believe these emissions are a major contributing factor to climate change.[2] Under both international law and U.S. domestic law, CO_2 is a pollutant, but it cannot be controlled with the techniques used to control traditional air pollution.[3] One option for preventing CO_2 emissions from being released to the atmosphere is to require combustion sources to utilize carbon capture and storage (sequestration) (CCS). This involves capturing CO_2, compressing it to a supercritical state, injecting it into an underground geological depository, and managing the site to assure permanent sequestration. Because the electric power industry emits over 40% of U.S. CO_2 emissions,[4] it is a primary target for government efforts aimed at developing and using CCS.

CCS is evolving from the technology used for enhanced oil recovery (EOR), which is a technology that has been used for more than 40 years and is subject to a long-established regulatory regimen. CO_2 is injected into an oil field to increase its production, but EOR is not designed to achieve long-term sequestration. A few electric power plants are attempting to capture CO_2 and sell it to the petroleum industry. The first commercial-scale, coal-fired power plant using CCS technology is the Texas Clean Energy Project (TCEP). It is to be constructed with the assistance of $450 million in federal funding and is expected to capture 90% of the CO_2, most of which will be used for EOR.[5] The Hydrogen Energy California (HECA) is to receive $400 million in federal grants to capture CO_2 for EOR. It plans to use coal and petcoke to produce hydrogen to fuel an integrated gasification combined cycle (IGCC) power plant.[6] In Indiana, the Department of Environmental Management issued the nation's first draft prevention of significant deterioration (PSD) permit that includes greenhouse gas (GHG) limits based on capturing CO_2 that will be shipped to Texas in a pipeline to be injected for EOR.[7] The draft permit is being reviewed because of environmentalist objections to the permit not requiring permanent sequestration.[8]

CCS has little chance of being used by electric utilities unless it involves EOR. Despite expenditures of about $6.9 billion by the U.S. Department of Energy (DOE) since 2005 to develop and commercialize CCS technology, it is still a costly way to deal with CO_2.[9] Removing CO_2 from exhaust gas and compressing it into a liquid is an energy-intensive process, which is expected to require approximately 15-30% of a power plant's net power output.[10] On average, electricity generated by CCS-equipped plants would be expected to cost about 75% more than if generated by conventional coal-fired plants.[11] Moreover, it will require many plants to be built over many years using CCS before significant cost reductions can be expected to occur.[12] CCS's parasitic power demand would require sig-

1. For example $CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$ + heat.
2. *See generally* U.S. Envtl. Protection Agency (EPA), *Causes of Climate Change*, http://www.epa.gov/climatechange/science/causes.html (last visited Mar. 7, 2013); National Association of Clean Air Agencies, *Primer on Climate Change Science* (July 2011).
3. United Nations Framework Convention on Climate Change, 9 May 1992, U.N.Doc. A/CONF.151/26, *reprinted in* 31 I.L.M. 849 (1992); Massachusetts v. U.S. Envtl. Protection Agency, 549 U.S. 497, 37 ELR 20075 (2007).
4. U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010, Executive Summary* ES-4, tbl. ES-2 (2012).
5. Susan Pagano, *Utility to Purchase Electricity From Plant in Texas With Carbon Capture Technology*, 43 Env't Rep. (BNA) 141 (Jan. 20, 2012).
6. *Re-Proposed California Power Plant With CCS Seeks EPA BACT Decision*, 23 Clean Air Rep. (Inside EPA) 12:34 (June 7, 2012).
7. Dawn Reeves, *Draft Indiana GHG Permit Includes First-Ever Limit for Carbon Capture*, 23 Clean Air Rep. (Inside EPA) 3:31 (Feb. 2, 2012).
8. *Indiana Permit to Test Air Law's Scope Over Permanent CO_2 Sequestration*, 29 Envtl. Pol'y Alert (Inside EPA) 11:31 (May 30, 2012).
9. Congress of the United States, Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide*, Summary (June 2012).
10. U.S. Dept. of Energy (DOE), National Energy Technology Laboratory, *Carbon Dioxide Capture and Storage RD&D Roadmap 26* (Dec. 2010). The higher number would apply to retrofits of existing facilities. CO_2 can be removed prior to combustion, but the technology is not as proven. *See* Arnold W. Reitze Jr., *Federal Control of Carbon Capture and Storage*, 41 ELR 10796, 10798 (Sept. 2011).
11. U.S. DOE, *supra* note 10.
12. *Id.*

nificant new electric-generation capacity to be constructed if CCS was widely adopted.

High costs and the absence of effective sanctions on CO_2 emissions limit adoption of CCS. Six power plant projects with CCS are planned or under construction.[13] Five of the six are to receive federal funds totaling over $2 billion; the sixth project's organizers are seeking federal funds.[14] One of these five projects was recently abandoned, and several other projects were abandoned prior to receiving funding.[15]

There are more cost-effective ways for electric utilities to deal with their CO_2 emissions than by adopting CCS. They can choose not to burn fossil fuel to generate electricity by using nuclear energy, hydroelectric, or other renewable energy sources. Each of these energy sources has an economic and environmental cost that results in the electric power industry continuing to use fossil fuels as their primary source of energy. In 2011, approximately 42% of the electricity generated in the United States came from coal-fired plants, 25% came from natural gas-fired plants, 19% came from nuclear plants, 8% came from hydroelectric plants, and less than 5% was generated from other renewable sources.[16] It would require massive investment in new generating facilities to end the use of fossil fuels.

Another approach is to substitute fossil fuels having a higher ratio of hydrogen to carbon than is found in coal. Petroleum combustion produces 72% of the CO_2 emissions as coal having the same heat value. Natural gas produces 58% of the CO_2 compared to coal.[17] The use of natural gas to generate electricity has grown from 18% in 2002 to 25% in 2011, during which time electric power generation increased by over 6%.[18] In April 2012, natural gas-fired power plants in the United States for the first time generated the same amount of electricity as coal-fired plants.[19] The U.S. Energy Information Administration's (EIA's) projection is that the percentage of electricity generated from coal will drop to between 40 and 37% by 2020.[20] The use of natural gas is driven by its relatively low price, but its use results in both lower conventional air pollution and CO_2 emissions than using coal.

Another approach to lower CO_2 emissions is to generate electricity from fossil fuel in a more thermally efficient process. New plants usually are more fuel-efficient than old plants and therefore produce less CO_2 per megawatt (MW) hour. But because coal-fired plants have a long useful life and the cost of replacing them is high, existing plants are kept in operation for as long as possible.[21] However, the legal requirements to control conventional air pollutants, the nascent regulation of CO_2, and the high costs of maintenance for aging plants is leading to the retirement of many old facilities, and they usually are replaced with plants that do not burn coal.

The U.S. Environmental Protection Agency's (EPA's) standards for hazardous air pollutants from coal-fired and oil-fired power plants that were promulgated on February 16, 2012,[22] are an example of EPA's rules that make old coal-fired power plants candidates for retirement and make new plants a risky investment.[23] The rule applies to about 1,100 existing coal-fired units and 300 oil-fired units at about 600 power plants.[24] Existing and new coal-fired generating units have numerical limits for mercury emissions, particulate matter (PM, as a surrogate for toxic non-mercury metals, including arsenic, chromium, and nickel), and hydrogen chloride (HCL, as a surrogate for toxic acid gases).[25] The rule also modifies the new source performance standard (NSPS) for fossil-fueled electric generating units (EGUs) to include revised numerical emission limits for PM, sulfur dioxide (SO_2), and nitrous oxides (NO_x).[26] EPA predicted that this rule will result in the generation capacity for pulverized coal plants being reduced by about 10 gigawatts (gW), and the generating capacity of combined-cycle natural gas plants will increase by about eight gW.[27] The rule is being challenged in the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit in at least 30 lawsuits brought by industry, environmentalists, and 24 states because of its high costs and potentially unachievable time lines.[28] On November 16, 2012, EPA signed a proposed rule to revise the mercury and air toxics limits for new coal- and oil-fired power plants to make them more stringent.[29]

Coal-fired power plants are also subject to EPA's PSD program, which applies in areas that meet EPA's air qual-

13. Congressional Budget Office, *supra* note 9.
14. *Id.* at 4, tbl. 4.
15. Arnold W. Reitze Jr., *Carbon Capture and Storage Program's NEPA Compliance*, 42 ELR 10853, 10859 (Sept. 2012).
16. U.S. Energy Information Administration (EIA), *Table 1.1 Net Generation by Energy Source*, calculated from http://www.eia.gov/electricity/monthly/index.cfm (last visited Mar. 7, 2013).
17. Biomass Energy Centre, *Carbon Emissions of Different Fuels*, http://www.biomassenergycentre.org.uk/portal/page?_pageid=75,163182&_dad=portal&_schema=PORTAL (last visited Mar. 7, 2013).
18. EIA, *supra* note 16 [calculated from the data].
19. *April Marked First Month Coal, Natural Gas Generated Equal Amounts of Electricity*, 43 Env't Rep. (BNA) 1811 (July 13, 2012).
20. EIA, *Fuel Used in Electricity Generation Is Projected to Shift Over the Next 25 Years*, http://www.eia.gov/todayinenergy/detail.cfm?id=7310 (last visited Mar. 9, 2013).
21. *See generally* Arnold W. Reitze Jr., *Federal Regulation of Coal-Fired Electric Power Plants to Reduce Greenhouse Gas Emissions*, 32 Utah Envtl. L. Rev. 391 (2012); Arnold W. Reitze Jr., *The Intersection of Climate Change and Clean Air Act Stationary Source Programs*, 43 Ariz. St. L.J. 901 (2011).
22. National Emission Standards for Hazardous Air Pollutants, 77 Fed. Reg. 9304 (Feb. 16, 2012) (EPA subsequently announced corrections to the rule on Apr. 19, 2012).
23. Bobby McMahon, *EPA Air Rules, Gas Prices Further Weaken Prospects for New Coal Power*, 23 Clean Air Rep. (Inside EPA) 4:6 (Feb. 16, 2012).
24. National Emission Standards, 76 Fed. Reg. 24976.
25. *Id.*
26. *Id.*
27. Bobby McMahon, *EPA Data Predicts Utility MACT Will Not Spur Growth in Renewable Power*, Clean Air Rep. (Inside EPA), Mar. 31, 2011, at 4.
28. Jessica Coomes, *25 Additional Lawsuits Challenge EPA on Mercury, Air Toxics Rules for Utilities*, 43 Env't Rep. (BNA) 1005 (Apr. 20, 2012).
29. U.S. EPA, Fact Sheet Mercury and Air Toxics Standards for Power Plants, http://www.epa.gov/mats (last visited Mar. 15, 2013).

ity standards.[30] Beginning January 2, 2011, construction permits are required to include GHG requirements. On November 10, 2010, EPA made available the PSD and Title V Permitting Guidance for Greenhouse Gases (Guidance), which was updated in March 2011.[31] The Guidance provides that a major CO_2 source seeking a PSD permit is to use the best available control technology (BACT). EPA does not prescribe GHG BACT requirements, but emphasizes the importance of BACT options that improve energy efficiency.[32] To control the number of permits that will need to be issued for GHG emission sources, EPA promulgated the "tailoring" rule on June 3, 2010.[33] The rule subjects GHG sources to the PSD permitting program if their emissions exceed specified GHG thresholds.[34] EPA's tailoring rule was upheld by the D.C. Circuit in *Coalition for Responsible Regulation v. EPA*.[35]

Facilities that attempt to obtain PSD permits are often subject to opposition by EPA and environmentalists opposed to coal-fired power plants. The Chase Power Development's 1,300 MW, coke-fired Las Brisas Center at Port of Corpus Christi, Texas, is seeking to avoid GHG controls and has filed suit in the D.C. Circuit challenging EPA's takeover of the GHG permitting program in Texas.[36] In South Dakota, an application by Hyperion for a construction permit to build a petroleum refinery and integrated gasification combined-cycle power plant led to a detailed analysis of the BACT choices by the state's Department of Environment and Natural Resources (DENR). The DENR approved Hyperion's design because GHG emissions per barrel of refined product were equivalent to the best performing plant.[37] The DENR rejected additional controls, and specifically rejected requiring CCS.[38] A revised PSD permit was issued on September 15, 2011, and challenges to the permit were argued in October 2012.[39]

In Iowa, the Department of Natural Resources issued a permit on May 16, 2011, to allow MidAmerican Energy Company's George Neal South Power Plant, owned by Berkshire Hathaway, to install pollution controls at an existing plant. The permit restricts CO_2 emissions to 2,588 pounds per MW hour, which will not require the plant to significantly reduce CO_2 emissions beyond its current emissions, but it will reduce mercury and SO_2 emissions.[40]

EPA supported a Michigan permit for the Wolverine Power Supply Cooperative in Michigan issued on June 29, 2011, that has weak and cursory BACT requirements related to GHG emissions.[41] That permit was upheld by a Michigan circuit court and has been appealed by environmentalists to the Michigan Court of Appeals.[42]

In Illinois, state officials issued a draft PSD permit for the Taylorville Energy Center that allows it to emit five million tons of CO_2 per year and rejected the need for including CCS.[43] EPA and environmentalists objected to approving a permit without CCS.[44] On April 30, 2012, the Illinois EPA issued a PSD permit that included weak CO_2 limits, but it did not require CCS.[45] Subsequently, the facility's management indicated that they were considering using natural gas to cut costs and avoid possible legislative barriers to the projects construction.[46] Moreover, environmentalists were challenging the permit with EPA's Environmental Appeals Board.[47] Faced with opposition by EPA because the permit did not have mandatory CO_2 limits based on CCS, Illinois EPA withdrew the PSD permit on July 6, 2012.[48]

Operating permits are required for major sources as well as sources subject to NSPS or the hazardous air pollutant regulations.[49] For facilities that are subject to operating permit requirements, CO_2e requirements are imposed beginning July 1, 2011.[50] Facilities that do not have an operating permit are required to obtain one if emissions exceed 100,000 tons per year of CO_2e, even if they emit no other pollutants.[51]

An important action by EPA concerning CCS is the April 13, 2012, proposed NSPS to limit CO_2 emissions from new or modified EGUs greater than 25 megawatt electric (MWe) located in the continental United States.[52] The

30. 42 U.S.C. §7475 (2006).
31. *See* U.S. EPA Office of Air Quality Planning & Standards, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases (2011) [hereinafter EPA's Permitting Guidance].
32. *Id.* at 29. *See also* Steven D. Cook, *EPA Issues Guidance to States, Localities on Controls for Greenhouse Gas Sources*, 41 Env't Rep. (BNA) 2504 (Nov. 12, 2010).
33. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31514 (June 3, 2010) (codified at 40 C.F.R. §§51, 52, 70 & 71).
34. *Id.* at 31523.
35. Coalition for Responsible Regulation, Inc. v. EPA, No. 09-1322 (D.C. Cir. June 26, 2012). *See Appeals Court Assigns Panel for Bulk of Suits Over Climate Rules*, Clean Air Rep. (Inside EPA), Nov. 10, 2011, at 17 [hereinafter *Appeals Court Assigns Panel*].
36. Dawn Reeves & Stuart Parker, *Texas Coke Plant May Be Key Test for EPA Takeover of State GHG Permits*, Clean Air Rep. (Inside EPA), Nov. 24, 2011, at 34; Andrew Childers, *Texas Power Plant Among Those Suing EPA Over Carbon Dioxide Performance Standards*, 43 Env't Rep. (BNA) 1542 (June 15, 2012).
37. Vinson & Elkins, Publications: First GHG Permits Issued by State Regulatory Agencies (Mar. 21, 2011), *available at* http://velaw.com/resources/FirstGreenhouseGasPSDPermits IssuedStateRegulatoryAgencies.aspx.
38. *Id.*
39. *Hyperion Energy Center: Air Quality*, S.D. Dep't of Env't & Nat. Resources, http://denr.sd.gov/hyperionaqmain.aspx (last visited Mar. 10, 2013).
40. Dawn Reeves, *EPA Backs First Coal Plant GHG Permit Without Strict Emission Limits*, Envtl. Pol'y Alert, June 15, 2011, at 31.
41. *Id. See also* Dawn Reeves, *Environmentalists Challenge First Coal Plant Permit to Include GHG Limits*, Clean Air Rep. (Inside EPA), Oct. 13, 2011, at 7.
42. Dawn Reeves, *Activists Appeal Ruling Upholding First Coal Plant With GHG Permit Limits*, Clean Air Rep. (Inside EPA), Apr. 26, 2012, at 9.
43. Dawn Reeves, *Fearing Precedent, EPA, Activists Press Illinois to Require CCS in Air Permit*, 23 Clean Air Rep. (Inside EPA) 2:5 (Jan. 19, 2012).
44. *Id.*
45. Dawn Reeves, *Activists Eye Suit Over CCS Permit Without Carbon Limit to Set Precedent*, 23 Clean Air Rep. (Inside EPA) 10:29 (May 10, 2012).
46. *Contested Illinois Coal Plant With CCS Permit May Switch to Natural Gas*, 23 Clean Air Rep. (Inside EPA) 11:40 (May 24, 2012).
47. Dawn Reeves, *Activists' Permit Suit Challenges GHG BACT for Excluding Carbon Capture*, 23 Clean Air Rep. (Inside EPA) 13:14 (June 21, 2012).
48. *Illinois Pulls Permit to Weigh Novel EPA Call for CCS as GHG Control Option*, 23 Clean Air Rep. (Inside EPA) 15:36 (July 19, 2012).
49. 42 U.S.C. §661(2).
50. CO_2e is carbon dioxide equivalent and is used to provide a common measure for the impact of the various GHGs.
51. U.S. EPA, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, 75 Fed. Reg. 31524 (June 3, 2010) (codified at 40 C.F.R. §§51, 52, 70 & 71).
52. U.S. EPA, *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 Fed. Reg. 22392

standards are based on the emissions produced by a natural gas combined-cycle (NGCC) facility. EPA does not expect any coal-fired EGU to meet this standard without utilizing CCS technology to prevent 50% or more of the CO_2 emissions from being released to the atmosphere. EPA's proposed NSPS creates a new Subpart TTTT in 40 C.F.R. Part 60 that will regulate GHG emissions from all fossil fuel-fired EGUs including electric utility steam-generating units and IGCC units currently regulated in Subpart Da and natural gas combined-cycle units currently regulated in Subpart KKKK.[53] By combining coal-fired and natural gas-fired units into one NSPS, EPA has essentially mandated that new EGUs be fueled by natural gas, unless they are willing to gamble on the use of coal with the costly and commercially unproven CCS technology.[54] The utility industry has challenged EPA's proposed rule in the D.C. Circuit, but the court has not ruled on whether this is a final agency action subject to judicial review.[55] On July 24, 2012, H.R. 6172 was introduced to prevent EPA from requiring CCS until it can be demonstrated that it is technologically and economically feasible.[56] Even if EPA modifies the proposed NSPS when it is promulgated in final form, the coal-fired electric power industry can expect the pressure to reduce CO_2 emissions from its power plants will continue.

EPA's proposed NSPS does not cover existing plants unless they are modified, but Canada, in September 2012, announced a new rule that recognizes CCS as a control option for existing coal-fired plants.[57] Canada requires all coal-fired utilities to meet a performance standard generally equivalent to EPA's proposed 1,000 pounds of CO_2 per MW hour.[58]

The Safe Drinking Water Act (SDWA)[59] requires EPA to establish minimum requirements for state underground injection control (UIC) programs. On December 10, 2010, a final rule was promulgated governing underground injection of CO_2, effective January 10, 2011.[60] The rule creates a new Class VI category for wells used for CCS that requires minimum technical criteria for Class VI wells to protect underground sources of drinking water.[61] EPA has issued numerous guidance documents that cover the five plans that must be submitted with a Class VI permit application.[62] Primacy guidance was released in June 2011, as a draft guidance document, and states must submit primacy application to EPA if they want to run the CCS program. No state was granted Class VI primacy in 2012, but Wyoming has an application under consideration. Thus, EPA remains the permitting authority.

CCS adoption has been driven by a carrot-and-stick approach. The stick as discussed above is to use federal laws to restrict the release of CO_2. Efforts to make it costly to emit CO_2 through the imposition of a carbon tax, a cap-and-trade program, or some similar economic sanction have been unsuccessful. In 2013, the political climate for enacting such measures does not exist.[63] Even if such efforts reemerge, electric utilities will be more likely to convert to natural gas than use CCS on a coal-fired plant. This has already been the reaction by electric utilities to EPA's more stringent pollution control requirements aimed at conventional pollutants. Announcements are regularly being made that old plants are being shut down and plans for new coal-burning plants are being cancelled. The Sierra Club claims to have blocked more than 150 proposed coal plants.[64]

The carrot to encourage CCS is federal funds and tax benefits, but the enthusiasm for this approach is being tempered by concern for the federal deficit. Since 2005, DOE's coal program has been funded at a level of about $0.4 billion per year.[65] The American Recovery and Reinvestment Act of 2009 provided an additional $3.4 billion for CCS development, although much of this money remains unspent because of the time lag in developing large projects and because the private sector canceled projects that were to receive federal funds.[66] Moreover, several different tax credits for plants that incorporate "clean coal" technologies that capture and store CO_2 cost the federal government about $0.2 billion per year in foregone revenue through 2015.[67] Most observers, however, believe the time of substantial federal funding for CCS is coming to an end. DOE's fiscal year 2013 budget request includes cuts of $19 million for CCS-specific funding research, and the Obama Administration eliminated new funding for CCS demonstration projects, although funds are still available under the 2009 stimulus law.[68]

Coal is projected to continue to be used for generating electricity for many years, but its role will slowly diminish. The driving force is the economics of electric power generation, which at this time is dominated by the relatively low cost of natural gas. Inexpensive natural gas appears to have ended the prospects for large-scale adoption of CCS.

(Apr. 13, 2012).
53. 77 Fed. Reg. 22398.
54. The proposed NSPS are discussed in more detail in Arnold W. Reitze Jr., *EPA's Proposed New Source Performance Standards to Control Greenhouse Gas Emissions From Electric Utility-Generating Units*, 42 ELR 10606 (July 2012).
55. Dawn Reeves, *EPA, Industry Spar Over Appeals Court's Power to Hear Climate NSPS Suit*, 23 Clean Air Rep. (Inside EPA) 20:10 (Sept. 27, 2012).
56. Andrew Childers, *Power Companies, Miners Support Bill to Block EPA Carbon Capture Regulation*, 43 Env't Rep. (BNA) 2461 (Sept. 28, 2012).
57. *Canada's New Power Plant GHG Rule May Hinder Push to Stall EPA's*, 23 Clean Air Rep. (Inside EPA) 20:8 (Sept. 27, 2012).
58. *Industry Doubts Canada Rule Will Drive CCS Without EPA Expanding NSPS*, 23 Clean Air Rep. (Inside EPA) 21:29 (Oct. 11, 2012).
59. 42 U.S.C. §§300f to 300j-26, ELR Stat. SDWA §§1401-1465.
60. 75 Fed. Reg. 77229 (Dec. 10, 2010).
61. The rule is discussed in Arnold W. Reitze Jr., *Federal Control of Geological Carbon Sequestration*, *supra* note 10.
62. The list is available at http//epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm (last visited Mar. 9, 2013). EPA amended its implementation guidance in October 2012. *See* Bridget DiCosmo, *EPA Amends CCS Project Plan Guide to Grant Industry Greater Flexibility*, 29 Envtl. Pol'y Alert (Inside EPA) 21:31 (Oct. 17, 2012).
63. The effort to control carbon emissions through taxes or cap and trade is discussed in Arnold W. Reitze Jr, *Electric Power in a Carbon Constrained World*, 34 Wm. & Mary Envtl. L. & Pol'y Rev. 821 (2010).
64. Bryan Walsh, *The War on Coal*, Time, Nov. 21, 2011, at Business 2.
65. Congressional Budget Office, *supra* note 9, at 5.
66. *Id.*
67. *Id.* at 6.
68. Dawn Reeves, *CRS Report Finds Research Likely Underfunded in Light of EPA NSPS*, 23 Clean Air Rep. (Inside EPA) 10:30 (May 10, 2012).