Deploying Low-Carbon Coal Technologies Series

TACKLING CO_2 EMISSIONS FROM EXISTING COAL-FIRED POWER PLANTS

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1. Introduction

The coal value chain has undergone significant changes over the past four years. A combination of low natural gas prices, high construction costs for new coal-fired power plants, new air quality regulations, and the EPA's evolving rules limiting CO_2 emissions are affecting both short-term operational and long-term investment decisions across the coal value chain. Today, energy modeling suggests that natural gas prices will remain low for the foreseeable future[1] and that there will be very few, if any, new coal-fired power plants in the coming decades. Even in the absence of new coal-fired generation in the United States, the nation's existing fleet of coal-fired power plants will continue to provide a major portion of the nation's electricity for the foreseeable future, and global demand for coal is projected to increase for the foreseeable future absent significant policy intervention.[2]

Due to the continued presence of existing coal plants in the domestic electricity fleet, any effort to significantly reduce CO_2 emissions in the United States must address existing coal plants. The challenge of addressing CO_2 emissions from existing power plants raises a number of technical and economic challenges, including the cost of retrofit technologies, space constraints for installing new industrial equipment at existing facilities, and concerns about triggering New Source Review.[3] Effectively addressing these hurdles will require a continued focus on developing new technologies to capture CO_2 emissions from the existing coal-fired fleet. Despite the need for new technologies, barriers to private and public investment in innovative coal technologies persist because of uncertainty regarding future CO_2 emission limits and the likelihood of a shrinking federal budget for energy technology research, development, and demonstration (RD&D).

Numerous government entities, scholars, trade groups, and environmental NGOs have proposed detailed strategies for pursuing carbon capture and storage (CCS) technologies.[4] This paper does not propose another broad strategy for consideration. Instead, it details the challenge of continuing to develop low-carbon technologies for existing coal-fired power plants and focuses on two near-term federal policy mechanisms currently under discussion that will affect RD&D for carbon capture technologies. These policy mechanisms include federal funding for energy RD&D in a period of federal budgets cuts and CO_2 regulation under the Clean Air Act, including performance standards limiting CO_2 emissions from existing power plants.

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[1] Relative to prices observed from 2003 to 2008.

[2] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2013 Early Release*, Table Browser: Energy Consumption by Sector and Source, United States, 1980–2035 (December 5, 2012); International Energy Agency (IEA), *World Energy Outlook 2012*, at 51 (2012) (hereinafter AEO 2013 Early Release).

[3] Ed Rubin et al., *The Outlook for Improved Carbon Capture Technology*, 38 PROGRESS IN ENERGY AND COMBUSTION SCIENCE 630, 637 (2012).

[4] See, e.g., IEA, *A Policy Strategy for Carbon Capture and Storage* (January 2012), http://www.iea.org/publications/freepublications/publication/policy_strategy_for_ccs.pdf; Coal Utilization Research Council & Electric Power Research Institute, *The CURC-EPRI Coal Technology Roadmap* (August 2012), http://www.coal.org/userfiles/file/FINAL%20Roadmap%20Report%20Update%20-%20August%202012.pdf; Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage* (August 2010), http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf; John Thompson et al., *The Carbon Capture and Storage Imperative: Recommendations to the Obama Administration's Interagency Carbon Capture and Storage Task Force*, Clean Air Task Force (July 2010), http://www.catf.us/resources/publications/files/The_Carbon_Capture_and_Storage_Imperative.pdf; *The Future of Coal: An Interdisciplinary MIT Study*, 95–103 (2007), http://web.mit.edu/coal/The_Future_of_Coal.pdf.

The paper first describes the economic and regulatory factors affecting domestic coal-fired generation. It then provides an overview of CO_2 emission projections associated with the existing fleet of coal-fired power plants to underscore the importance of reducing emissions from this class of facilities. The final section highlights the near-term policy choices regarding RD&D funding for carbon capture technologies and regulatory options under the Clean Air Act to limit CO_2 emissions from existing facilities.

2. The State of Coal-Fired Electricity Generation in the United States

In the United States, reliance on coal as a percentage of electricity generation is declining primarily due to a dramatic decrease in natural gas prices coupled with rising coal prices and a range of new environmental regulations affecting the operation costs of existing coal-fired power plants.[5] In 2011, coal-fired generation accounted for 42% of the nation's annual electric power production,[6] a 10% decline from 2000 levels.[7] The *Annual Energy Outlook 2013 Early Release,* published by the U.S. Energy Information Administration (EIA), projects this number to fall to 35% by 2040 under its reference scenario.[8] Although coal as a percentage of domestic electricity generation is decreasing, the EIA projects that the *amount* of coal consumed annually for that purpose will rise by 16% from 2012 to 2040, from 16.1 quadrillion British thermal units (Btus) to 18.7 quadrillion Btus, due to projected increases in total energy consumption attributable to population growth.[9]

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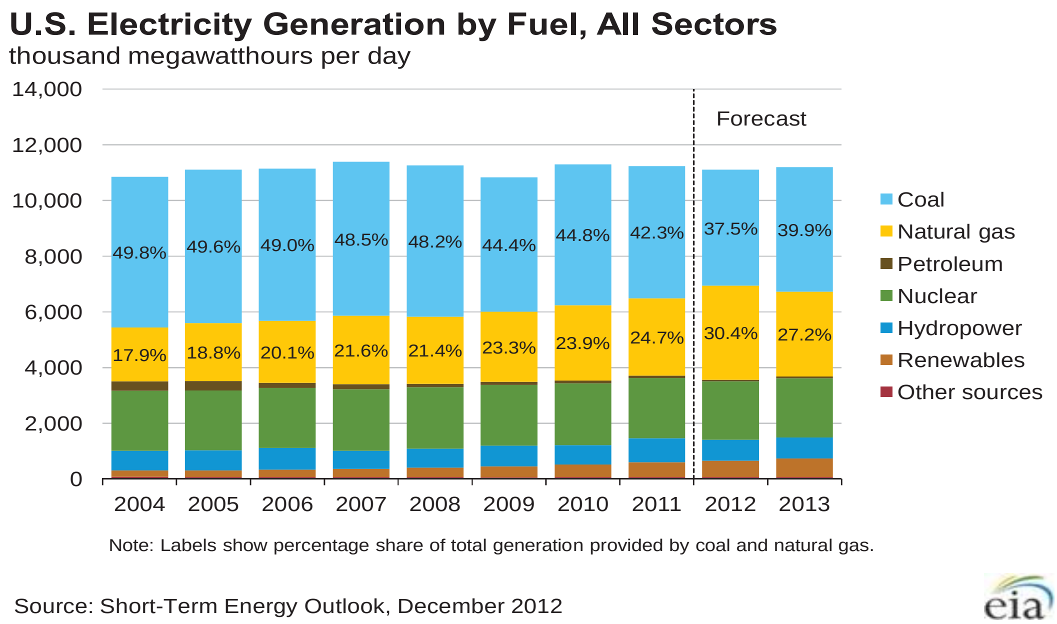
[5] Susan F. Tierney, *Why Coal Plants Retire: Power Market Fundamentals as of 2012,* Analysis Group (February 16, 2012). Available at http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/2012_Tierney_WhyCoalPlantsRetire.pdf.
[6] EIA, *Annual Energy Outlook 2013 Early Release,* Energy Consumption by Sector and Source, United States, 1980–2040.
[7] EIA, *Annual Energy Outlook 2002*. Available at http://www.eia.gov/forecasts/archive/aeo02/.
[8] EIA, *Annual Energy Outlook 2013 Early Release,* Electricity Generation.
[9] EIA, *Annual Energy Outlook 2013 Early Release,* Energy Consumption by Sector and Source, United States, 1980–2040.



The future of coal-fired electricity generation depends on a number of factors, including long-term natural gas prices and the type and stringency of future environmental regulations.[10] The following subsections describe the current coal and natural gas market dynamics and the suite of environmental regulations affecting existing coal-fired power generation.

Natural gas and coal market dynamics

Natural gas consumption for electricity generation increased by 24.6% between 2009 and 2012 as coal consumption for electricity generation decreased over the same period to the lowest level since 1992.[11] Natural gas prices decreased from an average spot price of $7.97 per million metric (mm) Btu in 2008 to $2.75/mmBtu in 2012, although the EIA predicts that the 2013 average spot price will be $3.53/mmBtu.[12]

In contrast to natural gas prices, coal prices have risen steadily over the past decade, increasing almost 6% from 2010 to 2011, although decreased demand for coal and higher inventories are expected to curb these

[10] U.S. Government Accountability Office, *Electricity: Significant Changes Are Expected in Coal-Fueled Generation, but Coal Is Likely to Remain a Key Fuel Source*, 25–31 (October 2012), http://www.gao.gov/assets/650/649744.pdf. Other factors include renewable energy mandates, electricity demand, and the availability of cost-effective technologies to mitigate coal's environmental impact, including carbon capture technologies. *Id.*

[11] EIA, *Short-Term Energy Outlook,* U.S. electricity generation by fuel all sectors (December, 2012). Available at http://www.eia.gov/forecasts/steo/data.cfm?type=figures; *Short-Term Energy Outlook Custom Table Browser* (U.S. natural gas consumption for electric power increased from 18.83 billion cubic feet/day (bcf/day) in 2009 to 24.96 bcf/day in 2012).

[12] EIA, *Short-Term Energy Outlook* (February 2013).

increases through 2014.[13] Because of falling natural gas prices and rising coal prices, utilities are deploying natural gas units, originally built to run intermittently, for baseload power generation in some regions of the country.[14] This trend continued throughout 2012, contributing to a sharp decline in coal consumption by the power sector.[15] Between 2012 and 2016, power plant operators in the United States expect to retire 175 coal-fired plants, representing 27 gigawatts (GW) of capacity or 8.5 percent of the total U.S. coal-fired capacity in 2011.[16] The characteristics of retiring facilities has changed noticeably in the past four years—the coal-fired units facing retirement between 2012 and 2015 are twice the size and 12% more efficient than facilities retired between 2009 and 1011.[17] Although coal prices, production, and consumption will rise and fall in the coming years, coal consumption for electricity generation is not expected to return to pre-recession levels through 2040 without major shifts in energy prices, environmental regulations, or both.[18]

Environmental regulations affecting coal-fired energy production

Recently enacted environmental regulations reinforce these market trends. The Mercury and Air Toxics Standards (Utility MATS), finalized in December 2011, is contributing to the retirement of old and inefficient coal-fired units, for which the installation of control technologies is not financially feasible.[19] In addition to Utility MATS, a slate of other new regulations also affect coal-fired power plants. Some of these rules are already final, such as the tightened National Ambient Air Quality Standards (NAAQS) for SO_2[20] and NOx.[21] Others are still in the proposal or comment stage, including a rule regulating coal combustion residuals[22] and stricter cooling water intake structure rules.[23] The EPA is also assessing regulatory options for addressing interstate SO_2 and NOx emissions after the D.C. Circuit Court of Appeals struck down the Cross State Air Pollution Rule in August 2012.[24]

In April 2012, the EPA proposed a New Source Performance Standard (NSPS) for CO_2 emissions from new power plants that, if enacted as proposed, will have a substantial impact on new coal-fired power

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[13] EIA, "2011 Brief: Energy Commodity Price Trends Varied Widely during 2011," *Today in Energy*, January 9, 2012; EIA, *Short-Term Energy Outlook* (March 12, 2013).

[14] See, e.g., John Downey, "Low Price of Natural Gas Prompts Duke Energy Power Shift," *Charlotte Business Journal*, February 24, 2012; National Petroleum Council, *Power Generation and Natural Gas Demand* (September 15, 2011) ("Generally power plants are dispatched based on variable generation costs with lower cost power plants being dispatched first. With low coal prices in most regions of the country, coal-fueled power plants will nearly always dispatch ahead of natural gas fuel power plants. Only where we find very efficient gas plants (NGCC) and low gas prices ($3–$5/MMBtu) does a gas-fired plant move ahead in the dispatch.").

[15] EIA, *Short-Term Energy Outlook* (January 2013).

[16] EIA, "27 Gigawatts of Coal-Fired Capacity to Retire over Next Five Years," *Today in Energy*, July 27, 2012. Available at http://www.eia.gov/todayinenergy/detail.cfm?id=7290.

[17] *Id.*

[18] EIA, *Annual Energy Outlook 2013 Early Release*, Energy Consumption by Sector and Source, United States.

[19] EIA, "27 Gigawatts of Coal-Fired Capacity to Retire over Next Five Years," *Today in Energy*, July 27, 2012.

[20] 40 CFR Parts 50, 53, and 58; Primary National Ambient Air Quality Standard for Sulfur Dioxide, 75 Fed. Reg. 35520 (June 22, 2010).

[21] 40 CFR Parts 50 and 58; Primary National Ambient Air Quality Standards for Nitrogen Dioxide, 75 Fed. Reg. 6473 (February 9, 2010).

[22] U.S. EPA, *Coal Combustion Residuals—Proposed Rule*. Available at http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/index.htm.

[23] U.S. EPA, *Cooling Water Intake Structures—CWA § 316(b)*. Available at http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

[24] U.S. EPA, *Interstate Air Pollution Transport*, http://www.epa.gov/airtransport/; *EME Homer City Generation v. EPA*, 696 F.3d 7 (D.C. Cir. 2012).

generation in the long term.[25] The proposed output-based standard of 1,000 pounds of CO_2 per megawatt-hour (lb CO_2/MWh gross) is achievable with natural gas combined-cycle units, but even the most efficient coal-fired units in operation or under construction would not meet the proposed emission standard without additional controls to capture CO_2 emissions (for storage or reutilization).[26] The proposed NSPS does not apply to modifications or to units that start construction within 12 months of the rule's publication.

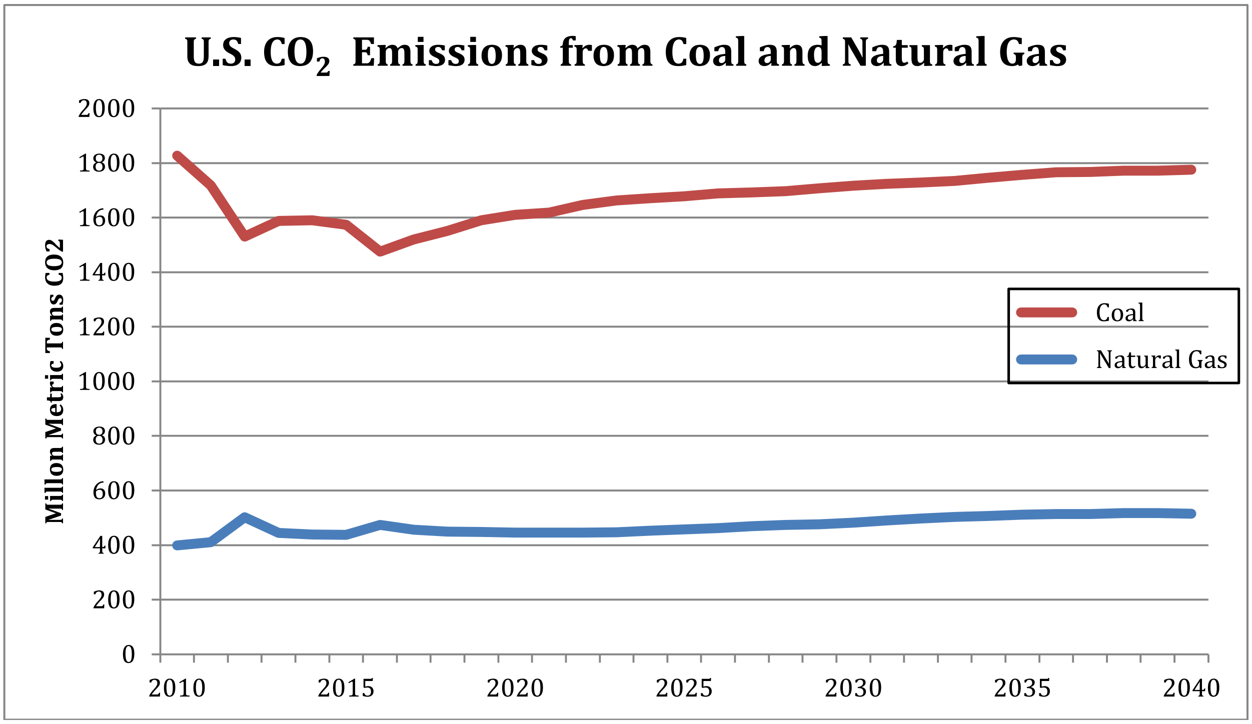
Once finalized, the CO_2 NSPS rule will trigger a requirement that the EPA and the states develop performance standards limiting CO_2 emissions from existing fossil fuel-fired power plants.[27]

Regulation	Status
Title V operating permitting for major emitters of greenhouse gases	Final rule published December 1, 2010
PSD permitting for major emitters of greenhouse gases	Final rule published December 1, 2010
Toxics Rule (Utility MACT + Utility NSPS)	Final rule published December 16, 2011
CWA Section 316(b) (Cooling Water Intake Existing Facilities Rule)	Proposed rule published April 20, 2011
New Source Performance Standards for CO_2 emissions	Proposed rule for new sources published April 13, 2012; timeline for existing sources unknown
Cross-State Air Pollution Rule	Final rule overturned by the U.S. Court of Appeals for the D.C. Circuit; the EPA is reviewing regulatory options for limiting interstate SO_2 and NOx emissions
Coal combustion residuals (coal ash)	Proposed rule issued June 21, 2010; EPA has offered no timeline for announcement of the final rule

[25] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (proposed April 13, 2012).
[26] *Id*. For a description of IGCC and ultra-supercritical technologies, see National Energy Technology Laboratory (NETL), Coal-Fired Power Plants (CFPPs): Integrated Gasification Combined Cycle (IGCC), http://www.netl.doe.gov/technologies/coalpower/cfpp/technologies/igcc_systems.html; NETL, Coal-Fired Power Plants (CFPPs): Supercritical and Ultra Supercritical Boilers, http://www.netl.doe.gov/technologies/coalpower/cfpp/technologies/supercritical_utltr_boilers.html.
[27] 42 U.S.C. 7411(d).

3. CO_2 Emissions from Coal-Fired Power Plants

In 2010, coal use accounted for approximately 35% of domestic anthropogenic CO_2 emissions[28] and 43% of global emissions.[29] Despite the increased generation from natural gas,[30] announced retirements of coal-fired power plants, and a negligible amount of anticipated new coal generation, the EIA's reference case in the *Annual Energy Outlook 2013 Early Release* projects that U.S. emissions from coal-fired power will remain relatively constant due to increased generation at the remaining facilities—1,874 million metric tons (MMT) of CO_2 per year by 2030, slightly higher than the 1,866 MMT attributed to coal-fired power in 2011.[31]



Source: EIA, *Annual Energy Outlook 2013 Early Release,* Reference Case.

In contrast to the U.S. projections, global CO_2 emissions from coal-fired power are expected to increase significantly in the next two decades. The International Energy Agency reports that electricity production from hard coal-fired electricity and combined heat and power amounted to 3,036 terrawatt hours (TWH) in 2011 in OECD countries and 2,692 TWH in non-OECD countries in 2010; coal combustion produced 13.1 gigatons of CO_2, or 43% of total global CO_2 emissions.[32] Barring major technology advances and a changed policy environment for CO_2 emissions, emissions from existing coal-fired power plants will

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[28] *Id.*

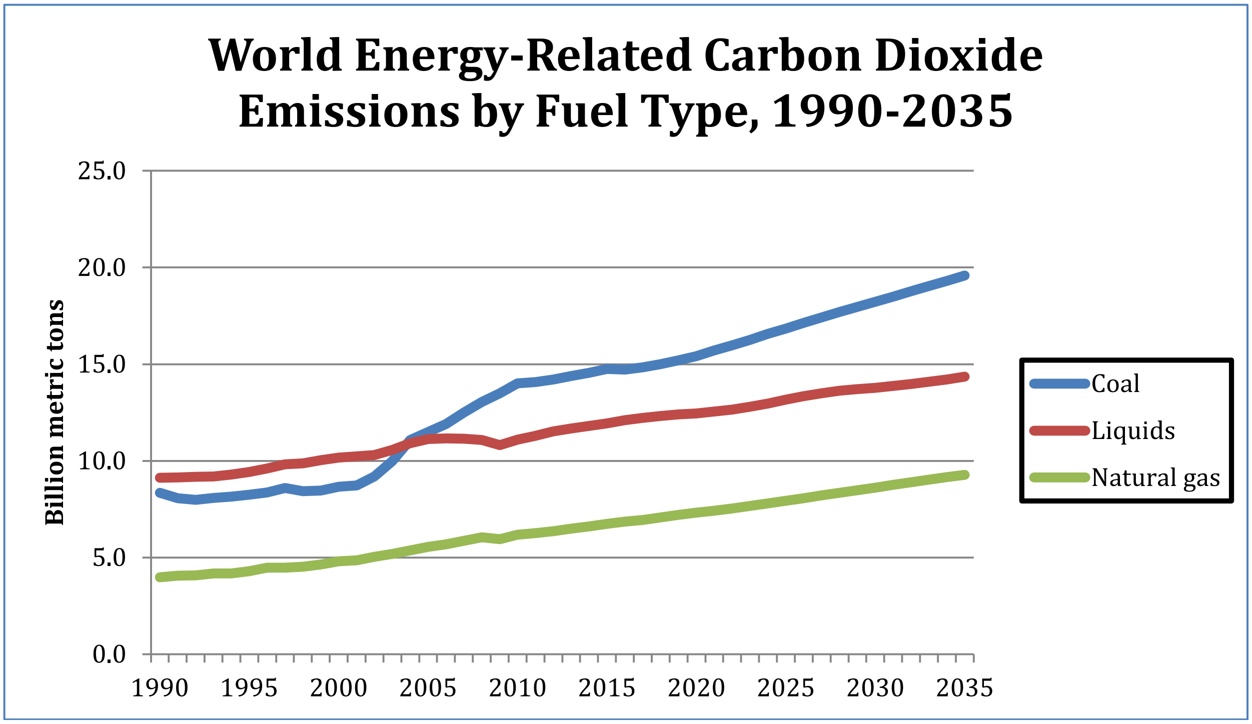
[29] IEA, *CO_2 Emissions from Fuel Combustion: Highlights*, at 8 (2012).

[30] Generating electricity from natural gas emits approximately 50% less CO_2 than coal-fired generation. U.S. EPA, *Clean Energy: Natural Gas*, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html (updated October 17, 2012).

[31] EIA, *AEO 2013 Early Release*, Energy-Related CO_2 Emissions.

[32] IEA, *Electricity Information* (2012 edition), at II.8–11.9. Total electricity generation from "[e]lectricity production from all coal sources, including pete and coal-derived gases" reached 3,710 TWH in OECD countries and 4,951 TWH in non-OECD countries during the same time period. *Id.*

remain unchecked. The EIA's *International Energy Outlook 2011* base case projects a 76% increase in coal-related CO_2 emissions by 2035.[33]



Source: EIA, *International Energy Outlook 2011.*

The Global CCS Institute lists 39 power generation facilities with carbon capture in various stages of development across the globe as of January 2013; the majority are still under evaluation.[34] Given the scale of additional coal-fired capacity anticipated in the coming decades, it appears that the vast majority of new facilities will not include carbon capture. Once operational, retrofit technologies would be necessary to dramatically reduce CO_2 emissions from these facilities.

These projections highlight the importance of deploying carbon capture technologies for existing power plants, both domestically and internationally. In the United States, coal will likely remain the dominant fuel source for electric power for the foreseeable future, and the EIA's reference case projects that emissions from coal-fired power will be more than three times higher those from natural gas-fired power in 2040: 1,775 mmt/CO_2 from coal compared with 514 mmt/CO_2 from natural gas. Significant CO_2 reductions from the U.S. power sector, therefore, will require either reduced generation from coal or installation of carbon capture technologies. Internationally, cost-effective carbon capture technologies for both new and existing facilities will be important to achieving climate stabilization goals.

[33] EIA, *International Energy Outlook 2011: Energy Related Carbon Dioxide Emissions*, http://www.eia.gov/forecasts/ieo/emissions.cfm. The EIA's upcoming 2013 International Energy Outlook may include revised projections.
[34] Global CCS Institute, *Status of CCS Project Database* (updated January15, 2013), http://www.globalccsinstitute.com/data/status-ccs-project-database.

4. Near-Term Public Policy Choices

The market and regulatory factors described above create a bleak outlook for developing and deploying new technologies aimed at coal-fired generation. With electric utilities and merchant electric generators turning away from coal for new electricity generation and the lack of a policy driver requiring major CO_2 emission limits for existing power plants, there is no immediate market demand for such technologies. Continuing improvements in carbon capture technology, therefore, will likely require a significant ongoing federal role in technology development and deployment.

Two near-term policy choices will have a large impact on deployment of low-carbon technologies for existing coal-fired power plants: addressing energy RD&D funding in an era of shrinking federal budgets and developing Clean Air Act regulations limiting CO_2 emissions from existing fossil fuel-fired power plants. This subsection outlines these policy choices and describes options for aligning technology goals and environmental policy approaches.

Federal funding for CCS RD&D

Estimates for the cost to capture and store CO_2 range between $35 and $70/ton of CO_2 avoided at a new pulverized coal plant.[35] The Department of Energy (DOE) Office of Fossil Energy estimates that today's CCS technologies could increase the cost of electricity from a new pulverized coal-fired power plant by up to 80%.[36] The cost of retrofitting an existing facility could be higher, depending on "site-specific factors such as the plant size, age, efficiency, the type and design of existing air pollution control systems and availability of space to accommodate a capture unit."[37] The DOE's Carbon Capture Program aims to address this cost barrier by

> achiev[ing] a capture cost of less than $40/tonne of CO_2 captured for second generation technologies and less than $10/tonne of CO_2 captured for transformational technologies. These goals are expressed in 2011 dollars and assume 90 percent CO_2 capture. Given the significant economic penalties associated with currently available carbon capture technologies, step-change improvements in both cost and energy penalty will be required to achieve these goals.[38]

The DOE's National Energy Technology Laboratory (NETL) plans to focus on laboratory-scale research through 2017, exploring "advanced second and third generation solvents, sorbents, membranes, oxy-combustion systems, and chemical looping."[39] Small-scale pilot projects also commenced in 2010 and, assuming adequate funding, will continue through 2021.[40] NETL plans to follow this round of testing with large pilot-scale testing between 2016 and 2025 and demonstration-scale testing after 2020.[41] NETL

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[35] Mohammed Al-Juaied and Adam Whitmore, *Realistic Costs of Carbon Capture*, Discussion Paper 2009–08, Energy Technology Innovation Research Group, Belfer Center for Science and International Affairs, Harvard Kennedy School, July 2009; Ed Rubin et al., *The Outlook for Improved Carbon Capture Technology*, 38 PROGRESS IN ENERGY AND COMBUSTION SCIENCE 630, 637 (2012).

[36] Dept. of Energy, *Post Combustion Capture Research*, http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/Retrofitting_Existing_Plants.html (updated March 19, 2012).

[37] Ed Rubin et al., "*The Outlook for Improved Carbon Capture Technology*, 38 PROGRESS IN ENERGY AND COMBUSTION SCIENCE 630, 637 (2012)."

[38] Dept. of Energy, *DOE's Carbon Capture Program,* http://www.fossil.energy.gov/programs/sequestration/capture/index.html.

[39] NETL, *DOE/NETL Advanced Carbon Dioxide Capture R&D Program Accomplishments*, at 1 (April 2012).

[40] *Id.*

[41] *Id.*

anticipates "that successful progression from laboratory through demonstration-scale testing will result in several of these advanced technologies being available for commercial deployment after 2030."[42]

The Advanced Research Projects Agency–Energy (ARPA-E) is another entity within the DOE focusing on carbon capture technologies.[43] ARPA-E's stated mission is to "advance[] high-potential, high-impact energy technologies that are too early for private-sector investment," providing funding and technical assistance to universities and private sector companies.[44] ARPA-E's Innovative Materials and Processes for Advanced Carbon Capture Technologies (IMPACCT) program is currently funding 15 projects at a total of $33.7 million. The stated goals of the IMPACCT program include (1) capturing up to 90% of CO_2 at significantly lower costs than is currently possible and (2) increasing global implementation of carbon capture technology.[45]

Congress has appropriated nearly $6 billion for DOE's CCS research and development since 2008, with $3.4 billion provided by the American Recovery and Reinvestment Act of 2009 (Recovery Act) as a one-time investment in CCS-related programs.[46] Six large-scale carbon capture projects are currently planned or under way at coal-fired power plants. As shown in the table below, five of the six projects are receiving DOE funding. Only one of the projects—NRG Energy's W.A. Parish Plant in Thompsons, Texas—is taking place at an existing facility.

Large-Scale Projects to Install CCS Technology in Power Plants That Are Currently Planned or Under Construction in the United States

Project	Private-Sector Project Leader	Location	Size (Megawatts)	DOE Funding (Millions of dollars)	Planned Completion Date
FutureGen 2.0	FutureGen Industrial Alliance	Meredosia, Ill.	200	1,000	2015
Hydrogen Energy California	SCS Energy	Kern County, Calif.	390	308	2014
Kemper County	Mississippi Power/Southern Company	Kemper County, Miss.	582	270	2014
Tenaska Trailblazer Energy Center	Tenaska, Inc.	Sweetwater, Tex.	600	0	2014
Texas Clean Energy	Summit Power Group	Ector County, Tex.	400	450	2014–2015
W.A. Parish Plant	NRG Energy	Thompsons, Tex.	60	154	2017

Source: Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide, Table 1.*

The small number of CCS plants under construction and the large amounts of federal funding for all but one of them demonstrate that carbon capture technologies are not commercially viable under current conditions without federal support. If policy makers wish to achieve the DOE's cost reduction goals,

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42 *Id.*
43 ARPA-E, *About ARPA-E*, http://arpa-e.energy.gov/?q=arpa-e-site-page/about.
44 *Id.*
45 U.S. Department of Energy, *Innovative Materials and Processes for Advanced Carbon Capture Technologies* (IMPACCT). Available at http://arpa-e.energy.gov/ProgramsProjects/IMPACCT.aspx.
46 Peter Folger, *Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy*, Congressional Research Service (June 19, 2009).

continued funding for demonstration projects will almost certainly be necessary.[47] As Rubin, et al. point out in a recent article on the outlook for carbon capture technologies:

> [I]nnovation is stimulated not only by support for R&D, but also by the experience of early adopters, plus added knowledge gained as a technology diffuses more widely into the marketplace. The reductions in product cost that are often observed as a technology matures—commonly characterized as a "learning curve"—reflect the combined impacts of sustained R&D plus the benefits derived from "learning by doing" (economies in the manufacture of a product) and "learning by using" (economies in the operating costs of a product).[48]

The level of federal funding available for energy RD&D is in question. Congress enacted the Budget Control Act in 2011, requiring automatic budget cuts to all federal discretionary spending starting on March 1, 2013, unless lawmakers reached an alternate budget compromise. The budget cuts—referred to as the "sequester"—went into effect as originally enacted, requiring a $55 billion cut to defense discretionary spending and up to $38 billion in cuts to nondefense discretionary spending.[49] According to an analysis by the American Association for the Advancement of Science, DOE energy programs (including "fossil, nuclear, renewables, efficiency, ARPA-E, and other research") will face a budget cut of $854 million between FY2012 and FY2017 unless Congress amends the mandatory across-the-board budget cuts. If Congress opts to maintain defense spending at pre-March 2013 levels and instead allocate the $55 billion to non-defense discretionary budgets, cuts to the DOE's energy programs could jump to almost $2 billion.[50]

<u>Options for near-term RD&D funding targeting CO_2 emissions from existing power plants</u>

- At a minimum, federal lawmakers interested in continuing to support CCS RD&D could seek to return federal funding for DOE carbon capture projects to pre-March 1, 2013, levels, either as part of a broad budget compromise or through targeted legislation.
- To ensure a focus on existing power plants, federal legislation could earmark a portion of any future CCS RD&D funding for technologies that are capable of capturing CO_2 emissions at existing power plants.
- Future CCS RD&D funding could also facilitate collaboration between DOE's Office of Fossil Energy and ARPA-E. Pairing the expertise at these distinct DOE entities could streamline federal efforts to promote development and deployment of cost-effective carbon capture technologies. In addition, collaboration between ARPA-E and the Office of Fossil Energy to deploy carbon capture technologies at existing power plants could create an early market for ARPA-E-funded technologies.

CO_2 regulations under the Clean Air Act

The EPA has undertaken a number of rulemaking processes aimed at GHG emissions (including CO_2).[51] Most significant for deployment of carbon capture technologies at exiting coal-fired power plants are the

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[47] Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide,* Pub. No. 4146 (June 2012). Available at http://www.cbo.gov/sites/default/files/cbofiles/attachments/43357-06-28CarbonCapture.pdf.

[48] Ed Rubin et al., *The Outlook for Improved Carbon Capture Technology*, 38 PROGRESS IN ENERGY AND COMBUSTION SCIENCE 630, 638 (2012).

[49] Matt Hourihan, *Brief: Federal R&D and Sequestration in the First Five Years*, at 1 (September 27, 2012).

[50] *Id. at* 8.

[51] Portions of this subsection are taken from the Nicholas Institute publications "Primer on GHG Regulation of Stationary Sources under the Clean Air Act: Interaction of Tailoring Rule and Proposed NSPS" by Jonas Monast

Tailoring Rule,[52] which went into effect in 2011, and the upcoming performance standards that will regulate CO_2 emissions from existing fossil fuel-fired power plants. The Clean Air Act sections governing these programs both call for consideration of costs,[53] demonstrating the direct relationship between the federal government's efforts to develop cost-effective technologies and the capacity of Clean Air Act policy to drive adoption of the policies.

The Tailoring Rule requires any new stationary facility emitting more than 100,000 tons per year (tpy) of GHG emissions to obtain a Prevention of Significant Deterioration (PSD) air quality permit. The rule also covers modifications of a facility that emits 100,000 tpy of GHGs when the modification increases GHG emissions by at least 75,000 tpy.[54] The PSD program is a part of the New Source Review program and requires the installation of the Best Available Control Technology (BACT)—a source-specific strategy for limiting emissions through equipment or production processes.[55] A permitting agency (typically at the state level) determines BACT on the basis of "the maximum degree of reduction" achievable for a pollutant, considering costs as well as energy, environmental, and economic impacts.[56] The EPA's guidance to permitting authorities states:

> For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants ... This does not necessarily mean CCS should be selected as BACT for such sources. Many other case-specific factors, such as the technical feasibility and cost of CCS technology for the specific application, size of the facility, proposed location of the source, and availability and access to transportation and storage opportunities, should be assessed at later steps of a top-down BACT analysis.[57]

Although the EPA's BACT guidance is clear that CCS is not necessarily BACT at this time, it is possible that future BACT determinations could require installation of carbon capture technologies if the cost of the technologies falls significantly.

The Clean Air Act provision with the most potential to affect carbon capture technologies in the near term is the upcoming action under Section 111—the section covering NSPS and existing source performance standards. As described above, the EPA issued a proposed NSPS for CO_2 emissions from fossil fuel-fired power plants in April 2012. The Clean Air Act also requires states to regulate *existing* sources under the following conditions:

- the pollutant is covered under an NSPS rule;

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and Jeremy Tarr and "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act: Options, Limits, and Impacts" by Jeremy M. Tarr et al.

[52] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514, 31516 (June 3, 2010) [hereinafter "Tailoring Rule"].

[53] 42 U.S.C. §§ 7411(1) & 7479(3).

[54] Tailoring Rule, 75 Fed. Reg. at 31,516. The Clean Air Act requires a PSD permit for any modification at a major emitting facility. 42 U.S.C. § 7475(a) (2006) (requiring a permit for any "construction," which is defined in section 7479(a)(C) to include any "modification" to a source or facility). The Tailoring Rule treats GHG emissions differently than emissions of other pollutants. A modification may be subject to PSD permitting requirements for non-GHG emissions but not subject to PSD permitting requirements for GHG emissions.

[55] 42 U.S.C. §§ 7470(1), 7475(a) (2006).

[56] 24 U.S.C. § 7479(3) (2006).

[57] U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 32 (March 2011), http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

- the pollutant is not a criteria pollutant[58] or a hazardous air pollutant; and
- the existing source would be subject to NSPS if it were a new or modified source.[59]

Typically, pollutants regulated under NSPSs are also listed as criteria pollutants or hazardous air pollutants. However, GHGs do not fall under either category, and thus the EPA is required to regulate existing sources of GHGs under Section §111(d) of the Clean Air Act.

Under Section 111(d), the EPA specifies a procedure for states to submit performance standards for existing sources to the agency for approval. This process is similar to the state implementation process for the NAAQS program (specifically Section 110). Each state must then submit a plan to the Agency that establishes standards of performance for existing sources.[60] The definition of "standard of performance" calls for the application of the "best system of emission reduction," taking cost into account, that "the Administrator determines has been adequately demonstrated."[61] The statute does not define the term "best system." According to the EPA's regulations governing Section 111(d) rulemakings, the agency will identify the potential emission limits achievable from existing emission reduction systems and will assess each limit on the basis of costs and benefits to determine the "best system of emission reduction."[62] The states must then establish a performance standard that achieves the emission limit and decide how to implement the standard.[63] Although existing-source standards typically set a "numerical emissions limit, expressed as a performance level (i.e., a rate-based standard)," the EPA has previously determined that averaging emissions across facilities or an emission trading system can qualify as a "best system."[64]

Options for incentivizing deployment of carbon capture technologies under Section 111(d)

- Although it is unlikely that the states' Section 111(d) rules alone would lead to the installation of carbon capture technologies, they could provide incentives that contribute to a plant owner's decision to retrofit an existing plant with such technologies. For example, a state Section 111(d) rule that allows power plant operators to average emissions across a firm or trade allowances could provide credit for a dramatic reduction in CO_2 emissions.[65]
- Coupling Section 111(d) policy design that rewards installation of emission-reducing technology with federal funding for CCS deployment could further incentivize plant operators to retrofit a coal-fired plant with CCS.

5. Conclusion

There is a pressing need for technology improvements that make it cost-effective for coal-fired power plants to capture carbon emissions. CCS technologies are particularly important for the fleet of existing

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58 Criteria pollutants include the six pollutants subject to the National Ambient Air Quality Standards (NAAQS) program: carbon monoxide, nitrous oxides, sulfur dioxide, sulfur oxide, ozone, particulate matter, and lead. EPA, National Ambient Air Quality Standards (NAAQS), http://www.epa.gov/air/criteria.html.

59 42 U.S.C. § 7411(d)(1).

60 42 U.S.C. § 7411(d)(1).

61 42 U.S.C. § 7411(a)(1).

62 40 C.F.R. § 60.22.

63 Regulating Greenhouse Gas Emissions Under the Clean Air Act (Advanced Notice of Proposed Rulemaking), 73 Fed. Reg. 44486.

64 *See* Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units (Clean Air Mercury Rule), 70 Fed. Reg. 28,606 (July 18, 2005); Emission Guidelines for Municipal Waste Combustor Metals, Acid Gases, Organics, and Nitrogen Oxides, 40 C.F.R. § 60.33b(d).

65 For a discussion of the legal and economic issues associated with flexible compliance options under §111(d), see Jeremy M. Tarr et al., *Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act: Options, Limits, and Impacts*, Nicholas Institute for Environmental Policy Solutions, January 2013.

coal-fired power plants, as energy projections suggest that these facilities will continue to provide a major portion of the nation's electric power—and the nation's CO_2 emissions—for decades to come. Federal policy makers have two upcoming choices that will affect the development and deployment of these technologies—budget decisions regarding federal funding for RD&D and implementation of Clean Air Act rules limiting CO_2 emissions from the power sector. The outcome of the budget decision, in particular, will potentially determine the scale of research and the ability of the federal government to fund early demonstration plants for many years, both of which are important elements of the technology innovation process.