A Risky Proposition

The Financial Hazards of New Investments in Coal Plants

Union of Concerned Scientists

Citizens and Scientists for Environmental Solutions

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The opinions and information expressed herein are the sole responsibility of the authors.

Executive Summary

Across the United States, the electric power sector is placing new bets on an old technology—coal-fired power plants. Utilities and other electricity producers are poised to invest heavily in retrofitting their old plants or in building new ones. Each major retrofit or new plant represents an enormous long-term financial commitment to coal power. But as discussed in this report, current economic, technological, and policy trends make such commitments exceedingly risky.

Demand for coal power is being steadily eroded by competition from energy efficiency and renewable energy, which are benefiting from rising policy support, growing public investment, advancing technologies, and often-falling prices. Coal power also faces much stronger competition both from new and existing (though underutilized) natural gas plants, which can take advantage of today's relatively low gas prices.

Coal prices, by contrast, are on the rise. Having spiked in 2008 in response to global coal demand, they are climbing again with the global economic recovery. There is growing concern, moreover, that they could be driven much higher by soaring demand from China and India, as well as by falling productivity across all U.S. coalfields and by shrinking reserve estimates. Construction costs for coal plants, which skyrocketed in the years prior to 2008, remain high, and all these risks make the financing of long-term coal investments both harder and costlier. Coal plants, new and old, are losing the cost advantages they once had, and they lack the operational flexibility that will be increasingly valuable as the power grid evolves to integrate more sources of clean but variable renewable power.

In addition to these ongoing structural changes, which are making coal power increasingly costly and less competitive, coal power faces the financial risks posed by its many environmental impacts. The continuing damages that coal power poses to our air, land, and water—and our health—are a major financial liability that remains unresolved. Coal plants emit air pollutants that still kill thousands of people yearly, costing society over $100 billion per year, by one estimate (CATF 2010). These plants are also a leading source of mercury, which threatens children's brain development; they create vast quantities of toxic ash, which require careful handling in order to prevent leakage; and their huge cooling-water withdrawals strain our increasingly vulnerable water bodies. Expected regulations would reduce many of these costly harms, but as several recent financial analyses point out, much of the nation's coal fleet is already old, inefficient, and ripe for retirement. Rather than retrofit them, it makes greater economic sense to close them.

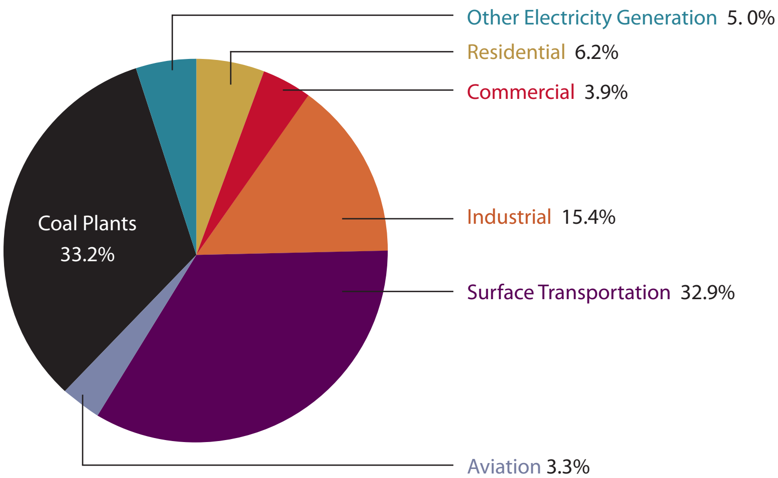
Finally, there is the unavoidable financial risk associated with coal's critical role in destabilizing the global climate. Given the increasingly dire nature of global warming, climate legislation is still widely expected in the years ahead, with inevitable cost implications for coal plants.

Combined, these trends and developments create risks that no one considering a long-term investment in new or existing coal plants can afford to ignore. They also create unique opportunities to invest instead in the cleaner technologies that will be in growing demand as we transition toward a more modern, flexible, diversified, and sustainable energy system.

"The need for urgent action to address climate change is now indisputable." This warning was part of a 2009 joint statement by the U.S. National Academy of Sciences and its counterpart academies from 12 other nations, urging world leaders to take action to slow global warming (NAS 2009). Already, the climate is changing, both faster and in more dangerous ways than computer models had projected, and much worse lies ahead if we fail to make deep cuts in our global warming emissions (NRC 2010a).

Deep emissions cuts are needed from coal plants. Coal power is the nation's largest source of CO_2, emitting more than all of our cars, trucks, and other modes of surface transportation combined (Figure ES.1, p. viii). As the source of one-third of energy-related CO_2 emissions, coal plants must be a primary source of the reductions we need to protect the climate. Indeed, reducing emissions from coal plants is a particularly cost-effective approach to climate protection (Cleetus, Clemmer, and Friedman 2010).

Figure ES.1. U.S. CO_2 EMISSIONS FROM ENERGY USE BY SOURCE, 2009



More CO_2 is emitted from coal plants than from any other technology or sector, including all modes of surface transportation combined (EIA 2011a). (Power plant emissions are presented under coal plants and other electricity generation, rather than under the residential, commercial, and industrial sectors where the power is consumed.)

A future price on carbon still threatens coal investments. The 111th Congress failed to pass a comprehensive climate bill, and the 112th Congress is even more deeply divided on the issue, thereby perpetuating uncertainty over the timing and nature of future climate policies and their impacts on coal plants. However, the growing urgency of global warming means that Congress will face sustained pressure to tackle the problem again, perhaps repeatedly over the years, until the nation is off the dangerous path it is currently traveling (unless other factors, such as a steep decline in coal use driven by the other risks discussed in this report, succeed in slashing our carbon emissions). Because a price on carbon would help to stimulate private-sector innovation, it remains a likely element of such future climate policies; and as the source of power that has the highest carbon emissions, coal would thereby be disadvantaged compared with cleaner technologies.

Carbon-capture retrofits cannot be counted on to cut emissions affordably. While projects to demonstrate the potential of carbon capture and storage (CCS) are important, it would be financially reckless to make coal-plant investments based on the assumption that CCS retrofits will provide an affordable way for those plants to avoid a future price on CO_2 emissions. There are still no coal-fired power plants using CCS on a commercial scale. Design estimates indicate that CCS could increase the cost of energy from a new pulverized coal plant by 78 percent, and costs would be even greater if CCS were added as a retrofit (ITF CCS 2010). It is always possible that future advances in CCS technology will drive such costs down substantially, but the CCS projects under development today have faced serious cost overruns and delays. Moreover, the fall in natural gas prices, concern over future coal supplies and prices, and the failure of the 111th Congress to pass climate legislation—which would have put a price on carbon and established massive subsidies for CCS—may further delay CCS development.

Many of the nation's coal plants are old, inefficient, and ripe for retirement. Seventy-two percent of present U.S. coal capacity is already older than 30 years—the operating lifetime for which coal plants were typically designed—and 34 percent of the nation's coal capacity is more than 40 years old (Bradley et al. 2010). Older plants become increasingly inefficient and unreliable, and they face high maintenance and capital costs if they are to continue operating economically. And because they were built before modern pollution controls were required and over the decades many have avoided adding those controls, Coal is no longer a reliably low-cost fuel, in part because it is increasingly vulnerable to volatile global markets.

older plants are generally far more polluting than new ones and face significant retrofit costs as a result.

Coal plant operators in various parts of the country—including Colorado, Delaware, Georgia, Illinois, Indiana, Minnesota, North Carolina, Ohio, and Pennsylvania—have already announced the retirement of dozens of their oldest plants (Bradley et al. 2010). By December 2010, 12 gigawatts (GW) of coal plant retirements had already been announced (Salisbury et al. 2010). Financial and industry analysts expect the wave of retirements to grow. In the words of a Credit Suisse analyst, "a large chunk of the U.S. coal fleet is vulnerable to closure simply due to crummy economics" (Eggers et al. 2010). In announcing the closure of three of its older coal units, Exelon Corp. noted, "these aging units are no longer efficient enough to compete with new resources" (Power-Gen Worldwide 2009).

Excess generating capacity in the United States will facilitate coal retirements. The nation currently has ample generating capacity, which can help it accommodate the projected coal plant retirements and still maintain the reliability of the power system (Bradley et al. 2010; Shavel and Gibbs 2010). One recent analysis found that the power sector "is expected to have over 100 GW of surplus generating capacity in 2013" (Bradley et al. 2010).

New coal plants are not economic, even under current policies. The economic outlook for new coal plants is very different from what it was just a few years ago.[1] When most new plant projects in the pipeline today were announced, the U.S. Energy Information Administration (EIA) computer model predicted a large amount of new coal plant construction in the years ahead (Figure ES.2, p. x). But now the same model no longer projects any new coal plants without CCS coming online through 2030 (apart from 11.5 GW of new coal plants that the EIA counts as already under construction and assumes will be completed). The EIA's modeling has historically underestimated coal plant costs, but it is starting to reflect the economic realities that have already led to the recent cancellation or rejection of about 150 coal plant proposals nationwide and that threaten the remaining coal plant proposals as well.

Demand for coal power will continue to fall as the nation turns to cleaner options. Coal provided almost 53 percent of U.S. power demand in 1997, but market share dropped to less than 46 percent in the first half of 2010. Given the strong growth of competing cleaner technologies, this decrease is likely to continue.

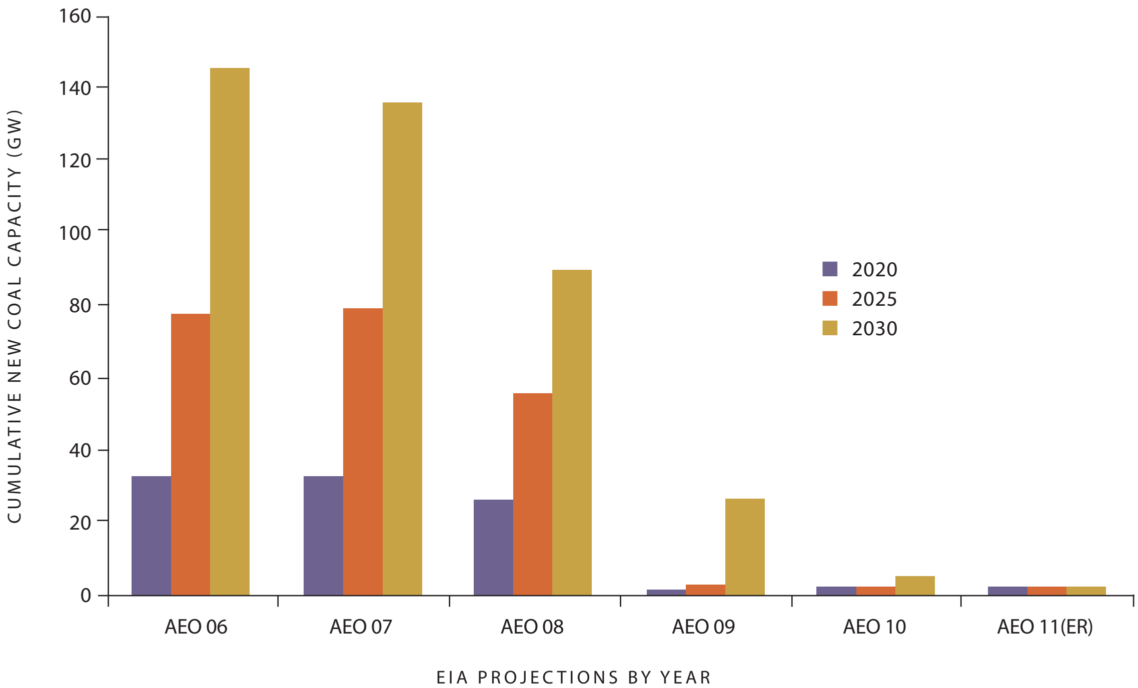
- *Energy efficiency* has enormous potential to cut power demand—by 23 percent below projected levels by 2020 and by even more if the technology is assumed to advance (Goldstein 2010; Granade et al. 2009). That potential is beginning to be realized, as 27 states at present—double the number in 2006—have adopted or have pending energy efficiency resource standards that over time can greatly reduce electric demand (ACEEE 2010a). State spending on ratepayer-funded electricity- and gas-efficiency programs nearly doubled between 2007 and 2009, rising from $2.5 billion to $4.3 billion (ACEEE 2010a). And new federal appliance standards for more than 20 consumer products will help reduce consumer demand for years to come.

- *Renewable power* is capturing a growing share of the market from coal, and it has the potential to go much further. While non-hydro renewable power provided 3.6 percent of U.S. generation in 2009, the EIA projects that it will increase to 11.7 percent by 2030, primarily because of existing state policies and federal incentives (EIA 2010a). Federal research also concludes that we could meet nearly a quarter of our power needs with renewable power by 2025 with no significant impact on consumer prices at the national level (Sullivan et al. 2009). Wind alone could meet 20 percent of demand by 2030 (EERE 2008),

1 While many of the new coal plants announced over the last few years were subsequently cancelled or blocked (largely as a result of the economic and policy trends discussed in this report), dozens of proposals are still on the table. The Sierra Club maintains a database of coal-fired power plant proposals around the country. As of January 2011, it lists 149 coal projects as recently cancelled or rejected, 50 plants as active or upcoming, 26 plants as progressing (some of which have been completed), and 18 plants with uncertain status (Sierra Club 2011).

Figure ES.2. DECLINING FEDERAL PROJECTIONS OF NEW COAL PLANTS THROUGH 2030

In its Annual Energy Outlooks (AEOs), the EIA's projections of unplanned coal capacity coming into service by 2020, 2025, and 2030 have dropped dramatically. In 2006 the EIA projected 145 GW of new coal by 2030 (the equivalent of about 240 new plants of 600 megawatts). But the agency now projects only 2 GW by 2030, consisting entirely of advanced plants with CCS technology that are inputs to the model based on the assumed response to federal subsidies. Planned capacity additions—plants that the EIA understands to be under construction already—are not reflected (EIA 2006, 2007, 2008a, 2009a, 2010a, 2011a).

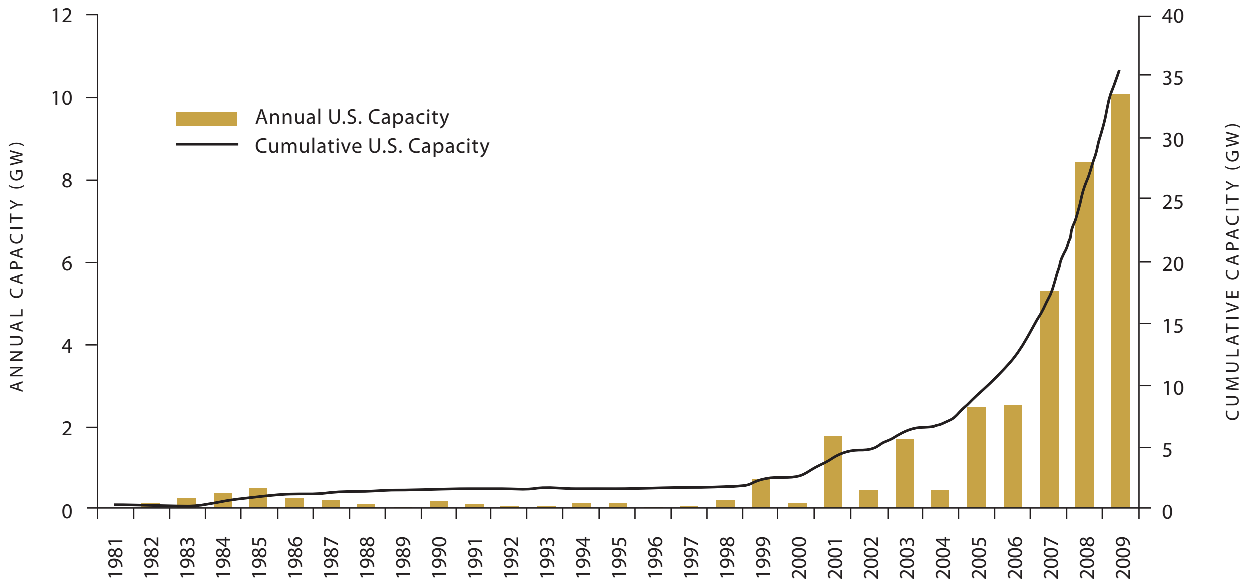


and indeed wind capacity has been added to the grid at a remarkable pace over the last few years (Figure ES.3). Both photovoltaic (PV) and concentrating solar power (CSP) are seeing dramatic growth in their market shares as well, with major new projects moving forward and prices for solar panels falling markedly. New renewable capacity will continue to enter the system, even without further policy changes, as a result of the renewable energy standards already adopted by 30 states and advances in renewable technology.

- *Natural gas* represents another major threat to coal power. The nation has more than 220 GW of efficient natural gas combined-cycle plants, many built in just the last decade. These plants are still greatly underused, operating at 42 percent of capacity in 2007 (Kaplan 2010) and at only 33 percent in 2008 (Bradley et al. 2010). Moreover, gas prices—and price projections—have fallen significantly, partly as a result of technological breakthroughs in drilling that have the potential to dramatically increase domestic gas production for years (as long as the industry can resolve growing concerns over impacts on water and new questions about methane leakage during production). Ramping up the use of existing gas plants could allow the nation to substantially cut its coal-based electricity generation (Casten 2010; Kaplan 2010). Moreover, new

Figure ES.3. WIND POWER GROWING AT RECORD PACE

U.S. wind power capacity expanded by over 50 percent in 2008 alone and continued to expand in 2009 despite the recession (Wiser and Bolinger 2010).



gas plants could be built at a relatively low cost and existing coal plants could be repowered to burn natural gas. While environmental concerns or other factors may drive gas prices back up, would-be coal investors cannot ignore the competitive threat from gas. "Coal is losing its advantage incrementally to gas," a gas analyst with Barclays Capital recently told the *New York Times*, and an energy analyst with Credit Suisse said that the shift from coal to gas "has the potential to reshape energy consumption in the United States significantly and permanently" (Krauss 2010).

U.S. coal prices are rising and could be driven much higher by soaring global demand and shrinking reserves. Coal is no longer a reliably low-cost fuel, in part because it is increasingly vulnerable to volatile global markets. Eastern U.S. coal spot prices spiked in 2008 (Figure ES.4, p. xii), mainly in response to the rising price of coal in international trade, and prices are climbing again as rapidly rising coal demand in China pushes global coal prices higher. Western U.S. coal producers are currently less exposed to global markets, but the price for a one-month contract for Powder River Basin coal still rose 67 percent between October 2009 and October 2010 (Jaffe 2010). Moreover, Powder River Basin coal producers are seeking to build transportation infrastructure to expand their reach to Asian markets, potentially subjecting Western coal to price spikes similar to those experienced in the eastern United States. Chinese officials have announced plans to cap their own coal production, putting even greater upward pressure on global and U.S. coal prices (Reuters 2010a).

New questions are also being raised about just how much economically recoverable coal exists, both in the United States and elsewhere. Official reserve estimates are based on decades-old data and methods. More modern assessments are finding less economically recoverable coal than was commonly thought, including in Wyoming's important Gillette coalfield (Luppens et al. 2008). The fact that productivity at U.S. mines has been dropping for years, not only in the more mature and depleted eastern coalfields but also in the newer mines of the west, points to likely higher coal production costs ahead—in contrast to the lower production costs expected for natural gas. New studies that project future coal production, including some that make projections by fitting a bell curve to past production levels (an analytic method that remains controversial), predict that we are much nearer to peak coal production than traditional reserve estimates suggest (Heinberg and Fridley 2010; Patzek and Croft 2010; Rutledge 2010; EWG 2007). Coal prices in some markets may also rise in response to efforts to reduce the damage caused by mountaintop-removal mining.

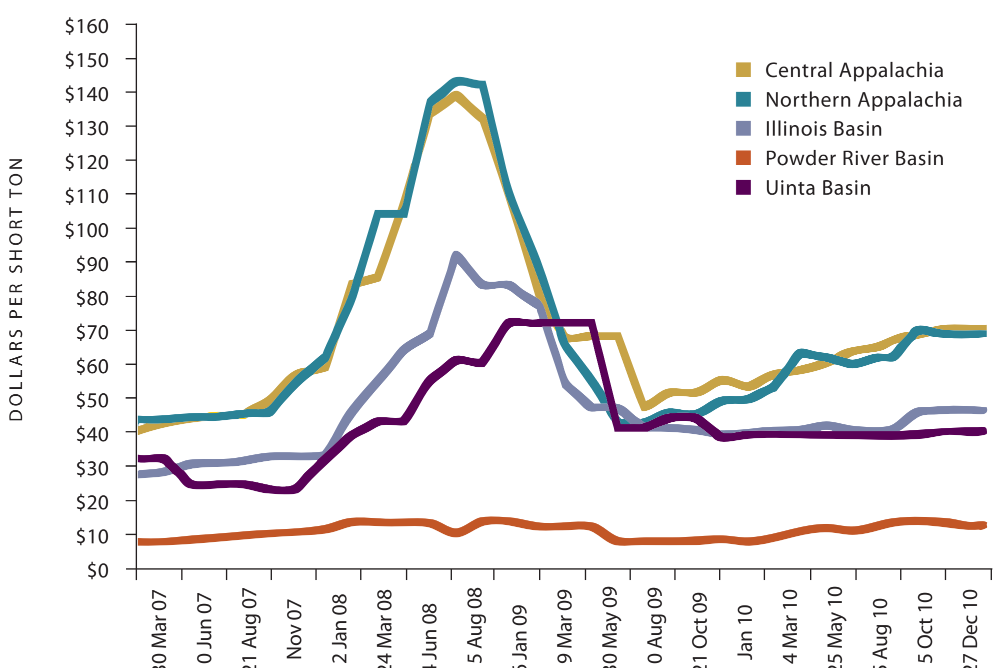
Coal plants also face costs associated with reducing their non-climate environmental impacts. Because coal plants, especially older ones, cause grave harm to the environment and public health, the U.S. Environmental Protection Agency (EPA) is developing more protective regulations (largely in response to court orders requiring it to implement existing statutory standards). Plants face costs associated with:

- *Preventing thousands of deaths from heart and lung disease.* Coal power is a major source of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions, which are transported downwind and cause ozone and particulate pollution that shorten the lives of thousands of Americans yearly; these emissions have been estimated to impose annual costs on society of more than $100 billion (CATF 2010). The EPA's proposed Clean Air Transport Rule would prevent many of these premature deaths, as old and uncontrolled plants would finally be required to install controls on SO_2 and NO_X.

- *Protecting children's brains from impairment.* Coal power is the source of at least half of U.S. emissions of mercury, a

Figure ES.4. AVERAGE WEEKLY COAL SPOT PRICES

Coal prices spiked dramatically in 2008, largely in response to the influence of global coal demand on U.S. coal markets, particularly in Appalachia (EIA 2010e). Prices in most basins are rising again with the economic recovery.



potent neurotoxin that threatens fetal and infant brain development. The EPA's forthcoming Air Toxics Rule, limiting mercury and other toxic emissions, would require uncontrolled plants to install controls on these pollutants.

- *Keeping toxic coal ash from contaminating the water.* Coal ash contains many toxic components and is currently stored in ways that can result both in catastrophic releases (such as the Kingston, TN, ash spill of 2008) and in slow leakage into ground and surface waters. Proposed EPA rules would require safer ash handling and potentially oblige many plants to convert from "wet" handling in surface impoundments to "dry" handling in lined landfills; plants could also be required to add new water treatment systems in order to keep toxins out of our water supplies and ecosystems.

- *Reducing fish kills and protecting water bodies.* Coal plants use vast quantities of water from adjacent rivers, lakes, and bays, taking a heavy toll on aquatic life as a result. The EPA is considering new rules that would require more coal (and other thermal power) plants to install cooling towers that would greatly reduce the amount of water they withdraw and the thermal pollution they discharge.

Retrofitting coal plants with pollution controls and other technologies could greatly reduce these environmental and health damages, and the retrofits would cost much less than what the damages currently cost society. However, the retrofit costs would be substantial for many plants, particularly the oldest and dirtiest. The limited remaining useful life of many older coal plants would make such investments difficult, if not impossible, to recover, making retirement the better financial option.

Major coal projects face high and unpredictable construction costs. Coal plant construction costs rose at a rapid rate in the years leading up to 2008, contributing to the cancellation of many proposed facilities. Despite the subsequent recession, construction costs have remained high (IHS CERA 2010), and some coal plant projects were still announcing substantial cost increases in 2010. Much of the construction-cost increase was driven by rising global commodity costs. While these commodity prices went back down with the global economic crisis, they rebounded quickly, and experts project that they will remain high by historical standards (IMF 2010).

Coal project financing may be harder to obtain and may cost more. The trends discussed above increase the risk that coal investment projects will fail to obtain the financing they need or that they will have to pay more for it than planned. The financial community is becoming increasingly wary of the risks associated with new investments in coal. A series of utilities and other power producers have seen their credit ratings and outlooks downgraded, in part because of the ratings agencies' concerns about coal construction or retrofit costs.

New coal plants cost more than cleaner options. The traditional cost advantage that coal power enjoyed over cleaner energy has largely disappeared with respect to new plants. Figure ES.5 (p. xiv) compares the levelized costs of electricity[2] from new coal plants to those of other new sources of power, both with and without incentives and using a range of assumptions described in Part 8 (and in Appendix A, which is available online). Power from new coal plants clearly costs more than power from new gas plants, wind facilities, and the best geothermal sites, and much more than investing in energy efficiency. When either carbon prices or incentives are factored in, power from new coal plants (with or without CCS) becomes even less competitive, costing more than power from biomass facilities or from the best solar thermal and solar photovoltaic sites. These comparisons reflect a range of coal prices (but do not fully represent the risk that coal prices could rise steeply due to volatile global markets and other causes) and they incorporate conservative assumptions about falling prices of renewable technology.

In addition to losing their cost advantage, coal plants' relative lack of operational flexibility makes them poorly suited for the grid of tomorrow, which will surely include greater quantities of variable sources—wind and solar power, for example—and place a premium on other power sources, such as natural gas, that can ramp up or down quickly as needed.

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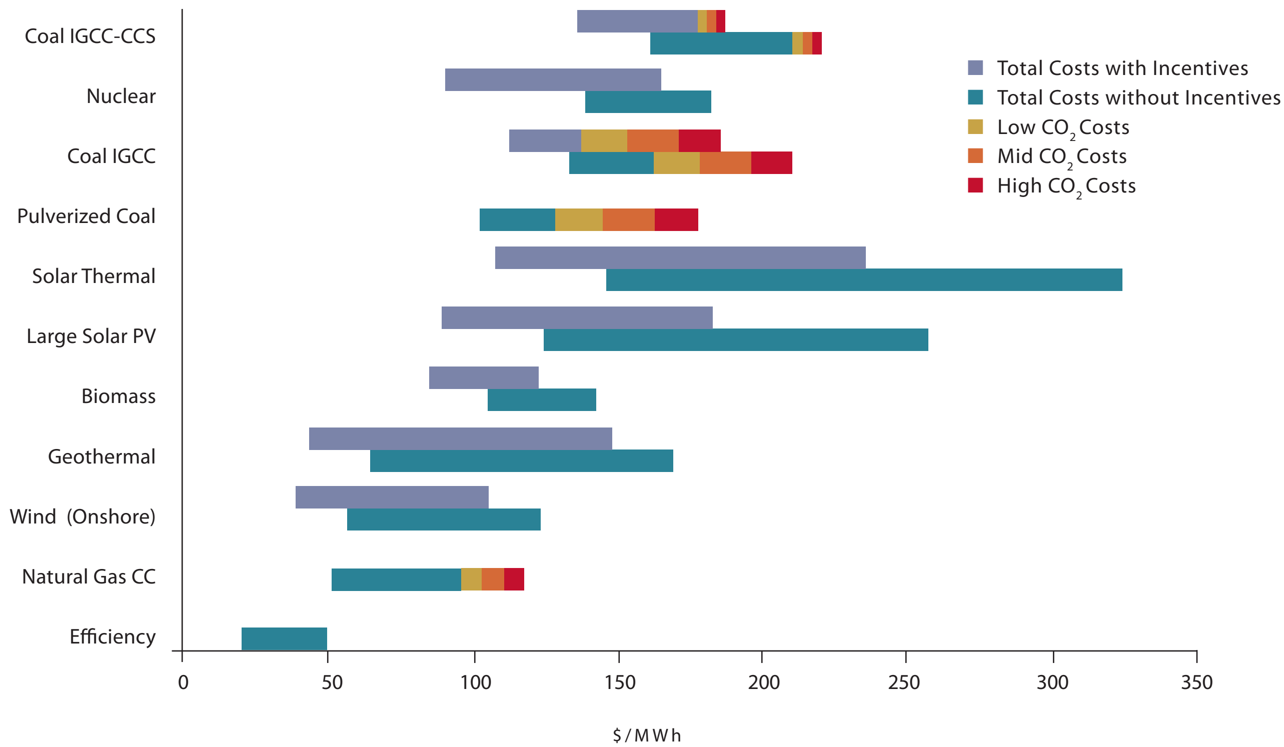
2 Levelized cost of electricity (LCOE) is an economic assessment of the cost of energy generation of a particular system. LCOE includes all of the costs over the system's lifetime, such as capital expenditures, operations and maintenance, fuel cost, and cost of capital, discounted to a net present value. The LCOE is the price at which energy must be sold for the project to break even.

Figure ES.5. LEVELIZED COST OF ELECTRICITY FOR VARIOUS TECHNOLOGIES

All projections assume newly built installations coming online in 2015 and represent levelized costs over a 20-year period. A range of capital costs is assumed for all technologies; a range of fuel costs is assumed for coal, natural gas, and biomass; and a range of capacity factors is assumed for wind, solar, natural gas, and nuclear power. A range of CO_2 prices is taken from Synapse projections (discussed in Part 4). Current tax incentives for wind and biomass are assumed to be extended to 2015.



We can dramatically reduce our dependence on coal power. Long-term investments in coal would be less risky if the nation had no choice but to continue with its current level of coal use, no matter how high the costs. But that is not the case. Studies by the Union of Concerned Scientists and others show that we could in fact replace most of our coal power using renewable energy, demand reduction, and natural gas within the next 15 to 20 years, with additional reductions in coal power afterward (Keith et al. 2010; Specker 2010; Cleetus, Clemmer, and Friedman 2009). And the overall benefits of transitioning to a cleaner energy system—saving lives, protecting air and water, and helping us avoid severe climate changes while stimulating technological innovation and building new clean-energy industries—would be tremendous.

A costly history threatens to repeat itself. When considering long-term investments in coal today, it is helpful to remember an earlier era of power-sector investments that did not end well. In the 1970s, utilities invested massively in both coal and nuclear plants while ignoring the sweeping changes that were increasing the costs of, and decreasing the demand for, such plants. The result was staggering financial losses around the country as scores of plants were cancelled after years of spending. We can avoid repeating that costly history by recognizing that changes under way today are making long-term investments in coal power an unacceptably risky proposition.

PART ONE

Background

The Changing Outlook for Coal

Scientific concern over global warming continues to grow, and the need for steep reductions in carbon emissions is now widely recognized within the science community. While the 111th Congress failed to pass a law limiting heat-trapping emissions, the fact that the climate threat is both grave and growing means that Congress will be under sustained pressure to tackle the problem again, perhaps several times, during the operating lifetime of a long-term investment in coal. Coal plants, as the nation's largest source of global warming emissions, would surely be targeted by any future climate laws.

Meanwhile, even without a price on carbon, the economic outlook for new coal plants has already changed dramatically under U.S. Energy Information Administration projections. As for existing coal plants, many are several decades old, highly polluting, and facing the prospect of finally having to install technologies to reduce the substantial damage they do to the air, water, land, and public health. Industry analysts are therefore projecting a wave of coal plant retirements ahead—indeed, such a wave has already begun—made possible by the fact that the nation's electric grid has substantial surplus generating capacity.

"The Need for Urgent Action to Address Climate Change Is Now Indisputable"

No one planning a long-term investment in coal can afford to be unaware of the scientific evidence that shows how urgently and deeply we need to reduce our carbon emissions. Based on its most comprehensive survey of climate research to date, the National Academy of Sciences (NAS) released in May 2010 a series of congressionally requested reports that concluded yet again that the earth is warming, that emissions from the burning of fossil fuels are largely to blame, that this warming poses a wide range of serious risks to society and natural systems, and that "there is an urgent need for U.S. action to reduce [greenhouse gas] emissions" (NRC 2010a and 2010b).[3] This conclusion reaffirmed the National Academy's 2009 joint statement, with its counterpart scientific academies of 12 other nations, bluntly stating, "the need for urgent action to address climate change is now indisputable" (NAS 2009). In this spirit, the NAS has specifically recommended that the United States "accelerate the retirement, retrofitting, or replacement of [greenhouse gas] emission-intensive infrastructure" (NRC 2010b).

Our climate is already changing in dangerous ways, with more frequent and severe droughts, heat waves, and downpours, among other manifestations. And climate change poses both direct and indirect threats to public health, such as through heat- and weather-related stresses, respiratory illnesses, insect-borne diseases, and contamination of food and water (APHA 2010; NIH 2010; EPA 2009e). In recognition of these threats, the nation's leading public health groups have recently added their voices to the call for laws that would limit

3 In 2009, allegations of scientific misconduct were made against certain U.S. and U.K. climate scientists, based on stolen and misinterpreted email correspondence. These allegations, which were given broad media coverage, created confusion in some nonscientific circles about the certainty of the science behind researchers' global warming conclusions. Subsequent investigations that exonerated these scientists of misconduct, and reaffirmed the strength of the underlying climate science, received far less coverage (Oxburgh et al. 2010; Penn State 2010; Russell et al. 2010). In actuality, the fundamental science underlying climate concerns, based on multiple independent lines of evidence and the work of thousands of scientists, is robust and was never in doubt.

heat-trapping emissions (APHA 2010). Many of the changes to the world around us are unfolding faster than scientists projected just a few years ago (NAS 2009; Rosenzweig et al. 2008; Rahmstorf et al. 2007; Stroeve et al. 2007). In addition, the data show that much worse lies ahead if we do not change course (Meinshausen et al. 2009; Solomon et al. 2009). Indeed, we may be very close already to triggering natural amplification mechanisms that could cause irreversible changes with catastrophic consequences (NRC 2010a).

Deep Emissions Cuts Are Required from the Coal Sector

Most climate experts agree that in order to have a reasonable chance of avoiding the most severe impacts of global warming, we must prevent average global temperatures from rising more than two degrees Celsius[4] above preindustrial levels (UCS 2008; Climate Change Research Centre 2007). The Copenhagen Accord, negotiated at a meeting of world leaders in December 2009, formally embodies this goal (UNFCCC 2009). However, there is no guarantee that a two-degree warming would be safe, and some prominent scientists now think that allowing even that much warming would be a "recipe for global disaster" (Hansen 2008). The Copenhagen Accord explicitly calls for reassessment of the two-degree target and consideration of a 1.5-degree target by 2015 (UNFCCC 2009).

Even the two-degree limit would require ambitious reductions in heat-trapping emissions by 2020 and beyond. The above-mentioned National Academy of Sciences joint statement notes that, "limiting global warming to 2 degrees C would require a very rapid worldwide implementation of all currently available low-carbon technologies" (NAS 2009). To have a reasonable chance of achieving that limit, industrialized nations taken collectively would have to reduce emissions to 25 to 40 percent below 1990 levels (or 35 to 48 percent below 2005 levels) in the next 10 years (IPCC 2007). The Union of Concerned Scientists recommends that the United States reduce emissions by *at least* 35 percent below 2005 levels by 2020, based on the work of the Intergovernmental Panel on Climate Change (IPCC) and other studies (Baer et al. 2008; den Elzen et al. 2008). Under the Copenhagen Accord the Obama administration set a lesser but still ambitious target of reducing U.S. emissions "in the range of 17 percent" by 2020 (pending legislative action) (Stern 2010).

Apart from plants already under construction, the EIA's model no longer projects the construction of *any* new coal plants through 2030 without carbon capture and storage (CCS).

Even deeper emissions cuts beyond 35 percent are needed in the years following 2020—in the range of at least 80 percent by 2050 (NRC 2010b; Luers et al. 2007). The United States and other developed economies agreed for the first time, at the 2009 G8 Summit, that developed countries should cut their heat-trapping emissions by 80 percent or more from 1990 levels by 2050 (G8 2009).

These longer-term reductions are possible but require an immediate and sustained national campaign to move away from high-carbon-emitting energy. Because coal plants alone account for more than a third of all U.S. CO_2 emissions from energy use—they emit more than all of the nation's cars, trucks, and trains combined (Figure 1)—we cannot achieve the reductions we need without slashing carbon emissions from coal power in the years ahead. Even if the coal power sector only made its proportional share of reductions, it would face reductions of at least 17 percent in the next decade and more than 80 percent over four decades. But as many studies have shown (some of which are discussed in Parts 4 and 8), if society follows anything resembling a least-cost path, a disproportionate share of the emissions reductions will be achieved by shifting away from coal power.

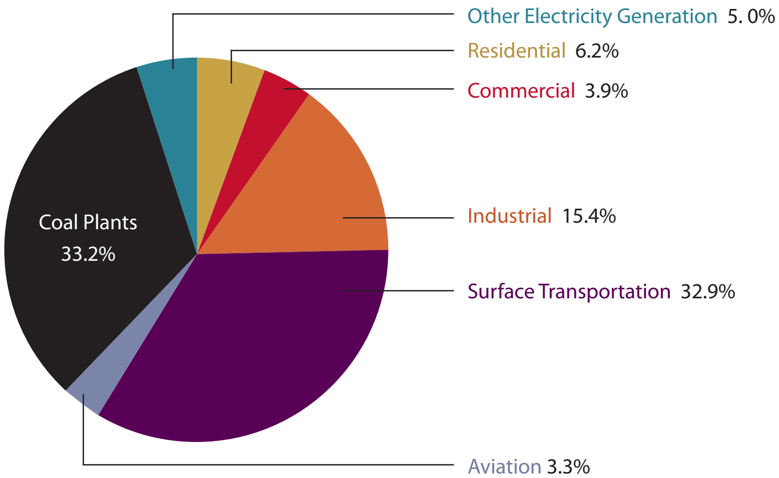
These scientific realities, which are driving policy responses elsewhere in the world, will keep fueling demands for stronger policies in the United States as well—including a law that puts a price on carbon, which would have financial implications for coal that we discuss in Part 4. But even without such a price in place, the economic prospects both of old coal plants and proposed new plants have already changed profoundly.

Federal Projections of New Coal Plants Plummet

One of the most commonly cited sources of information about the nation's energy sector is the Energy Information

4 This is equivalent to about 3.6 degrees Fahrenheit. We have already warmed by 1.7 degrees Fahrenheit above preindustrial levels (Arndt, Baringer, and Johnson 2009).

Figure 1. U.S. CO_2 EMISSIONS FROM ENERGY USE BY SOURCE, 2009



More CO_2 is emitted from coal plants than from any other technology or sector, including all modes of surface transportation combined. (Power plant emissions are presented under coal plants and other electricity generation, rather than under the residential, commercial, and industrial sectors where the power is consumed.)

Administration (EIA)—an independent agency, within the U.S. Department of Energy, that is the source of official federal energy statistics and analyses. The EIA publishes an Annual Energy Outlook (AEO) that makes long-term forecasts, based on highly detailed computer-based econometric modeling, about U.S. energy markets. As a matter of methodology, the AEO reference-case forecast assumes implementation of existing laws and regulations only. These annual forecasts therefore do not factor in a future price on carbon (discussed in Part 4), nor do they reflect many of the pollution control upgrades that existing plants face (discussed in Part 5).

Just a few years ago, when many plants in the pipeline today were first announced, the EIA foresaw a robust future for new coal plants. In the AEO 2006, the EIA's model projected the construction of 145 gigawatts (GW) of "unplanned" new coal capacity by 2030, or the equivalent of about 240 new coal plants of 600 MW in size (in addition to the 9.3 GW of "planned" capacity, which the EIA put into the model to reflect new coal projects that it understood to be under construction and that it assumed would be completed) (EIA 2006). While critics, including the Union of Concerned Scientists, pointed out that these forecasts were based on inappropriately low coal-plant construction-cost assumptions, and that they did not reflect carbon regulatory risk, backers of new coal plants pointed to these federal projections as evidence of the economic wisdom of building more coal capacity.

But in the EIA's AEO 2011 (Early Release), those hundreds of projected coal plants have vanished, a reflection of the profound economic changes that have occurred since 2006. Apart from 11.5 GW of plants already under construction, the EIA's model no longer projects the construction of *any* new coal plants through 2030 without carbon capture and storage (CCS) (EIA 2011a) (see Figure 2, p. 4). Only 2 GW of coal power with CCS are projected by 2030, which reflect new plants that the EIA assumed would be stimulated by existing government subsidies (EIA 2011a).

Widespread Retirements Expected among Existing Plants

A large percentage of U.S. coal plant capacity has reached or exceeded its originally assumed useful lifetime. Seventy-two percent of U.S. coal plants (by capacity) are older than 30 years, 34 percent are older than 40 years, and 14 percent are older than 50 years (Bradley et al. 2010). Only 1 percent are 10 years old or less, and only a few new plants are now in the pipeline. As Figure 3 (p. 5) shows, however, the nation does have substantial newly built energy capacity in the form of natural gas plants (which have been greatly underutilized in recent years, as discussed in Part 2) and, increasingly, wind power and other renewable sources.

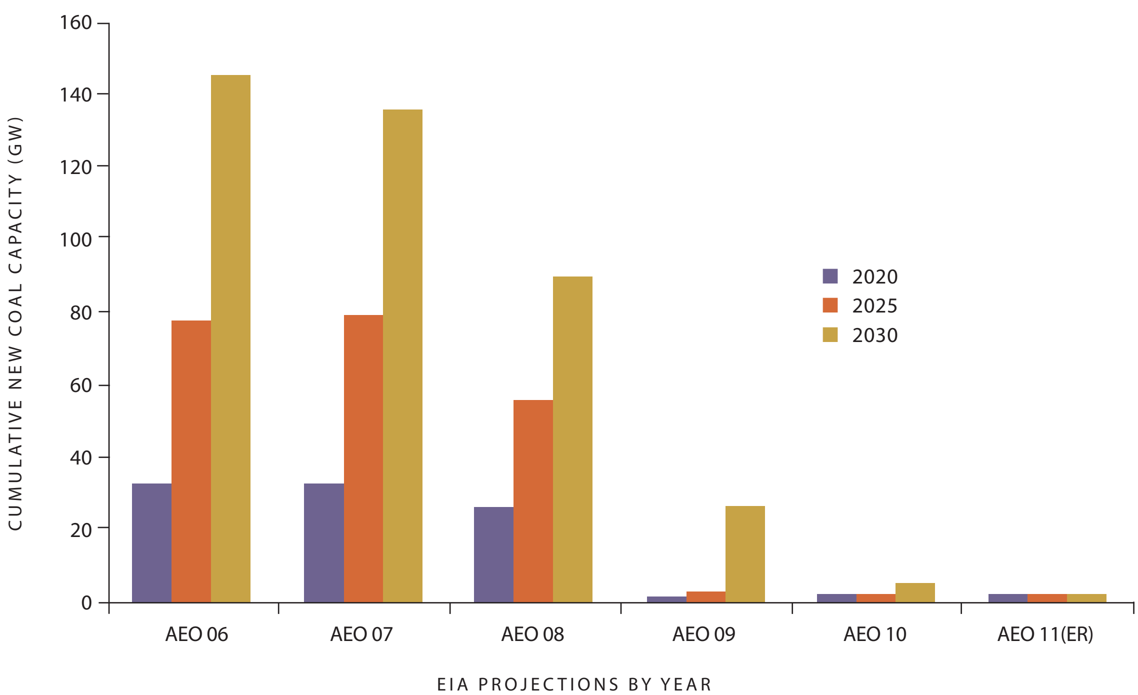
The advanced age of so many coal plants presents two problems. First, they require additional investments just to keep running. After 30 years of operation, the availability of a coal-fired boiler declines sharply and the plant faces higher rates of forced outages; large capital-improvement projects, which overhaul or replace key plant components, are typically needed to extend the plant's operating life.[5] Such projects are not only costly but can also require extended plant shutdowns (Slat 2010).

Second, many older plants lack modern pollution control technologies, so they typically pose much greater threats to air, water, land, and public health (and somewhat greater climate impacts, given their lesser fuel efficiency) than do new plants. These highly polluting plants face the prospect of new and more protective regulatory standards (discussed in Part 5), which would force their owners to decide whether to retire them or finally invest in pollution reduction technologies. Several closures of old coal plants around the country have

5 Much of the litigation under the Clean Air Act's New Source Review program has involved coal plant operators that failed to obtain preconstruction permits before replacing major plant components. Among the plant components that required upgrading have been economizers, reheaters, primary and secondary superheaters, waterwalls, cold end air heaters, and boiler floors. See U.S. v. Ohio Edison Co., 276 F. Supp. 2d. 829 (S.D. OH 2003).

Figure 2. DECLINING FEDERAL PROJECTIONS OF NEW COAL PLANTS THROUGH 2030

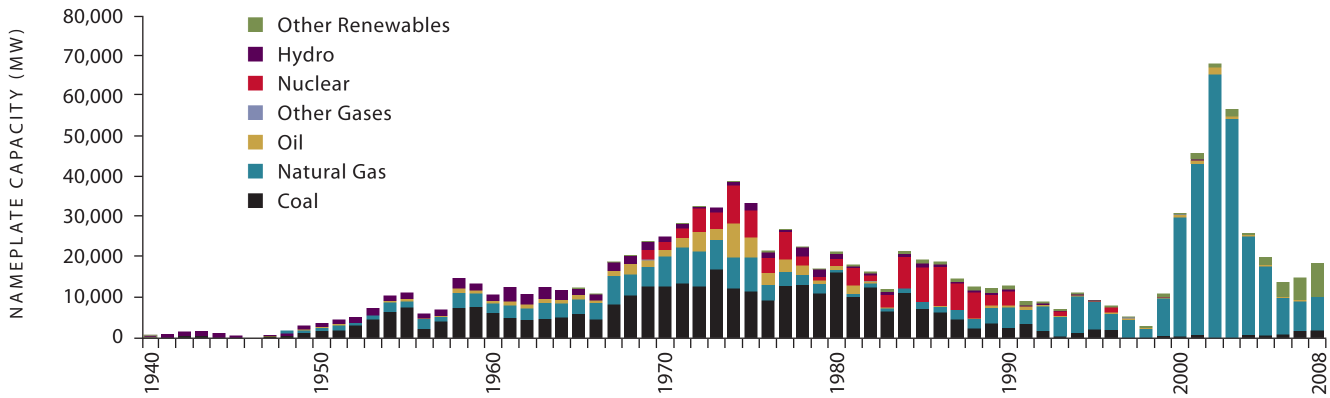
In its Annual Energy Outlooks (AEOs), the EIA's projections of unplanned coal capacity coming into service by 2020, 2025, and 2030 have dropped dramatically. In 2006 the EIA projected 145 GW of new coal by 2030 (the equivalent of about 240 new plants of 600 megawatts). But the agency now projects only 2 GW by 2030, consisting entirely of advanced plants with CCS technology that are inputs to the model based on the assumed response to federal subsidies. Planned capacity additions—plants that the EIA understands to be under construction already—are not reflected.



Sources: EIA 2006, 2007, 2008a, 2009a, 2010a, 2011a

Figure 3. **U.S. ELECTRIC GENERATING CAPACITY BY IN-SERVICE YEAR**

Most of the nation's coal plants are decades old, with many at or well beyond their expected operating lifetimes. However, the United States has added a large amount of new natural gas generating capacity in the last decade (much of which is currently underused), and the country has growing renewable power capacity as well.



Sources: Ceres et al. 2010; EIA 2008d

already been announced by Progress Energy, Xcel, Duke, TVA, and Exelon, among others (Bradley et al. 2010). Xcel's analysis of two aging coal units in Minnesota showed that making the needed life-extension and pollution control investments would cost more than repowering them with natural gas under each of the 10 scenarios examined, including a high gas price scenario (Xcel Energy 2010).

The scale and implications of the forthcoming wave of coal plant retirements are the subject of intense speculation, with a resulting flurry of new scenarios and estimates—some of which are listed in Table 1 (p. 6)—from consulting firms, investment houses, and others. These estimates all reflect the impact of the U.S. Environmental Protection Agency's (EPA's) forthcoming air regulations on the nation's aging coal fleet, and some also include expected ash and cooling-water regulations (all of which is further discussed in Part 5). The current and projected low natural gas prices (discussed in Part 2) are also a major factor in these observers' analyses.

The gigawatts of coal plant capacity expected to be retired in the next few years varies substantially from one analysis to another, with notable congregation in the neighborhood of 40 to 60 GW. (By way of comparison, the size of the existing fleet of coal plants is about 313 GW of net summer capacity and 337 GW of nameplate capacity (EIA 2010d).[6]) However, some of the analyses conclude that a much larger share of the fleet potentially faces retirement. The Deutsche Bank analysis, for example, projects that 60 GW of coal plants will retire by 2020, but it also notes that an additional 92 GW of coal plants are "ripe for retirement" (Mellquist et al. 2010).

The declining economic competitiveness of the aging coal fleet is an important factor in most of the analyses. According to investment bank Credit Suisse, "a large chunk of the U.S. coal fleet is vulnerable to closure simply due to crummy economics, where we see coal pricing at a premium to natural

6 Nameplate capacity is the maximum output of a generator under specific conditions designated by the manufacturer (and is usually indicated by an actual nameplate attached to the generator). Net summer capacity is the expected maximum output of the coal fleet during summer peak demand after subtracting electricity use for station service or auxiliaries.

gas … when adjusting on an electricity equivalent basis. … Awful energy margins suggest to us that owners should be reevaluating their coal fleets due to pure energy economics before even taking on the burden of a [capital expenditure] for environmental control equipment" (Eggers et al. 2010). Coal plant retirements are projected to have a positive economic effect on many power producers. The Credit Suisse analysis, entitled "Growth from Subtraction," predicts that among these producers the new EPA regulations will produce "mostly winners and bigger winners" and have the effect of "culling the herd of bad plants" (Eggers et al. 2010).

Excess Generating Capacity Facilitates Coal Plant Retirements

Fortunately, with projections of extra generating capacity on the grid for years to come, the United States is now in a relatively good position to handle a wave of coal plant retirements.

Each region of the country must maintain enough electric generating capacity to meet expected demand, plus an additional "reserve margin" to deal with plant outages, transmis-

> A large chunk of the U.S. coal fleet is vulnerable to closure simply due to crummy economics.
>
> — CREDIT SUISSE

sion failures, unexpected demand, and other factors. In most regions, the minimum target reserve margin is 15 percent or less, but in recent years actual reserve margins around the country have been well above that threshold, and in 2013 reserve margins are expected to range from 22 to 46 percent, depending on the region. According to a recent analysis by M.J. Bradley and Associates, in aggregate "the electric sector is expected to have over 100 GW of surplus generating capacity in 2013" (Bradley et al. 2010).

The North American Electric Reliability Corporation (NERC) issued an assessment in late 2010 of the impact of four different forthcoming EPA regulations on reliability; it found potential for an impact, depending on "whether sufficient replacement capacity can be added in a timely manner"

Table 1. COAL PLANT RETIREMENT PROJECTIONS

A recent series of reports and presentations has attempted to predict the scale of coal plant retirements over the next few years. The reports vary in the factors they considered and the type of analysis, but all agreed that the aging U.S. coal fleet faces significant retirements ahead.

SOURCE OF ANALYSIS	PROJECTIONS
Black and Veatch (Griffith 2010)	54 GW (in response to "pending" environmental regulations)
Brattle Group (Celebi et al. 2010)	50–66 GW "vulnerable to retirement" by 2020
Charles River Associates (Shavel and Gibbs 2010)	39 GW retired by 2015
Credit Suisse (Eggers et al. 2010)	60 GW assumed retired in base case by 2017 35 GW and 103 GW retirements considered on other scenarios
Deutsche Bank Climate Change Advisors (Mellquist et al. 2010)	60 GW "expected" to retire by 2020 92 additional GW "inefficient and ripe for retirement"
FBR Capital Markets (Salisbury et al. 2010)	45 GW retired in base case by 2018 (30–70 GW range)
ICF International (Fine Maron 2011)	20% decline in coal fleet by 2020 12% decline in coal generation by 2020
Wood Mackenzie (Snyder 2010)	"Nearly 50" GW by 2020

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(NERC 2010). The NERC analysis assumed 33 to 70 GW of plant retirements, but these figures included 30 GW of small, old oil and gas units retired in response to the EPA's as-yet-unproposed cooling-water rule. However, as the subsequent Charles River Associates (CRA International) analysis pointed out, the number of projected coal plant retirements nationwide is small compared with the rate at which the United States has added generating capacity in the past. CRA International also found that after the 39 GW of coal retirements it projected, all of the regional transmission organizations would still have sufficient resources to meet reserve margin requirements even if new additions in the planning and site preparation stages were not included in the analysis (Shavel and Gibbs 2010).

These ample reserve margins result in no small part from the many new natural gas plants that came online in the last decade (Figure 3) but that have been operating at just a fraction of their capacity. These plants could replace the power lost from substantial numbers of retiring coal plants, and lower projected natural gas prices make this prospect even more likely (see Part 2). In addition, demand dropped substantially with the recession, with power sales in 2009 about 5 percent below their 2007 levels (EIA 2010h). While the demand for power began to rebound in 2010, surplus generation capacity is still likely to persist for longer than was expected before the recession. According to the Deutsche Bank's analysis, "there is ample capacity, stranded from the 1998–2003 'dash to gas' overbuild[,] and the recession has increased reserve margins, reducing pressure on adding new plants in many regions" (Mellquist et al. 2010). These analysts assume that at least two-thirds of the coal-to-gas switch they project could occur by increasing the use of existing gas plants; combined with growing reliance on renewable power, Deutsche Bank shows a pathway that would reduce power sector CO_2 emissions by 44 percent by 2030.

In the longer term, the United States can retire a far larger share of its coal fleet than those projected in these analyses; indeed, doing so would be a central feature of making the deep cuts in global warming emissions that we need. For example, in a multiyear modeling analysis released in 2009, the Union of Concerned Scientists showed how we could reduce coal use by 84 percent by 2030, replacing it mainly with efficiency savings and more renewable power while saving energy consumers money (Cleetus, Clemmer, and Friedman 2009). We discuss this study further in Part 8, along with other research showing that the United States could retire its old coal plants at a rapid pace and still meet its energy needs (Keith et al. 2010; Specker 2010).

Growing Opposition to Coal

Among the very real but hard-to-quantify risks faced by those investing in coal is the likelihood that public opposition to coal will keep building, particularly as temperatures climb in the years ahead. Many new coal plant proposals have already been stopped by public opposition, driven at least in part by climate concerns. And because slashing the carbon emissions of existing plants is critical to climate protection, activists—already mobilized to oppose new plants—can be expected to increasingly turn their attention to closing existing plants. The failure to pass a comprehensive climate bill during the 111th Congress may just sharpen climate activists' focus on coal plants, given that they are the biggest carbon polluters and the most obvious targets.

But rising opposition to coal use is based not just on climate concerns. Mountaintop-removal mining increasingly draws protests and acts of civil disobedience, including at the White House in September 2010, when 1,000 protestors demonstrated and 100 were arrested (Reis 2010). And the threats posed by coal ash, made evident by the 2008 ash spill in Kingston, TN, have also prompted protests and heavy citizen turnout at EPA hearings around the country to call for stricter ash regulation.

In short, those planning to make long-term investments in coal power should expect greater scrutiny, more controversy, and stronger legal and political opposition in the years ahead. This opposition poses the risk that projects may be delayed or stopped altogether.

PART TWO

Eroding Markets for Coal Power

The Impacts of Energy Efficiency, Renewable Power, and Natural Gas

Proposed and existing coal plants are also threatened by increasing competition from energy efficiency, renewable energy, and natural gas, which are cutting into the long-term demand for coal power. Coal's share of the U.S. electricity market has already dropped significantly since 1997, when it accounted for 53 percent of the power mix. In the first half of 2010, coal provided only 46 percent of U.S. generation (and 45 percent in 2009) (EIA 2010c; EIA 2010d). Given the policy support for cleaner competing technologies, their growth, and their cost and performance improvements, coal's market share will likely continue to decline.

Energy Efficiency

Energy efficiency has enormous potential to reduce electricity demand. A recent analysis by the McKinsey Corp. found that the United States could reduce annual non-transportation energy consumption by 23 percent below projected levels by 2020, using only measures that paid for themselves and without assuming a price on carbon (Granade et al. 2009). A National Academy of Sciences study concluded that deploying currently available technology could reduce projected electricity consumption from commercial and residential buildings by 26 percent by 2020, and at costs well below retail electricity prices (NRC 2009). Other studies have made similar findings (Cooper 2010; Cleetus, Clemmer, and Friedman, 2009; James et al. 2009; Ehrhardt-Martinez and Laitner 2008; Creyts et al. 2007). With more optimistic assumptions about technology improvements, one recent study concluded that the United States could cut energy use in all of its forms by 30 percent by 2020 and 88 percent by 2050 (Goldstein 2010).

The United States has not yet taken advantage of such potential savings from efficiency because market barriers have prevented the associated investments from being made. But these barriers can be overcome by the kinds of policy changes increasingly being adopted by state and federal governments.[7] The proliferation of new state energy efficiency policies over the past several years "suggests that the next decade may see a dramatic and sustained increase in overall funding levels, and a fundamental redrawing of the energy efficiency map," concluded a 2009 Lawrence Berkeley National Laboratory review of state policies (Barbose, Goldman, and Schlegel 2009). These analysts found upcoming increases in efficiency investments not only among states that have supported it for years but also among populous states—including Illinois, Maryland, Michigan, North Carolina, Ohio, and Pennsylvania—that until recently invested little but have now enacted aggressive new policies.

One of the more effective and popular policy mechanisms for deploying energy efficient technologies is the Energy Efficiency Resource Standard (EERS), which requires utilities to implement programs to reduce energy demand by a specified percentage over time. Currently, 27 states have enacted an EERS or have one pending, about twice as many as just four years ago; several states, including Arizona, Illinois, Indiana, Massachusetts, Ohio, and Vermont, require annual savings that ramp up to 2 percent or higher (ACEEE 2010a). Overall

7 For a broader discussion of the barriers to energy efficiency and policy solutions, see the Union of Concerned Scientists report *Climate 2030* (Cleetus, Clemmer, and Friedman 2009).

spending on ratepayer-funded gas and electric efficiency programs nearly doubled between 2007 and 2009, rising from $2.5 billion to $4.3 billion (ACEEE 2010a). Such aggressive and sustained investments in energy efficiency could not only greatly reduce the need for new sources of generation (including coal) but also cut demand for existing power plants.

A renewed commitment to energy efficiency at the federal level will help to drive demand reductions nationwide. For example, the American Recovery and Reinvestment Act of 2009 (ARRA) provided approximately $17 billion in incentives for homes and businesses to invest in energy efficiency (ACEEE 2010b). Moreover, since January 2009 the U.S. Department of Energy has finalized new efficiency standards, for more than 20 household and commercial products, estimated to cumulatively save consumers $250 billion to $300 billion by 2030 (DOE 2010). These are billions of dollars that will no longer need to be spent on coal power or any other kind of electricity supply.

Renewable Power

The potential of renewable sources to meet a far greater share of our electricity needs is well documented. The major renewable energy technologies—wind, solar, geothermal, bioenergy, and small-scale hydropower—have the potential to produce many times the current U.S. power demand (Cleetus, Clemmer, and Friedman 2009). Of course, not all of that potential is practically realizable, but numerous studies have consistently found that the United States could significantly increase renewable energy generation in an affordable and reliable way (ASES 2007; Nogee, Deyette, and Clemmer 2007). A National Renewable Energy Laboratory (NREL) study recently concluded that by 2025 the United States could meet 22 percent of its electricity needs using non-hydro renewable power—up from about 3.6 percent in 2009—with no significant impact on consumer prices at the national level (EIA 2010b; Sullivan et al. 2009).[8] In addition, a 2009 EIA study projected that increasing the share of renewable electricity to 25 percent nationally by 2025 would lower consumer natural gas bills slightly compared with business as usual, thereby offsetting slightly higher electricity bills (EIA 2009g).

According to a landmark 2008 analysis by the U.S. Department of Energy, wind power alone could meet 20 percent of our electricity needs by 2030 without compromising reliability or raising electric rates by more than 2 percent (not considering avoided future carbon costs) (EERE 2008). Despite its variable output, several U.S. and European utility studies have shown that wind power could provide up to 25 percent of total generation on utility and regional systems at modest integration costs (of less than $10/MWh, or roughly 5 to 10 percent of wind power's wholesale cost) (Wiser and Bolinger 2009; Holttinen et al. 2007).

> The next decade may see a dramatic and sustained increase in overall [energy efficiency] funding levels, and a fundamental redrawing of the energy efficiency map.
>
> — LAWRENCE BERKELEY NATIONAL LABORATORY

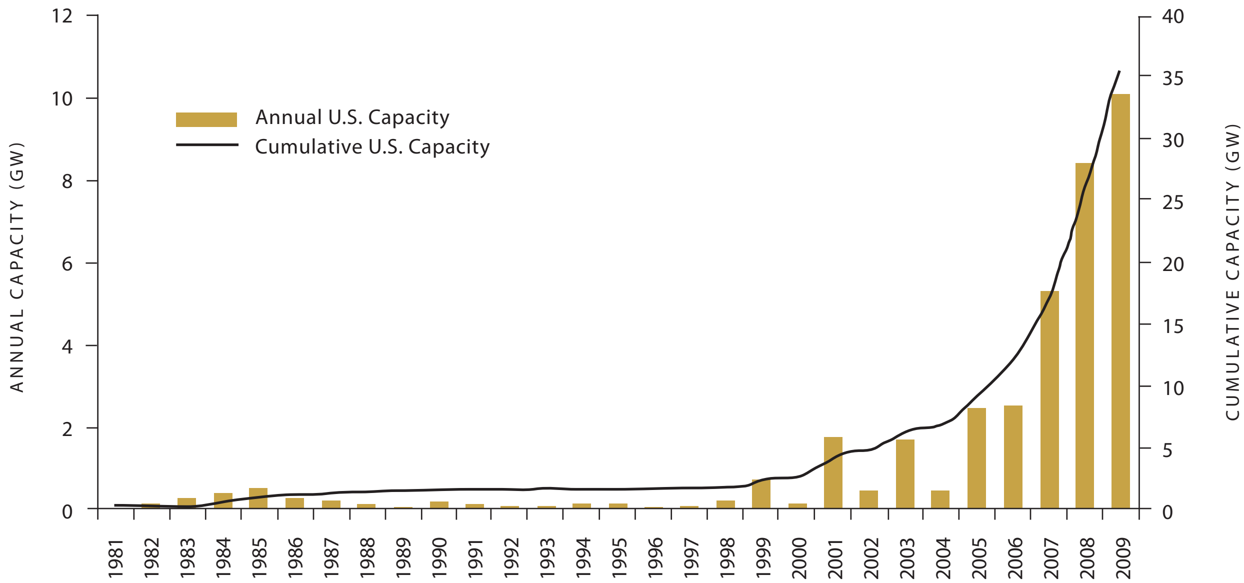
The installation of wind and solar energy technologies has expanded at a striking pace, with wind growing at an average annual rate of 39 percent between 2004 and 2009 and solar growing at an annual average rate of 41 percent over that period. In 2007, for the first time, the United States added more renewable capacity, mainly wind, than it did nonrenewable capacity (EIA 2009c). From 2008 to 2009, more wind capacity was added to the U.S. power supply than in the previous three decades combined (Figure 4, p. 10) (Wiser and Bolinger 2009). In 2010, however, wind installations dropped off considerably from the recent record pace, due in large part to the recession as well as to increased competition from low-priced natural gas (AWEA 2010a; AWEA 2010b).

The market share of solar photovoltaic (PV) power is also growing rapidly, and this option has the potential to transform the energy grid as solar panel prices continue to fall. PV installations during the first half of 2010 were 55 percent higher than in 2009 on an annualized basis (SEIA 2010b). California now has 600 MW of PV capacity online, as part of a push to install 3,000 MW (CPUC 2010), and New Jersey has 120 MW under development (Belson 2009). Unlike most other

8 The NREL analysis examined three proposed renewable energy standards, the most stringent of which would require 25 percent of retail power sales to derive from renewable power by 2025. However, because smaller utilities were exempted from this standard, the effective renewable requirement was only 22 percent by 2025.

Figure 4. WIND POWER GROWING AT RECORD PACE

U.S. wind power capacity expanded by over 50 percent in 2008 alone and continued to expand in 2009 despite the recession.



Source: Wiser and Bolinger 2010

power sources, onsite solar PV projects become competitive when costs fall below retail rather than wholesale power prices. Net metering policies and innovative financing mechanisms (such as property-assessed clean energy, or PACE, financing), which help reduce the barriers to wider use of PV, are spreading quickly (Rose 2010; SEIA 2010a).

Other renewable technologies are also seeing impressive growth. Concentrated solar power (CSP) can function around the clock when paired with new heat-storage technologies. This option is taking off particularly in California, where state regulators approved nine new projects totaling over 4,000 MW over a four-month period in late 2010 (Kraemer 2010). One such project, at 1,000 MW, will be the largest in the world (Hsu 2010). On another front, in 2009 geothermal power grew 26 percent in new projects under development, with 7,875 MW of projects under way in 15 states (GEA 2010).

Renewable power continues to become more competitive with fossil fuels because of technological advances, economies of scale, and other factors. Solar panel prices have dropped by 50 percent in the last two years, partly due to new low-cost manufacturing facilities in China (Bradsher 2010). Analysts at Deutsche Bank report, “looking at learning curves, we expect many renewable technologies will likely be as cheap as fossil fuel-fired power generation on [a levelized cost of electricity] basis within the next 5–10 years” (Mellquist et al. 2010). While these analysts focus particularly on rapidly falling solar PV prices, they note that even the relatively mature onshore wind industry saw turbine prices fall in 2010 and that prices are projected to be 20 percent lower in 2011 than in 2009 (Mellquist et al. 2010).

Even without such falling prices, renewable power would see continuing growth driven by federal tax credits and state-level renewable electricity standards, which require electricity suppliers to provide a minimum percentage of their electricity from renewable sources. Already, 29 states and the District of Columbia have enacted such standards, a number that has more than doubled since 2004. A recent analysis projected that if full compliance with these state standards were achieved, it

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would result in some 76 GW of new renewable energy capacity by 2025—or as much as 97 GW if the newly enhanced California standard and the voluntary goals adopted in seven additional states were included (Wiser 2010). Federal support has also been important, with extended tax credits for renewable generation extended through 2012 as part of the 2009 ARRA legislation. The EIA projects that these tax credits, combined with existing state-level standards, will increase renewable energy's share of electricity generation to 12.3 percent by 2020 (EIA 2010a).

In short, while coal power is shrinking and faces new regulatory hurdles and rising costs, renewable power is expanding with growing policy support; moreover, costs are falling for many of these technologies. Renewable power's market share will thus continue to increase to a substantial fraction of the U.S. power market, meeting electricity demand that might otherwise be filled by coal.

Competition from Natural Gas

Natural gas plants hold important advantages over coal plants. They burn cleaner, producing less than half the carbon emissions, about one-tenth the nitrogen oxides, and negligible amounts of sulfur dioxide, mercury, and particulates.[9] Thus natural gas will have an added edge over coal as the EPA tightens standards for these pollutants, as well as under any future carbon-cost scenario. Natural gas plants also have the capability to increase or reduce their output as market demand fluctuates, which coal plants cannot efficiently do. This flexibility makes gas plants inherently better adapted to a grid onto which a growing number of variable renewable energy sources are being added, pursuant to state policies and shifting economics.

The prospects for all power sources, including coal, are greatly affected by natural gas prices. When prices were low, in the 1990s and early 2000s, the power sector built a great many efficient natural gas combined-cycle power plants designed to operate as around-the-clock baseload capacity.[10] When gas

9 A federal analysis of power plant performance found that a new natural gas combined-cycle plant emitted 58 percent less CO_2 per megawatt-hour than a new coal plant using subcritical technology and 55 percent less CO_2 than a new coal plant using the more efficient supercritical technology (NETL 2007).

10 Baseload power is the term used for those sources of electricity that are run most of the time and at a steady rate. This is in contrast to peaking or intermediate plants, which are turned on when demand reaches a certain point and ramped up and down as demand shifts, and in contrast with intermittent sources such as wind, which provide power only when available. Traditionally, coal, nuclear, hydroelectric (except in drought years), biomass, and geothermal plants have provided the baseload power, though lately natural gas combined-cycle plants have also been a source of significant amounts of baseload power in some parts of the country.

prices later increased, much of the new natural gas capacity was left underutilized and the power sector launched a coal plant building spree, with announcements of over 150 proposed new coal plants at its height. Since then, natural gas prices have fallen, contributing to the cancellation of some of those new coal plants and prompting the owners of several old coal plants to announce plans to replace them with natural gas units (Smith 2010).

Natural gas prices are particularly hard to forecast, but it is worth noting that while estimated coal reserves are being reduced and coal prices are rising (see Part 3), the opposite is happening with natural gas. Industry experts recently expanded their estimates of U.S. domestic gas resources by a dramatic 39 percent since the last estimate in 2006, announcing "an exceptionally strong and optimistic gas supply picture for the nation" (Potential Gas Committee 2009). This confidence resulted from advances in drilling technology—horizontal drilling and hydraulic fracturing—that let drillers reach the formerly inaccessible shale gas supplies located in many states.

There are many unresolved concerns over the impact that hydraulic fracturing can have on water quality and supply, however. And there are questions as to whether the global warming impact of methane leaked during the production of natural gas more generally has been fully counted (Lustgarten and ProPublica 2011). These issues, and the public opposition to expanded drilling in some areas, could dampen expectations about future gas production. Still, shale gas is viewed by many as causing a dramatic improvement in the outlook for domestic natural gas production. This increase in natural gas availability could have significant implications for coal power, especially when combined with climate-protection policies. A 2010 analysis by Resources for the Future found that expanded production of shale gas, combined with a cap-and-trade program, would reduce coal generation in 2030 by more than half compared with business-as-usual levels (Brown and Krupnick 2010).

The threat to coal from natural gas is particularly great at present, given the many natural gas plants built in the last decade that have been operating at far below capacity.

The threat to coal from natural gas is particularly great at present, given the many natural gas plants built in the last decade that have been operating at far below capacity. For example, combined-cycle natural gas plants were operating at 42 percent in 2007 (Kaplan 2010) and at only 33 percent in 2008 (Bradley et al. 2010). A Congressional Research Service report estimated that bringing utilization of those plants to 85 percent, as is technically feasible, would be sufficient to cut coal generation by nearly a third and reduce CO_2 emissions by 19 percent (Kaplan 2010). Another assessment concluded that almost 70 percent of the coal fleet could be idled by fully utilizing the natural gas combined-cycle potential (Casten 2009). These and other reports have acknowledged the many practical barriers to a widespread substitution of gas for coal (Aspen Environmental Group 2010). Still, the existence of so many underused gas plants when gas prices are projected to remain relatively low represents yet another potentially significant threat to coal power's market share.

PART THREE

Fuel Prices at Risk

Coal has traditionally been considered a reliably low-cost fuel, but the price volatility of the last few years shows that this distinction has already been eroded and that much greater changes may lie ahead. In predicting future coal prices, investors must consider the risks that prices could be pushed far higher by increased exposure to the global market (particularly, rising coal demand from Asia), by new uncertainties about the size of coal reserves (both in the United States and globally), and by new constraints on mining.

The Threat to U.S. Coal Prices from Volatile Global Markets

Spot coal prices in the eastern United States rose dramatically in 2008 (Figure 5, p. 14).[11] This shift occurred largely in response to the rise in the global trade in coal, to which the eastern U.S. markets were particularly exposed (Freme 2009; Victor 2008). Global coal prices also rose steeply in 2008—because of growing demand, especially from Asia, and of supply problems in other countries (Mufson and Harden 2008). After spiking in 2008, spot prices dropped with the recession, largely because of declining demand for power domestically and falling steel production globally (EIA 2009e).

As nations' economies recover from the woes of the past two years, the same kinds of global forces are driving coal prices upward again. China is the world's largest coal consumer and producer by far, mining and burning about three times as much as the United States (in second place) in 2009 (EIA 2011b; EIA 2010f). China also switched from being a net coal exporter to a net importer in 2009 (Rosenthal 2010). China's coal use has risen about 10 percent annually for the last decade, and it now accounts for almost half of global consumption (Rudolf 2010). India as well is increasingly relying on imported coal to meet its growing demand, and Citigroup predicts that in 2011 China and India combined will increase their coal imports by 78 percent (Sethuraman and Sharples 2010). Some industry analysts describe the coal demand in the Asia-Pacific region as experiencing "absolutely stupendous, fantastic growth," which they expect will bring about a "seismic shift" in the global coal markets (Gronewold 2010).

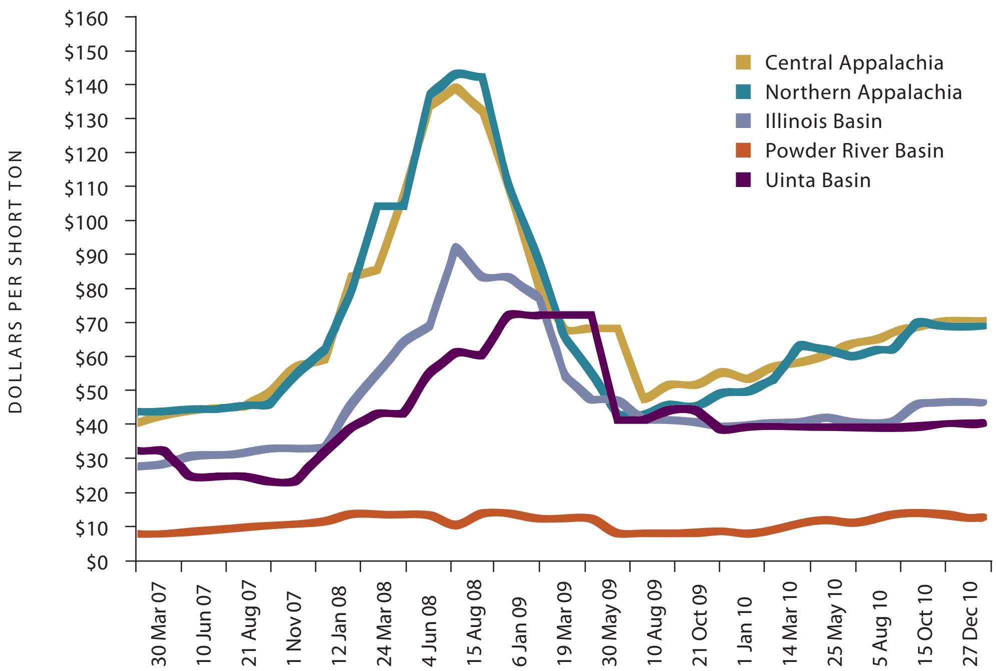
That seismic shift could be even stronger given the recent announcement by Chinese officials that they plan to cap their nation's domestic coal production at 3.6 billion to 3.8 billion tonnes (compared with the 2009 production of 3.2 billion tonnes), in part to prevent Chinese reserves from running down too quickly (Reuters 2010a; Winning 2010). This move, combined with still-soaring demand for coal in China, could have profound implications for global coal prices—which in December 2010 reached their highest point in two years (Sethuraman and Sharples 2010)—and for U.S. coal prices.

U.S. coal prices are already rising, at least partly in response to global prices. Appalachian spot prices have been on an

11 Given long-term contracts (of one year or longer), most U.S. coal plants are buffered from the immediate effects of short-term spot price volatility, but they still feel the coal price trend. On a national-average basis, delivered prices of coal to electric utilities in 2009 were 43 percent higher than in 2005 (EIA 2009h). Delivered coal prices in 2009 were 8 percent higher than in the year before, even though 2009 demand for coal dropped by 10 percent in the power sector. The EIA attributes this rise mainly to the new contracts signed during the 2008 spike in spot prices. And notably, despite the global economic slowdown, the average price per ton of U.S. steam coal exports rose by 28 percent in 2009 (EIA 2009h).

Figure 5. AVERAGE WEEKLY COAL SPOT PRICES

Coal prices spiked dramatically in 2008, largely in response to the influence of global coal demand on U.S. coal markets, particularly in Appalachia. Prices in most basins are rising again with the economic recovery.



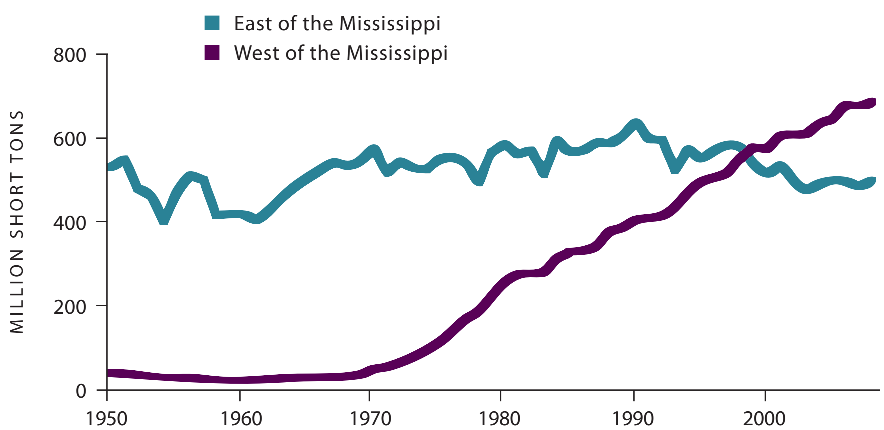
Source: EIA 2010e

upward trajectory since mid-2009 (Figure 5). Even in the western United States, which historically has been less exposed to global markets, the price for a one-month contract for Powder River Basin (PRB) coal rose 67 percent between October 2009 and October 2010 (Jaffe 2010).

Currently, limited amounts of PRB coal are shipped to Asia via Canada, but Peabody Energy, the largest U.S. coal producer, admits it is "planning to send larger and larger amounts of coal" to China (Rosenthal 2010). Peabody is seeking to build a West Coast terminal for this purpose, and an Australian coal company is separately exploring the purchase of a site in Washington State for a bulk coal export terminal (Learn 2010). If such plans are realized, the coal plants in the 34 U.S. states that currently get their coal from Wyoming will increasingly be forced to compete for their fuel with China and India. It is plausible that demand growth in Asia could drive up U.S. coal prices for years, even while the size of the U.S. coal fleet shrinks because of plant retirements.

U.S. coal plants dependent on PRB coal must also contend with the risks associated with long-distance rail transportation and the bottlenecks that can threaten reliable delivery. In 2005, heavy rain and snow, two derailments, and resulting track damage reduced deliveries of PRB coal to power plants for months and caused PRB spot prices to more than double (NRC 2007). One long-contemplated rail project designed to expand PRB deliveries (the Dakota, Minnesota, and Eastern Railroad expansion) has effectively been put on hold, in part because of uncertainty over future U.S. coal policy (Dowd 2010). In addition, the cost of long-distance coal deliveries can be significantly affected by the price of diesel, which rose steadily in 2010.

Figure 6. **U.S. COAL PRODUCTION**



The nation has become increasingly dependent on coal from west of the Mississippi, particularly the Gillette coalfield of Wyoming's Powder River Basin, as coal production in the eastern United States has declined and the need for lower-sulfur coal has increased. However, USGS estimates of coal reserves based on new drilling data show less economically recoverable coal in the Powder River Basin than has been commonly assumed.

Source: EIA 2009b

New Doubts about the Sizes of U.S. and Global Coal Reserves

Coal prices could also rise significantly in the future if economically recoverable reserves turn out to be smaller than previously estimated. For years, Americans have heard that the United States had enough coal to last 250 years, or some other high figure, so that those investing in coal could afford to ignore its nonrenewable nature. However, multiple studies have pointed out that the quality of the data underlying the estimates both of U.S. and global coal reserves is surprisingly poor. Newer and more detailed assessments, together with recent production trends, suggest that the true amounts of economically recoverable coal left in the ground could be far less than previously estimated. If so, depleting reserves could drive up coal prices well within the lifetime of new coal investments.

A 2007 review by the National Academy of Sciences found that present estimates of U.S. coal reserves are based on decades-old methods and data and, moreover, that updated methods of analysis in limited areas "indicate that only a small fraction of previously estimated reserves are actually recoverable" (NRC 2007). The study also found that the often-quoted estimate of a 250-year supply of coal at current production rates could not be confirmed. And while the study estimated that there was enough coal to meet the EIA's projections of rising demand through 2030—and "probably" enough U.S. coal to last 100 years—the authors warned that, "the data that are publicly available for such [long-term] projections are outdated, fragmentary, or inaccurate." Thus they called for more in-depth analyses using better data (NRC 2007).

In 2008, the U.S. Geological Survey (USGS) provided just such an in-depth analysis—of the critically important Gillette coalfield in Wyoming's Powder River Basin. Over the years, the nation has seen a dramatic shift in coal production from east of the Mississippi to the west. As Figure 6 shows, coal production in the east has been on a generally downward slope for two decades, with growth in national demand accommodated by rising production in the west, mainly from the PRB. The Gillette coalfield is the most productive in the nation by far—it is the source of 37 percent of U.S. coal in 2006—and home to nine of the nation's 10 most productive coal mines (Luppens et al. 2008).

It is therefore particularly significant that the USGS study showed far less economically recoverable reserves of coal in the Gillette field than had commonly been assumed. Its analysis, which drew on data from thousands of drill holes associated with recent coal-bed methane development, found that for the

It is plausible that demand growth in Asia could drive up U.S. coal prices for years, even while the size of the U.S. coal fleet shrinks because of plant retirements.

six coal beds evaluated, only 10.1 billion short tons (6 percent of the original resource total) could be profitably mined at $10.47/ton (the price prevalent in January 2007) and only 18.5 billion short tons at a price of $14/ton (Luppens et al. 2008). The head of the USGS team that conducted the study told the *Wall Street Journal*, "We really can't say we're the Saudi Arabia of coal anymore" (Smith 2009). The size of economically recoverable coal reserves did increase with rising coal prices under the USGS's analysis, but coal plants would bear the increased costs.

The EIA, by contrast, does not factor specific coal prices into its estimated recoverable reserve (ERR) figures. Its estimates are based largely on a 1974 study by the USGS, which calculated the quantity of coal recoverable using then-standard mining methods and "assuming a market and an adequate selling price at the time of mining" (EIA 1997). The EIA has not yet updated its reserve figures to reflect the 2008 USGS Gillette study.

One costly challenge looming for the U.S. coal industry will be in the opening of new mines or the expansion of existing ones. Even in Wyoming, the amount of remaining coal reserves at active mines was only 7 billion short tons in 2008, or roughly 15 years of current state production (EIA 2009f). A separate 2009 review of U.S. coal reserves and of the life spans of existing mines in the Gillette coalfield noted that, according to public records, many of the major PRB mines had only 10 to 15 years remaining at current rates of production (Glustrom 2009). Moreover, this review found that even if the new federal coal leases that the mines had requested were approved, the life spans of most of the major mines would still be typically less than 20 years. And because the mines would be expanding into portions of the coalfield with greater overburden and otherwise less favorable mining conditions, it is fair to assume that their production costs would continue to rise.

Already, warning signs are pointing to increasing difficulties and costs ahead for U.S. coal mines. Production of the higher-quality bituminous coal (found mainly in Appalachia and the Illinois basin) peaked in 1990. In central Appalachia in particular—which includes Kentucky and West Virginia, the nation's second- and third-biggest mining states after Wyoming—total production is projected to fall by 2015 to about half of what it was in 1997, with additional declines beyond 2015 (Leer 2010; McIlmoil and Hansen 2010).

When considered by heat content rather than tonnage, total U.S. coal production was actually higher in 1998 than in any year since (BP 2010; Heinberg 2009; BP 2008). This is because western sub-bituminous coal, while lower in sulfur, is also considerably lower in heat content. So while the number of tons of U.S. coal annually mined has generally been rising (with the exception of 2009, when it dropped 8.5 percent), the nation is increasingly relying on lower-quality fuel.

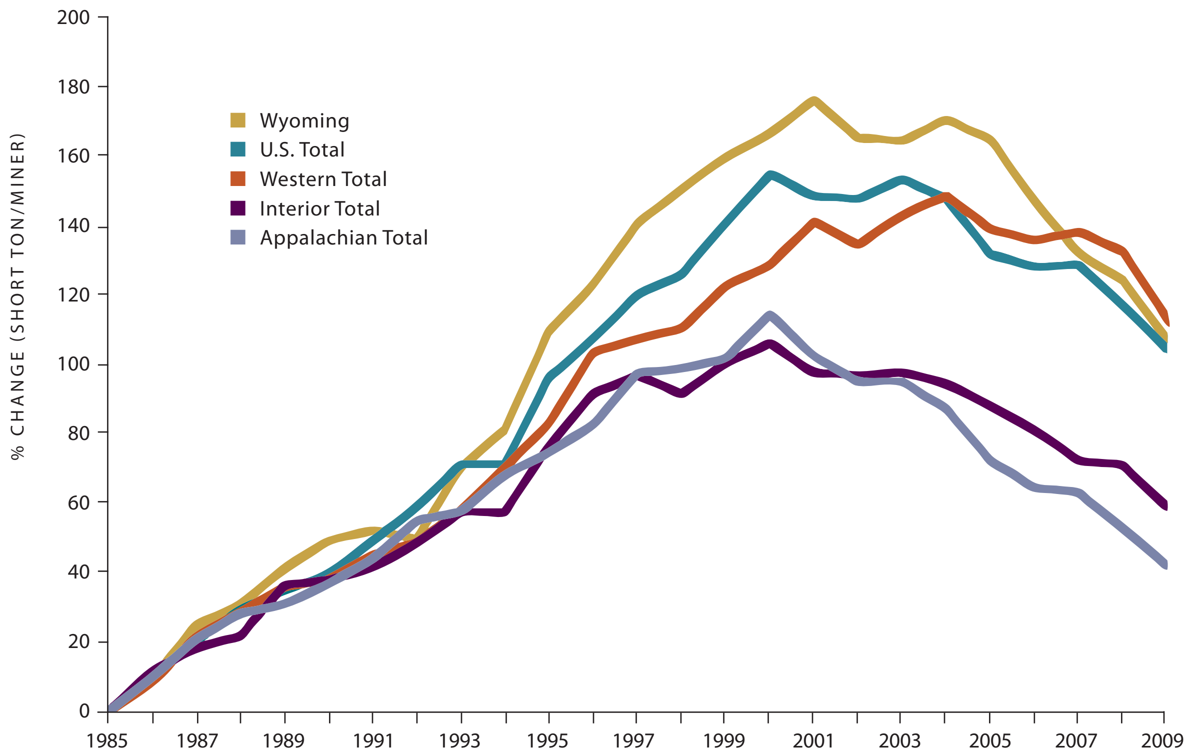
Meanwhile, the labor productivity of U.S. mines has been dropping since 2000. Prior to that year, productivity (tons mined per miner) had been increasing for years, largely due to increased mechanization and a shift toward surface mining. In 2000, however, this trend reversed (Figure 7). By 2008, coal mines were 15 percent less productive, on a national average, than in 2000. The decline of labor productivity has been steepest in the aging coalfields of Appalachia, with a 29 percent drop since 2000.

Even the new coalfields of the Powder River Basin, on which the nation is increasingly dependent, have suffered a 20 percent drop in labor productivity since 2001 (EIA 2009f; EIA 2002; EIA 2000). Steadily falling productivity is an indicator that the easiest-to-mine fuels are being depleted. This trend, along with a larger analysis of global reserves and production data by the German-based Energy Watch Group (EWG), led the EWG to predict that total U.S. coal production in tons would peak between 2020 and 2030 (EWG 2007).

The increasing exposure of U.S. coal markets to international demand, discussed in the preceding section, means that investors need to factor in the quality of reserve estimates in other countries as well. The EWG assessment concluded that coal reserve estimates around the world were of poor quality and "that there is probably much less coal left to be burnt than most people think." The analysts noted that some nations had recently lowered their reserve estimates drastically (such as Germany, which in 2004 reduced its estimated hard coal reserves by 99 percent). As a result, global reserve estimates are

Figure 7. CHANGES IN U.S. COAL MINE LABOR PRODUCTIVITY

After decades of greatly increasing labor productivity, U.S. coal mines have experienced significantly declining productivity since about 2000. This trend suggests that technological changes are no longer compensating for the depletion of the easiest-to-mine coal, even at the relatively new coal mines of the Powder River Basin (PRB). (Note that the graph shows Wyoming mine productivity, rather than PRB productivity in particular, for the sake of continuity across the years, but PRB mines dominate Wyoming production.)



Sources: EIA Annual Coal Reports, 2001–2009; Coal Industry Annuals, 1994–2000

shrinking even though, with higher coal prices, they should be rising (Heinberg and Fridley 2010; EWG 2007).

China's coal reserve estimates are of particular interest, given its enormous and accelerating coal consumption. A series of recent articles raised the prospect that China could deplete its reserves far sooner than earlier estimates had suggested (Rudolf 2010). For example, in their *Nature* article "The End of Cheap Coal," authors Richard Heinberg, of the Post Carbon Institute, and David Fridley, deputy leader of the Lawrence Berkeley National Laboratory's China Energy Group, noted that if China's coal demand were to grow in step with its economic growth, the nation's reserves would last only 19 years (Heinberg and Fridley 2010). A recent *Wall Street Journal* article, "China's Coal Crisis," cited a Hong Kong-based brokerage firm as estimating that even if the growth in China's coal demand were halved, to 5 percent yearly, the country would run out of coal in 21 to 28 years (depending on which reserve estimate is used) (Winning 2010). The Chinese government's announced cap on domestic coal production, discussed earlier, will slow the depletion of Chinese reserves, but the cap will also accelerate the depletion of reserves in other nations while driving up global coal prices.

These projections use the traditional method of estimating coal reserves, based on geologic data and assumptions about how much of the underground resource can be economically mined. The estimated amount is then typically divided by a given production rate to determine how many years of coal is left at that rate. But this approach fails to reflect the pattern of rising costs and falling production that characterize the depletion of nonrenewable resources. In many ways, the more important question from an economic or planning standpoint is the time at which production of coal will peak and then begin its decline, thereby putting sustained upward pressure on prices. Some analysts attempt to predict these production peaks using historical production rates and then projecting future rates through the use of a bell curve. This approach has been described as a "mathematical way of modeling the fact that we tend to find and produce the most accessible portion of the [nonrenewable] resource first, so that production requires more effort over time" (Heinberg 2009).

The curve-fitting approach can lead to much smaller estimates of future production than the traditional approach (Rutledge 2010; Kerr 2009). One recent analysis using the curve-fitting method concluded that the peak in global coal production from existing coalfields would be close to 2011 (Inman 2010; Patzek and Croft 2010). While estimates using this approach are still controversial, they deserve greater attention, particularly in light of their major implications and the poor quality of the data on which current U.S. and global coal reserve estimates are based.

Other Production-Cost Increases Ahead

Other upward pressures on coal production costs arise from issues such as underground-safety requirements and the potential difficulty of obtaining permits for new surface mines (EIA 2009e). The average cost of coal from low-cost producers in central Appalachia has more than doubled since 2003, and this change may be attributable in part to a greater focus in recent years on mine safety (Mellquist et al. 2010). Even so, coal mining remains dangerous, having caused 29 fatal injuries and 4,760 nonfatal injuries in 2008, mostly in underground mines (NRC 2010c). In 2010, 29 miners were killed in a single accident—at Massey Energy's Upper Big Branch mine in West Virginia—leading to calls for stronger regulation of mine safety (Wald 2010b).

Surface mining, especially the practice of mountaintop-removal mining in Appalachia, is also getting much closer scrutiny than in previous years (McIlmoil and Hanson 2010). As its name implies, the technique involves blasting away the tops of mountains and then disposing of the wastes in adjacent valleys (a practice known as "valley fill"). The EPA estimates that almost 2,000 miles of Appalachian headwater streams have been buried by these valley fills (EPA 2010h). A growing body of scientific evidence shows that mountaintop removal and valley fills have impacts that are "pervasive and irreversible," with a high potential for harming human health (Palmer et al. 2010).

In January 2011 the EPA vetoed the water permit for what would have been one of the largest mountaintop-removal operations ever (Ward 2011). Earlier, in 2010, the agency had also issued new guidance to better protect Appalachian watersheds from the impacts of mountaintop removal. EPA Administrator Lisa Jackson told reporters, "no or very few valley fills … are going to be able to meet standards like this" (Ward 2010). And a federal court dealt what could be a significant blow to mountaintop mining with a decision in September 2010. Under the ruling, an Appalachian coal company would have to install a treatment system to reduce discharges of the water pollutant selenium from two of its mountaintop-removal mines (Schoof 2010). Even if mountaintop mining were allowed to continue, such decisions could increase the price of Appalachian coal.

PART FOUR

Carbon Risk

A Costly Problem in a Warming World

Anyone making a long-term investment in coal plants faces the inherent financial risks associated with locking into the most high-carbon energy technology during an era when the nation and the world must slash carbon emissions. This includes the continued risk that coal plants in the future will have to pay for the right to emit CO_2.

While climate legislation failed to pass in the 111th Congress and it appears at this writing that the 112th Congress will remain deeply divided on the issue, the urgency of the climate threat ensures that Congress will be pressured to take up the issue again, perhaps repeatedly in the years ahead, as long as we stay on our current dangerous path. The advantages of including a price on carbon to help mobilize market forces are great enough that it will likely be included in future legislation. The continued expectation of such eventual carbon restrictions is one of the reasons why so many utilities have recently announced the closure of old coal plants and shown a renewed interest in natural gas (Smith 2010).

In this part, we discuss present projections of CO_2 prices and their likely impacts on coal power. We also discuss why the fact that CCS technology may become commercially available in the years ahead does not make it safe to invest today in coal plants that lack CCS.

The Impact of a Carbon Cost on Coal Generation

Not surprisingly, computer models show that putting a price on carbon makes investments in new coal plants less attractive. As noted earlier, the EIA's latest Annual Energy Outlook no longer forecasts any new coal plants without CCS before 2030 (other than those already under construction). Back in 2009, however, the EIA was still forecasting a few such "unplanned" plants before 2030 until it added a price on carbon under its modeling of the American Clean Energy and Security Act (ACES, the comprehensive climate bill that passed the House in 2009), when those plants disappeared from the forecast (EIA 2009d). The EPA's modeling of the same bill, and previous modeling of other climate bills in earlier Congresses, similarly showed otherwise-projected new coal plants without CCS disappearing under a carbon price (EPA 2009a; EIA 2008b; EPA 2008). It is also worth noting that these analyses all assumed natural gas prices higher (and therefore less competitive with coal) than many analysts and utilities now forecast, given the expanded estimates of domestic production discussed in Part 2.

Of course, the impacts of a price on carbon would go beyond new plants. Existing coal plants would see their costs rise even more because they emit more carbon per kilowatt-hour than new ones.

A long series of studies shows that replacing today's coal plants with something less carbon-intensive is a central feature of the nation's least-cost path to CO_2 emissions reductions (ACCF/NAM 2008; Banks 2008; CRA International 2008; DeLaquil, Goldstein, and Wright 2008; Murray and Ross 2007; Paltsev et al. 2007). These analyses make widely varying assumptions about future fuel prices and technology development, they use different models, and they address different legislation. Some of the modeling organizations support cap-and-trade and others oppose it. Some show the United States turning more to nuclear and natural gas; others have it favoring renewable power and efficiency. Most of the models make assumptions that are highly favorable to coal generation. But even with such coal-friendly assumptions, the models' results show that generation from coal plants without CCS declines steadily and often steeply.

It is hardly surprising that a law designed to squeeze carbon pollution out of the economy as cost-effectively as possible would drive the nation away from coal. Coal power is our largest source of CO_2 emissions and the most carbon-intensive source of power, and there are many ways in which we can cost-effectively replace it. Indeed, any path toward carbon reduction that did not greatly reduce our dependence on coal generation would almost surely be straying from the least-cost (and most beneficial) path while imposing greater overall costs on society. To be sure, political pressures may continue to delay or mitigate the impacts of climate protection policies on coal generation. But the fact that shifting from coal is the most obvious way to reduce carbon emissions means that the coal power sector will remain under pressure to shrink as the world warms and as society seeks the best way to cut emissions.

Carbon Prices Still on the Horizon

There is now a substantial literature, largely derived from the computer modeling analyses conducted by the federal government and others, that forecasts possible future CO_2 allowance prices.[12] Most of the studies are tied to one of the climate bills that have been proposed in recent years, particularly the ACES bill that passed the U.S. House in 2009, and they generally look at multiple scenarios that vary key assumptions such as the features of the federal program and the costs of available technologies.

The bills in question did not pass, but several factors ensure that Congress will be under continual and growing pressure to put comprehensive carbon restrictions in place over the next few years. Among these factors is the increasingly urgent need to reduce carbon emissions, which will become even more apparent as concentrations of global warming gases rise, pushing the planet toward higher temperatures, more extreme weather events, and other negative climatic consequences.

Another factor is industry's desire to forestall the emerging patchwork of state climate policies in favor of the uniformity and greater certainty of federal legislation. The power sector is already subject to a cap-and-trade program in the Northeast under the Regional Greenhouse Gas Initiative, California is moving ahead with its own cap-and-trade program (which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received broad support from California voters when they decidedly rejected a referendum attempt to roll back the state's emission-reduction laws in November 2010), and there is already a futures market developing in California carbon allowances (Point Carbon 2011).

Among the top energy recommendations of a November 2010 conference of corporate leaders sponsored by the *Wall Street Journal* was a call for "a comprehensive energy policy that provides consistency and predictability for investment," including clearer policy on "carbon constraints" to avoid a patchwork of state rules (Ball 2010). "There was a recognition that some type of carbon pricing will be needed," said one of the CEOs in describing the conference; another CEO, after similarly noting that, "we're going to need some kind of a signal on carbon," highlighted the "hundreds of billions of dollars that companies are ready to invest" if the uncertainty over carbon were cleared up (Ball 2010). "I think the prospect of no carbon [regulation] is putting blinders on," said the author of a new report by consulting group ICF International, which predicted that coal plant owners will still factor climate regulations into their decisions (Fine Maron 2011).

12 Under various climate bills that have been considered by Congress in recent years, a limited and declining number of allowances would be issued by the government that grant the right to emit one ton of carbon dioxide. The allowances would be tradable and their prices set by market forces.

I think the prospect of no carbon [regulation] is putting blinders on.

— STEVE FINE, ICF INTERNATIONAL

Congress will also be subject to pressure to act from the international community, as it grows more impatient for the United States to join other developed countries in reducing carbon pollution. And Congress may also act in response to climate-related litigation working its way through the courts or as part of an effort to prevent (or enhance) executive action on climate change. Finally, congressional action could well be driven by a desire to pursue the many nonenvironmental benefits of moving to a cleaner and more diversified energy system—including greater global competitiveness, accelerated technological innovation, enhanced national security, and new jobs in clean-energy growth industries.

It remains reasonable, therefore, to expect future federal legislation on climate, and—given the benefits of sending a market signal to stimulate innovation in the private sector—it should be expected that such legislation will include a price on carbon. Obviously, there is great uncertainty over what a future climate law would look like, but any form of carbon price would likely present the energy markets with the same fundamental set of choices among the same set of available technologies that the markets would have faced under the modeled climate bills. Because the computer analyses of the previous cap-and-trade bills looked at how the markets would respond under so many varied scenarios, they created a spectrum of simulated outcomes that put boundaries on the likely costs of different kinds of carbon restrictions. These model results represent, therefore, a still relevant and useful starting point for assessing the long-term carbon risk faced by those investing in coal today; the results are the most comprehensive data available on the range of allowance prices likely under the various approaches a future climate bill might take.

Of course, the failure of climate legislation to pass thus far means that the onset of a carbon price is delayed beyond the dates assumed in the literature; this delay should be factored in when assessing future financial risk. However, given the long operating lifetime of a new coal plant or one that has been subject to a major life-extending retrofit, the delay may not substantially reduce the overall levelized carbon costs such projects face. Moreover, the nation may decide to pursue a more aggressive rate of emissions reduction than previously proposed in order to make up for lost time, thereby putting upward pressure on the carbon costs faced by a coal investment.

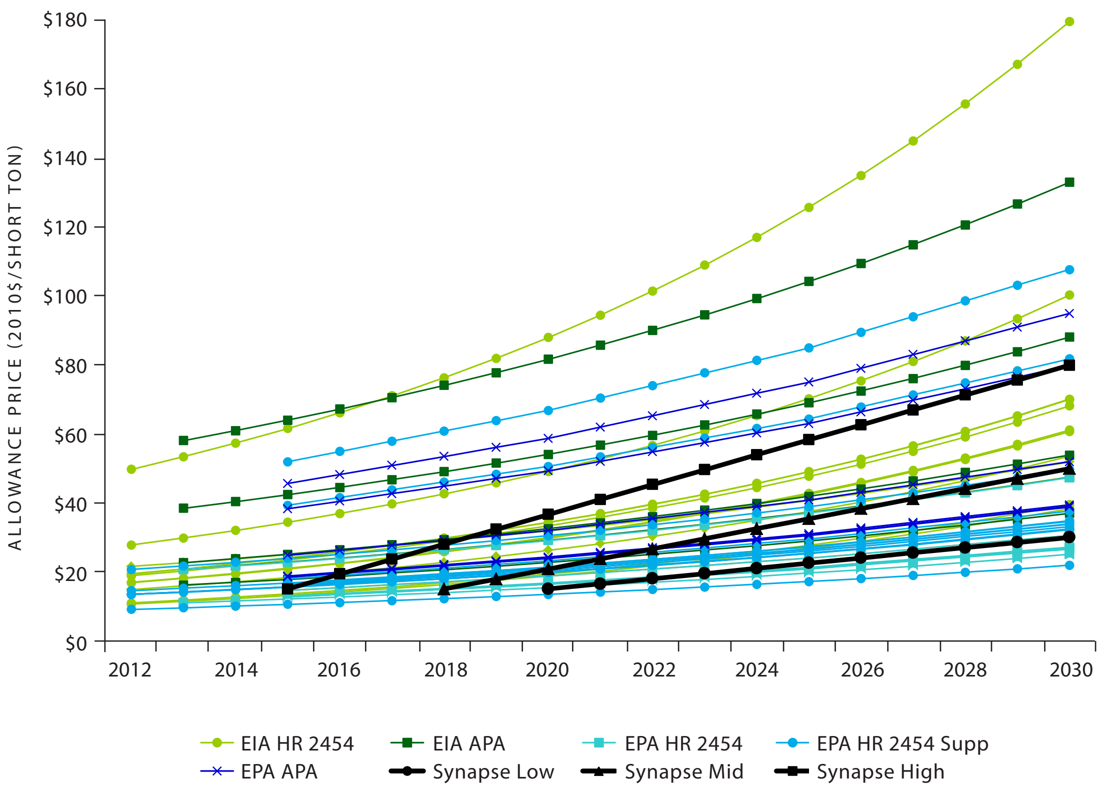
Synapse Energy Economics (a consulting firm with a wide range of clients, including environmental groups, grid operators, businesses, and government agencies) recently conducted a detailed review of more than 75 different scenarios examined in the recent modeling analyses of various climate bills. It also surveyed the allowance price projections used by a number of electric companies in their resource plans over the last two years. Based on these allowance projections, on a review of recent climate policy developments, and on its analysis of the carbon-price impact of a range of policy and technology assumptions, Synapse has projected low-, medium-, and high-cost cases that provide a range of allowance prices through 2030 (Johnston et al. 2011).

Figure 8 (p. 22) shows Synapse's three projected cost trajectories, and it compares them to allowance prices projected by the EIA and EPA for various scenarios under the ACES bill and its Senate counterpart, the American Power Act. Given the failure of these bills to pass, Synapse assumes a delayed onset of any carbon price, ranging from 2015 (under the high-cost case) to 2020 (low-cost case). Synapse considers the high-cost case to be consistent with more aggressive reduction targets, greater restrictions on the use of offsets, some restrictions on the availability or cost of low-carbon technologies, more aggressive international actions (which reduce available international offsets), or higher baseline emissions. The low-cost trajectory is consistent with a sustained political stalemate that delays a carbon price till 2020 and other factors such as less aggressive reduction targets, a safety-valve mechanism limiting allowance prices, or greater availability of offsets.

In Part 8, we show the impact that this range of projected CO_2 costs would have on a new coal plant and other energy technologies. On a per-megawatt-hour levelized basis, the cost of electricity from a new coal plant would rise from an additional $13.70 (using the low-cost estimate) to an additional $44.20 (using the high-cost estimate) (Figure 12, p. 40). While new coal plants are already more costly than many cleaner options, future CO_2 prices in this range would make them even less economically competitive (Figure 13, p. 41).

Figure 8. CO_2 ALLOWANCE PRICE FORECASTS COMPARED WITH PREVIOUSLY MODELED SCENARIOS

Recent forecasts by Synapse Energy Economics of high-, mid- and low-cost CO_2 prices are contrasted with the CO_2 prices projected under multiple scenarios by federal modeling of climate bills considered by the last Congress.



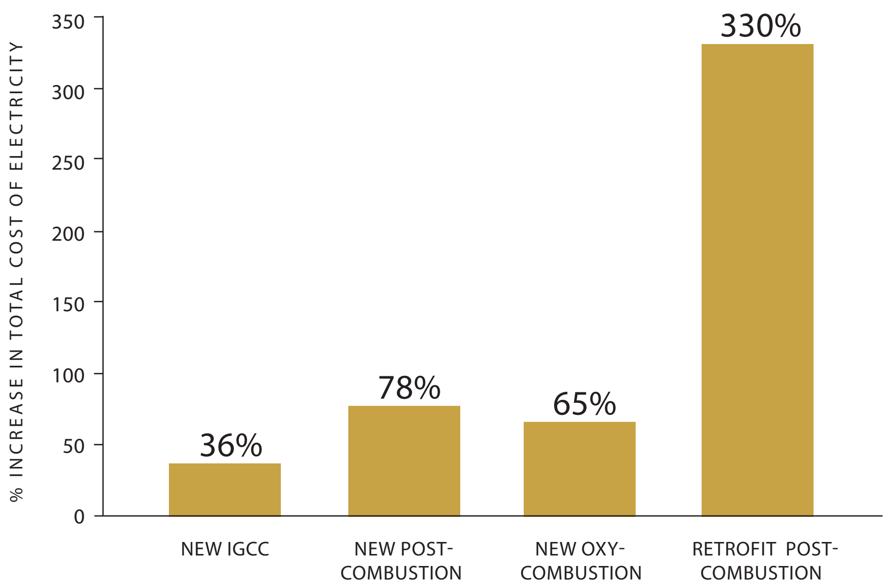
Source: Synapse Energy Economics (Johnston et al. 2011)

Uncertainties around Carbon-Capture Retrofits

Some proponents of new coal plant investments point to CCS technology as something they could eventually add to those plants. After all, to the extent that CO_2 emissions could be captured and stored underground rather than emitted, the plants' owners would not be required to buy CO_2 allowances. However, this technology must overcome numerous hurdles before it is commercially viable, including very high costs and efficiency losses under current designs, particularly when added as a retrofit to an existing coal plant.

While many of the component technologies that would likely be used to capture, transport, and store the CO_2 in geologic formations have been used in other industrial applications, there has not yet been a commercial-scale demonstration of CCS at a coal-fired power plant. With this need in mind, the Union of Concerned Scientists published a report in 2008 that described CCS technology, reviewed its status, potential, and costs, and called for the federal government to subsidize 5 to 10 full-scale demonstration projects (Freese, Clemmer, and Nogee 2008). However, despite support for such projects

Figure 9. RELATIVE COST INCREASES FROM ADDING CARBON CAPTURE TO COAL-FIRED POWER PLANTS



Adding CCS to coal plants is projected to add substantially to the levelized cost of electricity from those plants. A recent federal study projected that costs would increase 36 percent if adding pre-combustion capture to a new IGCC plant, 78 percent if adding post-combustion capture to a new pulverized coal plant, 65 percent if adding oxy-combustion to a new pulverized coal plant, and 330 percent if adding post-combustion capture to an existing pulverized coal plant. The much greater relative cost increase for the existing plant is largely because it is assumed to start with much lower levelized costs.

within the power sector and the federal government, progress toward commercial demonstration to date has been slow.

Adding CCS to a coal plant is estimated to greatly increase the cost of electricity from that plant, particularly if the CCS were added as a retrofit (Figure 9). Almost all coal plants in operation today use pulverized coal technology,[13] and they could employ either a *post-combustion* capture process or a variation called *oxy-combustion* (in which the coal is burned using pure oxygen rather than air). Two plants currently in operation in the United States use the alternative integrated gasification combined-cycle (IGCC) technology,[14] which could employ a *pre-combustion* capture process. According to federal estimates based on current technological designs, adding CCS to a new pulverized coal plant would increase its levelized cost of electricity by 65 percent or 78 percent (using oxy-combustion or post-combustion, respectively); and adding pre-combustion capture to a new IGCC plant would increase its levelized costs by 36 percent. Adding CCS as a retrofit to a pulverized coal plant would increase its levelized cost of energy by as much as 330 percent, though this estimate is relative to a much lower assumed levelized cost than those of new plants (Figure 9).

As CCS technology finally moves into the phase of commercial-scale demonstration projects and as we incorporate the lessons from such projects into plant design, these high costs may well come down (Al-Juaied and Whitmore 2009). Also, a number of innovative approaches to carbon capture are being researched, some of which may have potential for breakthroughs in cost reduction. But substantial research and development will be required before we know if any of these approaches can be successfully commercialized.

13 Some plants use a variation on pulverized coal combustion called circulating fluidized bed (CFB) combustion.

14 One additional IGCC plant is under construction and several others have been announced.

On the other hand, recent developments with CCS projects suggest that the initial cost estimates using current technology may be too low. For example, U.S. power producer Tenaska has proposed an IGCC plant in Taylorville, IL, designed to capture more than 50 percent of its carbon emissions. However, a cost review by the Illinois Commerce Commission (required by state law before the project could receive a legally guaranteed market for its output), found that the project would cost over $210/MWh (or 21¢/kWh), with uncertainties that could push costs higher (ICC 2010). The project subsequently failed to get necessary approval from the Illinois legislature (Reuters 2011).

The FutureGen CCS project—the federally supported flagship effort to develop CCS—has already been cancelled once for cost overruns; now revived, it recently shifted course. Rather than testing pre-combustion capture as part of a new IGCC plant, it will test oxy-combustion capture at a retired oil-burning Illinois power plant altered to burn coal and use pure oxygen instead of air (Wald 2010a). This type of carbon capture technology could someday be added to the existing fleet of pulverized coal plants, unlike the pre-combustion approach that the project was formerly planning to test. This change in direction therefore offers greater potential to reduce the emissions of existing coal plants. But because oxyfuel combustion is a relatively untested technology, the shift could also lead to further delays and make costs harder to project.

CCS development has run into problems abroad as well. The Norwegian oil company Statoil is one of the pioneers of CCS; it has long experience pumping CO_2 captured from natural gas production into deposits below the North Sea. But Statoil is still reportedly facing a nine-fold jump in costs to build a CCS test center at a Norwegian refinery (Reuters 2010b). Meanwhile, the Norwegian government recently announced that it is reevaluating the technology it had planned to use in a subsequent project, which would install full-scale CCS at the refinery. The government was responding to new evidence of health and environmental risks linked to the amine chemicals it had intended to use in the capture process (Bhatia 2010).

One of the leaders in developing CCS technology at coal plants in Europe has been the Swedish utility Vattenfall. While the company is reportedly continuing to pursue CCS, its CEO recently announced that, “there will be no CCS before 2020, so Vattenfall has to reduce CO_2 by other means.” He also said it was unlikely that Vattenfall would “invest to prolong the lives of the older coal plants” it owns in Germany (Platts 2010).

Such difficulties and delays do not mean that CCS has no future but simply that it will be years before we know what the technology is capable of achieving. Certainly no one contemplating a long-term investment in a coal plant today can safely assume that CCS technology will develop fast enough to offer an affordable way to cut that plant’s CO_2 emissions.

PART FIVE

Coal's Damages—to Air, Water, Land, and Public Health—and the Costs of Reducing Them

Quite apart from their impact on climate, coal plants cause a staggering array of other harms to the environment and human health. Coal plants contribute to the premature deaths of thousands of Americans each year from heart and lung disease, for example. They are the source of more than half of the nation's atmospheric emissions of mercury, a potent neurotoxin that each year threatens thousands of newborns with lifelong reduction in brain function. Coal plants generate millions of tons of toxic ash and other solid wastes known to leak into ground and surface waters. And coal plants require enormous quantities of water for cooling, thereby putting stress on water supplies and taking a heavy toll on aquatic life.

Coal plants face the prospect of having to more thoroughly reduce these and other environmental and public health impacts over the next few years. The EPA is currently working through a backlog of standards to address such threats—a backlog that developed largely under the previous administration, when the EPA in some instances adopted rules that the courts struck down as insufficiently protective and in other instances failed to act altogether.

In addition to triggering the series of financial analyses that projected the coal plant retirements discussed in Part 1, these pending rulemakings have provoked political opposition and prompted calls for legislation that would bar their adoption. However, it would be reckless for those investing in coal plants to count on such legislation being passed, given that the health and environmental benefits of the rules would greatly outweigh their projected compliance costs.[15] One of the recent analyses of forthcoming air quality rules concluded, "the EPA actions are more 'viable' than past expectations around Congressional action on climate change (carbon) or renewables since this EPA 'event' is mostly about enforcement of existing laws where the health and societal good benefits are of limited debate at this point" (Eggers et al. 2010).

The exact compliance costs faced by any given plant would depend, among other things, on what the future rules actually required and what pollution controls and other equipment the plant already had in place. But coal plants are clearly at risk of major new costs, especially the oldest plants that in many cases have managed for decades to entirely avoid installing modern controls, thus externalizing the associated costs of health and environmental damage onto others.

The regulatory efforts likely to impose the most significant costs are discussed below.

Transport Rule: Preventing Thousands of Deaths from Pollution-Related Diseases

Public health experts and governmental regulators have long recognized that air pollutant emissions from U.S. coal plants kill thousands of people yearly and cause many more nonfatal health effects. An extensive body of research shows, for example, that fine particulates in the air increase the death rates from heart and lung conditions and strokes (CATF 2010; EPA

15 The Clean Air Act has been particularly successful in delivering benefits far in excess of compliance costs. The EPA estimates that the total benefits of the Clean Air Act—in lives saved, reduced heart disease, fewer asthma attacks, and other positive effects—amount to more than 40 times the costs of regulation (Jackson 2010).

2010d; NRC 2010c; Lockwood et al. 2009). Research suggests further that this pollution may shorten the lives of its victims by an average of 14 years (CATF 2010). To some extent, coal plants emit these tiny particulates directly, but their much greater contribution to particulate pollution comes from their emissions of sulfur dioxide (SO_2) and a suite of nitrogen oxides (NO_X)—gases that condense into particulate form in the atmosphere.

Earlier regulatory efforts have already brought about significant reductions in SO_2 and NO_X emissions from U.S. coal plants, thus greatly reducing their death toll. But a recent analysis by the Clean Air Task Force (CATF) estimated that coal plant contribution to fine particulates would still kill more than 13,000 people in 2010 alone (CATF 2010).[16] Combined with the thousands of nonfatal heart attacks, other effects, and the hospitalizations that these pollutants also cause, the CATF estimates this pollution causes monetized damages of more than $100 billion yearly. The CATF may actually have underestimated such mortality, health, and cost impacts, because it conservatively focused on the low end of the ranges established by the scientific literature. The high end would yield costs at least twice as great (EPA 2010d).

In the eastern half of the United States, SO_2 and NO_X emissions from coal plants are polluting the air of downwind states, preventing those states from meeting their health-based air quality standards under the Clean Air Act both for fine particulates and ozone. In 2005, the EPA attempted to address this problem through the Clean Air Interstate Rule (CAIR). In 2008, an appellate court remanded the CAIR rule to the EPA, in part because it found that the emissions trading allowed by CAIR meant that the EPA could not show the rule would sufficiently protect downwind states (EPA 2010d).

In July 2010, the EPA released another proposed rule, called the Clean Air Transport Rule, to replace CAIR. While the EPA's preferred option would still allow some trading within states, the Transport Rule increases the likelihood that coal plants in the 32 states to which it applies would need to install new pollution controls for SO_2 (scrubbers) and for NO_X (selective catalytic reduction [SCR] or other measures) or else upgrade existing controls. Controls limiting SO_2 and NO_X emissions may also be required under other rules that the EPA is required to pursue under the Clean Air Act, including updated health-based ambient air quality standards for sulfur dioxide, ozone, and particulates; regional haze reduction requirements; and regulations to reduce emissions of mercury and other toxic air emissions (discussed in the next section).

Adding SO_2 and NO_X controls to an existing coal plant could cost hundreds of millions of dollars in total. In Table 2, we show a range of costs for scrubbers and SCR, including their incremental impact in dollars per megawatt-hour.

These costs are vastly outweighed, however, by the Transport Rule's benefits. The EPA has done a detailed cost-benefit analysis, as required by law, and found that the Transport Rule would yield benefits ranging from $120 billion to $290 billion in the year 2014 alone, mainly from the thousands of lives saved; these estimates do not even include the many unquantified benefits of the rule, such as increased agricultural crop and commercial forest yields, visibility improvements, and better ecosystem functioning because of reduced acid rain (EPA 2010e). The compliance costs, by contrast, were estimated by the EPA at only $2 billion to $3.2 billion on an annualized basis. The agency may be assuming somewhat lower compliance costs than those estimated in the studies cited earlier, but such costs could be several times higher and still be greatly outweighed by the rule's health benefits. And while coal plants will face costs to cut their SO_2 and NO_X emissions, the Transport Rule is really just shifting onto the plants a fraction of the costs that the American public has borne for years as a result of those emissions' adverse impacts.

Air Toxics Rule: Protecting Children's Brain Development

Coal plants emit several highly toxic air pollutants, including arsenic, lead, selenium, dioxins, acid gases, and, most notably, mercury. A potent neurotoxin that impairs the brain development of infants and children, mercury has also been linked to heart problems. Coal plants are the source of more than half of U.S. anthropogenic emissions of mercury into the atmosphere (EPA 2010a).

After leaving the smokestack, emitted mercury falls to earth and accumulates in water bodies, where it chemically

16 The deaths, heart attacks, and other health impacts from each coal plant, as estimated in the CATF's study, are presented at *http://www.catf.us/coal/problems/power_plants/existing*.

Table 2. SELECTED AIR POLLUTION CONTROL COSTS

Coal plants that still lack the air pollution control technologies listed above may be required to install some combination of them under forthcoming EPA rules that will limit emissions of mercury and other hazardous air pollutants.

	CONSTRUCTION COST ($/KW)	FIXED O&M COST ($/KW-YR)	VARIABLE O&M COST ($/MWH)	INCREMENTAL LEVELIZED COST ($/MWH) (8)
Flue gas desulfurization (FGD or scrubbers)(1)				
500 MW plant	282–508	8.27	1.84	7.39–10.9
100 MW plant (2,3)	432–790	23.55	9.13	19.01–24.7
Selective catalytic reduction (SCR)(4)				
500 MW plant	133–390	1.39	0.54	2.83–6.85
100 MW plant (2,5)	168–550	1.96	0.76	3.66–9.67
Activated-carbon injection (ACI)(6)	7–10	0.29	0.37	0.52–0.57
ACI and baghouse (7)	150–161	0.74	0.37	2.83–3.00

O&M = Operations and maintenance
All values are in 2010 dollars.
(1) Lower scrubber cost from EIA 2010g; higher scrubber cost from CRA International 2010.
(2) Used linear regression on EIA data to estimate the 100 MW FGD and SCR construction-cost range (low value). Used EPA-IPM model of wet FGD to estimate capital costs for 100 MW (high value) (Sargent and Lundy 2010).
(3) Used EPA-IPM model of wet FGD to estimate O&M costs for 100 MW unit.
(4) Lower SCR cost from EIA 2010g; higher SCR cost from NERC 2010.
(5) Used CRA International MRN-NEEM equations to estimate construction costs and fixed O&M. Variable O&M costs for 100 MW unit were proportionally adjusted with installed 500 MW capacity (CRA International 2010).
(6) Lower ACI cost from CRA International 2010; higher ACI cost from UBS 2010.
(7) Lower ACI/baghouse cost from Eggers et al. 2010; higher ACI/baghouse cost from CRA International 2010a.
(8) Assumes fixed-charge rate of 11.7 percent consistent with the EIA-NEMS model (personal communication); assumes a capacity factor of 85 percent.

transforms into methyl mercury. In this form, the mercury builds up in the tissues of fish as well as in the animals (including people) that consume them. Two major new federal studies document the fact that the United States suffers from widespread mercury contamination of its waters and fish. A multiyear EPA survey of lake fish collected in 500 locations throughout the lower 48 states found mercury in every single fish sample collected, and nearly half of the lakes had tissue concentrations of mercury that exceeded the EPA's human health screening value (EPA 2009b). A U.S. Geological Survey study had similar findings for stream fish. The study detected mercury contamination in every fish sampled from 291 streams nationwide, and about a quarter of the fish contained mercury levels exceeding the EPA's health-based safety criterion (USGS 2009a).

Consumption of contaminated fish by women who are pregnant (or even before they become pregnant) has led to widespread fetal exposure to mercury levels that have been linked to reduced brain function. One startling analysis has estimated that, each year, between 316,000 and 637,000 babies—or 7.8 to 15.7 percent of all U.S. newborns—have been exposed in utero to mercury levels associated with a permanent reduction in I.Q. (Trasande, Landrigan, and Schechter 2005). These numbers reflect the impacts of mercury emissions from all sources—not just from coal plants—including buildup from past emissions, but as the main source of

Public health experts and governmental regulators have long recognized that air pollutant emissions from U.S. coal plants kill thousands of people yearly.

human-caused atmospheric mercury emissions today (and as a major contributor in the past), coal power is responsible for a significant fraction of this exposure (O'Neill et al. 2009).

Efforts to protect children from mercury impairment have been hindered by years of litigation and delay. Under the Clinton administration, mercury was listed as a hazardous air pollutant under the Clean Air Act, which triggered the application of the act's most stringent pollution control standards—involving maximum achievable control technology, or MACT. The Bush EPA tried to reverse course in favor of a more lenient regulatory approach that would have allowed emissions trading, but that rule was struck down by a reviewing court. The EPA is now obliged under a consent decree to complete a MACT standard by November 2011 that would limit mercury emissions from coal plants old and new.

The forthcoming MACT standard is expected to have a particularly large impact on coal plant operations. It is to be issued under Section 112 of the Clean Air Act, which, dealing as it does with the most toxic of substances, requires the most stringent of limits. Under the law, this new rule must impose emissions limits on all existing coal plants, no less stringent than the average limits achieved by the best-performing 12 percent of those plants. Moreover, this MACT standard would not only address mercury but also the other hazardous air pollutants (cited above) from coal plants.

Because coal plants with scrubbers, baghouses, activated-carbon injection (ACI), and SCR achieve the lowest emissions of toxic air pollutants, the MACT standard may finally force all coal plants that do not already have them to install these pollution controls, and to do so by 2015 (though one-year extensions may be allowed on a case-by-case basis). This is particularly true for plants burning eastern coal, though industry analysts have speculated that plants burning western coal may be allowed to use a different and somewhat less costly suite of control technologies (Eggers et al. 2010). Table 2 shows a range of cost estimates for each of the main types of air pollution controls that could be required under the rule.

Reducing coal plants' atmospheric emissions of mercury is critical to protecting our children's brain development from the damaging effects of this potent neurotoxin. However, the pollution controls listed above will not make the mercury or other toxic elements of a plant's exhaust disappear. By capturing and concentrating these pollutants they will make the coal plant's solid and liquid wastes more toxic, further necessitating their careful handling.

Ash Rule: Keeping Toxic Contaminants Out of Groundwater and Surface Water

Coal plants create an enormous amount of solid waste, including fly ash, bottom ash, coal slag, and scrubber residue (collectively termed "coal ash" in this report). This material contains many toxic components, such as arsenic, selenium, cadmium, lead, and mercury (EPA 2009d). The longstanding dispute over how coal ash should be managed was intensified after a surface impoundment failed at a Tennessee Valley Authority (TVA) coal plant near Kingston, TN, in 2008. The spill, which released a billion gallons of coal ash in the form of a thick sludge, destroyed three homes and damaged many others, covered 300 acres of land, and contaminated two rivers (Gottlieb, Gilbert, and Evans 2010). Cleanup costs for this spill were estimated to exceed $1 billion (Business Wire 2010).

A less visible but much more widespread threat posed by coal ash disposal facilities is the slow leakage of their toxic components—which include carcinogens and neurotoxins—into ground or surface water. The EPA has identified 67 cases of proven or potential damage from such leakage, and subsequent analyses by others of state agency records have brought the total up to at least 137 sites in 34 states (Stant 2010). The full extent of leakage from coal ash disposal sites is unknown, however, because many states do not require groundwater monitoring and federal oversight has been inconsistent.

The EPA estimates that U.S. coal plants generated some 136 million tons of coal ash in 2008 (EPA 2010f). By way of comparison, the municipal solid waste created in the entire country in 2008 was about 250 million tons (EPA 2010g). Thirty-seven percent of the coal ash went to a "beneficial reuse," though under today's spotty state regulations this term has been used to include not just those practices thought to encapsulate the toxic components of the ash (such as incorporation into concrete) but also practices that clearly do not (such as spreading it on icy roads for traction or using it as a soil additive or as fill in the construction of a golf course) (Gottlieb, Gilbert, and Evans 2010; McCabe 2010). About 8 percent of the coal ash was placed in defunct mines, and the rest was disposed of either in wet form (in at least 629 surface impoundments) or in the dryer confines of 311 onsite landfills at power stations or more than 100 offsite landfills (EPA 2010f; Gottlieb, Gilbert, and Evans 2010). The EPA has estimated that in 2004 some 62 percent of the surface impoundments and 31 percent of the landfills lacked liners (EPA 2010f).

In June 2010, the EPA proposed new rules to regulate the disposal of coal ash (EPA 2010f). The proposal included two alternative approaches to future regulation: one to treat coal ash as a "special waste" under Subtitle C of the Resource Conservation and Recovery Act (RCRA); and the other to establish guidance under Subtitle D of RCRA that would allow the states to continue their own oversight of the ash disposal. If coal ash were regulated under Subtitle C, it would be subject to standards that better protect public health and water quality. For example, ash ponds would have to be monitored more carefully and eventually phased out, and new landfills would be required to use composite liners and leachate-collection systems and to monitor the groundwater.

Coal plants also face new requirements for handling the wastewater associated with their ash handling and disposal facilities and with the scrubbers they will increasingly be required to install. In a multiyear study completed in 2009, the EPA concluded that although treatment technologies were available to remove pollutants from such wastewater, these systems were only in use at a fraction of coal plants. The EPA consequently announced plans to revise its existing water-discharge standards for coal plants (EPA 2009c), and

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More than 1 billion gallons of coal plant waste were released into the environment near Kingston, TN, in December 2008, when a waste impoundment operated by the Tennessee Valley Authority ruptured.

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this revision might require the construction of new wastewater treatment facilities at many plants.

As a result of the Kingston ash spill, the TVA now plans to spend $1.5 billion to $2 billion to convert 11 coal plants from wet to dry storage (TVA 2009). Industry sources estimate that converting a coal plant to dry handling of its bottom ash would cost $20 million to $30 million per unit, that conversion to dry handling of fly ash would cost $15 million per unit (or $200 per ton of fly ash), that building a new landfill would cost $30 million, and that new wastewater treatment facilities would cost $80 million to $120 million per facility (ICF International 2010; EOP Group 2009). The industry's cost estimates could be exaggerated, but clearly anyone making a long-term investment in a coal plant that currently lacks the capability to safely handle its coal ash faces the risk of significant new costs.

As with the EPA's other regulations, rather than creating new costs, the forthcoming coal ash rules are just shifting onto the coal plants some of the costs that the public at large has borne for years as a result of the plants' pollution. In aggregate, the EPA expects that the benefits of the new regulation will amount to some four or five times its costs (EPA 2010f). These estimates do not reflect the many benefits to plants and wildlife that the EPA left unquantified, such as diminished harm to migratory birds from selenium poisoning, reduced damage to wetlands, and fewer deformities among fish and amphibians. Such benefits are substantial. In a recent analysis that evaluated the ecological and other damages from the contamination of fish and wildlife caused by just six leaking surface impoundments, the estimated value of these losses exceeded $1.8 billion (Lemly 2010).

Cooling Water Rule: Reducing Fish Kills and Other Strains on Water Bodies

Thermoelectric plants (coal, gas, oil, nuclear, and some renewable technologies) withdraw vast amounts of water, mainly for cooling. Combined, they withdrew more than 200 billion gallons of water per day in 2005, accounting for nearly half of all U.S. water withdrawals (USGS 2009b). Thirty-nine percent of all freshwater withdrawals were attributed to these plants in combination,[17] and 63 percent of that fraction was due to coal plants (Shuster 2009). Although most of this water is subsequently returned to the water body, the act of withdrawing it (and returning it significantly warmer) has substantial environmental impacts.

Cooling water intake structures take a heavy toll on fish and other aquatic life, through impingement (trapping the organisms against the intake screens) or entrainment (drawing them into the cooling system). These losses not only kill billions of individual organisms but also can disrupt the aquatic food chain and alter species composition and biodiversity (EPA 2004). Analysis of the impact of the 631 MW Bay Shore coal plant near Toledo, OH, estimated that its water withdrawal (an average of 650 million gallons daily) annually impinges 46 million to 52 million fish and entrains 209 million fish eggs, 2.2 billion fish larvae, and 13.8 billion juvenile fish. Not all of those eggs, larvae, and juveniles would have survived to adulthood, but a biological assessment estimated that the plant prevents 54.5 million fish from reaching adulthood each year, causing annual losses of nearly $30 million in lost recreational and commercial fishing (Gentner 2010).

Coal plants' heavy dependence on cooling water threatens not only the environment but also the plants' future operations. A recent analysis funded by the U.S. Department of Energy found that nearly 350 coal plants were vulnerable to potential water concerns, either because of falling supplies (especially in already water-scarce areas) or rising water demands—from competing sources or from changes at the plant itself (NETL 2010). Of particular concern was the higher demand for water that would occur if existing plants installed carbon-capture equipment, which the report found could increase water consumption by 30 to 40 percent.[18] The report warned that if these issues remain unaddressed, future water conflicts could lead to power disruptions as well as to increased costs to consumers. Some plants have already been forced to limit their operations because of water shortages, and water-availability concerns have fueled opposition to new plants (DOE 2006). This situation is likely to worsen as global warming—ironically, caused in large measure by CO_2 emissions from coal plants—is projected to exacerbate water shortages in some regions.

Virtually all new coal plants are required to use a closed-cycle cooling system that allows the plant to keep recycling the same water (after running it through cooling towers, where some of it evaporates and must be replaced with new withdrawals). Closed-cycle cooling withdraws 93 to 98 percent less water than a once-through system (NETL 2010; NY DEC 2010).[19] However, because most coal plants were built decades ago, about 39 percent of plants still use once-through cooling (Shuster 2009). In 2004, the EPA issued rules that stopped short of requiring all existing plants to add cooling towers, in part because of cost. But the agency is now reconsidering those rules (EPA 2010b).

The EPA estimated in 2004 that adding closed-cycle cooling to the largest power plants built without it would cost $130 million to $200 million (EPA 2004). A recent study by the North American Electric Reliability Council calculated the cost in per-kilowatt terms and for different plant sizes. NERC estimated that upgrading from once-through cooling would cost about $150/kW to $160/kW for plants larger than 500 MW, about $200/kW for 300 MW plants, and much more for plants smaller than 300 MW (NERC 2010). The use of cooling towers also reduces a plant's power output by as much as 4 percent when summer conditions are at their worst, though generally by less than 2 percent overall (DOE 2008).

Regulation of Global Warming Emissions: The EPA's Climate Protection Mandate

Quite apart from any federal market-based carbon limit that may be enacted in the future, coal plants face new limits on CO_2 under existing provisions of the Clean Air Act. In 2007, in the landmark case of Massachusetts v. EPA, the U.S. Supreme Court held that CO_2 is a "pollutant" under the Clean Air Act; consequently, the court ordered the EPA to formally determine

17 Irrigation accounted for about the same percentage.

18 In fact, according to an earlier analysis by the federal National Energy Technology Laboratory, adding carbon capture to a pulverized coal plant could nearly double its water use, largely due to the increased water demands of the capture process (NETL 2007). This comparison assumed that both the plant without capture and the one with it were equipped with cooling towers.

19 While recirculating systems withdraw vastly less water, they do consume more water than once-through systems because of evaporation from the cooling towers. However, when excess downstream evaporation caused by once-through systems is factored in, the difference is reduced. Overall, once-through cooling systems consume about 300 gal/MWh versus closed systems' 480 gal/MWh (Shuster 2009).

whether CO_2 endangers public health or welfare. In December 2009, the EPA announced that it had made a finding of endangerment, as indeed it had to, given the wealth of supporting scientific evidence (EPA 2009e). This finding triggered requirements to regulate CO_2 from coal plants under existing Clean Air Act programs, including the New Source Review (NSR) and New Source Performance Standard (NSPS) provisions.[20]

Under the EPA's subsequently adopted Tailoring Rule, new coal plants that emit more than 100,000 tons of CO_2 per year will be subject to NSR, as will modified coal plants that increase their CO_2 emissions by more than 75,000 tons (EPA 2010c). As they apply for permits from state authorities, the new or modified plants will have to employ Best Available Control Technology (BACT) to reduce such emissions. It is not yet clear what technologies or practices will be considered to be BACT, which is determined by permitting authorities on a case-by-case basis after considering many factors, including cost. In November 2010, the EPA released guidance on how permitting authorities should determine BACT for coal plants (EPA 2010i).

The EPA has also announced that in July 2011 it will propose new rules addressing global warming emissions from coal plants under its NSPS authority (as required by court order). These rules are scheduled to be completed by November 2012 (EPA 2010j). Unlike the case-by-case BACT determinations, the NSPS rules will be universal, requiring all new coal plants in the nation to meet global warming emissions limits. These NSPS rules will also trigger a process that eventually results in the issuance of performance standards applicable to existing coal plants.

It is too soon to say what kinds of changes and costs the forthcoming BACT and NSPS standards may require of coal plants, but at the very least the prospect of CO_2 limits under these provisions, as well as under future climate legislation, will have to be factored into any decision to invest in coal.

Need for Long-Range Planning and Regulatory Oversight Prior to Any Retrofits

Before making or approving any expensive retrofit to an old coal plant, a realistic assessment is needed that takes into account its remaining useful life, the higher maintenance costs and reduced efficiencies that old plants face, and the costs of any life-extending capital projects. A single retrofit investment, considered in isolation, might appear financially reasonable, but it would be reckless to start down the retrofit path without first considering the combined effect of all the upgrades that may be needed over the next few years. The assessment should include not just the capital and operating costs of all likely retrofits but also their impacts on the plant's energy output; in addition, any physical space constraints that may prevent plants from installing required equipment must be considered. And of course, the assessment should factor in all the other financial risks discussed in this report while considering the increasingly available alternatives to burning coal.

A wide-ranging and transparent assessment is particularly important where a rate-regulated utility seeks regulatory permission to pass its upgrade costs on to ratepayers, who have no other way of knowing the full costs ahead. It will generally be in the utility's financial interest to make such a sequence of heavy capital investments, which expand the rate base on which it is guaranteed the opportunity to earn a certain rate of return (presuming regulators' approval)—even when it would be better for ratepayers for the utility to take another path, such as investing in energy efficiency. In some cases, a utility's financial incentive to put costly controls on old plants can be substantial; for example, by adding a scrubber to the 40-year old Merrimack coal plant in New Hampshire, the utility that owns it will increase its yearly return on investment in the plant by more than five times—from \$10 million to over \$50 million (Schlissel 2009).

20 The regulation of global warming pollution by the EPA remains controversial, despite the Supreme Court decision that established the agency's authority over these emissions. The prospect of such regulation has attracted a large number of legal challenges, from industry and the states alike, as well as calls for congressional action to amend the Clean Air Act. However, as the author of a recent report by ICF International has noted, blocking the EPA rules "just throws more uncertainty into the mix because it's not that the central problem has gone away…it's just that the perceived remedy for now has been put on hold. You're still left with that issue hanging out there" (Fine Maron 2011).

PART SIX

Construction Costs

High and Volatile

Coal plant construction costs rose at a startling rate in the years leading up to 2008, contributing to the cancellation of many proposed coal plants. Despite the recession, construction costs have remained high, and in 2010 some projects were still announcing substantial cost overruns (Hawthorne 2010; O'Malley 2010).

Steep Cost Increases

Between 2000 and 2008, capital costs for coal-fired power-plant construction roughly doubled, with particularly steep price hikes between 2005 and 2008. Synapse Energy Economics estimated in July 2008 that costs for new coal plants had reached $3,500/kW before financing costs, up from as little as $1,500/kW to $1,800/kW in 2005 (Schlissel, Smith, and Wilson 2008). And the IHS Cambridge Energy Research Associates (CERA) Power Plant Capital Costs Index, which tracks the costs associated with the construction of a portfolio of power plants in North America, showed construction costs nearly doubling between 2000 and 2008 (Figure 10, p. 34).

Power plant construction costs dropped somewhat during the recession that followed. However, the IHS CERA index showed that the decline was modest, and in late 2009 and early 2010 costs actually rose slightly before flattening out later in 2010 (IHS CERA 2010a and 2010b).

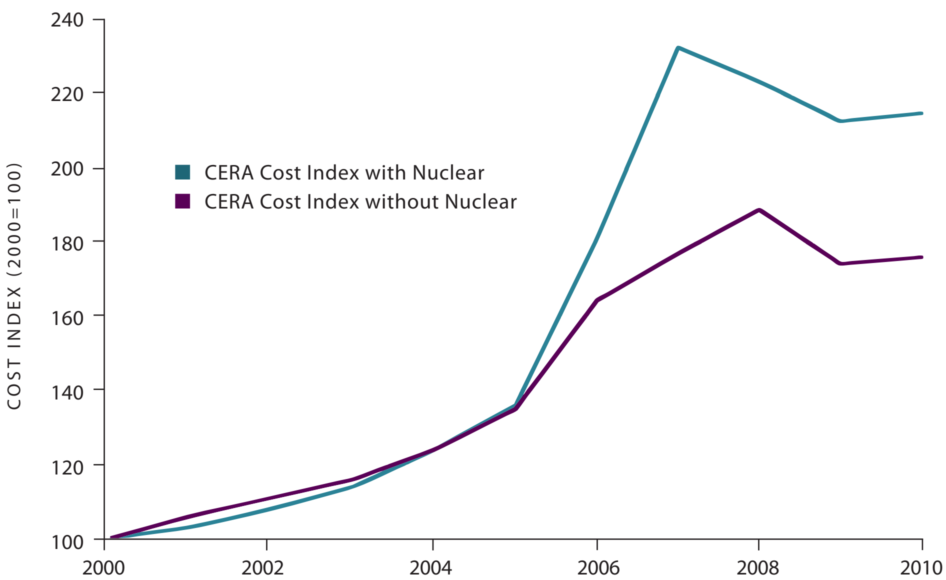
The cost increases between 2000 and 2008 were partly the result of increases in the global cost of commodities and of competing international demand for power plants, particularly from Asia (IHS CERA 2008; Schlissel, Smith, and Wilson 2008). Other factors driving the increase included competition for limited equipment, labor, and engineering and construction resources, as well as the declining number of engineers in the workforce due to retirements and an insufficient replacement rate (IHS CERA 2008).

Rising global commodity prices driven by Asian demand have again been cited for keeping construction costs high in 2010 (IHS CERA 2010a). While the commodity prices that had been raising power plant costs did fall steeply with the economic crisis, they bottomed out in early 2009 and then quickly rebounded. These price increases were in large part attributable to the rapid economic recovery in the emerging Asian economies, according to the International Monetary Fund (IMF), and it expects commodity prices to remain high by historical standards (IMF 2010).

Even during the months where the index shows that power plant prices were dropping, particular coal plant projects were still announcing substantial cost increases. In November 2009, American Municipal Power (AMP) announced that the projected costs of its proposed Ohio plant had jumped 37 percent since the preceding May; as a result, AMP announced the project's likely conversion to a natural gas plant (AMP 2009). More recently, it was reported in 2010 that the costs of Peabody's Prairie State coal plant in Illinois, which is well under construction, had jumped to $4.4 billion, more than double the original estimates of 2001 (Hawthorne 2010).

Pollution control projects have also experienced rising construction costs. The addition of a scrubber and other changes at the 433 MW Merrimack coal plant in New Hampshire were estimated in 2006 to cost $250 million, but costs have since risen to $457 million (NH DES 2010; Colburn 2009). This steep cost increase prompted several groups, including the

Figure 10. **POWER PLANT CONSTRUCTION COSTS**



IHS CERA's tracking of a portfolio of power plant construction costs, indexed to prices in 2000, shows steep cost increases from 2000 to 2008, followed by a decline with the economic slowdown. However, costs rose slightly in late 2009 and early 2010.

Sources: IHS CERA 2010a; IHS CERA 2008

Union of Concerned Scientists, to press for a regulatory reconsideration of the project that could compare its costs to the state's energy efficiency and renewable energy alternatives. The large number of coal plants that simultaneously will be seeking to make upgrades in time to meet compliance deadlines might put further upward pressure on construction costs.

Pulverized Coal Plant Costs

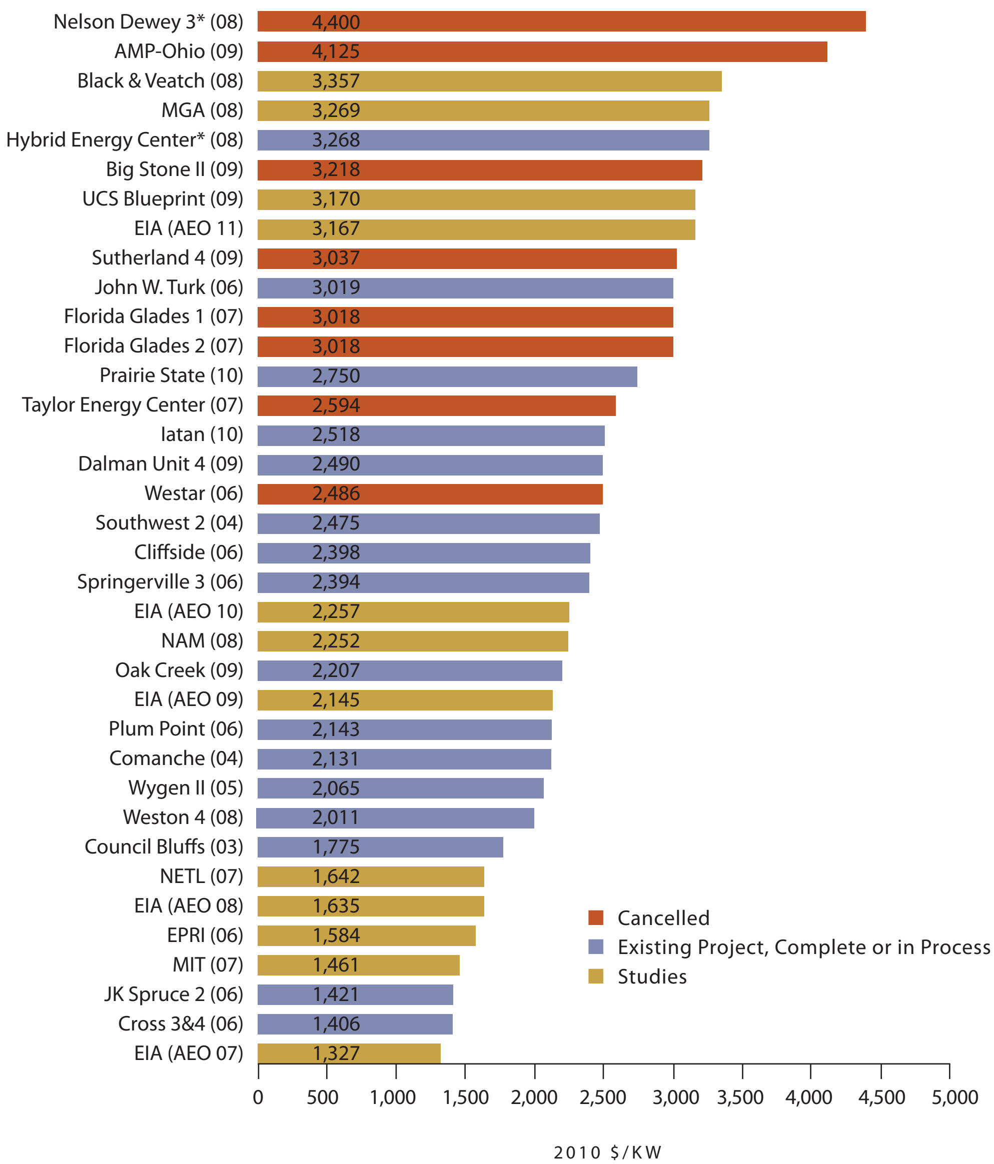
For years, estimates of average coal plant construction costs from several frequently used sources lagged well behind cost projections from actual projects (EIA 2009a; EIA 2008a; EPA 2008; EIA 2007; MIT 2007; NETL 2007; EPRI 2006). Figure 11 shows actual "overnight" construction cost estimates for a number of coal plant proposals, and it compares them to costs as projected by several studies. (Overnight costs do not include financing or escalating costs during construction.) The EIA raised its assumed capital costs estimates in each of its last four Annual Energy Outlooks as it attempted to belatedly catch up with rising project prices. Over the four years, the EIA increased its estimated overnight capital costs from $1,327/kW in 2007 to $3,167/kW (for a typical 600 MW plant) in the early release of its 2011 AEO (EIA 2011a; EIA 2007). The EIA's 2011 cost estimate, which we use in our cost comparisons in Part 8, is now almost exactly the same as the cost estimate that the Union of Concerned Scientists used in 2009, based on data from actual projects (Cleetus, Clemmer, and Friedman 2009).

IGCC Plant Costs

Reliable construction cost estimates for IGCC plants are limited, as no projects have recently been completed in the United States. Based on studies comparing IGCC and pulverized coal plants, we assume in Part 8 that IGCC plants will face capital costs approximately 16 percent greater than those of pulverized coal plants (EIA 2008c; MGA 2008; MIT 2007; NETL 2007). This translates into an overnight capital cost range of $3,200/kW to $3,800/kW (including real cost escalation) for plants with a 2015 in-service date. However, recently

Figure 11. **PULVERIZED COAL PLANT CAPITAL COSTS: ACTUAL PROJECTS VS. STUDIES**

Federal estimates of overnight capital costs of new pulverized coal plants have lagged behind actual project estimates, though between 2007 and 2011 EIA cost estimates rose considerably.
Notes: The figure includes some circulating fluidized bed plants (noted with an asterisk); the year of the cost estimate is shown next to the name of each plant and study.



Between 2000 and 2008, capital costs for coal-fired power-plant construction roughly doubled, with particularly steep price hikes between 2005 and 2008.

announced costs at the 618 MW Edwardsport IGCC facility in Indiana have been coming in much higher than our estimate. In 2010, estimated costs for the project rose to $2.9 billion, or 23 percent more than the 2009 estimate and 53 percent higher than the original price tag in 2006 (Duke Energy Indiana 2010; O'Malley 2010). The resulting capital cost is $4,693/kW (including financing costs).

Plant Costs with CCS

We note that the cost escalations discussed above relate solely to the cost of building plants without carbon capture and storage technology. As we discussed in Part 4, adding CCS would result in costs rising even higher. In our analysis in Part 8, we assume that overnight construction costs for IGCC plants with CCS would be $5,000/kW to $6,500/kW (in 2010 dollars) for a project with a 2015 in-service date, based on recent EIA, utility, and other estimates (EIA 2011a; Exelon 2010: MGA 2008). We note that the Tenaska IGCC plant with CCS in Taylorville, IL, is reporting a cost of $5,263/kW, which falls within this range (WorleyParsons 2010).

We did not determine a construction cost for pulverized coal plants with CCS because our cost comparisons derive originally from the EIA's model, which does not make that option available.

PART SEVEN

Harder-to-Get Financing

The many financial risks discussed in Parts 2 through 6 collectively lead to yet another risk for those intending to build coal plants: the possibility that they will be denied financing for the plant or charged far more for financing than they had planned. "Coal is a dead man walkin'," said Kevin Parker, global head of asset management at Deutsche Bank, to the *Washington Post.* "Banks won't finance them. Insurance companies won't insure them. The EPA is coming after them. . . . And the economics to make it clean don't work" (Mufson 2011).

Major Banks Trying to Limit Carbon Risks, Pressured to Do More

Many of the country's largest banks have endorsed a statement of "Carbon Principles" under which they commit to taking carbon risks explicitly into account when evaluating the financing of new power generation facilities (Bank of America et al. 2008). The Carbon Principles understandably make a special point of urging rate-regulated utilities to seek from regulators "clarity on potential CO_2 compliance-cost recovery," in recognition that future rate recovery for coal plant costs may be denied. However, in many cases state regulators have been reluctant to give assurances that costs can all be passed on to ratepayers. Some regulators, including those in Texas, Iowa, and Minnesota, have gone the other way, putting limits on the amounts of construction costs, CO_2 costs, or both that could be passed through to ratepayers (IUB 2009; MPUC 2009; PUCT 2008). Limits of this sort have contributed to the cancellation of coal projects such as Alliant's Marshalltown, IA, plant and the Big Stone II project in South Dakota. Duke Energy may also face limits on how much it can collect from Indiana ratepayers to cover its increasingly costly and controversial Edwardsport IGCC plant (Russell 2010).

Major banks are being called upon by environmental activists to go much further to reduce their funding of coal projects than they have to date under the Climate Principles (RAN 2011). And Bank of America has faced a series of protests, including a November 2009 demonstration by climate activists at which 20 people were arrested (Scott 2009). Banks have also increasingly been targets of criticism for their support of mountaintop-removal mining, and as a result many of the major banks have taken steps to limit their funding of the practice (Zeller 2010).

Downgraded Debt Ratings from Exposure to Coal Risk

Financial rating agencies have recently downgraded several utilities based at least in part on the costs they face in constructing new coal plants or retrofitting old ones. For example, Moody's downgraded the Southern Company and three of its subsidiaries partly because of the high risks associated with new IGCC (and nuclear) construction as well as with "longer-term pressures from potential carbon controls and renewable portfolio standards" (Moody's Investors Service 2010a). Moody's also downgraded Edison Mission and its Midwest Generation subsidiary, citing substantial uncertainties about how they would comply with upcoming state and federal environmental requirements (Moody's Investors Service 2010b). Standard and Poor's lowered its outlook on Duke Energy in response to the spiraling construction costs at its Edwardsport IGCC plant, and Citi downgraded the utility based on concerns that it will not be able to recover the costs of capital expenditures to

Financial rating agencies have recently downgraded several utilities based at least in part on the costs they face in constructing new coal plants or retrofitting old ones.

comply with environmental regulations (AP 2010; Chin 2010). And Fitch downgraded the debt ratings of PPL Energy Supply, citing "the uncertain cost and impact on gross margins of meeting potential environmental regulations addressing greenhouse gas emissions" and PPL's "high concentration of coal-fired generation," among other things (Fitch 2009).

Cooperative Funding Drying Up, Municipal Funding Questioned

A traditional source of coal plant funding for rural electric cooperatives has been the federal Rural Utilities Service (RUS). But in 2008, the RUS suspended its loan program for new coal plants, citing concerns over rising construction costs, legal challenges, and potential delays (Puckett 2008). The RUS still provides certain forms of indirect support that help rural cooperatives obtain coal-investment funding from other sources. However, it is being called upon to halt this practice and to review its policies for loans or loan guarantees for coal plant retrofits, particularly in light of President Obama's pledge to phase out fossil fuel subsidies (Johnston et al. 2010).

Publicly owned utilities may also use municipal bonds as a means of financing coal projects. However, public bond funding is facing increasing criticism for exposing taxpayers to significant financial risks by failing to adequately take into account the full costs of coal plants; such funding is also being criticized as an inappropriate taxpayer subsidy of coal power (Johnston et al. 2010).

For example, in 2008 William C. Thompson, Jr., the comptroller of New York City, requested that the U.S. Department of the Treasury conduct a review of the financial and environmental risks associated with tax-exempt financing for coal-fired power plants. He cited in particular the increased construction costs for new coal plants, the regulatory uncertainty surrounding CO_2 emissions, and the price of coal itself (Thompson 2008). The AMP-Ohio plant that Thompson singled out as a risky investment was subsequently cancelled when its costs jumped 37 percent between May and November 2009 (AMP 2009). And while capital investments in public power may seem less exposed to the financial risks discussed in this report, it is worth remembering that the infamous Washington Public Power Supply System's default on $2.25 billion in municipal bonds—the largest municipal bond default in U.S. history—was partly caused by public power entities' failure to appreciate the risks attached to their enormous investments in baseload power (Alexander, Zagorin, and Peterson 1983).

In short, backers of coal projects face the risks that financing will be harder to get and that it will cost more, given concerns over the costs faced by coal plants and by pressure to avoid funding environmentally destructive projects.

PART EIGHT

Bottom Line

The Wrong Investment for a Changing World

Coal has always had serious disadvantages as a power source, including the long list of harms it imposes on health and the environment. Coal plants are not only costly to build but also are not very flexible. They cannot ramp up or down easily, and coal power cannot be quickly added in small increments—only in large and expensive blocks that require many years of lead time and decades of operation in order to recover the initial investment.

On the other hand, coal power has had certain advantages that allowed many of yesterday's coal plant investments to pay off in the long run (not counting the major costs borne by society). Existing coal plants have been able to produce low-cost electricity by burning low-cost coal while largely avoiding many of the tougher environmental standards. And in addition to its price advantage, coal power has been able to provide dispatchable baseload power, not subject to the variable-output issues of wind- and solar-based sources.

But this relatively stable past is no guide to the future, as a volatile period lies just ahead. U.S. demand for coal power is weakening as both policies and markets accelerate investments in renewable energy and efficiency, and as low natural gas prices and an abundance of underused capacity at gas plants threaten coal's market share. Coal prices are at risk of being driven higher by international demand, declining mine productivity, and the possibility that we have far less cheaply accessible coal available than we have long thought. Tolerance for coal's multitude of adverse impacts is declining, and long-delayed health and environmental protections are moving forward, often under court order. Moreover, coal plant construction costs have risen dramatically and stayed high despite the recession. For all these reasons, investors and lenders are appropriately becoming wary of coal.

Finally, the changing global climate is altering policies and attitudes in ways that will put increasing pressure on coal power as temperatures rise and we search harder for ways to de-carbonize our economy. There is simply no avoiding the fact that a tremendous economic risk is attached to making a large and multi-decade financial commitment to the most high-carbon energy choice available at a time when we must cut carbon emissions deeply.

In other words, and as shown throughout this report, coal's longstanding problems are becoming even bigger problems, while its relative strengths are fading. Coal power is losing its cost advantage, and its baseload nature is no longer the asset it once was.

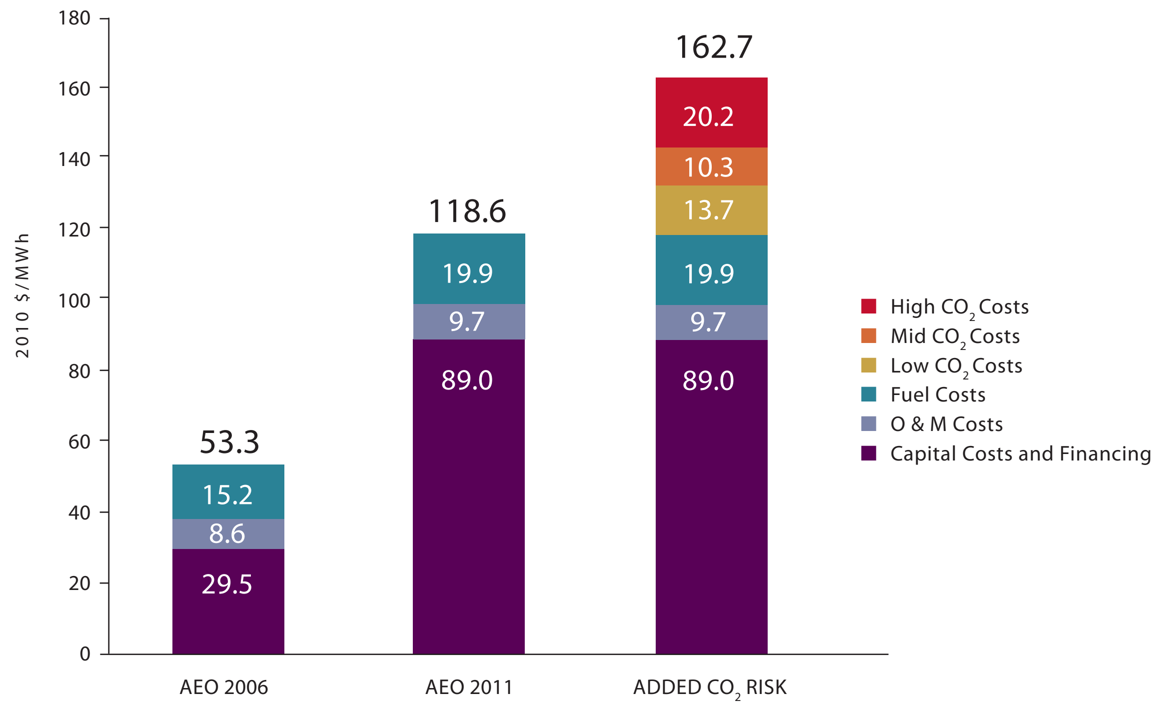
The High Cost of Energy from New Coal Plants

Figure 12 (p. 40) shows that the levelized cost of electricity for new coal plants has risen to nearly \$119/MWh—even without carbon prices—as estimated by the EIA in its latest Annual Energy Outlook (AEO) (EIA 2011a). This figure, more than double the EIA's estimate in its 2006 AEO, largely reflects the steep increases in capital costs and financing over the last few years.

The right-hand bar in Figure 12 shows the additional impact of potential future carbon costs, reflecting CO_2 allowance costs at low, medium, and high levels (using the range of projected CO_2 costs prepared by Synapse, as discussed in Part 4). With these carbon prices, the cost of electricity would range from \$132/MWh (with low CO_2 costs) to \$163/MWh (with high CO_2 costs). Importantly, these figures still do not represent many of the harder-to-quantify risks discussed in this report.

Figure 12. INCREASING LEVELIZED COST OF ELECTRICITY FROM NEW PULVERIZED COAL IN 2015

The projected levelized cost of electricity from a new coal plant more than doubled between 2006 and 2011, even without a price on carbon, as estimated by the EIA in its Annual Energy Outlooks for those years. The third bar shows the additional financial impact of potential carbon costs, taken from Synapse projections.[21]



Sources: EIA 2011a; Johnston et al. 2011; EIA 2006

For example, while the comparisons reflect a range of coal prices, they do not fully represent the risk that coal prices could rise steeply due to volatile global markets, falling productivity, shrinking reserves, or other factors (as discussed in Part 3).

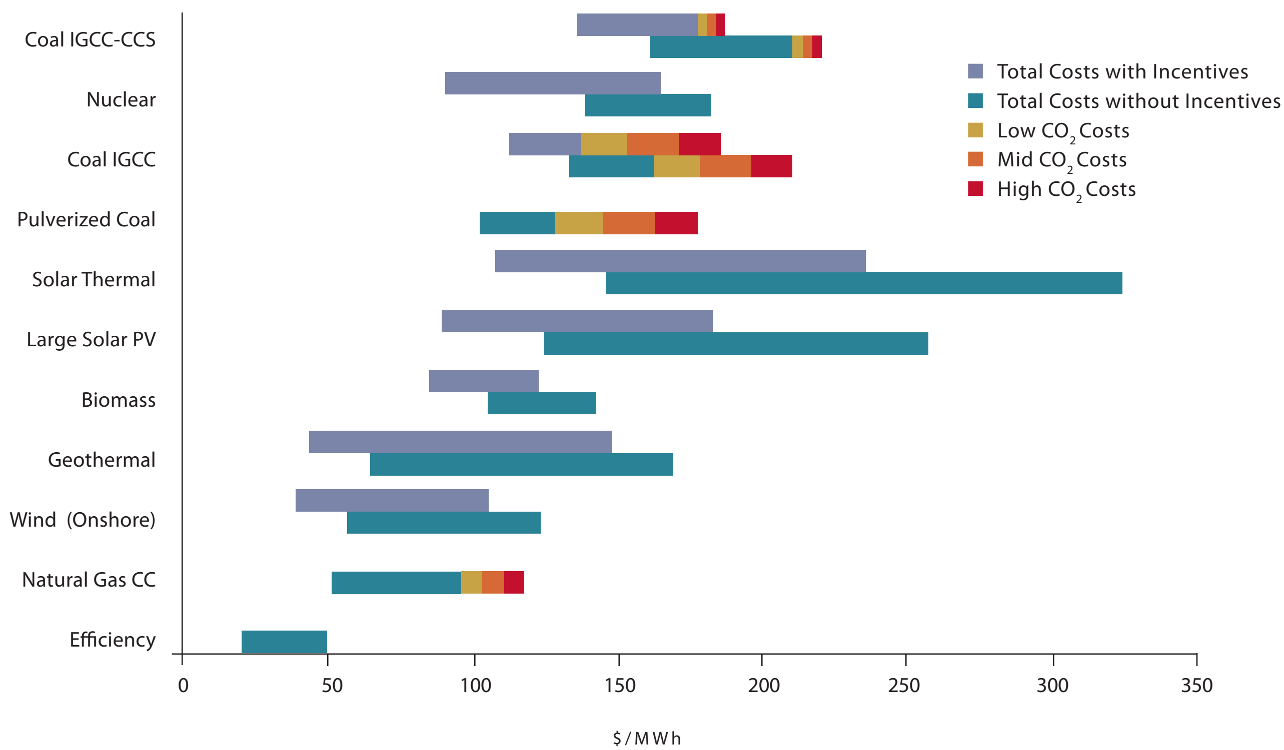
New Coal Costs More than Many Cleaner Options

Figure 13 illustrates how the cost of electricity from coal-fired power plants compares to other energy options, under a variety of assumptions. Explicit tax incentives are reflected, and it is assumed that today's incentives for wind and biomass will be extended, as they have been several times in the past. Figure 13 also reflects low, medium, and high CO_2 costs, taken from Synapse (Part 4). A range of costs is presented for all technologies so as to allow for some of the market uncertainties and site-specific variables. For example, the figure assumes a range of fuel prices (taken from the EIA) for biomass, natural gas, and coal, though it does not fully reflect the possibility that coal prices could be pushed dramatically higher by the factors discussed in Part 3. The figure also includes a range of capacity factors for wind, solar, natural gas, and nuclear power to account for the different levels of resource quality, operating conditions, and output at different sites. And for all technologies it incorporates a range of

21 For CO_2 allowance prices, each color represents incremental costs. Thus the cost of a medium CO_2 price is shown by the yellow and orange bars combined, and the cost of a high CO_2 price is shown by the yellow, orange, and red bars combined.

Figure 13. LEVELIZED COST OF ELECTRICITY FOR VARIOUS TECHNOLOGIES

All estimates reflect newly built technologies that come online in 2015 and represent all-in levelized costs over a 20-year period. A range of capital costs is assumed for all technologies; a range of fuel costs is assumed for coal, natural gas, and biomass; and a range of capacity factors is assumed for wind, solar, natural gas, and nuclear power. A range of CO_2 prices is taken from Synapse projections (see Part 4). For comparative purposes, tax credits for renewables in place through 2012 were assumed to be extended to 2015. Tax credits for supercritical pulverized coal plants were not included because they have limited funding and would not cover more than a few new plants. See Appendix A (available online) for additional assumptions.



The levelized cost of electricity for new coal plants has risen to nearly $119/MWh—even without carbon prices.

construction costs. We discuss these and other assumptions in more detail in Appendix A, available online.

Even without a carbon price, new coal plants clearly have higher overall costs than new gas plants, wind facilities, and the best geothermal sites, and much higher costs than investing in energy efficiency. When either carbon prices or incentives are factored in, new coal plants also cost more than biomass facilities or the best solar thermal and solar photovoltaic sites.

In short, the traditional cost advantage that coal power has enjoyed over cleaner energy—and that has been used to justify coal's profound environmental and health impacts—has largely disappeared with respect to new plants.

Coal Competing for Dispatch in the Market

The kind of levelized-cost comparison shown above can be useful for preliminary screening among new energy supplies to meet growing demand, but it oversimplifies the complex matter of deciding which options will best fit within the electric system or win market share. To the extent that coal projects sell their power on the wholesale markets, they will be competing for dispatch[22] with other power sources based not on their full levelized costs but on their variable costs (such as fuel and operating costs). Wind, solar, and geothermal generators face no fuel costs; so when available, their variable costs are usually lower than those of coal power, even without CO_2 costs added. And renewable energy does not need to have a lower levelized cost than coal power in order to expand its market share, as it is also being driven by policy choices (see Part 2). Moreover, the nation has a large fleet of new and underutilized natural gas plants already on the grid, ready to compete with coal. While natural gas price volatility is always a concern, several studies by the EIA and Union of Concerned Scientists have shown that the addition of renewable power to the grid helps to prevent gas prices from rising (Nogee, Deyette, and Clemmer 2007).

Of course, with a carbon price added to the mix, coal power would become even more disadvantaged in the energy markets, given that it emits so much more carbon per kilowatt-hour than natural gas plants. In the Midwest especially, coal plants are at risk of being squeezed out of the dispatch between increasing wind energy facilities on the one hand and natural gas plants on the other (Wood Mackenzie 2010).

The Disappearing Baseload Advantage

Coal's status as a source of baseload power does not represent the advantage it once did. In fact, coal power's lack of flexibility makes it poorly suited for the grid of tomorrow, which will surely include greater quantities of variable-output wind and solar power.

As discussed in Part 2, many studies show that large quantities of wind can be integrated into a power grid at low cost. This integration of wind (or solar) can be done partly by shaping demand (through "demand-side management" measures that help smooth out load) and partly through other sources of supply playing a "load-following" role (essentially, ramping up and down other power plants on the system to compensate for the rising and falling output of the renewables). Larger regions (or balancing areas), wind forecasting, a wider geographic distribution of wind turbines, and strong transmission interconnections can also help reduce the costs of integrating wind.

Natural gas plants have a major advantage over coal plants in their ability to adjust their output relatively quickly and efficiently, which allows for the integration of a greater quantity of variable output renewables onto the grid. Jon Wellinghoff, chair of the Federal Energy Regulatory Commission, has stressed the importance of this load-following ability:

> *[I]f you can shape your renewables, you don't need fossil fuel or nuclear plants to run all the time. And in fact, most plants running all the time in your system are an impediment because they're very inflexible. You can't ramp up and ramp down a nuclear plant. And if you have instead the ability to ramp up and ramp down loads in ways that can shape the entire system, then the old concept of baseload becomes an anachronism* (Straub and Behr 2009).

In other words, the power system of tomorrow will put an increasingly higher premium on flexibility over steadiness.

A Cleaner Path Forward

The costs discussed in this report would pose less of a financial risk to coal investments if the nation had no choice but to maintain its current level of coal dependence regardless of such costs. However, studies by the Union of Concerned Scientists (UCS) and others are challenging the assumption that coal power must indefinitely remain a major part of our power grid. These studies show that we could replace most of our coal power over the next 15 to 20 years by using renewable energy and demand reduction, with additional reductions in coal power thereafter.

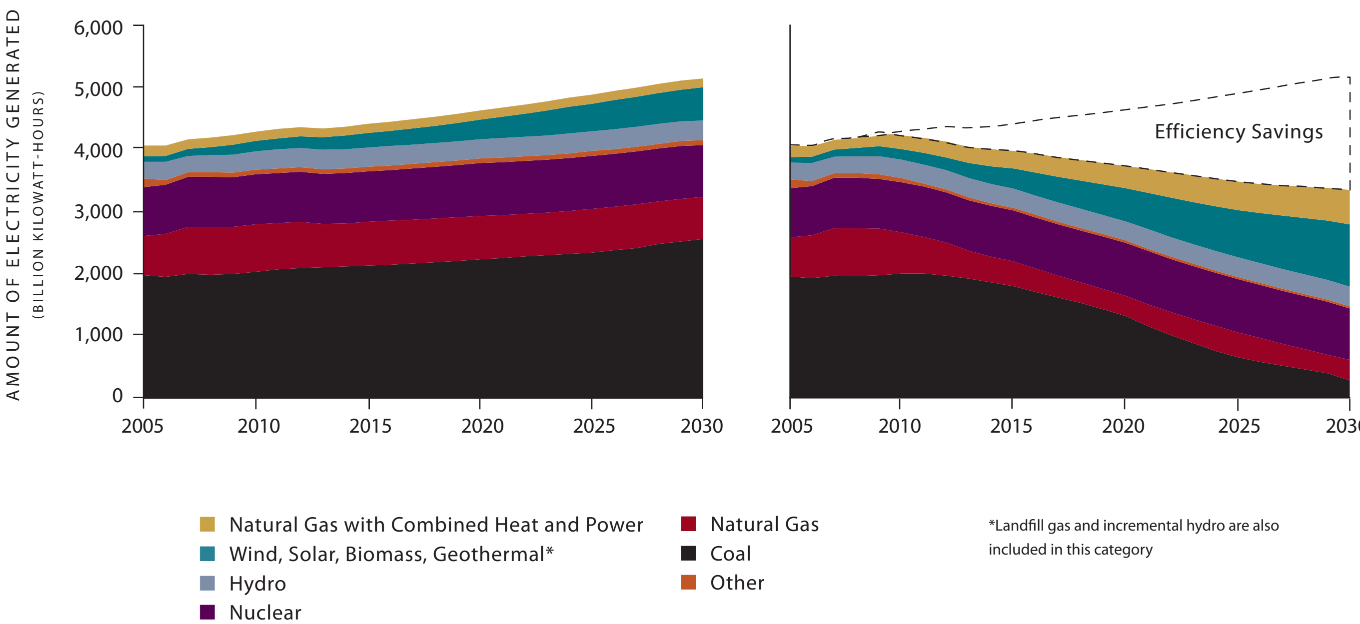
In 2009, UCS published *Climate 2030: A National Blueprint for a Clean Energy Economy,* a peer-reviewed analysis of the costs and benefits through 2030 of scenarios for reducing U.S. global warming emissions (Cleetus, Clemmer, and Friedman 2009). The analysis included a detailed review of technology costs and trends through the fall of 2008, using a modified version of the model that the EIA employs for its own analyses.

The UCS model showed how we could achieve global warming emissions-reduction targets of 26 percent below

22 For purposes of this discussion, we use "dispatch" to refer to the assignment of electric load to specific generating stations and other sources of supply within an integrated electric system.

Figure 14. FUTURE POWER GENERATION UNDER UCS BLUEPRINT

The left graph shows sources of electricity through 2030 under the UCS reference-case scenario. The right graph shows the energy savings and energy sources projected for the same period under the UCS Blueprint suite of policies, which include energy efficiency measures, a strong renewable energy standard, and a nationwide limit on emissions.



Source: Cleetus, Clemmer, and Friedman 2009

2005 levels by 2020 and of 56 percent by 2030—reductions that were steeper than those debated in the 111th Congress. Within the emissions limits and policy constraints provided (including a nationwide limit on emissions and complementary incentives and standards to increase the use of energy efficiency and renewable power), the model determined the combination of new generating resources needed to maintain electricity reliability at the lowest total cost (including any necessary costs for building new transmission, integrating technologies into the grid, and providing adequate reserve power supplies).

The model's results showed that the United States could achieve deep emissions cuts while saving energy consumers money. It also vividly demonstrated how a more aggressive pursuit of energy efficiency and renewable energy could greatly reduce our dependence on coal power.

Under the UCS Blueprint, coal burned at power plants declines by 84 percent—from more than a billion tons in 2005 to 137 million tons in 2030—with a commensurately dramatic cut in coal generation (Figure 14) and power plant carbon emissions. By contrast, under the UCS reference case[23]—with no new policies adopted after October 2008—coal generation is projected to increase 29 percent by 2030. Overall, the Blueprint policies save consumers and businesses

23 The UCS reference case is based on the assumptions used by the Energy Information Administration's Annual Energy Outlook for 2008, with certain modifications and updates. For example, UCS modified assumptions about the costs and performance of several energy and transportation technologies based on data from actual projects, information from more recent studies, and input from experts. The reference case also reflects tax credits signed into law in October 2008.

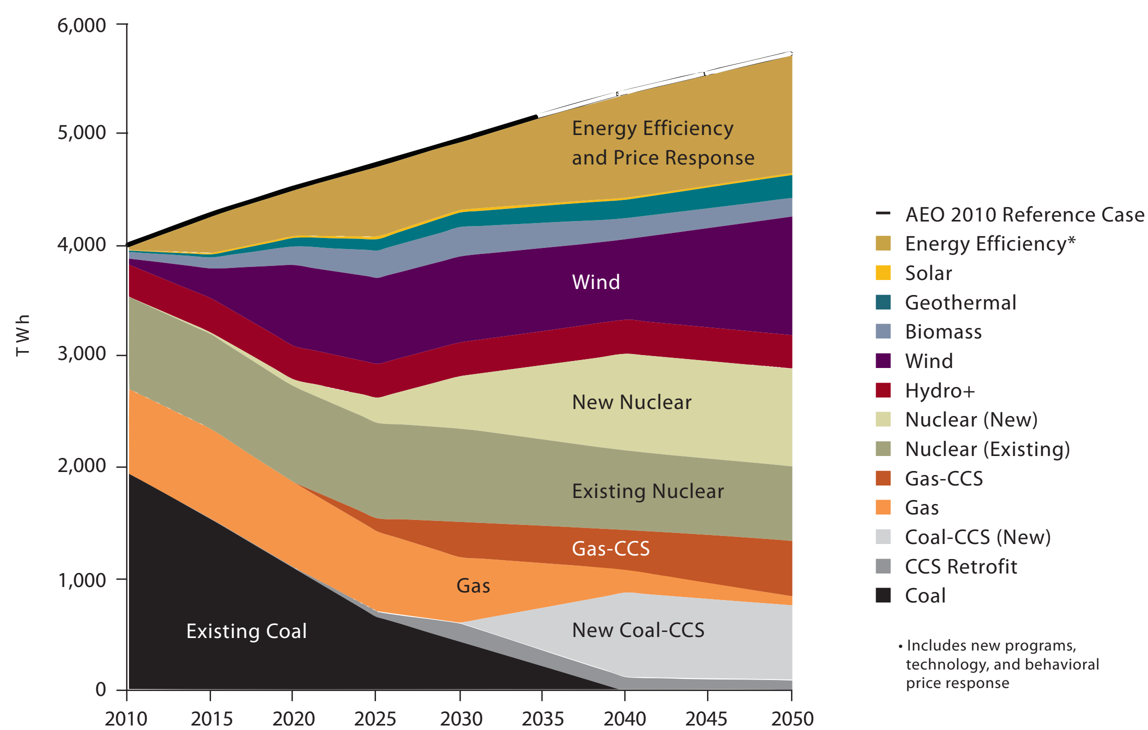
$464 billion annually in 2030 and $1.7 trillion in net cumulative savings between 2010 and 2030.

With the Blueprint policies, the electricity sector makes the biggest contribution to reducing U.S. global warming emissions, providing 57 percent of all cuts in 2030. As shown in Figure 14, significant emissions cuts in the sector come from replacing coal plants with efficiency, combined heat and power (CHP), and renewable energy. By 2030, energy efficiency measures—such as advanced buildings and industrial processes and high-efficiency appliances, lighting, and motors—reduce demand for electricity 35 percent below the reference case. CHP based on natural gas in the industrial and commercial sectors is nearly 3.5 times higher than today's levels, providing 16 percent of U.S. electricity by 2030. Largely because of a national renewable electricity standard, the options of wind, solar, geothermal, and bioenergy provide 40 percent of the nation's electricity use by 2030, after accounting for the drop in demand stemming from energy efficiency and CHP.

A recent modeling exercise by the Electric Power Research Institute (EPRI)—a nonprofit research group whose member companies generate most of the nation's power—yielded results strikingly similar to those of the UCS Blueprint. Under a scenario that reduces U.S. carbon emissions by 80 percent by 2050 and does not include any policies or incentives for

Figure 15. FUTURE POWER GENERATION UNDER EPRI MODEL

This figure shows the results of a 2010 "test drive" of the new regional economic model developed by the industry-funded Electric Power Research Institute. Under this scenario, power from existing coal plants declines by about two-thirds by 2025, replaced almost entirely by renewable sources and energy efficiency; new coal with CCS emerges after 2030; and U.S. carbon emissions are reduced by 80 percent by 2050.



Source: Specker 2010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specific technologies, the EPRI model projects that about two-thirds of today's coal power would be retired by 2025 and replaced primarily with efficiency and renewable power (Figure 15) (Hannegan 2010; Specker 2010). Power from existing coal plants continues to drop through 2040, with only a fraction of them retrofitted with CCS and operational in 2050. New coal with CCS does not begin to come in until after 2030. The results of this modeling run, released in the summer of 2010, do not include the price impacts of these changes.

A third study, released in 2010 by Synapse Energy Economics, investigated a scenario that completely phases out coal by 2050 (while cutting nuclear power by 30 percent). The results show that this objective can be achieved at low consumer cost and with eventual consumer savings (Keith et al. 2010). Coal capacity drops by 85 GW by 2020, and coal generation is cut nearly in half by 2030 and phased out completely by 2050.

Synapse's spreadsheet-based analysis of regional energy balances uses data from the EIA's Annual Energy Outlook 2010, updated to reflect actual cost and performance data for each resource type based on recent actual projects. The incremental costs of this scenario (which includes a consideration of the avoided costs of air emissions controls at existing coal plants, but not of water or ash handling upgrades) are only about 0.25¢/kWh in 2020, or $2.20 per month for a typical residential customer, compared with the reference case.

The overall net benefits to society of aggressively moving away from coal would be tremendous. Not only would such a shift put us on a path to achieve the deep carbon reductions we need, but it would save thousands of lives yearly through better air quality, reduce the threat that mercury poses to our children, greatly reduce the strain on our increasingly precious water supplies, reduce the threat of toxic leakage from coal ash, keep Appalachian mountains standing, and protect the water and health of coal mining communities. On an economic front, it would stimulate what will surely be the growth industries of tomorrow—renewable power and energy efficiency—providing new clean-energy jobs and stimulating further technological improvements. As these benefits become increasingly apparent and hard to resist, policy makers will be under growing pressure to put the nation on this beneficial path. Anyone making long-term investments in coal today must factor in this risk.

Conclusion

In the 1970s, the electric power sector was investing huge amounts of money in baseload plants while ignoring the trends undermining the rationale for those plants, including changes in demand growth, construction and operating costs, regulations, and public sentiment. The financial results were disastrous, with more than 100 nuclear plants and 80 coal plants cancelled, sometimes after hundreds of millions or even billions of dollars were spent on a single project (Schlissel, Mullett and Alvarez 2009; Pierce 1984; GAO 1980). These losses led to skyrocketing electric rates and in 1983 triggered the largest municipal bond default in U.S. history (Alexander, Zagorin, and Peterson 1983). Legal battles arose around the country over how much of the financial calamity could have been foreseen and avoided.

If and when today's long-term investments in new coal plants or costly plant retrofits lead to steep financial losses, there will be no debate over whether they could have been foreseen. The trends currently undermining the economics of such investments are far too obvious. Making major new investments in coal power—as the planet warms, as the clean-energy economy emerges, and as the other developments described in this report play out—is an unacceptably risky proposition.

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A **Risky** Proposition

The Financial Hazards of New Investments in Coal Plants

Power producers across the United States are deciding whether to make massive, long-term investments in coal-fired power plants. Some are planning to build new coal plants, and many more are considering sinking new money into very old plants.

This report describes why these investments are, in fact, a risky proposition. Coal power faces higher costs on several fronts, including rising coal prices, high construction costs, uncertain financing, and the costs associated with addressing coal's tremendous ongoing impacts on our health, air, water, and climate. At the same time, coal is losing market share to its cleaner energy competitors—including energy efficiency, renewable power, and natural gas—which are in many cases benefiting from both falling costs and growing policy support.

These are trends that no one making, approving, financing, or expected to pay for a long-term investment in a coal plant can afford to ignore.

This report is available on the UCS website at *www.ucsusa.org/clean_energy*.

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