

Center for American Progress



Global Warming and the Future of Coal

The Path to Carbon Capture and Storage

Ken Berlin and Robert M. Sussman
May 2007

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The point of greatest peril in the development of a high-tech market lies in making the transition from an early market dominated by a few visionary customers to a mainstream market dominated by a large block of customers who are predominately pragmatists in orientation. The gap between these two markets, heretofore ignored, is in fact so significant as to warrant being called a chasm.¹

– Geoffrey Moore

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Executive Summary

Ever-rising industrial and consumer demand for more power in tandem with cheap and abundant coal reserves across the globe are expected to result in the construction of new coal-fired power plants producing 1,400 gigawatts of electricity by 2030, according to the International Energy Agency. In the absence of emission controls, these new plants will increase worldwide annual emissions of carbon dioxide by approximately 7.6 billion metric tons by 2030.² These emissions would equal roughly 50 percent of all fossil fuel emissions *over the past 250 years*.

In the United States alone, about 145 gigawatts of new power from coal-fired plants are projected to be built by 2030, resulting in CO₂ emissions of 790 million metric tons per year in the absence of emission controls. By comparison, annual U.S. emissions of CO₂ from *all* sources in 2005 were about 6 billion metric tons.³

Policymakers and scientists now recognize that the current growth of greenhouse gas emissions must be reversed and that emissions must be reduced substantially in order to combat the risk of climate change. Yet a dramatic increase in coal-fired power generation threatens to overwhelm all other efforts to lower emissions and virtually guarantees that these emissions will continue to climb. This would preclude any possibility of stabilizing greenhouse gas concentrations in the atmosphere at levels that would acceptably moderate the predicted rise in global temperatures.

In China and other developing countries experiencing strong economic growth, demand for power is surging dramatically, with low-cost coal the fuel of choice for new power plants. Emissions in these countries are now rising faster than in developed economies in North America and Europe: China will soon overtake the United States as the world's number one greenhouse gas emitter. With the power sector expanding rapidly, China and India will fall further behind in controlling greenhouse gas emissions unless new coal plants adopt emission controls. Lack of progress in these countries would doom to failure global efforts to combat global warming.

The Promise of Carbon Capture and Storage

Fortunately, there is a potential pathway that would allow continued use of coal as an energy source without magnifying the risk of global warming. Technology currently exists to capture CO₂ emissions from coal-fired plants before they are released into the environment and to sequester that CO₂ in underground geologic formations. Energy companies boast extensive experience sequestering CO₂ by injecting it into oil fields to enhance oil recovery. Although additional testing is needed, experts are optimistic this practice can

be replicated in saline aquifers and other geologic formations that are likely to constitute the main storage reservoirs for CO₂ emitted from power plants.

However, these so-called carbon capture and storage, or CCS systems, require modifications to existing power plant technologies. Today the prevailing coal-based generation technology in the United States is pulverized coal, with high-temperature (supercritical and ultra-supercritical) designs available to improve efficiency. It is possible to capture CO₂ emissions at these pulverized coal units, but the CO₂ capture technology currently has performance and cost drawbacks.

But there's a new coal-based power generation technology, Integrated Gasification Combined Cycle, or IGCC, which allows CCS systems in new plants to more efficiently capture and store CO₂ because the CO₂ can be removed before combustion. Motivated by this advantage, some power plant developers have announced plans to use IGCC technology but very few have committed to installing and operating CCS systems.

The great challenge is ensuring that widespread deployment of CCS systems at new IGCC and pulverized coal plants occurs on a timely basis. Despite growing recognition of the promise of carbon capture and storage, we are so far failing in that effort. The consequences of delay will be far-reaching—a new generation of coal plants could well be built without CO₂ emission controls.

Barriers to the Adoption of Carbon Capture and Storage Systems

Industry experts today are projecting that only a small percentage of new coal-fired

plants built during the next 25 years will use IGCC technology. IGCC plants currently cost about 20 percent to 25 percent more to build than conventional state-of-the-art coal plants using supercritical pulverized coal, or SCPC, technology. What's more, because experience with IGCC technology is limited, IGCC plants are still perceived to have reliability and efficiency drawbacks.

More importantly, IGCC plants are not likely to capture and sequester their CO₂ emissions in the current regulatory environment since add-on capture technology will reduce efficiency and lower electricity output. This will increase the cost of producing electricity by 25 percent to 40 percent over plants without CCS capability.⁴

These barriers can be partially overcome by tax credits and other financial incentives and by performance guarantees from IGCC technology vendors. Even with these measures, however, it is unlikely that IGCC plants will replace conventional coal plants in large numbers or that those plants which are built will capture and store CO₂. There are two reasons for this.

First, even cost-competitive new technologies are usually not adopted rapidly, particularly in a conservative industry such as the utility sector, where the new technology is different from the conventional technology. This is the case with IGCC plants, which are indeed more like chemical plants than traditional coal-fired plants.

Second, there is now no business motivation to bear the cost of CCS systems when selecting new generation technologies even though the cost of electricity from IGCC plants is in fact lower than

from SCPC plants once CCS costs are taken into account. This is because plant owners are not required to control greenhouse gas emissions and CCS systems are unnecessary for the production of power. The upshot: IGCC units (with and even without CCS capability) will lack a competitive edge over SCPC units unless all plant developers are responsible for cost-effectively abating their CO₂ emissions. No such requirement exists today.

A New Policy Framework to Stimulate the Adoption of CCS Systems

This paper considers how best to change the economic calculus of power plant developers so they internalize CCS costs when selecting new generation technologies. Five policy tools are analyzed:

- Establishing a greenhouse gas cap-and-trade program
- Imposing carbon taxes
- Defining CCS systems as a so-called Best Available Control Technology for new power plants under the Clean Air Act's New Source Review program
- Developing a "low carbon portfolio" standard that requires utilities to provide an increasing proportion of power from low-carbon generation sources over time
- Requiring all new coal power plants to meet an "emission performance" standard that limits CO₂ emissions to levels achievable with CCS systems.

Each of these tools has advantages and drawbacks but an emission performance

standard for new power plants is likely to be most effective in spurring broad-scale adoption of CCS systems.

In the current U.S. political environment, a cap-and-trade system is unlikely to result in a sufficiently high market price for CO₂ (around \$30 per ton) in the early years of a carbon control regime to assure that all coal plant developers adopt CCS systems. At lower carbon prices, plant developers could well conclude that it is more economical to build uncontrolled SCPC plants and then purchase credits to offset their emissions. A carbon tax that is not set at a sufficiently high level likely would have the same consequences.

A low carbon portfolio standard would be complex and difficult to implement because of the wide variations in generation mix between different regions. Moreover, unless the standard sets stringent targets for low carbon generation, it would not preclude construction of uncontrolled coal plants.

Although the recent Supreme Court decision defining CO₂ as a "pollutant" has opened the door to controlling new power plant emissions under the New Source Review program, legal uncertainties may prevent the Environmental Protection Agency from defining CCS systems as the Best Available Control Technology under current law. Individual states could also reject CCS systems during permitting reviews. Moreover, the New Source Review program would not allow flexible compliance schedules for installing and operating CCS systems, nor would it provide financial incentives to offset the increased cost of electricity.

An emission performance standard for new power plants is likely to be most effective in spurring broad-scale adoption of carbon capture and storage systems

How Emission Performance Standards for New Coal Plants Would Work

In contrast to other approaches, an emission performance standard that limits new plant emissions to levels achievable with CCS systems would provide certainty that new coal plants in fact capture and store CO₂. To provide a clear market signal to plant developers, this standard would apply to all new plants built after a date certain, although some flexibility would be allowed in the timing of CCS installation so that the power generation industry can gain more experience with various types of capture technology and underground CO₂ storage. For example, all plants that begin construction after 2008 could be subject to the standard and would be required to implement carbon capture technology by 2013, and then to meet all sequestration requirements by 2016.

To provide additional flexibility while CCS technology is being perfected, plant developers during the first three years in which the new performance standard is in effect could have the option to construct traditional coal plants that do not capture and sequester CO₂ if they offset on a one-to-one basis their CO₂ emissions by taking one or more of the following steps:

- Improving efficiencies and lowering CO₂ emissions at existing plants
- Retiring existing coal or natural gas units that generate CO₂ emissions
- Constructing previously unplanned renewable fuel power plants representing up to 25 percent of the generation capacity of the new coal plant.

In 2011, this alternate compliance option would sunset and all new plants subse-

quently entering construction would need to capture and sequester their emissions.

An emission performance standard for new coal plants should be accompanied by a cap-and-trade program for existing power plants, with the cap starting at 100 percent of emissions and progressively declining over time. A declining cap would encourage greater efficiencies in operating existing plants and incentivize the retirement of higher emitting existing plants. This would assure that an emission performance standard for new plants does not simply prolong the useful life of older plants. In addition, as the cap declines, retrofitting existing plants with CCS systems could become a viable option.

Mitigating Electricity Price Hikes

If legislation requiring an emission performance standard for new coal plants is enacted, then Congress should simultaneously take steps to offset the additional costs of installing CCS systems and provide relief from electricity price increases. This would prevent disproportionate costs from falling upon consumers who live in regions heavily dependent on coal for power generation. By reducing the financial risks and uncertainties of building power plants with CCS systems, it would also encourage investments in such plants by developers and their financial backers.

One approach would be to create a fund to “credit” utilities for all or part of the price increase that consumers would otherwise bear if they receive power from plants with CCS systems. Alternatively, financial incentives could be offered to plant developers which, in combination, offset a significant portion of the incremental costs of installing a CCS system as opposed to operating a coal-fired

An emission performance standard for new coal plants should be accompanied by a cap-and-trade program for existing power plants, with the cap starting at 100 percent of emissions and progressively declining over time.

plant that does not control CO₂ emissions. This new incentive program would replace current incentive programs for IGCC plants and other coal technologies that do not include CCS systems.

Assuming that government incentives cover 10 percent to 20 percent of total plant construction costs and that they apply to the first 80 gigawatts of new coal capacity with CCS systems built by 2030, these incentives could cost in the range of \$36 billion over 18 years. Although \$36 billion is a large sum, it is only a fraction of the \$1.61 trillion that the International Energy Agency predicts will be invested in new power plants in the United States between now and 2030.

Building a Technical and Regulatory Foundation for CCS Systems

Once the nation commits to a rapid timetable for requiring CCS systems at all new coal plants under an emission performance standard, then all of our regulatory and research and development efforts should be focused on implementing CCS technology as effectively as possible. This would require:

- An enhanced R&D program for capture technologies at both SCPC and IGCC facilities to reduce the costs of capture as quickly as possible
- An accelerated program to gain large-scale experience with sequestration for a range of geologic formations
- A comprehensive national inventory of potential storage reservoirs
- A new regulatory framework for evaluating, permitting, monitoring, and reme-

diating sequestration sites and allocating liability for long-term CO₂ storage.

Maintaining the Viability of Coal in a Carbon-Constrained World

Although an emission performance standard that requires CCS systems for all new coal plants would pose a daunting technological and economic challenge, it will ultimately assure coal a secure and important role in the future U.S. energy mix. Such a standard would establish a clear technological path forward for coal, preserving its viability in a carbon-constrained world and giving the utility industry confidence to invest substantial sums in new coal-fired power generation. In contrast, continued public opposition and legal uncertainties may cause investors to withhold financing for new coal plants, placing the future of coal in jeopardy.

If the United States is successful in maintaining the viability of coal as a cost-competitive power source while addressing climate concerns, our leadership position would enable U.S. industries to capture critical export opportunities to the very nations facing the largest challenges from global warming. Once our domestic marketplace adopts CCS systems as power industry standards, the opportunities to export this best-of-breed technology will grow exponentially.

This will be critical to combating the massive rise of coal-derived greenhouse gas emissions in the developing world. Boosting exports while also helping China, India, and other developing nations reduce emissions and sustain economic growth would be a win-win-win for our economy, their economies, and the global climate.

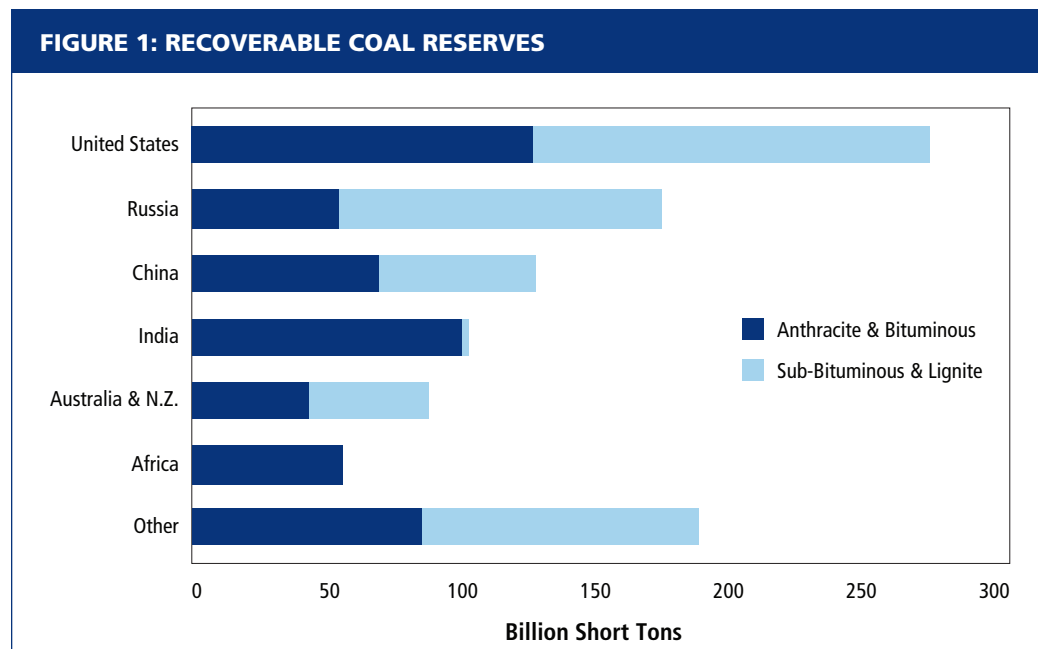
Global Warming and the Future of Coal

New Coal-fired Power Plants Threaten All Other Efforts to Combat Global Warming

For the last 15 years, most new power plants built in the U.S. have been fueled with natural gas. Today, however, coal is again emerging as a fuel of choice for the power sector as natural gas prices hit historically high levels worldwide and as demand for natural gas overtakes available supplies. In the U.S., coal is abundant, representing 27 percent of the world's known reserves,⁵ and is less subject to price volatility and supply constraints than petroleum and natural gas (see Figure 1). Because demand can be met from domestic sources, coal also offers important energy security benefits to the United States.

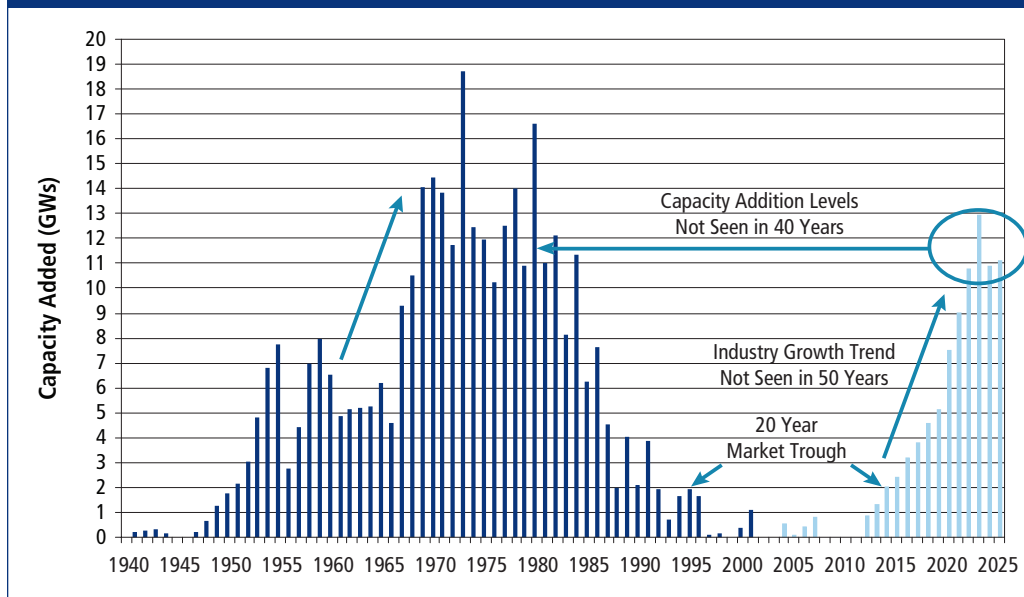
While only 11 gigawatts of new coal-fired plants were built in the U.S. from 1991 to 2003, and virtually none from 2001 to 2005,⁶ the National Energy Technology Laboratory of the U.S. Department of Energy now estimates that 145 gigawatts of new coal-fired plants will be built in the U.S. by 2030 (see Figure 2).⁷ Utilities and other power plant developers have already announced plans to build 151 coal-fired plants with a capacity of 90 gigawatts.⁸ Outside the U.S., the projections are more dramatic. Estimates of the worldwide total new construction of coal-fired plants by 2030 are around 1,400 gigawatts.⁹

Few of these new plants in the U.S. are likely to replace existing less efficient coal-fired plants. The U.S. government's Energy Information Administration predicts that by 2030 electricity demand in the U.S. will increase by approximately 40 percent,¹⁰



Source: James Katzer et al., *The Future of Coal: Options for a Carbon-Constrained World*, Massachusetts Institute of Technology Interdisciplinary Study.

FIGURE 2: U.S. FORECASTS LARGEST COAL GENERATION CAPACITY IN 40 YEARS
U.S. Coal Capacity Additions, 1940–2025



Source: U.S. Department of Energy NETL & Annual Energy Outlook 2005.

creating a need for increased power generation, and estimates that only about 3.6 gigawatts of coal power plants will be decommissioned by 2025.¹¹ In the developing world, where economic growth will be higher than in the U.S., almost all of the new coal-fired plants will represent an expansion, rather than a replacement, of capacity to meet soaring energy demand. China, for example, has the world's third largest coal reserves,¹² and is in the process of implementing a massive increase in coal-fired generation to meet growing energy needs.¹³

A serious drawback of coal-fired power generation is the formation of high levels of CO₂ during coal combustion—this CO₂ is then released from the stack and contributes to atmospheric buildup of greenhouse gases. Existing coal-fired power plants account for about one third of U.S. CO₂ emissions and make a substantial contribution to the total worldwide accumulation of CO₂ emissions in the atmosphere.¹⁴

A major expansion of worldwide coal generation would dramatically increase greenhouse gas emissions. A new 1,000 megawatt (1 gigawatt) coal power plant using the latest conventional pulverized coal technology produces about 6 million tons (5.4 million metric tons) of CO₂ annually.¹⁵ In the absence of CO₂ emission controls, the new coal plants projected to be built globally would generate as much as 8.4 billion additional tons (7.6 billion metric tons) of CO₂ each year (assuming 1,400 gigawatts of new coal-fired plants are constructed). This represents an increase of approximately 30 percent over current total annual world emissions of 25 billion metric tons of CO₂ from the consumption of fossil fuels (see Figure 3).¹⁶ Worldwide emissions from these new plants between now and 2030 would be equal to between 50 percent of all fossil fuel emissions during the past 250 years (see Figure 4).¹⁷

In the United States alone, 870 million tons (790 million metric tons) would be

FIGURE 3: PROJECTED WORLD-WIDE CO₂ EMISSION INCREASES WITHOUT EMISSION CONTROLS (1990–2030), IN METRIC TONS OF CO₂ EMISSIONS

	1990	2004	2010	2015	2030	2004–2030*
Power Generation	6,955	10,587	12,818	14,209	17,680	2.0%
Industry	4,474	4,742	5,679	6,213	7,255	1.6%
Transport	3,885	5,289	5,900	6,543	8,246	1.7%
Residential and Services**	3,353	3,297	3,573	3,815	4,298	1.0%
Other***	1,796	2,165	2,396	2,552	2,942	1.2%
Total	20,463	26,079	30,367	33,333	40,420	1.7%

* Average annual growth rate. ** Includes agriculture and public sector.

*** Includes international marine bunkers, other transformation and non-energy use.

Source: Int'l Energy Agency, *World Energy Outlook 2006*.

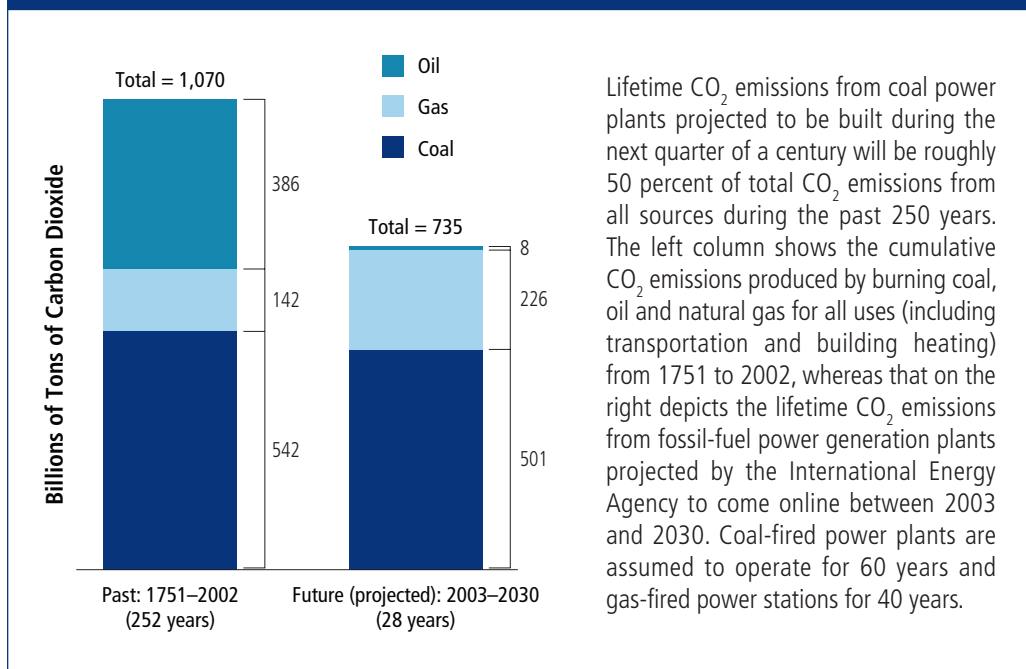
emitted if all of the currently proposed coal plants are built and do not control their CO₂ emissions.¹⁸ This compares to 2005 annual emissions in the U.S. of about 6 billion metric tons of CO₂ and 7.15 billion metric tons of CO₂ equivalent greenhouse gases from *all* sources.¹⁹ Moreover, new coal-fired plants, once built, will have a projected lifespan of up to 60 years. There will be powerful resistance to retiring them before investors have earned an acceptable return on their investment. These plants would therefore be high CO₂ emitters for decades to come.

In the U.S., there is growing public opposition to new coal plants that do not control CO₂ emissions. The recent proposal by private equity investors to cancel several coal plants originally announced by Texas utility TXU Corp. is evidence that public resistance may be strong enough to derail some new plants.²⁰ Yet in other parts of the world opposition to new coal plants is much less likely to prevent these plants from being built. The long-term increases in CO₂ emissions from new plants abroad would greatly impede the ability of developing nations such as India and China to moderate and ultimately reverse rapid greenhouse gas emission growth resulting from surging economic activity.

Even if no coal-fired plants are built between now and 2030, the world would face a daunting task in reducing global greenhouse gas emissions. But with greenhouse gas emissions from the power sector increasing due to the growth in coal-fired power generation, it will be almost impossible to reduce or even stabilize total emissions in the U.S. (not to mention the rest of the world) in the absence of aggressive CO₂ control measures. Between 1990 and 2005, for example, when few coal-fired plants were built in the U.S., emissions of CO₂ and other greenhouse gases increased by 16.3 percent,²¹ including a 2 percent increase from 2003 to 2004.²²

A dramatic increase in the rate of worldwide emissions growth due to new coal plants would make the goal of stabilizing atmospheric levels of greenhouse gases unattainable. Many experts support stabilizing atmospheric greenhouse gas levels at 450 parts per million. The 450 ppm goal is higher than the current greenhouse gas level of 380 ppm,²³ but hopefully is low enough to prevent precipitous increases in global temperatures.²⁴ However, only a sharp drop in worldwide emissions will bring the 450 ppm target within reach.

FIGURE 4: HISTORIC LEAP IN EMISSIONS



Source: Scolow, "Can We Bury Global Warming?" *Scientific American*, July 2005.

A Potential Path to Zero Emissions Through Carbon Capture and Storage

The threat to the global climate due to increased coal generation is urgent and serious, yet there is a potential technology pathway that would permit greater utilization of coal as an energy source without adding to existing global greenhouse gas emission levels. This path involves capturing and then sequestering CO₂ from coal-fired plants in secure underground repositories, effectively preventing its escape into the atmosphere. Government and the private sector are increasingly examining this new technology system, known as carbon capture and storage (or CCS), as a viable CO₂ emission control strategy for coal power plants and other industrial facilities that burn fossil fuels on a large scale.

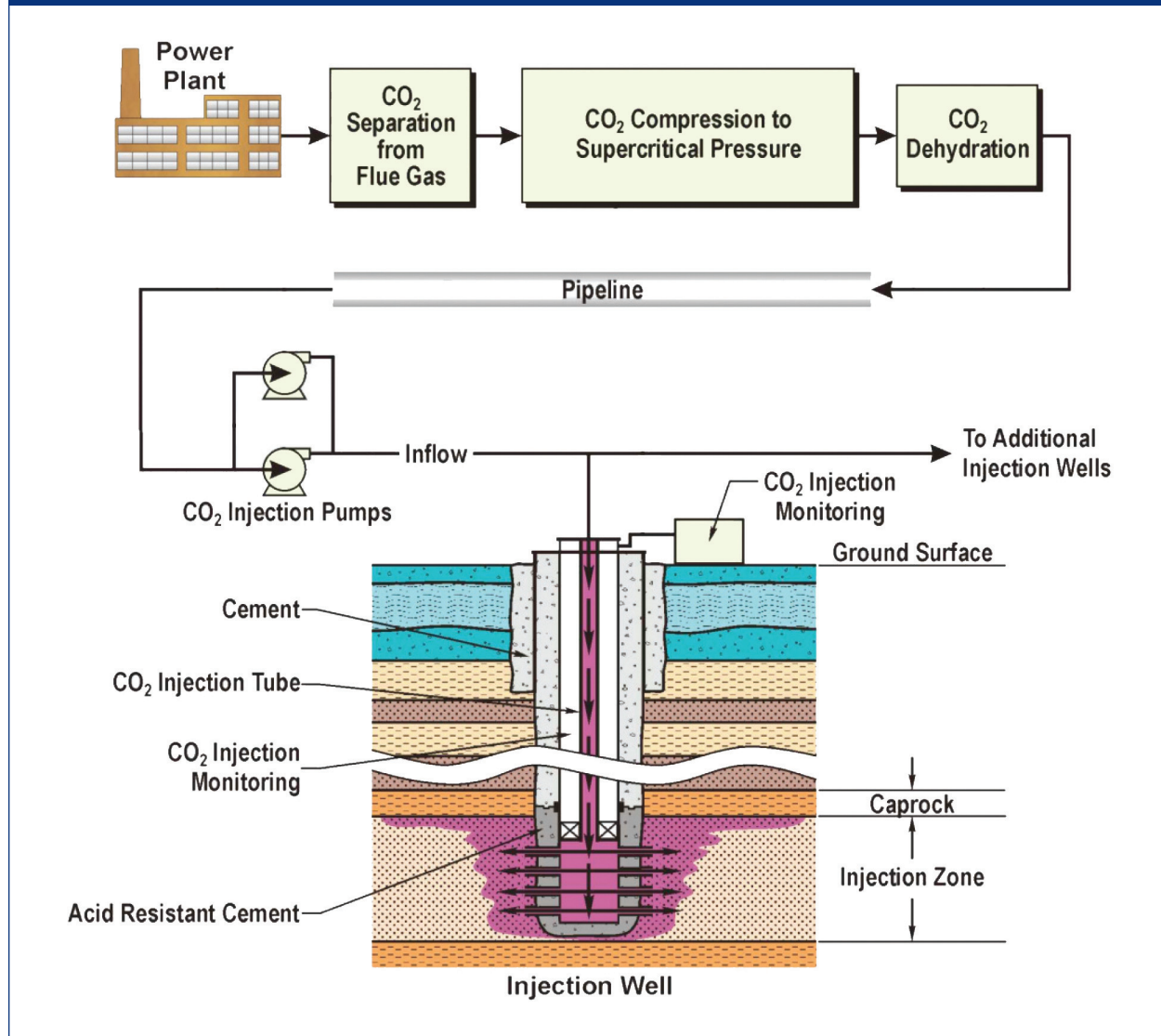
During CCS operations, CO₂ is compressed to a supercritical liquid, trans-

Lifetime CO₂ emissions from coal power plants projected to be built during the next quarter of a century will be roughly 50 percent of total CO₂ emissions from all sources during the past 250 years. The left column shows the cumulative CO₂ emissions produced by burning coal, oil and natural gas for all uses (including transportation and building heating) from 1751 to 2002, whereas that on the right depicts the lifetime CO₂ emissions from fossil-fuel power generation plants projected by the International Energy Agency to come online between 2003 and 2030. Coal-fired power plants are assumed to operate for 60 years and gas-fired power stations for 40 years.

ported by pipeline to an injection well and then pumped underground to depths sufficient to maintain critical pressures and temperatures. The CO₂ seeps into the pore spaces in the surrounding rock and its escape to the surface is blocked by a caprock or overlying impermeable layer. In some types of formations, the CO₂ may dissolve in water and react with minerals in the host rock to form carbonates, becoming permanently entrained (see Figure 5).

Long-term sequestration of CO₂ is possible in depleted oil and gas reservoirs, unminable coal seams, basalt structures, and deep saline aquifers. The latter are believed to be ubiquitous at depths generally below one kilometer and are estimated to underlie at least one-half of the area of inhabited continents.²⁵ These deep saline formations have the greatest capacity to store CO₂ and would play a critical role in any large-scale CCS program (see Figure 6).

FIGURE 5: CARBON CAPTURE AND STORAGE: HOW IT WORKS



Source: Battelle Climate Research Institute, *Carbon Dioxide Capture and Geological Storage*, April 2006.

There is considerable experience in the U.S. with underground injection of liquids and gases.²⁶ Over 100,000 technically sophisticated and highly monitored injection wells are currently employed to pump fluids as much as two miles below the earth's surface.²⁷ U.S. CO₂ pipeline transmission is also well-established, with CO₂ pipelines in use since the early 1970s, the longest of which runs for approximately 500 miles.²⁸

Similarly, CO₂ has long been pumped into the ground in oil and gas fields to improve extraction of these fuels. CO₂ injection has occurred extensively in the Permian Basin of West Texas and East New Mexico, plus several other areas of the U.S. and Canada, as part of enhanced oil recovery, or EOR operations. Currently 71 active CO₂-EOR projects inject, use and store 43 million tons/year of CO₂, 11 million tons/year (9.9 million

metric tons/year) of which comes from industrial sources (see sidebar below). A Department of Energy-funded study examined 1,581 large reservoirs in the U.S. and concluded (assuming low-cost sources of CO₂) that up to 89 billion barrels of oil could be recovered using current EOR technology.²⁹

To gain additional experience with injecting and storing CO₂, the U.S. Energy Department's seven Regional Sequestration Partnerships have initiated plans for conducting nearly two dozen pilot tests of injecting CO₂ into oil and gas reservoirs, coal seams and saline formations in the next three years.³¹ The goal of this program is to achieve 99 percent storage permanence of CO₂ at less than a 10 percent increase in the cost of energy services by 2012.³²

Although there is presently limited experience with capturing and sequestering CO₂ generated during the combustion of fossil fuels to produce electric power, a number of promising projects are on the horizon. Last August, for example, Midwest power producer XCEL Energy announced that it was committing \$3.5 million toward developing a coal-generation facility in Colorado that would capture and sequester CO₂.³³

BP and Irvine, California-based Edison Mission Energy announced plans in February 2006 to build a new 500-MW hydrogen-fueled power plant that will generate electricity using petroleum coke and will capture CO₂ for sequestration in nearby oil fields.³⁴ In addition, the proposed 1.2 Excelsior Mesaba Project in Minnesota plans to capture some of its CO₂ and transport it for sequestration through a pipeline that will likely be 265- to 450 miles long.³⁵

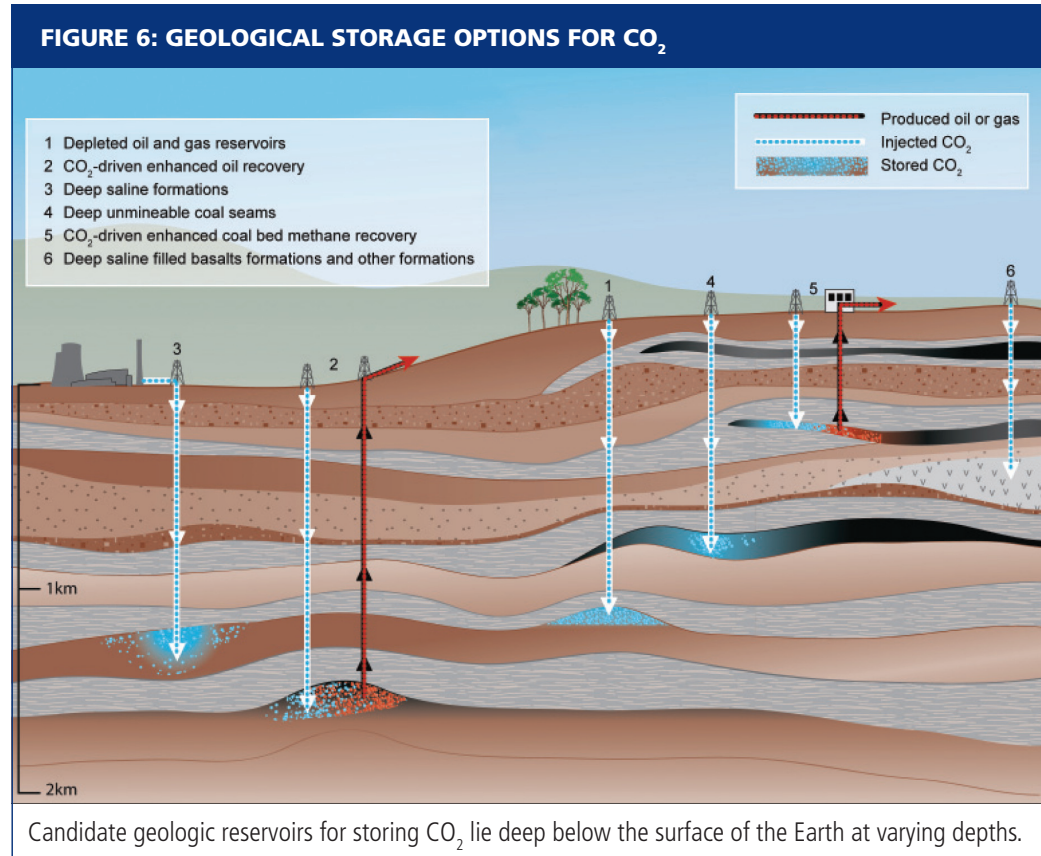
Industrial CO₂ Storage

Industrial CO₂ is derived primarily from gas processing, fertilizer and coal gasification plants. Of particular note is EnCana's CO₂-EOR sequestration project in the Weyburn Field of Saskatchewan, Canada. The CO₂ is created in North Dakota and goes through a 200-mile pipeline to reach the Weyburn Field. The EnCana project in combination with the nearby Apache project currently injects 2.5 million metric tons of CO₂ annually into the Weyburn Field and expects to sequester a total of 51 million metric tons of CO₂ by project end.³⁰

Overseas, the two most visible CO₂ capture and storage projects (not involving CO₂-EOR) are at the Siepner Field in the North Sea by Norway's Statoil ASA and the InSala Field in Algeria by Britain's BP plc. Each of these projects currently injects about 1 million tons of CO₂ per year into a saline formation either above or below the producing natural gas reservoir.

Most recently, American Electric Power (AEP) of Columbus, Ohio, announced that it will conduct a small CCS "validation" project at a West Virginia pulverized coal, or PC, plant and, starting in 2011, capture 1.5 million tons (1.36 million metric tons) of CO₂ annually at an Oklahoma PC unit for sale to oil companies for EOR.³⁶ Likewise, as part of the proposed leveraged buy-out of TXU by private equity investors, the Texas utility has announced preliminary plans to build two plants using advanced Integrated Gasification Combined Cycle, IGCC, technology with CCS systems.³⁷

Widespread implementation of CCS technology at coal-fired power plants would greatly expand the scale of CO₂ sequestration beyond the small number of projects underway today because of the massive



Source: The Australian CO₂CRC.

amounts of CO₂ that would be captured and then stored on a permanent basis. A one-gigawatt plant will require sequestration of 6 million tons of CO₂ per year (this is the equivalent of 50 million barrels of CO₂ per year).³⁸ If the 90 gigawatts of coal plants now in the planning stages are built, nearly 540 million tons (490 million metric tons) of CO₂ would have to be sequestered each year. In contrast, the EnCana project astride the North Dakota/Saskatchewan border, in combination with the nearby Apache project, is injecting only 2.5 million metric tons (2.7 million tons) per year into the Weyburn Field.

A critical challenge for industry, academia, and government will be to demonstrate that large quantities of CO₂

can be stored without leaks over long periods and under a range of geologic conditions. The large scale sequestration projects now underway provide reassuring evidence that leakage from CO₂ storage formations is unlikely. Long-term experience with EOR in oil and gas fields is also reassuring. The geology of these fields is well-known and their sealing potential well-established; they have been storing oil and gas for millions of years.³⁹

Nonetheless, there remain open questions about deep saline aquifers, which are expected to provide the bulk of the required CO₂ storage capacity. These aquifers are largely untested structures and additional effort will be required to validate their storage capacity and

integrity. The Energy Department's pilot sequestration program is focused on small storage sites and is unlikely to provide data on the performance of larger reservoirs storing CO₂ in the megaton quantities typical of emissions generation at baseload power plants.

Accordingly, the Pew Center on Climate Change says there is a need for four to six large-scale test projects at reservoirs with diverse characteristics in order to demonstrate the viability of carbon sequestration.⁴⁰ A recent study by the Massachusetts Institute of Technology similarly concluded that three to four large scale test projects "might be needed to demonstrate and parameterize safe injection."⁴¹ The MIT study also estimated the cost of studying three sequestration basins at \$500 million over eight years and at less than \$1 billion for five large sequestration tests.⁴² Legislation to build on MIT's recommendations by requiring rapid completion of large-scale sequestration testing has been introduced by New Mexico Senators Jeff Bingaman and Pete Domenici.⁴³

Despite the importance of additional testing, experts are confident that large-scale sequestration will be safe, feasible, and cost-effective. Thus, after reviewing the key questions of subsurface engineering and surface safety associated with carbon sequestration, the MIT coal study concludes:

There do not appear to be unresolvable open technical issues underlying these questions. Of equal importance, the hurdles to answering these technical questions will appear manageable and surmountable. As such, it appears that geological carbon sequestration is likely to be safe, effective, and competitive with many other options on an economic basis.⁴⁴

Establishing a Legal and Regulatory Framework for CCS

Even if CO₂ leakage concerns are remote, an effective regulatory framework and concerted public communication program will be needed to allay fears of catastrophic releases from insecure storage formations and resulting harm to property and human health, similar to concerns associated with nuclear waste disposal sites. Although a large-scale concentrated release of sequestered CO₂ that could have toxic effects on nearby populations or cause contamination of water supplies is highly unlikely, it will be necessary to establish credible requirements for site characterization, risk assessment, permitting and long-term site monitoring that address these scenarios.

Reliable measurement of CO₂ leakage rates will also be necessary for implementation and enforcement of any CO₂ emission-reduction program premised on the long-term effectiveness of CCS systems. Since CO₂ injection at most sites will stop after two or three decades, clearly defined liability and ownership rules will be required to delineate who bears long-term responsibility for effective CO₂ storage and remedial action if leaks occur at these sites. Some states, such as Texas, have decided to transfer ownership of post-injection sites to government bodies,⁴⁵ but most other states have yet to set liability rules.

There has been some discussion of a government-funded insurance program (akin to the Price Anderson Act for nuclear plants) to protect private owners and operators against serious financial exposure in the event of CO₂ leaks. But there is no consensus as yet that such insurance protection is needed to encourage power generators to commit to long-term CO₂ capture and storage programs.⁴⁶

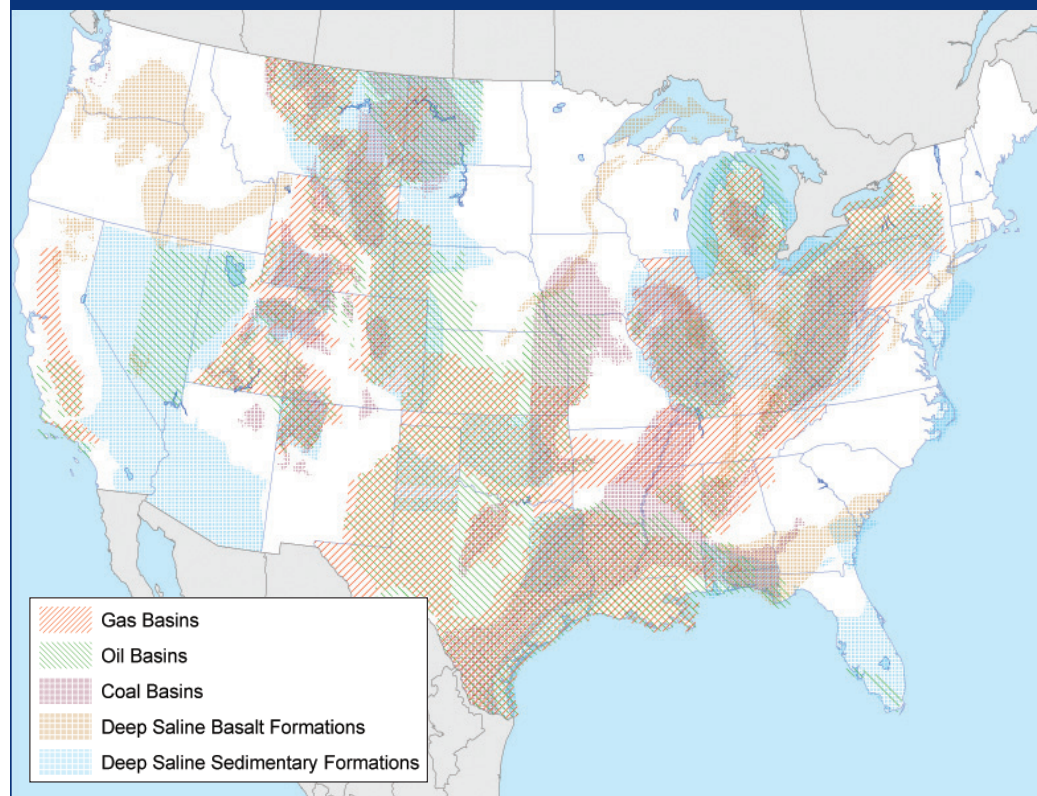
The EPA has long regulated underground injection at oil and gas wells under the Safe Drinking Water Act and recently issued guidance for CO₂ injection at sequestration sites.⁴⁷ Yet it is unclear whether EPA's existing authority is broad enough to encompass all the issues raised by CO₂ injection under a carbon control regime. Thus, a new national legislative framework may well be needed to create long-term public confidence in CCS systems.⁴⁸ Among other issues, such a framework could address the complex regulatory and safety aspects of creating a dedicated interstate pipeline network to transport massive quantities of CO₂.⁴⁹ This framework should be in place well before CCS technology is implemented on a broad scale.

Available data also provide confidence that there is ample underground capacity in the U.S. and most other areas of the world to sequester the CO₂ output from projected levels of fossil fuel combustion (see Figures 7 and 8). The Department of Energy recently released its first Carbon Sequestration Atlas of the United States and Canada based on a preliminary survey of potential sequestration reser-

voirs by its seven regional sequestration partnerships. The Atlas concludes that approximately 3,500 billion tons of CO₂ storage capacity exists in North America (mostly in deep saline formations) at diverse locations across the country.⁵⁰

A 2006 report by the Battelle Institute on U.S. sequestration capacity reaches remarkably similar conclusions, estimat-

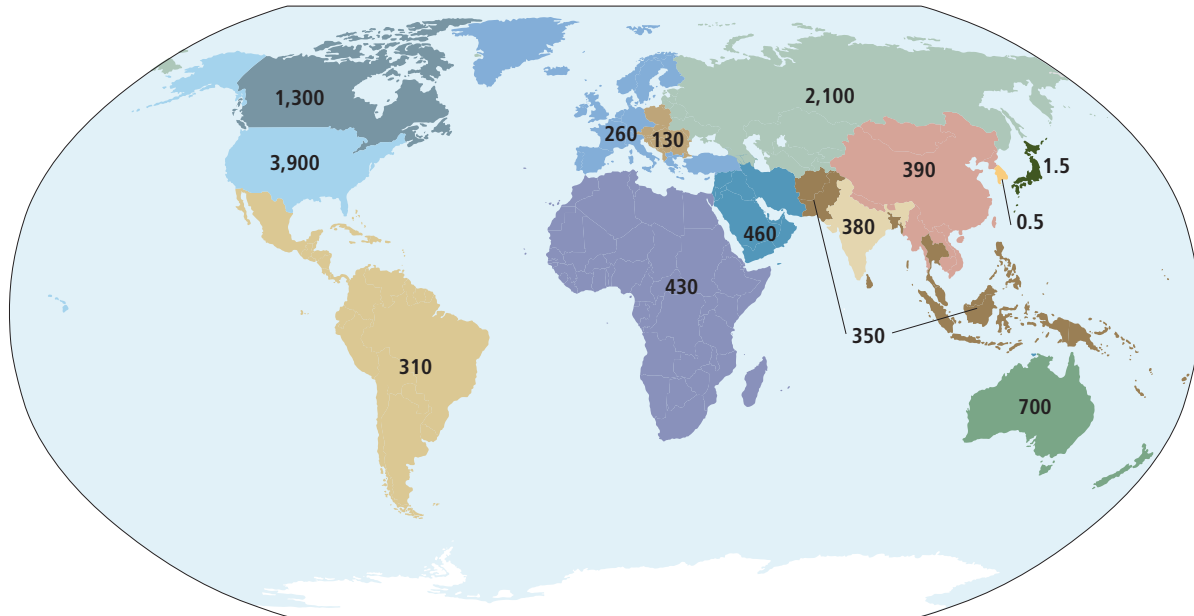
FIGURE 7: POTENTIAL GEOLOGIC CO₂ STORAGE RESERVOIRS IN THE U.S.



The United States is fortunate to have an abundance of theoretical CO₂ storage potential, well distributed across most of the country. Our preliminary and ongoing assessment of candidate geologic CO₂ storage formations reveals that the formations studied to date contain an estimated storage capacity of 3,900+ gigatons of CO₂ within some 230 candidate geologic CO₂ storage reservoirs.

- 2,730 gigatons in onshore deep saline formations, with perhaps close to another 900 gigatons of storage capacity in offshore deep saline formations
- 240 gigatons in onshore saline-filled basalt formations
- 35 gigatons in depleted gas fields
- 30 gigatons in deep unmineable coal seams with potential for enhanced coalbed methane recovery
- 12 gigatons in depleted oil fields with potential for enhanced oil recovery

Source: Battelle Climate Research Institute, *Carbon Dioxide Capture and Geological Storage*, April 2006.

FIGURE 8: GLOBAL CO₂ STORAGE CAPACITY (GIGATONS)

Initial assessments of theoretical global CO₂ storage capacity reveal an important and encouraging result: there is more than enough theoretical CO₂ storage capacity in the world to meet likely storage needs for at least a century, and in many key regions the storage capacity is in the right places to meet current and future demand from nearby CO₂ sources.

Source: Battelle Climate Research Institute, *Carbon Dioxide Capture and Geological Storage*, April 2006.

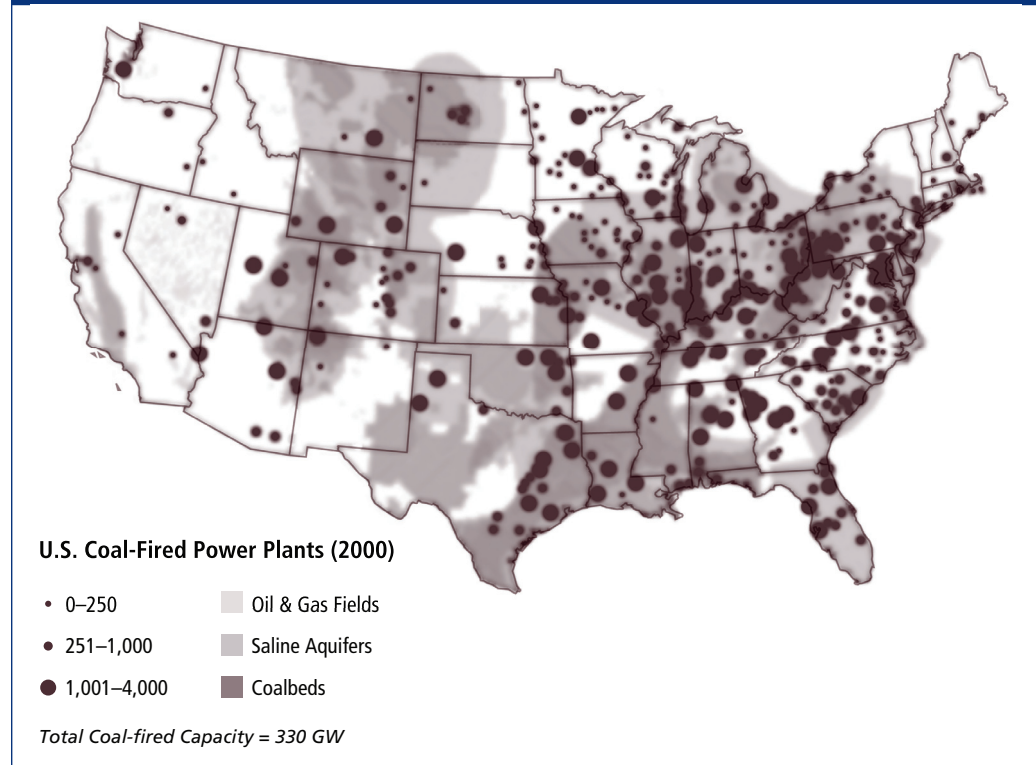
ing total U.S. capacity of 3,900 gigatons of CO₂ and finding that usable formations underlie parts of 45 states and two thirds of the land mass of the contiguous 48 states (see Figure 7).⁵¹ This capacity would be sufficient to store the CO₂ emissions of the 145 projected new coal plants in the U.S. for several thousand years.

A third report published in 2005 by the Intergovernmental Panel on Climate Change, entitled *IPCC Special Report on Carbon Dioxide Capture and Storage* likewise concluded that there is considerable worldwide geological storage capability for CO₂ (see Figure 8).⁵² The IPCC also concluded that it is likely that the CO₂ retained in underground formations will

likely exceed 99 percent of the quantity injected over 1,000 years.⁵³

It is widely agreed that a comprehensive survey of storage capacity is needed to improve the accuracy of existing estimates.⁵⁴ Notwithstanding uncertainties in estimation, there is little doubt that most regions of the U.S. are endowed with ample geological formations suitable for sequestration. Thus, underground CO₂ storage opportunities are likely to be within close proximity (zero to 250 miles) to the majority of coal plants that would be built, although some coal-dependent states may need to transport CO₂ for longer distances in order to sequester it (see Figure 9).⁵⁵

FIGURE 9: LOCATION OF COAL PLANTS RELATIVE TO POTENTIAL STORAGE SITES



Source: James Katzer et al., *The Future of Coal: Options for a Carbon-Constrained World*, Massachusetts Institute of Technology Interdisciplinary Study.

CO₂ Capture at Coal Plants: the Promise of IGCC and Other Technologies

The separation and capture of CO₂ at large coal-fired power plants pose larger economic and technical challenges than the transportation and sequestration of CO₂. The dominant coal generation technology in the world today is pulverized coal, or PC in industry parlance, in which coal is ground to fine particles and then injected into a furnace with combustion air; the flue gas from the boiler contains CO₂ and other combustion byproducts, which are treated to remove certain pollutants (nitrogen oxides or NO_x, and sulfur dioxide or SO₂) and then released to the air.

Greater combustion efficiency (and lower CO₂ emissions per unit of energy output) can be achieved by supercritical and ultra-supercritical pulverized coal plants that reach higher steam temperatures and pressures. These designs, referred to in the industry as SCPC and USCPC, plants, respectively (for purpose of this paper both types of plants are referred to generically as SCPC), have been selected for many of the proposed new PC plants. The resulting CO₂ can be captured from flue gases following combustion at these plants by absorption into an amine solution, from which the absorbed CO₂ is then stripped via a temperature increase and cooled, dried, and compressed into a supercritical liquid (see Figure 11).

Research to optimize this post-combustion solvent “scrubbing” process is underway and may yield breakthroughs.⁵⁶ But post-combustion CO₂ capture using existing technology is now believed to impose a high energy penalty and create solvent degradation products that could have adverse environmental impacts.⁵⁷ Accordingly, there are significant disadvantages at this time to capturing CO₂ at SCPC plants, despite the historical dominance of PC generation technology in the power industry.⁵⁸

A new coal-based generation technology known as Integrated Gasification Combined Cycle, or IGCC, offers more promise as a pathway to CO₂ capture and downstream sequestration at the present time. The CO₂ emissions from IGCC plants are somewhat lower than those

from SCPC plants because of IGCC’s higher thermal efficiency. More importantly, IGCC plants are able to capture CO₂ emissions more cost-effectively than SCPC plants using current technology because IGCC technology does not rely on direct combustion but instead converts the carbonaceous feedstocks, by way of gasification, into a clean gas called syngas (see sidebar below).

Although CO₂ capture is relatively straightforward technically, it poses a major economic challenge. Because of higher capital costs, greater fuel utilization, and lower electricity output, coal plants that capture CO₂ are projected to be more expensive producers of electricity than plants without capture capability. Carbon capture is estimated to account for 83 percent of the total cost of CCS

The Integrated Gasification Combined Cycle Process

Integrated Gasification Combined Cycle plants are able to capture CO₂ emissions more cost-effectively than SCPC plants using current technology because IGCC technology does not rely on direct combustion but instead converts the carbonaceous feedstocks, by way of gasification, into a clean gas called syngas (see Figure 12). Typical feedstocks for gasification are coal and a variety of refinery residuals such as petroleum coke and high sulfur fuel oil. The gasification process breaks down the feedstock into hydrogen, carbon monoxide, and smaller quantities of carbon dioxide by subjecting it to high temperature and pressure using steam and measured amounts of oxygen.

Minerals in the feedstock (rocks, dirt, and other impurities) do not react in the gasifier, and instead form a slag which can be disposed of, or converted to marketable solid products. After purification, the syngas, which is very similar to natural gas, can be burned in a conventional combined cycle power unit to generate electric power.

Historically, syngas from gasification has been used as a starting material for the production of chemicals and liquid fuels. At

present, there are 117 gasification plants with 385 gasifiers operating around the world, with 35 additional facilities in various stages of development, design and construction, but most of these do not generate power.⁵⁹

A phase shifter can be used to convert carbon monoxide gas to carbon dioxide in the presence of steam at the end of the syngas refining stage and to separate the CO₂ stream from the syngas before combustion (see Figure 13). Because CO₂ concentrations are higher and pressure is lower when CO₂ is captured pre-combustion, the energy required for CO₂ separation is smaller for IGCC units than for SCPC units.

The carbon capture rate at IGCC plants is currently believed to be around 85 percent. The Energy Department’s research program has a goal of achieving a 90 percent carbon capture rate by 2012.⁶⁰ Likewise, the pilot FutureGen plant is designed to capture 90 percent of its carbon dioxide at the start of operations and subsequently increase to 100 percent.⁶¹

FIGURE 10: ESTIMATED ECONOMIC IMPACTS OF ADDING CARBON CAPTURE & SEQUESTRATION

	IGCC PLANTS			SCPC PLANTS		
	MIT STUDY	WISCONSIN REPORT	EPA REPORT	MIT STUDY	WISCONSIN REPORT	EPA REPORT
Increase in Capital Costs (%)	32%	35%	47%	61%	60%	73%
Decrease Total Efficiency (%)	19%	NA	14%	24%	NA	29%
Increase in Cost of Electricity (\$ / MWh) ⁶⁴	NA	\$ 18	\$ 18	NA	\$ 33	\$ 35
Increase in Cost of Electricity (%)	25-40%	30%	37.5%	60-85%	60%	67%
Cost of Preventing CO ₂ emissions (\$ per ton)	\$ 24	\$ 30	\$ 28	\$ 40	\$ 45	\$ 51

systems, with transportation and storage accounting for only 17 percent of such costs.⁶² Figure 10 summarizes the results of three recent studies that estimated the economic and performance impacts of adding carbon capture technologies to IGCC and SCPC plants.⁶³ As Figure 10 illustrates, although capture costs will be high with both technologies, IGCC is currently perceived to have a marked advantage over SCPC.

The Electric Power Research Institute also recently estimated the effect of adding CO₂ capture to the cost of electricity and

concluded that the cost would increase by approximately 40 percent-to-50 percent for IGCC plants and 60 percent-to-80 percent for SCPC plants.⁶⁵ However, EPRI also anticipates that these costs could be lowered as improvements are developed to decrease the energy penalty associated with carbon capture.⁶⁶

Barriers to Commercialization of IGCC Technology

The greater cost-effectiveness of IGCC technology in capturing CO₂ emissions has stimulated heightened interest in its deployment as concern about climate change and the likelihood of future carbon constraints have grown. Vendors of IGCC plants (see sidebar below) have established a higher profile in the marketplace and have stepped up their marketing and R&D efforts. Some major utilities have announced plans to construct IGCC plants. And governments at the state and federal level have put in place financial incentives to encourage IGCC plants.

Currently, there are five IGCC plants in operation around the world, two of which are located in the U.S., one in Indiana and the other in Florida. After

Technology Leaders in Gasification

The major U.S. vendors of gasification technology are General Electric Co. and Conoco-Phillips Inc. Additionally, Royal Dutch Shell plc has proposed several IGCC projects in Europe and China, but has a limited U.S. presence. These companies have partnered with construction and engineering companies such as Bechtel Corp. and Fluor Corp. to offer a single project "wrap" that includes a firm price for engineering, procurement and construction as well as guarantees for construction completion and plant performance. These packages are expected to lead to greater standardization of plant design and equipment, reduce costs and shift some of the operational risks of IGCC from utilities to vendors.

initial problems, the existing U.S. IGCC units have achieved improved reliability and are performing acceptably.⁶⁷ Now other utilities and power companies are stepping forward with proposals to build IGCC plants. The sidebar below identifies recently announced U.S. IGCC plants:⁶⁸

It is encouraging that major utilities are pursuing IGCC plans. But a far greater number of proposed coal plants are *not* expected to employ IGCC technology. According to St. Louis, Missouri-based Peabody Energy Corp., the nation's largest coal producer, 36 traditional

Recently Announced IGCC Plants by Plant Location

Alaska

- Agrium US—350 MW

California

- BP & Edison Mission Energy—500 MW⁶⁹

Colorado

- Xcel Energy—300-350 MW

Delaware

- NRG—630 MW

Florida

- Florida Power & Light—MW TBD
- Tampa Electric—630 MW
- Orlando Utilities Commission, Southern Co. & U.S. DOE—285 MW

Idaho

- Idaho Power Company—MW TBD
- Mountain Island Energy Holdings, LLC—250 MW
- Southeast Idaho Energy LLC—500 MW

Illinois

- Christian County Generation LLC—630 MW in Illinois⁷⁰
- Erora Group—777 MW
- Rentech Development Corp.—76 MW
- Clean Coal Power Resources—2,400 MW
- Madison Power Corp.—500 MW
- Steelhead Energy Co. LLC—545 MW

Indiana

- Duke Energy—630 MW
- Tondu Corp.—630 MW Minnesota
- Excelsior Energy Mesaba Project—603 MW

Mississippi

- Mississippi Power Co.—600 MW⁷¹

Montana

- DKRW Energy of Houston, Bull Mountain Companies and Arch Coal—300 MW⁷²

New York

- NRG Energy—680 MW

Ohio

- AEP—600 MW in Ohio
- CME International—600 MW in Ohio
- Global Energy—600 MW in Ohio

Washington

- Energy Northwest—600 MW

West Virginia

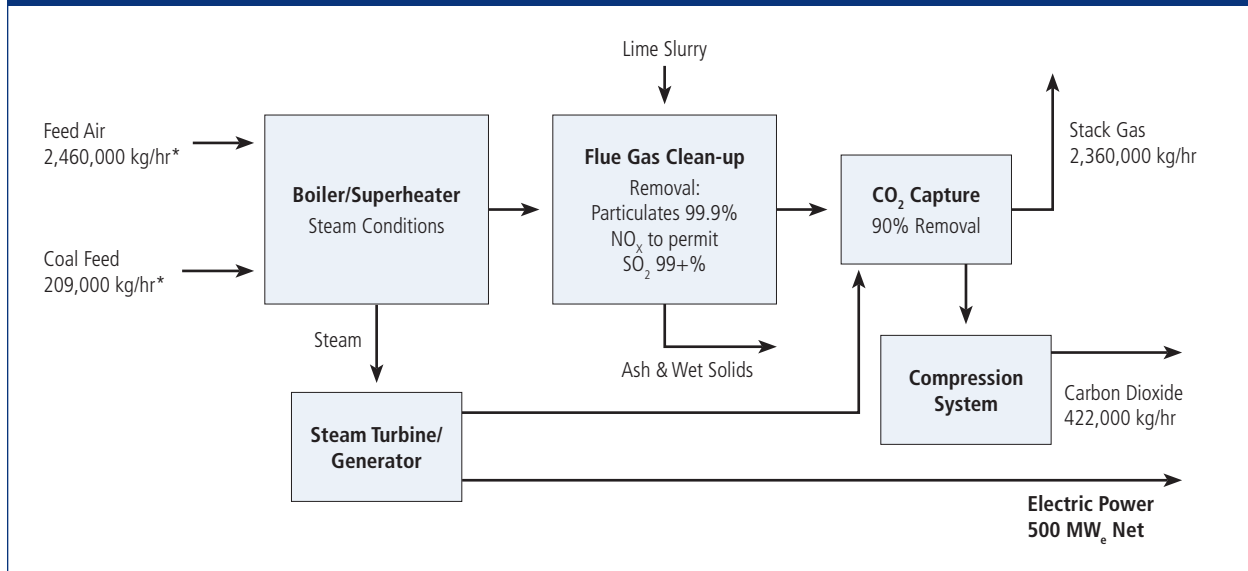
- AEP—600 MW in West Virginia

Wyoming

- Buffalo Energy—1,100 MW
- Rentech—104 MW
- DKRW & SNC Lavalin—200 MW
- PacifiCorp—450 MW
- Energy Expenditures Inc.—450 MW

Locations Pending

- Basin Electric Power Coop.—630 MW in North or South Dakota
- First Energy/Consol—Pennsylvania or Ohio, MW TBD

FIGURE 11: ULTRA-SUPERCRITICAL 500 MW_e PULVERIZED COAL UNIT WITH CO₂ CAPTURE

* Kilograms per hour.

Source: James Katzer et al., *The Future of Coal: Options for a Carbon-Constrained World*, Massachusetts Institute of Technology Interdisciplinary Study.

coal-fired plants will come online in 2009 and 2010, representing over 20,000 MW of capacity.⁷³ Moreover, as the sidebar on page 19 illustrates, of the approximately 145 new and proposed coal plants announced in the United States as of May 2007, only 34 are IGCC plants. While public resistance has derailed some notable SCPC projects, such as the well-publicized TXU proposal to build 11 new coal plants in Texas,⁷⁴ other proponents of SCPC plants have either been successful in avoiding public opposition or have defeated their opponents.

Assuming, then, that most utilities stick with their current plans, IGCC will not be the dominant technology for new coal plants for some time. Of equal concern, most of the announced IGCC plants will *not* have CCS capability.

Cost and Reliability Issues

What accounts for the reluctance of utilities to commit to IGCC plants with CCS systems? The current economics of

IGCC projects, coupled with inadequate regulatory drivers and financial incentives, are creating significant obstacles to widespread adoption of IGCC in the power sector and discouraging investments in CCS systems even where IGCC plants are built.

First, IGCC plants must become price competitive and meet industry reliability standards. Currently, capital costs of the IGCC plants themselves are about 20 percent-to-25 percent higher for IGCC than SCPC plants, although this differential is expected to decline to 10 percent as the technology matures and vendors like GE and Bechtel work toward standardized plant designs and equipment.⁷⁵

IGCC capital costs also vary widely with the type of coal used. Power plant performance is best with lower-ash, lower-moisture bituminous coals, but performance degrades with lower-rank and higher-ash coals, such as Western lignite and sub-bituminous coal. While this problem is likely to be overcome and some IGCC plants

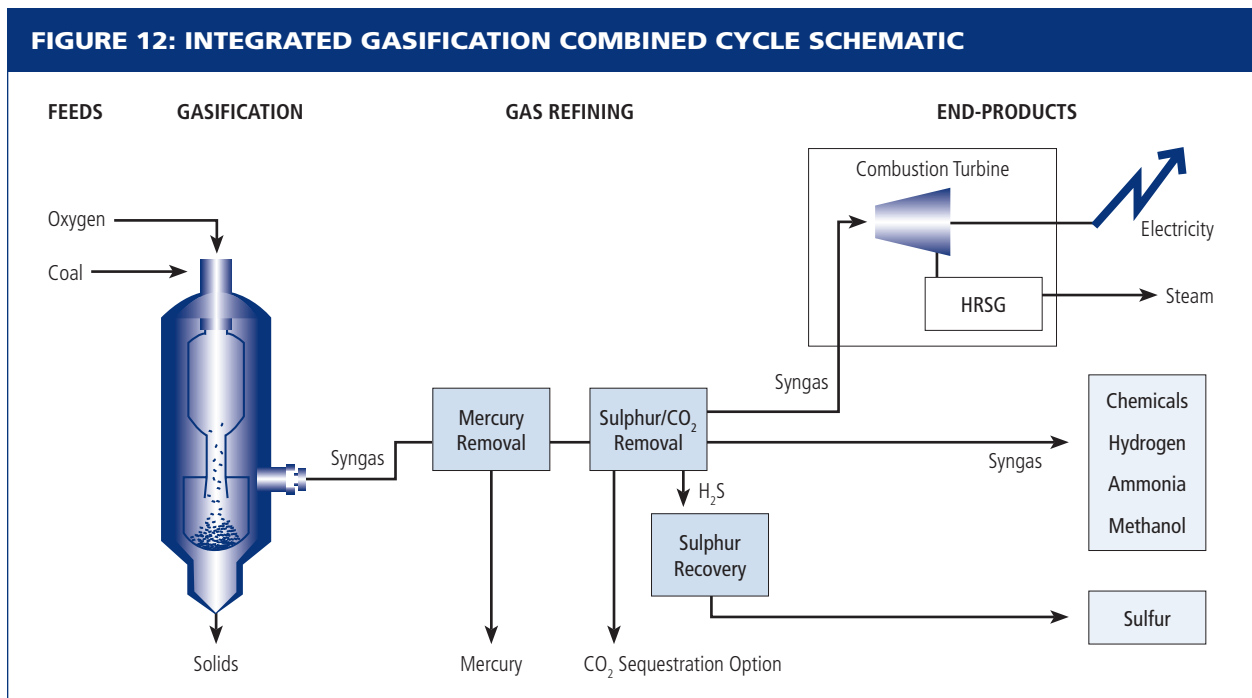
using sub-bituminous and lignite coal have already been proposed,⁷⁶ the higher cost and lower performance of IGCC plants using lower rank coals have given SCPC technology an additional edge in regions such as the Southwest, which rely on these types of coal.

Second, the lack of large-scale IGCC operating experience has created performance uncertainties and raised questions about the ability of IGCC plants to operate at levels of availability⁷⁷ that conventional plants can achieve. This is the case even though IGCC units achieve higher thermal efficiencies than the most advanced SCPC plants.

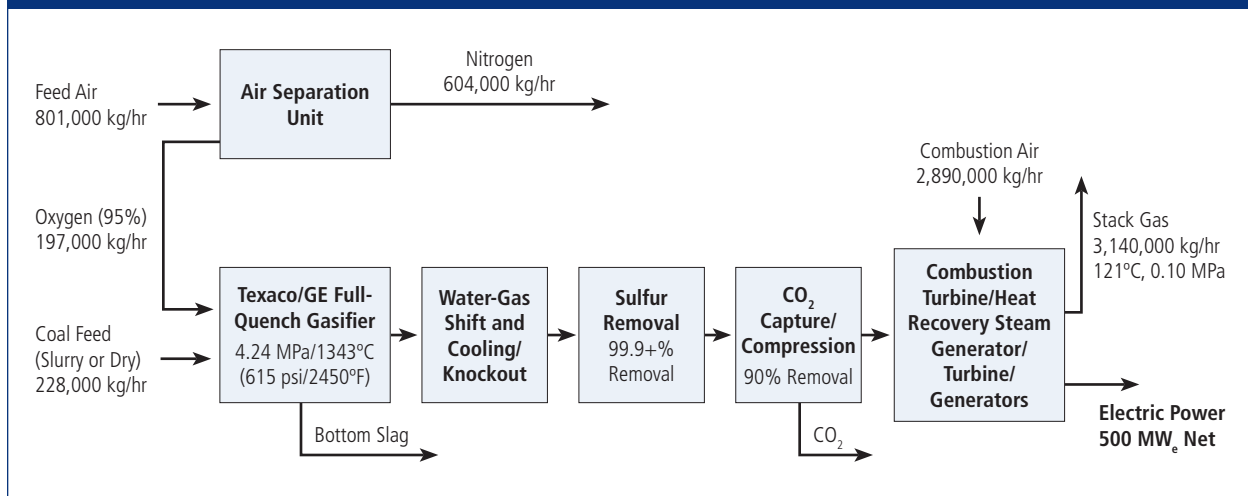
In the past, syngas production has resulted in excessive maintenance outages. Even with substantially better performance, existing IGCC plants have not yet consistently achieved 85 percent availability levels as compared to availability levels of over 90 percent with the most advanced SCPC designs. IGCC

plants with spare gasifiers can achieve higher availability levels but will have higher capital costs. Should IGCC plants fail to meet availability goals, the result would be higher debt requirements to offset increased operating costs and greater reliance on less efficient peaking or baseload generation in the event of IGCC shutdowns. IGCC vendors can mitigate these risks to some extent with performance guarantees, liquidated damages provisions and project acceptance testing, but the combination of a cost premium and operational uncertainties will still be a deterrent to investment in the highly conservative power sector.

The higher capital and operating costs and lower availability of IGCC plants as compared to SCPC plants are projected to result in higher electricity costs to consumers. The current differential (without taking into account CCS deployment) is estimated to be about \$5 per MWh for IGCC plants using Eastern coal and about \$7 for IGCC plants using



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FIGURE 13: 500 MW_e INTEGRATED GASIFICATION COMBINED CYCLE UNIT W/ CO₂ CAPTURE

Source: James Katzer et al., *The Future of Coal: Options for a Carbon-Constrained World*, Massachusetts Institute of Technology Interdisciplinary Study.

Western coal.⁷⁸ Since a typical coal-fired baseload plant generally produces electricity for around \$55/MWh, this differential represents over 10 percent of power generation costs.⁷⁹

When comparing the costs associated with SCPC and IGCC technologies, it is important to note that *the cost of electricity is likely to be significantly lower for IGCC plants than SCPC plants when the costs of capturing CO₂ emissions are taken into account.* This cost advantage is the reason why some policymakers are encouraging construction of IGCC plants, and why the IGCC option is receiving careful consideration by utilities concerned about the long-term costs of CO₂ control. At present, however, there is no *legal requirement* to capture and sequester or otherwise control CO₂ emissions from power plants.

In the absence of this requirement, the question is whether there are sufficient incentives to stimulate widespread adoption of IGCC despite its higher capital costs and performance uncertainties? To answer this question, we must examine the regulatory environment in which

utilities operate and current government programs to incentivize IGCC plants.

The Regulatory Environment for IGCC Plants

Traditional utilities are regulated by state-level Public Utility Commissions, or PUCs, which approve the rates charged for electricity service. Utilities can generally recover the costs of their operations plus a reasonable return on investment, but only if such rates represent the “least costs” required to provide reliable service.

For major capital projects with large costs, utilities often seek PUC approval for rate increases to cover these costs before construction begins in order to minimize the risk that these costs will later be unrecoverable through their rate bases. PUCs, however, are generally reluctant to approve large environmental expenditures that are voluntarily incurred and not legally required. Since carbon capture and sequestration are not now mandated by law, the cost premium for IGCC plants could be unrecoverable under the “least cost” test.

As a result, utilities planning IGCC plants have needed to argue that these additional costs should be recoverable under a flexible interpretation of the “least cost” concept. For example, AEP has contended before the Ohio PUC that IGCC is a lower cost option than pulverized coal when long-term climate-related obligations are considered in the cost analysis. On April 10, 2006, the Ohio PUC allowed AEP to recover pre-construction engineering and design costs, but deferred allowing recovery for construction and operating costs. The PUC decision is being appealed to the Ohio Supreme Court by power-users opposed to any cost recovery.⁸⁰ Similarly, in Indiana, Duke Energy Corp. is seeking cost recovery for its proposed Edward-sport IGCC plant, but consumer groups and industrial users have opposed Duke on the ground that less expensive options are available and the long-term costs of carbon sequestration are unknown.⁸¹

This initial experience suggests that cost recovery requests for IGCC plants will be contested in many states and that divergent approaches may ultimately emerge around the country, with cost recovery available in some states but not others. Even more uncertain is whether cost recovery will be available for CCS system add-ons after the basic IGCC plant is built.

Merchant power generators—companies that generate power in a competitive market and sell the power to retail providers at market prices—face even greater risks than regulated utilities because they operate in an unregulated environment with no guarantee of cost recovery. After record levels of default on new plant construction projects in

the 1990s, lenders are now reluctant to finance such plants in the absence of a long-term power purchase agreement between the merchant producer and power distributors or users.⁸²

Some merchant power producers with the ability to negotiate such agreements have proposed to build IGCC plants. But it is an open question whether such projects will generate a sufficient return on investment to entice investors in the absence of subsidies and tax incentives that offset the higher costs of IGCC plant construction and greater operating uncertainties.⁸³

Federal and State Incentive Programs for IGCC Plants

Some states have created innovative incentive programs for IGCC plants. Indiana has offered a 10 percent tax credit for the first \$500 million invested in an IGCC project and a 5 percent credit for amounts exceeding this level if the plant uses Indiana coal.⁸⁴ Kansas has established a similar program.⁸⁵ Colorado has enacted a law requiring proposed IGCC plants to sequester their CO₂ emissions and has allowed XCEL, the major utility in the state, to recover the costs of designing and building an IGCC plant through its rate base.⁸⁶ And Minnesota has enacted legislation granting Excelsior Energy eminent domain for its Mesaba IGCC plant, exempting it from certain regulatory requirements, and guaranteeing a long-term buyer (XCEL) for a portion of the plant’s power output.⁸⁷

At the federal level, the Energy Policy Act of 2005 contains a series of incentives for IGCC technology. These include:

Cost recovery requests for IGCC plants will be contested in many states, with recovery available in some states but not others

Even with greater government support that makes IGCC cost-competitive with SCPC plants, IGCC may still be resisted by risk-averse utilities

- Cost sharing grants of \$140 million per year from 2006 to 2014 that can cover up to 50 percent of the cost of IGCC demonstration plants and other gasification technology projects
- Allocation of \$2.5 billion from 2006 to 2013 for advanced coal-based power with priority to technologies that are not yet cost competitive and which achieve greater efficiency and environmental performance
- A 20 percent investment tax credit up to a total of \$800 million for property that is necessary for the gasification of coal, but not for the whole plant
- Loan guarantees for up to 80 percent of the individual loan amounts to an IGCC plant, but only if the Congress appropriates the needed funds.⁸⁸

These incentives will definitely encourage some IGCC projects. For example, the 20 percent tax credit (if it were fully applicable to an entire project) would reduce (and perhaps eliminate) the capital cost differential between IGCC and SCPC plants. The loan guarantees will make it easier to obtain low-cost financing and increase the debt-to-equity ratio. Together with the revenues from the plant's ability to "securitize" these loans, utilities could build IGCC plans without necessarily increasing electricity rates (although ratepayers would bear the risk of construction delays or operational difficulties).⁸⁹

Nonetheless, the impact of the Energy Policy Act programs is likely to be fairly modest. First, and most critically, the total amount of direct or indirect financial support available is limited. For example, on November 30, 2006 the Departments of Energy and Treasury

granted \$400 million in Energy Policy Act tax credits (half of the total amount authorized) to three IGCC projects, illustrating the limited availability of these credits to plant developers.⁹⁰

Second, the Energy Policy Act programs (except for the investment tax credit) require follow-up appropriations. To date, Congress has not come close to providing full funding. And third, except for grants, the incentives do not help public power organizations that do not pay taxes or finance their facilities with debt.

Thus, the current incentives at best will help in the building of only a limited number of IGCC plants.⁹¹ While providing useful operating experience at these plants, such incentives will not come close to addressing the urgent need to make IGCC plants broadly cost-competitive with PC plants now rather than many years in the future.

Would More Aggressive Incentive Programs Work?

Arguably, a more comprehensive program of grants, loan guarantees, and tax credits would provide a greater impetus for IGCC plant construction and, together with vendor guarantees and improvements in the technology, would minimize the disadvantages that IGCC now faces. Yet even with greater government support that makes IGCC cost-competitive with SCPC plants in the absence of CCS systems, IGCC may still be resisted by risk-averse utilities.

Why? New technologies, even after they become cost competitive, must cross the chasm described by Silicon Valley venture capitalist and technology writer Geoffrey Moore in the opening quotation of this paper:

The point of greatest peril in the development of a high-tech market lies in making the transition from an early market dominated by a few visionary customers to a main-stream market dominated by a large block of customers who are predominately pragmatists in orientation. The gap between these two markets, heretofore ignored, is in fact so significant as to warrant being called a chasm.

In most cases, it takes a new technology many years to become accepted in the market. There exists an inherent inertia regarding new technology. Aside from early adopters, most businesses want to invest in productivity improvements for existing operations, not a new cutting-edge technology like IGCC. This is especially true in the energy sector where it is generally recognized that second and third generation plants are less expensive than first generation plants, and there are fewer problems associated with “debugging” the new technologies. One industry executive recently said that “IGCC is not for us,” adding that “our industry is very intolerant of something that does not have extreme reliability and availability.”⁹² Another industry representative has described an IGCC facility as a chemical plant with a jet engine at one end—hardly a ringing endorsement. And an industry consultant with traditional coal-plant experience who strongly supports IGCC told one of the authors at a recent conference that “IGCC plants are spooky.”

The time lag in the adoption of a new technology is reflected in the prevailing skepticism among industry analysts about the near-term outlook for IGCC plants. Despite the promising state of development of IGCC technology, almost all commentators assume that only a small percentage of new coal-fired plants built during the next 25 years will use IGCC technology. One estimate is that

1,205 of the 1,391 gigawatts forecasted worldwide for new coal plants will likely be built with conventional coal technology.⁹³ Another projection (using a slightly different estimate of the number of new worldwide coal plants to be constructed) is that only 144 gigawatts of new coal plants worldwide will use IGCC technology.⁹⁴

What’s worse, the Energy Information Administration assumes that under current policies *none of the new IGCC coal plants expected to be built between now and 2030 in the United States will capture and sequester carbon.*⁹⁵ Even the Bush administration’s good faith effort to encourage the deployment of IGCC and

The Problem with Futuregen

The highly-publicized Bush administration FutureGen demonstration project, which aims to build a zero-emission coal plant, may actually delay rather than accelerate adoption of CCS technology if the coal industry waits for signs of its success from the side-lines.

FutureGen, which is jointly funded by Energy Department and several energy companies, is expected to be operational by 2012.⁹⁶ The FutureGen plant will employ IGCC coal gasification technology, and the resulting CO₂ emissions will be captured and permanently stored underground. The resulting syngas will be used to produce electricity, while the resulting hydrogen by-products will be recovered for industrial use.

FutureGen is likely to foster a belief in the power sector that until the new plant is successfully operating and its performance is proven, CCS technology is not ready for commercialization.⁹⁷ This attitude could discourage some utilities from proceeding with investments in these systems for at least another five to ten years. FutureGen should be looked at as a source of useful data that will enhance the efficacy of IGCC and CCS technologies, but not as a threshold demonstration project that must show success before IGCC/CCS systems are adopted on a commercial scale.

CCS technologies may be proving to be an impediment (see sidebar on previous page). The slow pace of development of CCS is simply not acceptable if the goal is to drastically reduce CO₂ emissions from the next generation of coal plants.

Even if the disincentives for IGCC technology were to be overcome, there would remain substantial barriers to investing in CCS capability. The reason: power plant owners are presently not required to control greenhouse gas emissions, and CCS systems are a costly add-on to the process of producing power. As a result, in the absence of a policy framework for greenhouse gas control, coal plants that capture and sequester CO₂ will never be on a level playing field with plants that don't because there would be no reward for incurring the costs of CO₂ emission control.

Even assuming utilities were to commit in large numbers to IGCC power plants, the odds of taking the next step and investing in CCS systems are small in the current economic and regulatory environment.⁹⁸ The consequence of delaying CCS installation and operation would be many billions of tons of additional CO₂ emitted to the atmosphere, whether or not IGCC or SCPC is the technology of choice for new coal plants.

Crossing the Chasm: A New Policy Framework to Push CCS Implementa- tion Forward

If a program of financial incentives would be largely ineffective in promoting widespread adoption of CCS systems at new coal plants at the pace required to address climate change, then the

only alternative is to consider more overt regulatory measures that change the economic calculus of new power plant developers. The goal of such a policy framework would be to force these developers to internalize CCS costs when selecting new generation technologies.

If this occurred, then the current competitive advantage of SCPC technology over IGCC technology would be eliminated because the costs of CO₂ abatement would need to be weighed along with the costs of plant construction and operation in selecting generation technologies. Power plants boasting IGCC technology with CCS capacity would then be more attractive on a total-cost basis unless cost-effective carbon capture technology could be developed for SCPC plants (see Figure 14).

Market-based mechanisms such as cap-and-trade programs are widely viewed as effective tools for reducing CO₂ emissions. Nonetheless, it remains questionable whether a cap-and-trade system for either utilities or a larger universe of emitting sources would assure that new coal plants adopt CCS systems within the next 10 years-to-15 years, when many new plants will be constructed. The political realities that will likely shape climate change legislation will probably not impose a sufficiently stringent cap in this initial stage of carbon control to create a market price for CO₂ (of around \$30 per ton) that would reliably incentivize construction of coal plants that capture and sequester CO₂ and foreclose higher emitting coal combustion technologies.

Four other strategies could potentially achieve widespread adoption of CCS systems and could be implemented either alone or in combination with a cap-and-trade program:

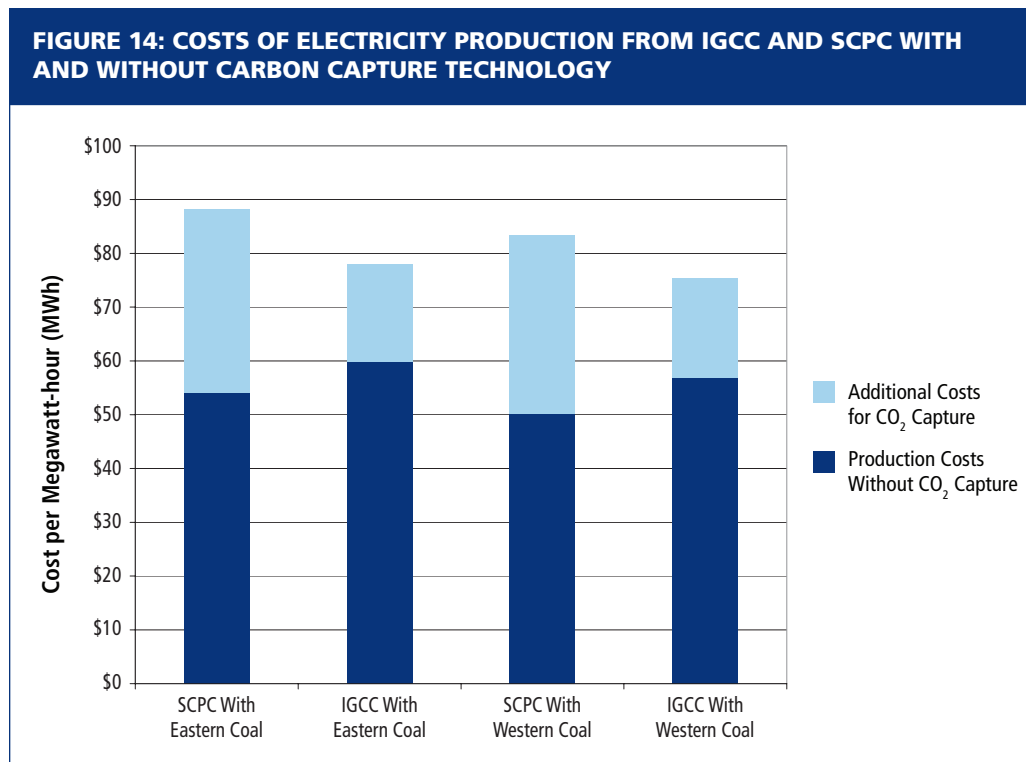
- Defining carbon capture and storage technology as the Best Available Control Technology, or BACT, for purposes of so called new source review under the Clean Air Act
- Adopting a “low carbon portfolio” standard that requires utilities to provide an increasing proportion of power from low-carbon generation sources over time
- Taxing carbon fuels or emissions
- Setting an “emission performance standard” that effectively requires all new coal plants built beginning in 2008 to capture and fully sequester CO₂ emissions by 2016.

Below, we discuss the implications of cap-and-trade approaches and then evaluate these four additional options (see Figure 15). This discussion concludes

that an emission performance standard for new fossil fuel units, coupled with a cap-and-trade system for existing power plants, represents the most effective approach, although implementing it successfully will pose several challenges that need to be carefully addressed.

Encouraging CCS Systems with Carbon Caps and Trading Programs

One strategy for controlling emissions from new power plants is to rely on a mandatory CO₂ cap, with trading in CO₂ emission allowances as a compliance mechanism to incentivize electricity generators to choose CCS as the technology path for new coal plants. A number of states have adopted programs to regulate CO₂ emissions (see sidebar on page 30) but there are as yet no mandatory CO₂ controls at the national level.



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FIGURE 15: OPTIONS TO PROMOTE CARBON CAPTURE AND STORAGE SYSTEMS AT NEW COAL PLANTS

OPTION	HOW IT WOULD WORK	BENEFITS	DRAWBACKS
Financial incentives for Integrated Gasification Combined Cycle plants, which are best suited for CCS systems	Increase grants, loan guarantees & tax credits for IGCC plants	<ul style="list-style-type: none"> • Would reduce cost differential between IGCC plants and existing plants • Would encourage more IGCC plants • Would provide more experience with IGCC technology 	<ul style="list-style-type: none"> • Would not make IGCC fully cost-competitive • Would not overcome reluctance to adopt new technology • Would not result in CCS at new IGCC plants unless incentives are limited to plants with CCS systems
Cap-and-trade systems	<p>Set mandatory cap on greenhouse gas emissions which declines over time</p> <p>Issue allowances to emitting sources and permit trading</p> <p>Allow sources to offset emissions from terrestrial sequestration or other projects in US or globally</p>	<ul style="list-style-type: none"> • Would put a price on carbon emissions and create disincentives for constructing new uncontrolled coal plants • Would allow market forces to determine most cost-effective emission reduction strategy • Could result in IGCC/CCS systems at all new coal plants if carbon price exceeds \$30 a ton 	<ul style="list-style-type: none"> • Current legislation contemplates modest reductions in early years, with carbon price likely to be below \$30 per ton • More stringent caps imposed at later dates (2030–2050) could increase carbon price to levels that would require CCS systems but Congress may not adopt such caps or condition them on future decisions • Broad access to offsets in US and globally will add to compliance flexibility but discourage CCS by creating low-cost compliance alternatives
Clean Air Act regulatory mandates	Based on determination that CO ₂ is a “regulated pollutant”, CCS systems could be defined as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) for new coal plants for purposes of the new source review (NSR) program under the Clean Air Act	<ul style="list-style-type: none"> • Could be implemented under existing law based on Supreme Court determination that CO₂ is a “pollutant” • Would avoid need for legislation • Would force consideration of CCS systems during permitting process for all new coal plants 	<ul style="list-style-type: none"> • Legal uncertainties could invite litigation • States could reject CCS systems during permitting reviews • NSR program would not allow flexible compliance schedules for installing and operating CCS systems • Without legislation, no financial incentives would be available for new coal plants with CCS systems
Retail Low Carbon Portfolio Standard	Require retail suppliers of electricity to purchase an increasing portion of power from low-emitting sources (renewables, clean coal and perhaps nuclear)	<ul style="list-style-type: none"> • Would force power producers to convert an increasing portion of their generation to low-emitting sources over time • Some uncontrolled coal plants would be retired and could be replaced by coal plants with CCS systems 	<ul style="list-style-type: none"> • Because the power mix varies widely by region, a uniform national goal for low-emitting generation would result in an unequal distribution of benefits and costs across regions • Adopting different portfolio standards for regions and even states would make it difficult to set a national emission reduction goal for the power sector • Unless the standard is very stringent, utilities could meet its targets for low carbon power while still building uncontrolled coal plants
Low Carbon Generation Standard	<p>Require all coal plant owners in U.S. to dedicate a growing portion of their power production to low carbon generation</p> <p>Low carbon commitment could be met by building CCS-equipped plants, purchasing power from such units or purchasing emission credits from low carbon generators</p> <p>Low carbon commitment would start off at 0.5 percent of the plant owner’s coal-based power output and increase to 5 percent by 2020</p> <p>Generators could reduce the size of their commitment by retiring coal-fired assets</p>	<ul style="list-style-type: none"> • If sufficiently stringent, would prevent construction of new coal plants without CCS systems because the existing coal fleet would have a collective responsibility to supply a certain portion of its power output from CCS-equipped coal units • Would spread the costs of building new plants with CCS systems over the entire industry, with utilities that do not build such plants subsidizing those who do by purchasing power and/or credits 	<ul style="list-style-type: none"> • The revenue stream from CCS-equipped coal plants could not be guaranteed in advance because of market uncertainties and the possibility that multiple plants with CCS systems could be constructed simultaneously • The large financial risks to plant developers may deter them from building any new coal plants, making the standard impossible to meet • Once the standard’s low carbon goals are met, there would be no bar to building additional coal plants without CO₂ controls

OPTION	HOW IT WOULD WORK	BENEFITS	DRAWBACKS
Carbon Tax	<p>Impose a tax on fossil fuels based on their carbon content</p> <p>Could be imposed downstream (on fuel users) or upstream (on fuel producers/importers)</p>	<ul style="list-style-type: none"> • Because a carbon tax would make higher carbon fuels more expensive, consumers would switch to lower carbon fuels or reduce fuel consumption • If the tax is imposed on CO₂ emissions, it would create incentives to avoid emissions by installing CCS systems 	<ul style="list-style-type: none"> • An upstream tax based on the carbon content of fuel would simply discourage coal generation, not create incentives for new plants with CCS systems • At the levels under consideration, a carbon tax would not be high enough to ensure that all new coal-fired plants have CCS systems
Emission Performance Standards for New Coal Plants	<p>Would require new plants to capture CO₂ emissions at the level (85 percent or more) achievable through the best performing CCS technology and then to sequester all captured emissions</p> <p>Would apply to all new plants that begin construction after a certain date (say 2008)</p> <p>These plants would need to be capturing substantially all their emissions by a second date (say 2013) and sequestering them by a third date (say 2016)</p> <p>As a transitional mechanism, new coal plants entering construction during an initial three-year period (say 2008–2011) could meet the performance standard by offsetting their emissions through improved efficiency, plant retirements and/or building renewable fuel power plants</p>	<ul style="list-style-type: none"> • Would provide certainty that new coal plants are in fact equipped with CCS systems and therefore sequester their emissions • Because capture and sequestration would not be required immediately, there would be time to acquire additional experience with large-scale sequestration, improve capture technologies and create a legal/regulatory framework for long-term CO₂ storage • Plant developers would nonetheless be on notice of the requirement to capture and sequester their emissions and would factor CCS requirements into decisions on plant cost, financing, technology and siting 	<ul style="list-style-type: none"> • The cost of electricity at plants with CCS systems would be increased by 20 percent to 40 percent, with these cost increases falling disproportionately on regions that rely heavily on coal • While there is agreement that large-scale carbon sequestration is probably viable, we need more data on the location of storage reservoirs and the effectiveness of different geological formations before embarking on a comprehensive national sequestration program • There may be areas of the country that are heavily dependent on coal but lack close proximity to sequestration sites • A national legal/regulatory framework addressing short-and long-term liability for carbon storage is needed before investors will finance new plants
Emission Performance Standard for New Coal Plants Coupled with Cap-and-trade System for Existing Plants	<p>Cap emissions from existing power plants, with the cap starting at 100 percent of emissions in a baseline year and declining to progressively lower levels over time</p> <p>Use allowance trading systems as a compliance mechanism to implement the cap</p>	<ul style="list-style-type: none"> • A declining cap would encourage greater efficiencies in operating existing plants and incentivize the retirement of higher emitting existing plants • With a sufficiently stringent cap, some generators may retrofit existing plants with CCS systems 	<ul style="list-style-type: none"> • None
How to lessen economic impact of an emission performance standard	<p>Create a national fund to provide “credits” against electricity cost increases from CCS-equipped plants</p> <p>Alternatively, provide plant developers with financial incentives (tax credits, loan guarantees and grants) that offset some or all of the incremental costs of new CCS-equipped plants</p> <p>Allowance auctions under a cap-and-trade program could provide a revenue source for CCS incentive programs</p>	<ul style="list-style-type: none"> • The increased costs of an emission performance standard would be borne at the national level rather than by certain regions • Consumers would not experience large electricity cost increases that would undermine support for CCS requirements • Financial incentives would encourage early adoption of CCS systems and overcome investor resistance to financing new plants 	<ul style="list-style-type: none"> • Offsetting the increased costs of new plants with CCS systems would require substantial government funding (\$36 billion over 18 years if 10 percent to 20 percent of total plant construction costs are covered) • Since the costs of CCS-equipped plants are uncertain, a program of financial incentives could turn out to be insufficient to make these plants economically viable • The need to build lengthy pipelines to transport CO₂ to sequestration sites could increase the costs of CCS systems and require additional government support

State Climate Change Programs

Three state programs to require CO₂ emission reductions have taken shape within the last year.

One is a coalition of ten states in the Northeast, which have entered into a Memorandum of Understanding in support of a program known as the Regional Greenhouse Gas Initiative.⁹⁹ The RGGI plans to commence implementation of a cap-and-trade program in 2009 for power generators within the member states, which would stabilize power plant CO₂ emissions at current levels through 2015 and then require a 10 percent reduction from those levels by 2020. If the price of CO₂ allowances exceeds \$7 a ton, then power plants could meet their obligations by purchasing offsets (up to a certain level) within the U.S. and (under some circumstances) abroad.

The second is a coalition of five Western states (California, New Mexico, Arizona, Washington, and Oregon), who signed an

agreement establishing the Western Regional Climate Action Initiative in February of this year to reduce greenhouse gas emissions. Under the agreement, the five states will jointly set a regional emissions target within six months, and by August 2008 will establish a market-based system—such as a cap-and-trade program covering multiple economic sectors—to aid in meeting the target.¹⁰⁰

The third is the recently enacted California legislation which seeks to return greenhouse gas emissions in California to 1990 levels by 2020, requiring a reduction of approximately 25 percent from current levels. In contrast to Northeast initiative, the California legislation potentially applies to all source categories, not simply power plants, and does not require an allowance trading system, although it allows the California Air Resources Board to establish one.

Legislation capping carbon emissions has been introduced in Congress, with a range of emission reduction targets, timetables and compliance mechanisms (see Figure 16). These bills generally impose modest caps in the early years, with successively more stringent caps taking effect by a series of deadlines extending to 2050.

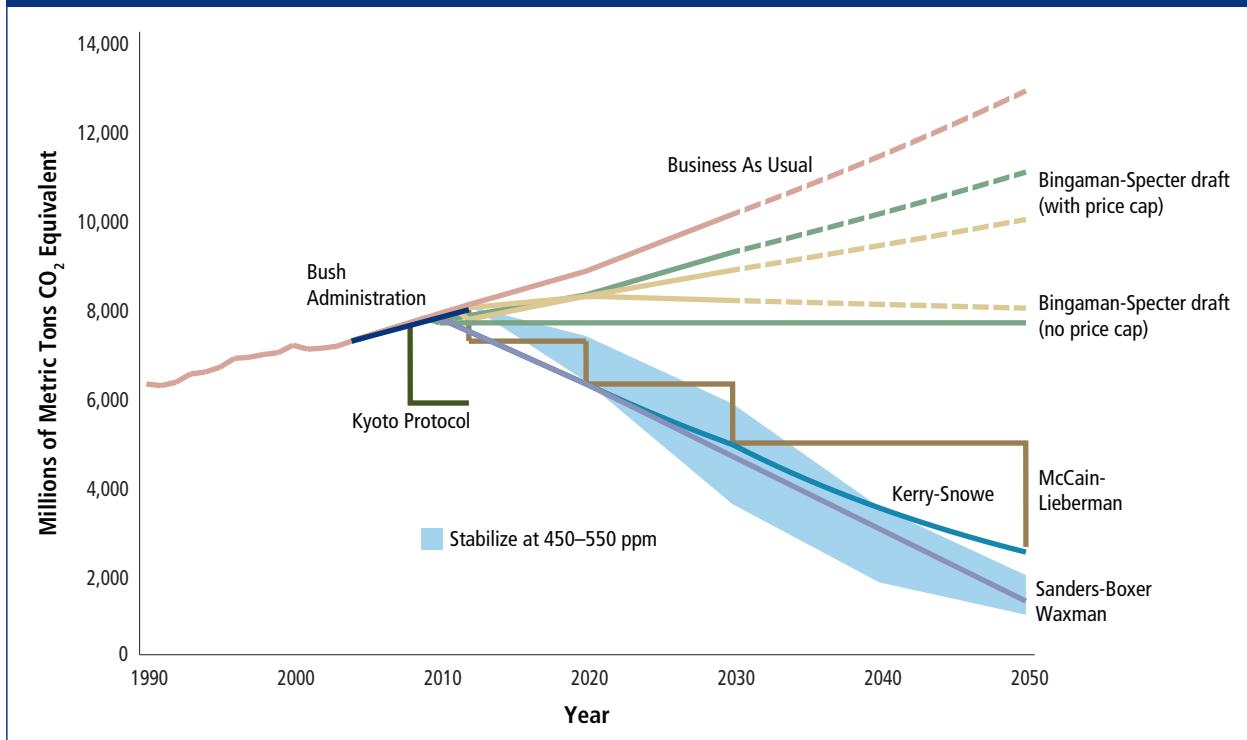
The latest proposal (S. 280) from Sens. John McCain (R-AZ) and Joe Lieberman (I-CT) would apply to all economic sectors and would cap emissions at 2004 levels by 2012. The cap would be periodically lowered, declining to 66 percent of 2004 levels by 2030 (this is the equivalent of a 17.7 percent reduction from 1990 levels) and 33 percent of these levels by 2050.¹⁰¹ S. 317, the Electric Utility Cap and Trade Act, introduced by Sens. Diane Feinstein (D-CA) and Tom Carper (D-DE), would apply only to utilities and would cap emissions at 2006 levels by 2011, and

2001 levels by 2015, with further reductions required at later dates.¹⁰² Both of these bills would require allowance trading systems and would give regulated sources of carbon emissions generous access to offsets (including from non-U.S. sources and terrestrial sequestration projects) to meet their obligations.

Senator Bingaman (D-NM) has also proposed cap-and-trade legislation which would not limit emissions per se but would reduce greenhouse gas intensity—defined as the ratio of greenhouse gas emissions to economic output—by 2.6 percent annually from 2010 to 2020 and by 3.0 percent from 2020 to 2024, and would set a carbon price ceiling of \$7 per ton in 2010 (rising by 5 percent annually thereafter).¹⁰³

At the other end of the spectrum are two more stringent bills: one (S. 309) sponsored by Sens. Bernie Sanders (D-VT) and Barbara Boxer (D-CA) and the other (S. 485) by Sens. John Kerry (D-MA)

FIGURE 16: COMPARISON OF ECONOMY-WIDE CLIMATE CHANGE PROPOSALS IN 110TH CONGRESS 1990–2050



Dotted lines indicate extrapolations of Energy Information Administration projections. Modified May 10, 2007.

Source: World Resources Institute.

and Olympia Snowe (R-ME).¹⁰⁴ These bills lack the modest early-year reduction targets of the other bills and instead would reduce economy-wide emissions to 1990 levels by 2020 (the California target), with additional reductions thereafter leading to a 2050 emission cap of 20 percent of current levels (S.309) and 38 percent of these levels (S. 485).¹⁰⁵ The Sanders-Boxer bill (S. 309) would authorize (but not mandate) allowance trading while S. 485 would require a cap-and-trade system. Neither of these bills contains the generous offset provisions in the other bills.

Importantly, under virtually all of the bills, the more stringent out-year targets do not apply automatically, but are instead subject to revision based on economic and scientific factors.¹⁰⁶ Moreover,

as the legislative process progresses, it can be expected that less ambitious bills will be introduced that set even more modest early-year targets and do not impose any long-term emission caps.

The impact of emission caps on the selection of power generation technology for new plants depends on how stringent the cap is and the mechanisms by which it is implemented. These two factors will determine the cost to utilities of reducing CO₂ emissions by one ton, which in turn will set the market price of CO₂. As Figure 10 indicates, current estimates are that IGCC plants with CCS systems will be economic at a CO₂ price of around \$30 per ton, whereas SCPC plants with CCS systems would be economical at a CO₂ price of around \$55 per ton.

If the market price of CO₂ is lower than the cost per ton of reducing emissions with CCS systems, other compliance strategies would be more desirable, including building SCPC plants and offsetting emissions

If the market price of CO₂ is above these levels, power plant developers would probably conclude that the only economically viable option for coal-fired plants is to construct such plants with CCS systems. Under current technology, these plants would be IGCC units, which capture carbon less expensively than SCPC units. But if the market price of CO₂ is lower than the cost per ton of reducing emissions with CCS systems, then other compliance strategies would be more desirable, including building new SCPC units without CCS systems, investing in other low-emitting generation, purchasing lower-cost credits on the open market or some combination of the three.

A cap that reliably assures that the price of carbon is above \$30 per ton would be one that sets a stringent emission-reduction goal (perhaps on the order of 25 percent from current levels) in the early years of a climate management regime and provides limited compliance options—either no trading or trading with little or no access to allowances from outside the utility sector. In this scenario, power generators would need to achieve sizable emission reductions either within their systems and/or through credits purchased from other generators; low cost credits from outside the power sector would not be available. Thus, the cost per ton for making the required reductions would be relatively high.¹⁰⁷

Utility compliance strategies to achieve such a cap would of necessity involve reducing emissions from existing generation and meeting growth in electricity demand without adding capacity that offsets these emission reductions. Non-emitting strategies (demand-side management, greater utilization of wind, solar and other renewable power

sources, building nuclear power plants) would thus receive close scrutiny both to displace existing fossil-fuel units and to accommodate system growth. The repowering of existing coal units with lower carbon fuels (principally natural gas) would also be a serious option to reduce emissions. Likewise, construction of IGCC plants with CCS systems would be attractive either to replace existing power plants (thereby eliminating their emissions) or to add capacity (without any increase in emissions). Such a strategy would also be less costly than higher-emitting options like IGCC or SCPC plants without CCS systems and perhaps even natural gas plants.

The difficulty, however, is the price of CO₂ would likely be well below \$30 per ton with an emission cap that is relatively modest in the early years, and which is implemented with a flexible allowance trading system that provides broad access to low-cost credits outside the utility sector, and perhaps internationally. A number of the proposed bills fit into this category.

For example, S. 280 would cap emissions at 2004 levels by 2012, and S. 317 would cap emissions at 2001 levels by 2015. Although more analysis is needed to determine the cost impacts of the pending bills, the CO₂ price per ton of lowering emissions to meet these targets would likely be fairly low. EPA estimates, for example, that achieving the 2011–2015 emission reduction targets now reflected in the Feinstein-Carper bill would cost in the range of \$1-to-\$2 per ton.¹⁰⁸

Even more problematic is the Bingaman carbon intensity proposal (and to a lesser extent the RGGI emissions initiative), which would protect generators against

incurring costs above \$7 per ton.¹⁰⁹ This is well below the estimated \$30 per ton cost of carbon capture and storage at IGCC units. Under these proposals, construction of plants with CCS systems would not be a cost-effective compliance strategy. Indeed, the costs of compliance would probably be too low to discourage the construction of coal-fired power plants without CCS, even though owners of these plants would incur substantial costs to offset their emissions. Why? Because the costs of electricity generation are comparatively low when employing SCPC technology without CCS technology additions. Thus, it would be more economic to build an uncontrolled SCPC plant and purchase allowances to cover its emissions than to invest in CCS systems.

This is why many utilities may conclude that they can comply with a modest carbon cap with a combination of purchasing low-cost greenhouse gas offsets (from coal-bed methane recovery or terrestrial sequestration projects, for example) and

constructing SCPC units to replace inefficient existing coal-fired plants and/or add generating capacity. An analysis by the Electric Power Research Institute illustrates this point, concluding that at a price of \$25 per ton of CO₂, the cost of electricity is *lower* for SCPC power plants with no CO₂ controls than for IGCC plants with CCS systems.¹¹⁰ That same analysis also concludes that at approximately \$8 per ton, the cost of electricity for uncontrolled SCPC plants is equal to the cost of electricity for nuclear power plants and below the cost of electricity for combined-cycle-natural-gas, wind and biomass plants. Indeed, this analysis indicates that SCPC plants with no emission controls become more expensive than combined-cycle-natural-gas plants (assuming a natural gas floor price of \$6/mmbtu) only at a CO₂ price above \$30 per ton.

Some of the proposed bills would, as noted above, substantially reduce emission caps in 2020 and later years. It

Virtual Carbon Price Calculations

Today, in the absence of a cap-and-trade system, many utilities are including “virtual” prices for carbon in their decision-making processes for new power plants. These virtual prices assume that CO₂ emissions will eventually be regulated. Nevertheless, several utilities are choosing uncontrolled SCPC plants over IGCC plants because they are betting that IGCC plants with CCS systems will still be uncompetitive even when there is a price for emitting CO₂.

Underlying this bet is a “political” judgment—that the cost of CO₂ abatement under national cap-and-trade legislation likely to be enacted by Congress will be too low to support the economic viability of IGCC plants with CCS systems. Utilities building IGCC plants without CCS systems may be making the same bet, but “hedging” against the possibility of more stringent carbon controls in the future by preserving a cost-effective CCS

retrofit option. This is why cap-and-trade systems that provide “flexibility” and “market-based” choices but do not send the right price signal run the risk of allowing utilities to pay for emitting CO₂ as opposed to investing in leading-edge technologies required to achieve dramatic emission reductions.

As happened under the European Union Emission Trading System, the inevitable political compromises that shape cap-and-trade systems may lead to status quo approaches—such as price caps, the issuance of too many emission allowances or broad availability of emission offsets—all of which achieve incremental emission reductions but fail to stimulate meaningful changes in technology. This would be the outcome under a U.S. cap-and-trade system in which the price of carbon is too low to motivate utilities to build coal power plants with CCS systems.

is therefore possible that SCPC plants with no emission controls that are cost-competitive in the early years of a cap-and-trade program could become uneconomic compared to plants with CCS systems as the market price of CO₂ rises in response to progressively more stringent caps. But if such caps are not built into the legislation enacted by Congress or are provisional and subject to later revision, then they may not be a factor in utilities' future planning. Indeed, utilities may be making this calculus right now (see sidebar on previous page)

If Congress fails to provide an aggressive long-term price signal to plant developers in its initial legislation, and if a substantial number of SCPC plants are then built, these plants will account for a large and constant stream of emissions during their operating lives of 60 years-to-70 years. These additional emissions will need to be offset by deeper cuts elsewhere in the economy. (See sidebar below) This will increase the overall costs of lowering emissions and

pose a serious impediment to achieving a more stringent national emissions cap in later years.

A final limitation of cap-and-trade programs in driving power plant developers to embrace CCS systems is the unpredictability of how trading markets will work in practice. The success of a cap-and-trade program in spurring widespread CCS deployment depends on a wide range of factors that cannot be controlled or even predicted in advance. The cost of building and operating coal plants with and without CCS systems, the cost of natural gas, nuclear power and renewable sources of power, the cost of emissions offsets from outside the utility sector, and ultimately the market price of CO₂ itself are all variables that will dictate the decisions of future power plant developers. These variables are all highly uncertain from today's perspective and may create a set of economic drivers dramatically different from those anticipated by policymakers.

Impact of Uncontrolled New Coal Plants on Other Emissions Sources

A cap-and-trade system that allows the construction of major new sources of emissions without carbon controls will place additional pressure on other emitting sources. For example, if Congress adopts a carbon cap that requires that emissions decrease by 30 percent from current levels by 2030, then the overall emission reduction necessary to meet that cap would be 2.1 billion tons (from 7 billion to 4.9 billion tons) of greenhouse gases per year, assuming no growth in emissions from new sources. Conversely, if greenhouse gas emissions increase by 900 million tons from new uncontrolled coal plants, then the needed reduction would increase from 2.1 to 3 billion tons per year or by over 40 percent.

If that happened, then existing emission sources would have to make deeper reductions (or purchase more emission offsets) to meet the carbon cap, raising the cost of CO₂ allowances as a result. The increased costs of these allowances would fall on every industry that is subject to the cap-and-trade system, creating additional opposition to the system. But if new coal power plants installed CCS systems, then there would be no net growth in emissions and the cost of allowances for other regulated sources would be lower.

All these considerations lead to one conclusion: If the goal of U.S. carbon policy is to assure early deployment of coal generation technology that captures and stores CO₂ emissions, then a legal framework that allows the marketplace to determine technology choices and the price of CO₂ emissions is a highly imperfect tool to achieve that goal.

Using the Existing Clean Air Act to Require CCS Systems for New Coal Plants

The Clean Air Act creates a rigorous permitting process for major new sources of pollution, including new power plants. In areas that are meeting air quality standards, major new emission sources are subject to the so called prevention of significant deterioration, or PSD, program and must install Best Available Control Technology, or BACT, at their facilities. In regions that are not attaining air quality standards, major new sources are subject to the new source review, or NSR, program and must meet the Lowest Achievable Emission Rate, or LAER, a somewhat more demanding standard than BACT.

This BACT/LAER framework compels developers of new facilities to undertake an analysis of emission control options utilized by similar sources. A BACT analysis starts with the most stringent control technology utilized in the industry and takes into account less stringent technologies as required by economic, energy and environmental considerations.¹¹¹ The statutory BACT/LAER provisions apply to “regulated pollutants,” although there is some latitude to take into account the environmental impacts of unregulated pollutants.

The traditional focus of BACT/LAER reviews for new power plants has been such regulated pollutants as NO_x, SO₂ and particulate matter, with mercury and certain other toxics now receiving attention with the recent adoption of emission requirements under Titles II and III of the Clean Air Act.¹¹² CO₂ emissions have not previously been controlled under the NSR/PSD programs, perhaps because of uncertainty whether CO₂ is a “pollutant” under the Clean Air Act.

The Supreme Court, however, recently decided that CO₂ does meet the definition of “pollutant” under the Act and also directed EPA to determine whether the science of climate change requires the agency to regulate CO₂ emissions from motor vehicles under Title II of the Act.¹¹³ Depending on the outcome of further EPA deliberations under Title II, CO₂ could become a “regulated” pollutant for purposes of the PSD/NSR programs for major new power plants.

This would open the door to consideration of whether BACT or LAER standards for CO₂ at new coal plants require CCS systems. In the event EPA adopts this position, CCS systems could then become a requirement for new coal plants without any further legislation. Before such a requirement were put in place, however, several legal hurdles would need to be overcome.¹¹⁴

Environmental groups, for example, have argued that IGCC should be considered BACT/LAER-compliant for new coal plants, but EPA has rejected this argument on the ground that IGCC units are fundamentally different in design from conventional coal plants and do not qualify as “similar” for purposes of

A legal framework that allows the marketplace to determine technology choices and the price of CO₂ emissions is a highly imperfect tool to assure early deployment of CCS systems

BACT/LAER determinations.¹¹⁵ EPA might take the same position with respect to CCS systems.

There are also questions about whether CCS technology would be considered by EPA to be an “available” emission control technology for which CO₂ reductions are “achievable” given the lack of full-scale commercial deployment of CCS systems at any U.S. coal power plant.¹¹⁶ Moreover, even if CCS systems are included in the BACT/LAER analysis, they could be rejected for economic, energy or other reasons by the permitting authority, which in many instances will be a state agency.

Indeed, a few states have included IGCC technology in their BACT/LAER reviews for new coal plants but have ultimately allowed developers to select SCPC technology instead.¹¹⁷ This outcome is not necessarily irrational in light of the lower cost and enhanced reliability of the latest SCPC designs and their ability to achieve emission limits for conventional pollutants such as NO_x, SO₂ and mercury which are not dissimilar to those achievable by IGCC units.

Despite the legal uncertainties, a proactive EPA might aggressively promote CCS systems as BACT- or LAER-compliant for CO₂ emissions at all new coal plants on the basis of the recent Supreme Court decision. Such a far-reaching initiative, however, could encounter legal challenges from the power industry and meet with resistance from states, which possess considerable discretion in making BACT/LAER determinations, and from Congress, which might feel that a CCS mandate for new coal plants should not be imposed administratively but (if warranted) adopted legislatively.

In addition, the NSR/PSD authorities in existing law provide no mechanisms to set flexible compliance schedules for implementing CCS systems, to determine what role these systems should play in an overall CO₂ cap-and-trade program or to use financial incentives to mitigate the costs of CCS deployment to utility ratepayers. These considerations suggest that a legislative framework for applying CCS systems to new coal plants would be preferable to invoking NSR/PSD programs under existing law.

Retail Low Carbon Portfolio Standard

The concept of retail low carbon portfolio standards has also received consideration as a tool for encouraging utilities to invest in clean coal generation. Such a standard, which would apply to retail suppliers of electricity, could be expressed in one of two ways—as a net CO₂ emission rate per kWh applicable to the power distributed by the supplier or as a percentage of the supplier’s power derived from low greenhouse gas-emitting sources.

The latter approach would be similar to state renewable portfolio standards, which require retail electricity suppliers to derive a certain portion of their power (usually around 10 percent) from renewable energy source such as wind, solar, and biomass.¹¹⁸ Retail low carbon portfolio standards would be broader than renewable portfolio standards, however, in that renewable energy would be combined with other low-emitting power sources, such as nuclear reactors and coal plants with CCS systems. This broader grouping would then be required to account for a certain minimum portion (say 30 percent) of the supplier’s power portfolio.

A proactive Environmental Protection Agency might aggressively promote CCS systems for carbon emissions at all new coal plants based on the recent Supreme Court ruling

As with renewable portfolio standards, power suppliers exceeding this percentage could “trade” credits with suppliers falling short of the minimum requirement. Under either an emission rate or percentage approach, the retail low carbon portfolio standard could become more stringent over time, requiring the generators supplying electricity to retailers subject to the standard to convert an increasing portion of their power production to low-emitting sources.

The idea behind retail low carbon portfolio standards is that they would force power producers to change their power generation mix by retiring high-emitting older plants and investing in low carbon energy sources. A complicating factor in implementing this approach, however, is that the relative dominance of different types of power sources now varies widely by region. Some Midwest and Southern states, for example, are heavily dependent on coal-fired plants. Northeastern states use little coal but substantial natural gas and nuclear-derived power. California has a similar generation mix while the Pacific Northwest is heavily dependent on hydroelectric power.

Because of transmission constraints, regions cannot readily change their mix of power sources by importing “clean” electricity in large volumes from other parts of the country. Thus, it would be impossible to set a uniform national target for “low-emitting” power portfolios without imposing disproportionate requirements on different regions. While a system of tradable credits could theoretically address disparities between utility systems and regions, in practice it would result in an unfair distribution of economic benefits and costs.

The alternative—setting separate standards for regions and even individual states—would be complex and controversial and make it difficult if not impossible to adopt and then implement an emission reduction goal for the power sector as a whole. That would defeat the principal purpose of a national emissions cap.

Moreover, how retail low carbon portfolio standards would affect technology choices by power generators would depend on how dramatically the standard alters the generator’s existing power mix. Small changes would not necessarily spur investment in a significant number of CCS-equipped coal plants and could in fact permit large numbers of new plants to be built that do not capture or sequester CO₂.

An intriguing variation on the low carbon portfolio concept has been proposed by David Hawkins of the Natural Resources Defense Council and Professor Robert Williams of Princeton University in an effort to stimulate application of CCS systems at new coal plants.¹¹⁹ The idea is that all owners of new and existing coal plants would be obligated to dedicate a certain portion of their power production to “low carbon” generation—defined as power produced from coal with an emission rate equal to the capture and sequestration effectiveness of current CCS technology.¹²⁰ This percentage would increase over time based on the projected increase in new U.S. coal generation capacity.¹²¹ Plant owners could meet their low carbon commitment by generating power with a CCS-equipped unit, purchasing power from such units or purchasing emission credits from low carbon generators.

This proposal would spread the costs of building new coal plants with CCS systems over the entire coal plant universe by requiring utilities that do not invest in CCS generation to subsidize those who do. Since no coal plant owner would be required to construct a CCS-equipped plant, plant developers will need to decide whether to assume the risk of constructing such plants (costing around \$1 billion) in the expectation of recouping their capital investment by selling power and/or credits to other generators. The size of this revenue stream, however, could not be guaranteed in advance since it would depend on future market prices for wholesale power and CO₂ allowances and on whether multiple developers build coal plants with CCS units at the same time.

Faced with an uncertain future revenue stream, investors and/or utility regulators could decide not to build any units with CCS systems. Moreover, even if some developers were to take the risk of constructing coal plants with CCS units, their total generating capacity may fall below the predicted levels on which the standard is based. In either event, coal generators would be unable to meet their low carbon commitments. Alternatively, if sufficient CCS capacity is built to fulfill each power generator's low carbon commitment, then additional coal plants could be constructed without controlling their CO₂ emissions.

In short, while the low carbon portfolio standard proposed by Hawkins and Williams has considerable potential, uncertainties about its actual operation raise questions about its effectiveness in assuring that all new coal plants are built with CCS systems.

Carbon Tax

A "carbon tax" is an excise tax on the sale of fossil fuels based on their carbon content. It could be imposed either "downstream" (where these fuels are consumed) or "upstream" (where they are imported, produced, or processed). Most experts favor an upstream tax because it could be collected from a relatively small number of entities while reaching virtually all the fossil fuel consumed by the U.S. economy.

Since it is the most carbon-intensive fuel, coal would be taxed at a higher rate than petroleum, which in turn would be subject to a higher tax than natural gas. Non-carbon fuels such as wind, solar, and nuclear would not be taxed at all. Because a carbon tax would make higher-carbon fuels more expensive, the intended outcome is that consumers would switch to lower carbon fuels or reduce their fuel consumption through energy efficiency and conservation. The result would then be declining CO₂ emissions.

After the ill-fated effort to adopt a tax based on the energy content (or Btu value) of different fuels and feedstocks in the early 1990s,¹²² it is generally assumed that a carbon tax would receive limited support in Congress.¹²³ Even apart from its political viability, a tax based on fuel carbon content and not emissions would discourage coal consumption regardless of whether CO₂ emissions were captured and sequestered.

Under a carbon tax regime, power producers might burn coal more efficiently or shift to less carbon-intensive fuels because of the tax but would have no incentive to invest in low-emitting coal-based generation technologies. Perhaps this problem could be addressed by providing

tax credits to utilities who build new plants with CCS capacity. It would be difficult, however, to assure that this credit would be large enough to not only offset the carbon tax itself but provide adequate inducements to invest in CCS systems as opposed to other options, including more efficient coal generation or plants that burn lower-carbon fuels such as natural gas.

A better alternative would be to directly tax emissions from power plants. By establishing a specific price for emissions, a tax would provide certainty to plant developers—a quality lacking under cap-and-trade programs, in which the market price of carbon will fluctuate and lack predictability. But the challenge for a tax on emissions is similar to the challenge faced by cap-and-trade systems—the tax may not be high enough to ensure that only coal-fired plants with CCS technology are built.

Recent carbon tax proposals have suggested tax rates beginning at \$5 and \$12 per metric ton of carbon and gradually increasing to higher levels.¹²⁴ This would be too low to offset the \$30-per-ton cost estimated for IGCC coal plants with CCS units. As with emission caps that are insufficiently stringent, a carbon tax that is too low would allow new high-emitting coal plants to continue to be built.

Emission Performance Standards for New Coal Power Plants

The most reliable strategy for assuring adoption of CCS technology at all new coal plants while reducing overall CO₂ emissions from the power generation sector is to require all such plants to meet an emissions performance standard.

This standard would be most effective if coupled with a cap-and-trade program for existing power plants.

Elements of an Emissions Performance Standard

An emissions performance standard would require new plants to capture CO₂ emissions at the level achievable through the best performing CCS technology and then to sequester all captured emissions. The current capture capability is in the range of 85 percent but is projected by the Energy Department to increase to 90 percent by 2012, and to nearly 100 percent by 2015.¹²⁵

The performance standard could be expressed as a ratio of the emissions rate to electricity output (CO₂ emissions per MWh), or as a percentage of total CO₂ generated. Senator John Kerry (D-MA) recently introduced a bill embodying the

Coverage of an Emissions Performance Standard

An emissions performance standard for new power plants could apply either to coal generation only or to all fossil fuel plants (coal, natural gas, and oil). A coal-only standard would arguably target the most carbon-intensive fossil fuel, thereby addressing the power-generation technology with the largest emitting potential. However, it would leave important emission sources uncontrolled and could create competitive imbalances between coal and other fossil fuels.

Natural gas, for example, is a lower-carbon fuel than coal, but it is still a significant source of CO₂ emissions.¹²⁷ Thus, applying emission performance standards to new natural gas plants may be necessary for the deep emission reductions that many consider essential as 2050 approaches. There are sound reasons for requiring CCS systems for new natural gas-fired power plants at the same time as new coal plants, but some lag-time might be appropriate to develop the technology and minimize increases in the cost of electricity.

former approach.¹²⁶ The standard could initially be applied to new coal plants but later extended to other large fossil fuel combustion facilities (see sidebar on previous page).

What are the benefits of an emissions performance standard for new power plants? Most importantly, it would explicitly preclude construction of new coal plants that are not designed to capture and sequester the plant's CO₂ emissions. This is in contrast to other approaches—such as a cap-and-trade program encompassing new and existing plants—that might seek to encourage CCS deployment but do not directly require it and leave open the possibility that large numbers of uncontrolled coal plants will be built.¹²⁸

An emissions performance standard would be technology-neutral and thus would allow plant developers to choose IGCC or SCPC technologies (using the existing amine stripping process or the promising but undemonstrated Oxy-fuel process) that capture and sequester CO₂. Nonetheless, so long as the higher costs of carbon capture made SCPC uncompetitive in supplying electricity, plant developers would presumably opt for IGCC plants over SCPC plants as the more cost-effective coal-based generation technology.

Flexibility in the Timing of Implementing CCS Systems

There is general agreement among experts that carbon capture technologies—particularly when they are deployed at IGCC coal plants—are sufficiently well-developed to warrant widespread deployment in the relatively near term. Even so, an emissions performance standard requiring CCS technol-

ogy for new coal plants could not take effect immediately because of the need for additional practical experience with large-scale sequestration, further technical refinement and cost-optimization of capture technologies, and creation of an effective legal and regulatory framework for long-term underground CO₂ storage.

How can the need for flexibility in the timing of CCS implementation be reconciled with the need to prevent substantially increased emissions from new coal plants constructed in the interim? One approach would be to require all new plants that begin construction after an initial date (say 2008) to be capable of capturing substantially all of their emissions by a second date (say 2013). Then, after a shakedown period of perhaps three years, all these new plants would need to capture and sequester those emissions at the required levels by a third date (say 2016). Over time, the three-year shakedown period would be reduced as the performance of capture and storage units becomes more reliable.

This three-phased approach would enable new plants to operate for an initial period while they work through the technical and operational challenges raised by capturing and sequestering their CO₂ emissions. It would also provide plant developers with enough lead time to investigate storage options, build pipelines or other systems for transporting CO₂ and install a carbon capture unit. Given the confidence of expert bodies that CCS systems will be ready for widespread commercial deployment by 2020,¹²⁹ a target date of 2016 for requiring CCS operation would be ambitious but achievable.

At the same time, because the emission performance standard would have an

early effective date, the need for eventual CO₂ capture and storage would be clear to plant developers from the outset and would inform decisions about the cumulative capital and operating costs of the new facility, its efficiency and electricity output, how it will be financed and where it will be sited. Thus, plant developers would be encouraged to choose the generation technology that represents the lowest-cost CCS option—even if other technologies would be more cost-effective in the absence of CO₂ emission controls. Likewise, project developers would select plant sites with the best access to cost-effective sequestration opportunities, avoiding the risk that new coal plants will be sited in locations where underground CO₂ storage is not feasible or prohibitively expensive.

As an additional form of flexibility while CCS technology is being perfected, plant developers could have the option during the first three years in which the performance standard is in effect (from 2008 to 2011) to begin constructing traditional coal plants that do not capture and sequester CO₂ provided they offset on a one-to-one basis their CO₂ emissions by one or more of the following steps:

- Improving system-wide efficiency and lowering CO₂ emissions at existing plants
- Retiring existing coal or natural gas units that generate CO₂ emissions
- Constructing previously unplanned renewable fuel power plants representing up to 25 percent of the generation capacity of the new coal plant.

At the end of the three-year period, this alternate compliance option would sunset and all new plants subsequently

entering construction would need to include CCS systems.¹³⁰

Creating the Legal and Technical Foundation for CCS

Importantly, a national target date for capturing and storing CO₂ at new coal plants would focus and accelerate the research and development programs required for CCS to be successfully deployed on a widespread basis. One such program, as recommended in the MIT report, is to undertake a small number of federally funded demonstration projects for different carbon capture technologies at IGCC and SCPC plants.¹³¹

Another component of this effort, also recommended by MIT, would be a concerted demonstration program to determine the large-scale viability of different types of underground storage repositories to assess the likelihood and scale of CO₂ leakage. Coupled with a comprehensive inventory of potential storage reservoirs, such a program would be an essential precondition for building public confidence that large-scale geological sequestration of CO₂ will reliably prevent emissions over the long term without harm to human health, property, and natural resources.

In parallel, a regulatory regime would be developed that establishes guidelines for sequestration site investigation, selection and permitting, monitoring of emissions and modeling of underground CO₂ migration, issuance of permits to entities responsible for CO₂ transportation and storage, and liability for long-term sequestration.¹³²

Legislation setting these activities in motion should be a top priority for Congress

A national target date for capturing and storing CO₂ at new coal plants would accelerate R&D programs necessary to ensure carbon capture and storage systems are successfully deployed on a wide scale

so that a sound technical and legal framework is in place before the effective date for CCS operation at new plants.

It is possible that unexpected technical, legal, or financial complexities could be encountered in developing the necessary foundation for CCS deployment. To avoid premature implementation of CCS technology in such circumstances, the president or Environmental Protection Agency administrator might be authorized to extend the effective date for operating CCS systems for some reasonable period of time. However, the conditions for such extensions would need to be clearly spelled out in advance by Congress to assure that CCS implementation at new coal plants remains an urgent national priority and is not unduly delayed.

Capping Emissions from Existing Power Plants

Even with a goal of zero net emissions for new plants, greenhouse gas emissions from the power sector might continue to increase if existing plants were not controlled. Thus, an emissions performance standard would need to be coupled with an emissions cap for existing plants in order to achieve an overall decline in emissions for the power sector.¹³³

This cap would encourage greater efficiencies in operating existing plants and incentivize plant owners to retrofit higher-emitting plants or retire them and build new low-emitting units. Unless emissions by existing plants are reduced, a stringent emissions standard for new plants might simply prolong the useful life of older plants and discourage new power generation—much as existing New Source Performance Standards under the Clean Air Act have encour-

aged continued operation of older power plants beyond their expected useful life.

As provided in several of the pending legislative proposals, a cap on existing plant emissions might decline over time—for example by starting off at 100 percent of emissions in a baseline year or average of years and declining to more stringent target levels in later years. This declining cap would make it more expensive to operate uncontrolled existing plants and reduce the cost-differential between these facilities and new plants with CCS capability.

A cap on emissions from existing power plants (in contrast to new plants) would best be implemented by an allowance trading program. This program would enable plant owners to seek out the most cost-effective emission-reduction opportunities within or beyond their own systems. For example, they could generate credits by replacing existing fossil-fuel generation with nuclear, clean coal or renewable power, by repowering coal units with natural gas, by improving the efficiency of existing units, or by reducing energy demand. Another important option under a cap-and-trade program would be to retrofit existing coal plants with CCS systems.¹³⁴

New coal plants equipped with CCS technology should be excluded from the scope of a cap-and-trade program for existing plants and should not receive allowances except perhaps where they begin operating CCS systems earlier than required by law. If allowances were provided to new plants, they would necessarily be very large, representing the difference between their emissions (essentially zero) and the CO₂ emissions from a new state-of-the-art coal plant

Unless emissions by existing plants are reduced, a stringent emissions standard for new plants might simply prolong the useful life of older plants

lacking carbon controls (which produces 6 million tons of CO₂ per gigawatt of energy).¹³⁵ Assuming that 145 gigawatts of power plants with CCS units were built in the United States, 790 million metric tons of allowances (about 13 percent of current total U.S. CO₂ emissions) would be allocated to owners of these plants. An equal number of allowances would then need to be withheld from other emitting sources to achieve emissions neutrality. This would impose considerable burdens on other sources, which would be required to reduce emissions by an additional 13 percent to offset the allowances granted to new coal plants.¹³⁶

Economic and Regional Costs and Benefits

The benefit of a stringent emission performance standard for new coal plants is that it would eliminate the uncertainty associated with an open-ended cap-and-trade program and provide a high degree of assurance that new coal plants are in fact negligible CO₂ emitters. Given the urgency of achieving dramatic long-term emission reductions from the electricity sector in order to stabilize atmospheric CO₂ levels, the highest priority arguably should be preventing emissions from new power plants to the greatest extent feasible and reducing emissions from existing plants as quickly as possible.

Nonetheless, the stringency of such an emissions standard could have unwarranted economic consequences as well as undesirable impacts on some regions of the country. The biggest obstacle to the acceptance of an emissions performance standard is the projected increase in the price of electricity resulting from reduced plant efficiency and increased construction and operational costs associated with

carbon capture technology. As shown in Figure 10, this increase is estimated by the state of Wisconsin, MIT, and the EPA to be on the order of 20 percent to 40 percent for IGCC plants with CCS units and considerably higher for CCS equipped SCPC units.¹³⁷

It is hard to assess how accurate these estimates are, given the lack of practical experience with CCS systems. However, the predicted higher costs of electricity from plants with CCS units may be ameliorated by several factors. First, for some power plants, the injection of CO₂ in oil or gas wells will increase production of these fuels, creating a revenue stream that partially or totally offsets the increased costs of capture and storage. One recent estimate is that, with enhanced access to CO₂, the prevalence of enhanced oil recovery opportunities could increase significantly, which in turn would boost the business case for CCS deployment.¹³⁸

Second, with advances in technology, IGCC and SCPC plants will achieve an even greater efficiency advantage over conventional PC plants now in service, offsetting a greater portion of the loss of efficiency from carbon capture. Similarly, the technology for capturing carbon will itself become more cost effective, imposing less of an efficiency penalty on electricity generation. The deployment of more plants with CCS systems would then be accompanied by cost reductions as capture technology matures.¹³⁹

Third, in the initial years, new plants would provide only a relatively small portion of the power generated by the utility sector, with the balance coming from lower-cost existing plants. Moreover, power production costs represent about 60 percent of the electricity charges

paid by consumers, with the remainder coming from the costs of transmission and distribution.¹⁴⁰ Thus the higher costs of producing electricity at an individual power plant with CCS capacity would be spread across utility rate bases, moderating the increase in electricity prices.¹⁴¹

Granted, more CCS-equipped plants would become a more significant part of the rate base over time, but the phased nature of this process coupled with cost-saving improvements in capture technology would likely cushion consumers from sharp price spikes.

Mitigating Economic Impacts

Because of increased costs of adding CCS units to either IGCC or SCPC plants, a strong case can be made for mitigating these cost differentials through incentives and other forms of financial support. This would serve a number of purposes.

First, the combination of a declining cap for existing plants and a CCS requirement for new plants would disproportionately burden generation systems that rely heavily on coal. Because coal use is concentrated in Midwest and Southern states, Texas and the Mountain West, ratepayers in those areas would pay a disproportionate share of the costs of CCS requirements. This disparity would be magnified if comparable emissions control costs are not required for other types of new power plants (such as natural gas units) and if plants with CCS systems replace existing coal plants that produce electricity more cheaply but are being retired to meet new greenhouse gas reduction mandates.

Indeed, if coal generation becomes uncompetitive because of CCS-related

costs in some parts of the country, the economic costs could extend beyond ratepayers to coal-producing communities. This would quickly erode political support for CCS systems in these disadvantaged regions and perhaps even undermine public willingness to address global warming at all. Since the benefits of CCS systems in addressing global warming will be realized by all regions, the costs should arguably be borne equally at the national level and not be imposed solely on regions that produce or use coal.

Second, there is a strong imperative to develop CCS technologies as quickly as possible so that CCS plants can start replacing older coal-fired plants. Incentives that reduce the financial risks and uncertainties of building CCS plants in the early years can secure commitments from otherwise reluctant investors. This will not only accelerate emission reductions in the United States but, by making CCS technologies better accepted and more cost competitive, encourage their adoption in other nations as well (see sidebar on page 46). Such incentives can be scaled back as the technology matures and costs become more predictable.

There are two approaches that would reduce the economic impacts of a CCS requirement for new coal plants. One is to create a fund that could be used to provide relief to consumers whose electricity bills would otherwise increase because they receive power from plants with CCS. This fund could simply “credit” the utility for the amount of the increase so that consumers do not see higher charges on their electricity bills.

A second approach is to provide plant developers a combination of financial incentives, including tax credits, loan

guarantees, and grants, that cover some or all of the added costs of building coal-fired power plants with CCS systems as compared to plants that lack such systems. The goal of these financial incentives would be to make plants with CCS systems more cost-competitive with uncontrolled coal plants, moderating price hikes to wholesale and retail electricity consumers and providing added inducements for the construction of CCS-equipped power plants.

These incentives would need to reflect not only the incremental cost of building the plant (if it is based on IGCC technology) but also cover the higher operating costs and reduced efficiency of plants with CO₂ capture technology as well as the costs of CO₂ transportation and storage. As these costs decline over time, the level of financial assistance to the plant developer would decline proportionately.

We propose that the incentives should be of sufficient magnitude to initially cover 20 percent of total construction costs (including the base-plant and add-on CCS capability) in order to offset a substantial portion of the currently estimated increase in electricity costs for coal plants with CCS units. This 20 percent cost recovery would be available for all new coal plants for which construction is commenced between now and 2012. The share of construction costs eligible for recovery would then drop 2 percent a year for the next eight years, at which point the incentives would be phased out.

In order to qualify for financial assistance, power plant developers would have to demonstrate that they are deploying the least costly CCS technology on a total \$/MWh basis—a requirement that would initially favor IGCC plants (at

least where they use Eastern coal) unless breakthroughs occur in post-combustion capture technology for SCPC plants.

The cost of such a program would likely be in the range of \$36 billion spread over 18 years, or about \$2 billion a year, based on projections that 80 gigawatts of new coal-fired capacity with CCS systems will be built between now and 2025.¹⁴² This \$36 billion estimate is based on the following assumptions:

- 40 gigawatts of the new coal capacity would qualify for incentives representing 20 percent of construction costs while the remaining 40 gigawatts would on average receive incentives at the 10 percent level
- Each gigawatt of new coal capacity with a CCS system would cost approximately \$3 billion to construct.

Although \$36 billion is a large sum, it is only a fraction of the \$1.61 trillion that the International Energy Agency predicts will be invested on new power plants in the United States between now and 2030. (During this same period the total worldwide investment for new electricity generating capacity is predicted to be \$11.3 trillion, with China making the single largest investment at \$3 trillion in this same period).¹⁴³

Moreover, with this new program of financial support in place, there would no longer be any basis for maintaining existing federal incentive programs for IGCC or SCPC plants without CCS capacity. Eliminating these programs would partially offset the increased outlays for new programs to incentivize new CCS-equipped plants.

We propose that financial incentives should be of sufficient magnitude to initially cover 20 percent of total construction costs in order to offset a portion of the increase in electricity prices

Cap-and-trade programs may provide a source of revenue to finance incentives for coal plants with CCS systems. A number of the proposed climate bills require the auctioning of emissions allowances, with the auction revenues used to fund new technologies or to offset the costs to industries and consumers of climate-related requirements.¹⁴⁴ One use for auction revenues could be to mitigate electricity cost increases for coal plants that employ CCS systems, and to provide financial incentives for building these plants.

Under a cap-and-trade program, owners of existing coal plants would be heavy allowance purchasers because of their large CO₂ emissions. Redistributing auction revenues to these owners if they build low carbon coal plants would serve the dual purposes of reducing their need for allowances (by helping to retire high-emitting plants) and providing economic relief to their customers (by cushioning them from increases in the cost of electricity).

In the absence of an allowance auction system, other funding mechanisms for an incentive program for low carbon coal plants could include implementation of a uniform per kilowatt “wires charge” on retail electricity sales implemented at the federal level or general tax revenues.

Both mechanisms would distribute the costs of financial incentives equally among all U.S. users of electric power—a fair and reasonable approach since CCS systems are being required because of a national commitment to reduce greenhouse gas emissions.

It is in the economic interest of China and India to adopt these technologies and systems because of the impact that climate change is likely to have on their economies and the greater cost and disruption that emission controls will impose if adopted later rather than sooner. Moreover, in the last five to 10 years, both China and India have arguably become sufficiently economically developed to

Setting the Standard for China and India

The coal-fired plants proposed for construction in the United States constitute only about 10 percent of the coal-fired plants currently projected for construction around the world, with most projections placing the vast majority of new coal fired plants in rapidly developing countries such as China and India. For instance, in its May 2007 report, the Intergovernmental Panel on Climate Change estimated that as much as three quarters of the projected increase in energy CO₂ emitted between now and 2030 will occur in emerging economies such as China.¹⁴⁵

This is not surprising given that China possesses the third-largest reserve of recoverable coal worldwide, and China’s coal consumption (in the absence of meaningful climate policies) is expected to increase to a level that is 52 percent greater than that of the United States by 2050, with precipitous increases

also expected in India.¹⁴⁶ Thus, a decision by the United States to adopt a standard that requires CCS systems at new coal plants is unlikely to have a significant impact on climate change unless other nations, particularly China and India, follow a similar approach.

CCS technology is far enough along the development cycle so that, with the proper regulatory drivers and financial incentives, it can be successfully implemented not only domestically but also exported to other countries. Doing so will provide developing nations with sound and timely technological solutions as they accelerate their energy production capabilities in lockstep with their economic growth.¹⁴⁷ China and India are in fact currently developing internal standards to address climate change,¹⁴⁸ and promising geologic sequestration formations appear to exist within China and India.¹⁴⁹

bear the cost of adopting these technologies. These countries' articulated (political) rationale for opposing greenhouse gas control measures is that the United States has not yet taken such action. This argument will vaporize once the United States incurs the cost and expense of developing CCS systems.

It is also in the economic interest of the United States to take the lead in developing the CCS technology and thereby speed its adoption by the rest of the world. Developing CCS technologies will create domestic jobs and give U.S. companies that develop these systems a leadership position in capturing the trillions of dollars that will be spent worldwide on coal plants between now and 2030.

Access to Underground Formations

Carbon sequestration, of course, requires a suitable underground reservoir to store the CO₂. The United States appears to be well endowed with geological forma-

tions with large CO₂ storage capacity, and these formations appear to be widely dispersed across most of the states. There will, however, be some areas currently reliant on coal power that may not have ready access to suitable sequestration reservoirs.¹⁵⁰ These areas could meet their power needs by importing power from other jurisdictions or investing in other types of power generation. Where coal is a particularly important economic resource, however, these alternatives could be unattractive.

Solutions for such regions might be to provide funding for CO₂ pipelines that exceed a certain length because there are no available sequestration formations within a defined distance of the project. A comparative survey of possible CO₂ sequestration sites across the country will better pinpoint areas where underground CO₂ storage is not a feasible option and thus the total pipeline investment necessary to provide access to sequestration sites to power plants in those areas.

Conclusion

One of the biggest challenges in addressing the risk of global warming is the potential for a dramatic increase in greenhouse gas emissions as a result of the construction of a new generation of coal-fired power plants. This challenge exists both in the United States, where abundant coal reserves are creating heightened interest in the construction of new coal plants, and in developing countries such as China and India, where demand for energy is growing at a rapid pace and coal-fired generation holds the most potential for meeting these increasing energy needs.

Fortunately, there is a potential pathway that would allow continued use of coal as an energy source without magnifying the risk of global warming. Technology currently exists to capture CO₂ emissions from coal-fired plants before they are released into the environment. And experts are confident that the captured CO₂ can be safely stored in underground geologic formations.

The great challenge, however, is ensuring that the widespread deployment of this technology happens on a timely basis. So far we are failing in that effort. This paper has considered policy options that would significantly increase the likelihood that all new coal plants are equipped with CCS systems.

To ensure widespread adoption of CCS systems, the paper recommends that Congress mandate a power emission performance standard that effectively requires all new coal plants to control emissions to the level achievable by CCS systems. This standard would be implemented in conjunction with an emissions cap-and-trade system for existing power plants. The standard would apply to all new plants for which construction is commenced after a date certain (say 2008), although flexibility would be allowed in the timing for CCS implementation so that the power industry can gain more experience with capture and sequestration technologies.

Bold action by the U.S. Congress to put in place an emission performance standard for new coal-fired power plants would demonstrate leadership in addressing climate change and build a technological and regulatory foundation that countries such as China and India could emulate as they attempt to tackle the risk of global warming without stifling economic growth. An emission performance standard that requires CCS systems for all new coal plants would pose a daunting technological and economic challenge. Yet achieving this goal would ultimately assure coal a secure and important role in the future U.S. energy mix by establishing a clear technological path forward for coal in a carbon constrained world.

Endnotes

- 1 Geoffrey A. Moore, *Crossing the Chasm: Marketing and Selling High-Tech Products to Mainstream Customers*, at 5 (1991).
- 2 A note about units of measure: the literature employs both metric and non-metric tons in relation to greenhouse gas volumes. We use metric tons except where the text relies on literature that is in non-metric tons. In this instance, we use the non-metric ton measure and for comparison purposes include the corresponding metric ton volume in parentheses.
- 3 Energy Info. Admin., *Emissions of Greenhouse Gases in the United States 2005*, at 13 and ix (Nov. 2006), available at <ftp://ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/ggrpt/057305.pdf> [hereinafter EIA 2006 Report]. In addition to CO₂, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride are considered greenhouse gases. Their impact is measured by converting the amount of each of these chemicals to CO₂-equivalent emissions. For example, one ton of methane emissions is considered the equivalent of 23 tons of CO₂ emissions. *Id.* at 29.
- 4 James Katzer et al., *The Future of Coal: Options for a Carbon-Constrained World*, Massachusetts Institute of Technology Interdisciplinary Study, at 36 (2007) [hereinafter, The MIT Study].
- 5 The Nat'l Coal Council, *Coal: America's Energy Future*, at xii, (March 2006), available at <http://nationalcoalcouncil.org/report/NCCReportVol1.pdf>. In 2005, U.S. coal consumption totaled 1.1 billion short tons. Energy Info. Admin., *U.S. Coal Supply and Demand: 2005 Review*, at 7 (April 2006), available at <http://www.eia.doe.gov/cneaf/coal/page/special/feature05.pdf>. In 2004, the United States accounted for nearly 20 percent of global demand, second only to China (approximately 34 percent). Int'l Energy Agency, *World Energy Outlook 2006*, at 127 (Nov. 2006) [hereinafter, WEO 2006]. The demonstrated coal reserve base—approximately 500 short billion tons—is projected to last for over 100 years, even at elevated consumption levels. The Nat'l Coal Council, *Coal: America's Energy Future*, at 2 (March 2006), available at <http://nationalcoalcouncil.org/report/NCCReportVol1.pdf>.
- 6 Ben Yamagata, *Clean Coal Opportunities in Electric Power Generation* (February 8, 2006) (unpublished PowerPoint presentation of the Coal Utilization Research Council) (on file with authors).
- 7 DOE Nat'l Energy Tech. Lab., *Tracking New Coal-Fired Power Plants: Coal's Resurgence in Electric Power Generation* (May 1, 2007) (unpublished PowerPoint presentation) (on file with authors), available at <http://www.netl.doe.gov/coal/refsshelf/ncp.pdf> [hereinafter, the NETL Tracking Report].
- 8 *Id.*
- 9 WEO 2006, *supra* note 5 at 493 (Nov. 2006); Yamagata, *supra* note 7 (estimating 1400 gigawatts based on data from the International Energy Agency and Platt's database).
- 10 Energy Info. Admin., *Annual Energy Outlook 2007*, (Feb. 2007) at 82, available at http://www.eia.doe.gov/oiaf/aeo/pdf/trend_3.pdf.
- 11 Energy Info. Admin., *International Energy Outlook 2005*, at 51, available at [http://www.stat-usa.gov/miscfiles/nsl/85e140505600107b852566490063411d/d0d08407366b117d85257157006fae32/\\$FILE/IEO2005_ch007.pdf](http://www.stat-usa.gov/miscfiles/nsl/85e140505600107b852566490063411d/d0d08407366b117d85257157006fae32/$FILE/IEO2005_ch007.pdf).
- 12 Energy Info. Admin., *Energy Information Sheets: Coal Reserves* (Aug. 2004), available at <http://www.eia.doe.gov/neic/infosheets/coalreserves.htm>.
- 13 Coal currently accounts for two-thirds of China's primary energy supply. Although the government has indicated its desire to decrease its coal usage, China is still predicted to drive over half of the growth in worldwide coal supply and demand in the next 25 years and coal will likely account for more than 50 percent of the country's energy supplies in the year 2030. See The MIT Study, *supra* note 4 at 63. See also *The Fourth Assessment Report, Working Group III, Summary for Policy Makers* (May 5, 2007). Prepared by the Intergovernmental Panel on Climate Change (stating that two-thirds to three-quarters of the increase in energy CO₂ emissions between 2000 and 2030 is projected to come from developing countries (e.g. those that are not "Annex I" countries or parties as defined in the IPCC report)) [hereinafter, IPCC Fourth Assessment Report].
- 14 EIA 2006 Report, *supra* note 3, at 23.
- 15 Robert Socolow, "Can We Bury Global Warming?," *Scientific American*, July 2005, at 50. See also The MIT Study, *supra* note 4, at ix (stating one 500 megawatt coal-fired power plant produces approximately 3 million tons per year of CO₂).
- 16 See International Energy Outlook 2006 Report, *supra* note 9 at 73. The total world emissions figure provided in this report is for CO₂ emissions from the consumption of fossil fuels only and relates to the year 2003.
- 17 Socolow, *supra* note 15, at 52 (estimating that coal plants accounted for 542 billion tons of CO₂ emissions from 1751–2002 and will account for 501 billion tons of CO₂ from 2002–2030).
- 18 EIA 2006 Report, *supra* note 3, at 13 and ix.

- 19 *Id.* at 29.
- 20 TXU initially proposed building 11 traditional coal-fired plants in Texas. In light of strong public opposition to the plants, TXU later cancelled plans for eight of these plants as part of the terms of a buyout deal with a private equity group led by Kohlberg Kravis Roberts and the Texas Pacific Group. It subsequently announced plans to build two IGCC plants in Texas. Kurt Fernandez, "TXU, Buyout Partners Announce Plans for Two Carbon Dioxide Capture Plants," *BNA Daily Environment Report*, Mar. 12, 2007, at A-9.
- 21 EPA, Executive Summary of the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005, at ES-4 (Apr. 2007), available at <http://www.epa.gov/climatechange/emissions/downloads06/07ES.pdf>
- 22 EIA 2006 Report, *supra* note 3, at ix–x.
- 23 Socolow, *supra* note 15 at 49. At the start of the industrial period, the concentration was 280 ppm, while the current concentration of 380 ppm is rising approximately 2 ppm per year. WEO 2006, *supra* note 5 at 144.
- 24 No one can know for certain what concentration of CO₂ would constitute a "safe" level, but many scientists have concluded that the CO₂ concentration in the atmosphere must not exceed 450 parts per million to prevent precipitous increases in temperatures. See David G. Hawkins et al., "What to Do About Coal," *Scientific American*, Sept. 2006, at 70.
- 25 Robert H. Williams, "Climate-Compatible Synthetic Liquid Fuels from Coal and Biomass with CO₂ Capture and Storage," Princeton Envtl. Inst., Princeton Univ., at 7 (Dec. 19, 2005) (unpublished PowerPoint presentation) (on file with authors), available at http://www.climatechange.ca.gov/documents/2005-12-19_WILLIAMS.PDF.
- 26 Except as otherwise indicated, the facts about sequestration were provided by Vello Kuuskraa of Advanced Resources International, Inc. ARI is the lead consultant on the EnCana project described in the text.
- 27 EPA Underground Injection Control Program, <http://www.epa.gov/safewater/uic/whatis.html> (last visited March 27, 2007).
- 28 See http://www.kindermorgan.com/business/co2/transport_cortez.cfm.
- 29 DOE Office of Oil and Natural Gas, Project Facts: Recovering "Stranded Oil" Can Substantially Add to U.S. Oil Supplies, Ten Reports Examine Basin-Oriented Strategies for Increasing Domestic Oil Production (Feb. 2006), available at http://www.fossil.energy.gov/programs/oilgas/publications/eor_co2/C_-_10_Basin_Studies_Fact_Sheet.pdf.
- 30 Email from Vello Kuuskraa, President, Advanced Resources Int'l, to Kenneth Berlin, Partner, Skadden, Arps, Slate, Meagher & Flom LLP (Apr. 30, 2007) (on file with authors).
- 31 On October 31, 2006, DOE announced the Department's support of seven tests in North America to advance carbon sequestration technologies. DOE will provide more than \$450 million over the next 10 years to validate that the capture, transportation, injection, and long-term storage of CO₂ can be done safely, permanently, and economically. See Press Release, DOE Nat'l Energy Tech. Lab., Department of Energy Advances Commercialization of Climate Change Technology (October 21, 2006; on file with authors), available at http://www.netl.doe.gov/publications/press/2006/06062-Carbon_Sequestration_Testing_Suppo.html. See generally, Nat'l Energy Tech. Laboratory, Carbon Sequestration Atlas of the U.S. and Canada (March 2007), available at www.netl.doe.gov/publications/carbon_seq/atlas/index.html [hereinafter, The NETL Sequestration Atlas].
- 32 DOE Nat'l Energy Tech. Lab., Carbon Sequestration and Technology Roadmap and Program Plan, at 9 (2006), available at http://www.netl.doe.gov/publications/carbon_seq/2006%20Sequestration%20Roadmap%20FINAL.pdf [hereinafter, The Roadmap].
- 33 Press Release, "Xcel Energy Increases Commitment to IGCC," August 15, 2006 (on file with authors), http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_15531_34200-28427-0_0-0,00.html (last visited Mar. 27, 2006).
- 34 Press Release, "BP and Edison Mission Group Plan Major Hydrogen Power Project for California," February 10, 2006 (on file with authors), available at <http://www.bp.com/genericarticle.do?categoryId=2012968&contentId=7014858> (last visited Mar. 27, 2006).
- 35 In the Matter of the Petition of Excelsior Energy, Inc. and Its Wholly Owned Subsidiary MEP-I, LLC, for Approval of Terms and Conditions for the sale of Power from Its Innovative Energy Project Using Clean Energy Technology under Minn. Stat. § 216B.1694 and a Determination that the Clean Energy Technology Is or Is Likely to Be a Least-Cost Alternative under Minn. Sta. § 216B.1693 at 3–4 (Prepared Surrebuttal Testimony of Excelsior Energy, Inc. and MEP-I LLC, by Richard Stone. October 31, 2006), available at http://www.excelsiorenergy.com/pdf/Regulatory_Filings/Docket_E6472_M-05-1993/20061031SurrebuttalTestimony/Steadman%20Surrebuttal%20Testimony%2010.31.06.pdf.
- 36 Press Release, "AEP to Install Carbon Capture on Two Existing Power Plants, Company Will Be First to Move Technology to Commercial Scale," (March 15, 2007; on file with authors), available at <http://www.aep.com/newsroom/newsreleases/default.asp?dbcommand=displayrelease&ID=1351>.
- 37 Fernandez, *supra* note 20.
- 38 Socolow, *supra* note 15, at 53.
- 39 Jon Davis, "Gasification and Carbon Capture and Storage: The Path Forward," Contributing Paper (Pew Center/NCEP 10–50 Workshop) at 1.
- 40 Sally Benson, "Carbon Dioxide Sequestration/Coal Gasification," Contributing Paper (Pew Center/NCEP 10–50 Workshop) at 17.
- 41 The MIT Study, *supra* note 4, at 53.
- 42 *Id.* at 53–54. The MIT study also concluded that about 10 projects would be needed to cover the range of important geological formations around the world. *Id.*
- 43 S. 962, introduced on March 21, 2007, would authorize \$315 million through 2009 for up to seven large-scale sequestration tests, including one conducted internationally.

- 44 The MIT Study, *supra* note 4, at 43.
- 45 In 2006, Texas passed House Bill 149, which transfers ownership of the CO₂ generated by the FutureGen Alliance to the Railroad Commission of Texas once it has been captured and stored. Testimony by Jay B. Stewart, *Carbon Capture and Sequestration—An Overview: Hearing Before the Subcommittee on Energy and Air Quality of the H. Comm. On Energy and Commerce*, 110th Cong. (March, 2007).
- 46 Doug Obey, “Industry’s CO₂ insurance plan seeks to block state waste rules,” *Inside EPA*, May 12, 2006.
- 47 Cynthia Dougherty, Office of Ground Water and Drinking Water, and Brian McLean, Office of Atmospheric Programs. Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects—UIC Program Guidance (UICPG # 83.) (March 1, 2007), *available at* http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonsequestration_final-03-07.pdf
- 48 Some states are moving ahead with legislation to establish a framework for regulating sequestration sites and to provide tax breaks for projects. See “States Proceed with CO₂ Storage Plans Ahead of EPA UIC Decision,” *Inside EPA*, Apr. 27, 2007.
- 49 See generally Paul W. Parfomak et al., “Carbon Dioxide (CO₂) Pipelines for Carbon Sequestration: Emerging Policy Issues,” Cong. Research Serv. (Apr. 19, 2007).
- 50 The NETL Sequestration Atlas, *supra* note 31.
- 51 Battelle Joint Global Change Research Institute, Carbon Dioxide Capture and Geologic Storage: A Core Element of a Global Energy Technology Strategy to Address Climate Change, at 26–27. (April 2006) [hereinafter the Battelle Report].
- 52 Intergovernmental Panel on Climate Change, IPCC Special Report on Carbon Dioxide Capture and Storage, at 11 (Ogunlade Davidson et al. eds., 2005). Both the NETL Sequestration Atlas, *supra* note 31 and the Battelle Report, *supra* note 51, provide higher estimates of CO₂ storage capacity than IPCC. For example, Battelle estimates worldwide storage capacity of 11,000 gigatons. More definitive inventories in the United States and globally will enable this range of uncertainty to be narrowed considerably. For comparison purposes, fossil fuel CO₂ emissions from 1400 gigawatts of new IGCC plants would total 8.4 billion tons per year (at 6 million tons per gigawatt). See Socolow, *supra* note 15, at 50 and the MIT Study, *supra* note 4, at ix.
- 53 IPCC Special Report on Carbon Dioxide Capture and Storage *supra* note 52 at 31.
- 54 Legislation has been introduced in both the Senate and the House (S. 731 and H.R. 1267, both introduced March 1, 2007) to require a more definitive inventory of U.S. sequestration capacity.
- 55 A Duke University study, for example, recommended that the most cost-effective way for North Carolina to sequester CO₂ was to build a pipeline that would run 2250 miles and support a CO₂ flow rate of 57 million metric tons of CO₂ per year, sufficient to handle captured emissions from 11 gigawatts of new coal-fired plants. The pipeline alone is estimated at a cost of \$5 billion, and according to the study would be cost effective at a CO₂ price of \$29 per ton. Eric Williams, et al., *Carbon Capture, Pipeline and Storage: A Viable Option for North Carolina Utilities?* (Working Paper, March 8, 2007), Nicholas Institute for Environmental Policy Solutions and Center on Global Change, Duke Univ. [hereinafter, The Duke Study]. See also Chris Holly, *Clean Coal’s Future in North Carolina Hangs On Big Pipe*, 35 *The Energy Daily* 71, 1–2 (Apr. 16, 2007). A price of \$29 per ton of CO₂ is consistent with estimates elsewhere in this article of the cost at which CCS becomes cost competitive.
- 56 Another technology, Oxy-fuel pulverized coal combustion, may be more cost-effective in capturing CO₂. The MIT Study concluded that the technology is in the early commercial development stage (with one 30 MW CO₂-free coal combustion targeting a start-up in 2008 and one a 24 MWe oxy-fuel electricity generation project under development) and that it appears to have considerable potential. The MIT Study *supra* note 4, at 31.
- 57 According to the MIT report, a 500 MW SCPC unit requires a 37 percent increase in plant size to accommodate the additional steam required for regeneration of the amine solution and, as a result, a plant with CCS is 9 percent less efficient than one without it. *Id.* at 24–25.
- 58 On March 15, 2007, however, AEP announced that it would experimentally retrofit two pulverized coal plants to capture carbon. AEP Press Release *supra* note 36.
- 59 Research Reports Int’l, Coal Gasification for Power Generation, at 10–11 (Sept. 2005).
- 60 The Roadmap, *supra* note 32, at 9 (2006).
- 61 John Fialka, “Kyoto Question as U.S. Moves on Coal—Energy Department Teams With Consortium to Build Model ‘Clean-Coal Plant,” *The Wall Street Journal*, December 6, 2006 at A2.
- 62 MIT estimates the cost of CO₂ capture and pressurization at about \$25 a ton and CO₂ transportation and storage at about \$5 a ton. The MIT Study, *supra* note 4, at xi.
- 63 The MIT Study, *supra* note 4, at 30, 36; Mark Meyer et al., *Integrated Gasification Combined-Cycle Technology Draft Report*, Dep’t of Nat. Res. Pub. Serv. Comm’n of Wisc. (June 2006), at 31–33 [hereinafter, the Wisconsin Report]; EPA, *Environmental Footprints and Costs of Coal-based Integrated Gasification Combined Cycle and Pulverized Coal Technologies*, at 5-11–5-12 (July 2006) [hereinafter, The EPA Report].
- 64 The efficiency of IGCC plans is now lower with Western subbituminous and Texas lignite coals, at least with some gasification technologies. As a result, the MIT report indicates that the cost differential between IGCC and SCPC narrows when these coals are used. The MIT Study, *supra* note 4, at 36–37.
- 65 Testimony of Brian Hannegan, *Future of Coal: Hearing Before the S. Comm. On Energy and Natural Resources*, 110th Cong. at 5 (March 22, 2007).
- 66 *Id.* at 3.
- 67 The MIT Study, *supra* note 4, at 34.

- 68 Unless otherwise noted, these new plants were reported in the NETL Tracking Report, *supra* note 7.
- 69 BP Press Release, *supra* note 34.
- 70 Barry Cassell, "Illinois EPA Issue Draft Air Permit for Taylorville IGCC Project," SNL Energy Coal Report at 12, 13 (Dec. 4, 2006).
- 71 Wayne Barber, "Southern Utility Subsidiary Laying Groundwork for Mississippi IGCC Plant," SNL Energy Coal Report at 14, 15 (Feb. 19, 2007).
- 72 "Coal: Mont. Announces CTL, IGCC Plants," *Greenwire*, Oct. 3, 2006.
- 73 Barry Cassell, "Peabody Foresees Major Coal-fired Capacity Additions by 2019," SNL Energy Daily Coal Report at 1 (April 9, 2007).
- 74 Fernandez, *supra* note 20.
- 75 Statement of Edward Lowe, General Manager Gasification Market Development, GE Energy *CO₂ Capture and Sequestration: An Overview Hearing Before the H. Subcomm. on Energy and Air Quality*, 110th Cong. at 4 (March 6, 2007).
- 76 See e.g., The NETL Tracking Report, *supra* note 7.
- 77 "Availability" is an industry term meaning the amount of time the plant is operating. Availability is reduced if there are lengthy outages for repairs and maintenance.
- 78 The Wisconsin Report, *supra* note 63, at 16.
- 79 *Id.* at 1.
- 80 The Public Utilities Commission of Ohio, *2006 End of Year Review*, at 4 (December 26, 2006).
- 81 Press Release, "Citizens Action Coalition of Indiana, Consumer and Environmental Groups Join to Challenge New Duke/Vectren Coal Plant that Would Cost Indiana Rate Payers Billions," Nov. 29, 2006 (on file with authors), available at <http://www.citact.org/newsite/>
- 82 In Minnesota, even after the state passed legislation providing for the Mesaba IGCC project to enter into a power purchase agreement, the major utility, XCEL, and consumer groups have opposed such an agreement before the Minnesota PUC on the ground that it is too costly. *Inside EPA*, Jan. 12, 2007.
- 83 NRG was recently selected by New York State to build an IGCC facility but its management acknowledged that this facility would not be viable without significant financial support from government programs. Press Release, "NRG Energy Inc., NRG Energy Inc. Receives Conditional Award to Build Advanced Coal-Gasification Power Plant in Western New York: Will Enter into a Strategic Alliance with NYPA," December 19, 2006 (on file with authors), available at <http://www.snl.com/irweblinkx/file.aspx?IID=4057436&FID=3211361> (last visited on Mar. 27, 2007).
- 84 IND. CODE § 6-3.1-29-15 (West Co. Rev. Stat. Ann. 2006).
- 85 Kansas Energy Council, *Kansas Energy Plan 2007*, at 3 (referencing Kansas House Substitute for S. 303 (passed in the 2006 Legislative session), available at http://kec.kansas.gov/energy_plan/energy_plan.pdf
- 86 C.R.S.A. § 40-2-123 (West Co. Rev. Stat. Ann. 2006).
- 87 MINN. STAT. § 216B.1694 (West Co. Rev. Stat. Ann. 2006).
- 88 Energy Policy Act of 2005, 42 U.S.C.A. § 16511 (West 2007).
- 89 A similar approach was advocated in a 2004 report published by the Kennedy School of Government, which proposed a "3 Party Covenant" between the federal government, state utility commissions and equity investors to lower the cost of financing IGCC plants. William Rosenberg et al., *Deploying IGCC in This Decade with 3 Party Covenant Financing: Overview of Financing Structure*, Harvard Univ., at 1 (July 2004) (explaining that the 3 party covenant seeks to reduce the cost of capital, raise the debt equity ratio, minimize construction financing costs and allocate financial risk). Under the 3 party covenant "the federal government provides AAA credit [through loan guarantees], the state [Public Utility Commission] provides an assured revenue stream to cover cost of capital and protect the federal credit, and the owner provides equity and know-how to build the IGCC project with appropriate guarantees" from the vendor and construction firm. *Id.* at 8.
- 90 DOE, *Fact Sheet: Clean Coal Technology Ushers In New Era in Energy* (2006), available at <http://www.doe.gov/media/clean-coalcreditfactsheet.pdf>. Subsequently, several utilities who had unsuccessfully sought tax credits expressed disappointment, saying that DOE's decision would slow commercialization of IGCC. See ARGUS AIR DAILY, December 11, 2006.
- 91 Case in point: Southern Company's 285 MW IGCC facility near Orlando, Florida, which is receiving \$235 million from the Department of Energy. See DOE Office of Fossil Fuel Energy, *Project Fact Sheet for Demonstration of a 285 MW Coal-Based Transport Gasifier* (Project ID DE-FC26-06NT42391), available at <http://www.fossil.energy.gov/fred/factsheet.jsp?doc=4884&projtitle=Demonstration%20of%20a%20285MW%20Coal-Based%20Transport%20Gasifier> (last visited Mar. 27, 2007).
- 92 Carbon Price Key for IGCC, CCS Argus Air Daily, May 11, 2007.
- 93 Natural Resource Defense Council, *Coal and Climate: Hitting the Wall* (unpublished PowerPoint presentation) (on file with authors), available at http://www.aaas.org/spp/rd/Forum_2006/hawkins.pdf
- 94 WEO 2006 *supra* 5 at 141.
- 95 *EIA Energy Outlook 2007*, *supra* note 10 at 9. In the NETL Tracking Report, *supra* note 7, NETL lowers the estimate of new coal-fired plant generation capacity to 145 gigawatts.
- 96 Press Release, DOE, "FutureGen Industrial Alliance Announces Site Selection Process for World's First 'Zero Emissions' Coal Plant," February 8, 2006 (on file with authors), available at http://www.fossil.energy.gov/news/techlines/2006/06007-Future-Gen_Site_Selection_Process.html

- 97 The MIT Study raised several concerns regarding the FutureGen project, including the continuing lack of clarity surrounding project goals, the incorporation of features extraneous to the commercial demonstration of CCS, the confusion of objectives caused by the inclusion of international partners, and whether the project will be bogged down by federal procurement rules and government cost auditing. The MIT Study, *supra* note 4, at 81–82.
- 98 Many companies building IGCC plants may believe they are “capture ready” and can be retrofitted with CCS capability if required to reduce CO₂ emissions under a future carbon management regime. However, the MIT Report questions whether such retrofits can be accomplished economically if the plant parameters are not initially designed with CCS in mind. The MIT Report, *supra* note 4, at 38.
- 99 The Regional Greenhouse Gas Initiative includes 10 states as of May 2007: Maine, Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Delaware, and Maryland. Information on the RGGI, including the Memorandum of Understanding, is *available* at <http://www.rggi.org/index.htm>.
- 100 Western Regional Climate Action Initiative, Ariz.-Cal.-N.M.-Or.-Wash., Feb. 26, 2007, *available* at http://www.climatechange.ca.gov/documents/2007-02-26_WesternClimateAgreementFinal.pdf. See also Press Release, “Office of the Governor for the State of Oregon, Five Western Governors Announce Regional Greenhouse Gas Reduction Agreement,” Feb. 26, 2007 (on file with authors), *available* at <http://governor.oregon.gov/Gov/pdf/letters/022607NGA.pdf>
- 101 Climate Stewardship and Innovation Act of 2007 (S. 280), introduced on January 12, 2007. A similar version of this bill was introduced in the House as H.R. 620 by Representative Olver.
- 102 Electric Utility Cap and Trade Act, S. 317, 110th Cong. (2007). Very similar targets are reflected in utility-only bills introduced by Senator Carper (S.1177)(Apr. 20,2007) and Senator Alexander (S.1168)(Apr. 19, 2007), which regulate emissions of NO_x, SO₂, and mercury as well as CO₂. See also, *Cong. Res. Service Comparison of Key Provisions of Greenhouse Gas Reduction Bills Introduced in 110th Congress*, [38] BNA Environmental Reporter, No. 6, at 337 (Jan. 31, 2007) (comparing key provisions of the Greenhouse Gas Reduction Bills introduced in the 110th Congress) [hereinafter, Env. Reporter Comparison].
- 103 The Bingaman draft bill was first developed in the 109th Congress and named the “Climate and Economy Insurance Act of 2005.” The bill was never formally introduced. Senator Bingaman has circulated a slightly revised version of the bill in the current Congress. See Bingaman-Specter Discussion Draft on Global Warming Legislation, “Market-Based GHG Emission Trading 2007 Discussion Draft,” *available* at http://energy.senate.gov/public/_files/DiscussionDraftSupportinginformation.pdf [hereinafter, the Bingaman Discussion Draft]. The original Bingaman proposal reflected 2004 recommendations by the National Commission on Energy Policy. The Commission recently issued revised recommendations which call for stabilizing emissions at current levels by 2020 and achieving a 15 percent reduction below these levels by 2030 and propose raising the starting price of the safety valve to \$10 per ton of CO₂ and increasing the rate of escalation to 5 percent per year. National Commission on Energy Policy, *Energy policy recommendations to the president and the 110th Congress*, April 2007. It remains to be seen whether Senator Bingaman will adopt these recommendations, which are still considerably less aggressive than other carbon cap proposals pending in Congress.
- 104 S. 309 basically reintroduces Senator Jeffords’ Global Warming Pollution Reduction Act from the last Congress. A similar bill (H.R. 1590) has now been introduced in the House by Representative Waxman and several co-sponsors.
- 105 A utility-only bill recently introduced by Sen. Sanders, S.1201 (Apr. 24, 2007) would cap emissions at 1990 levels by 2020 and Kyoto levels (7 percent below 1990 levels) by 2025.
- 106 For example, under S. 280, the targets must be reviewed biennially by NOAA, which must report its views and recommendations to Congress. Under the draft Bingaman bill, the targets are subject to interagency and Congressional review every five years. Similarly, under S. 317, EPA must review the targets every four years starting in 2015 and may make them more or less stringent.
- 107 For example, the Clean Power Act (S. 150) introduced by Senator Jeffords in the last Congress would cap utility CO₂ emissions at 2.05 billion tons in 2010, 21% below 2000 levels. U.S. Senate Committee on Environment and Public Works, <http://epw.senate.gov/pressitem.cfm?party=dem&id=230866>. As analyzed by EPA, the cost per ton of controlling CO₂ would be \$16 in 2010 and \$27 in 2020. James McCarthy and Larry B. Parker, “Cost and Benefits of Clear Skies: EPA’s Analysis of Multi-Pollutant Clean Air Bills,” *Congressional Research Service Report for Congress*, at CRS 14 (November 23, 2005).
- 108 *Id.*
- 109 Bingaman Discussion Draft, *supra* note 103, at 1.
- 110 *Generation Technologies for a Carbon Constrained World*, EPRI Journal, at 39 (Summer 2006).
- 111 See 42 U.S.C.A. § 7503 (LAER statutory provisions) and 42 U.S.C.A. § 7475 (BACT statutory provisions). The “top down” approach is described in the EPA 1990 New Source Review Workshop Manual. EPA, [New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting at B.5–B.9](http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf), *available* at <http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf>.
- 112 See e.g., EPA, [Fact Sheet: EPA’s Clean Air Mercury Rule](http://www.epa.gov/air/mercuryrule/pdfs/factsheetfinal.pdf), *available* at <http://www.epa.gov/air/mercuryrule/pdfs/factsheetfinal.pdf>.
- 113 Massachusetts v. EPA, No. 05-1120, slip op. (U.S. April 7, 2007).
- 114 A thorough discussion of many of these issues is provided in Gregory Foote, *Considering Alternatives: The Case for Limiting CO₂ Emissions from New Power Plants Through New Source Review*. 34 ELR 10642 (July 2004).
- 115 EPA’s position was conveyed in a December 2005 letter to an industry consultant which was later rescinded as an authoritative EPA interpretation of the CAA after being challenged by environmental groups because of the absence of public comment. See Letter from Ann Brewster Weeks, Clean Air Task Force, et al. to Stephen Johnson, Administrator—U.S. EPA (February 8, 2006), *available* at http://www.catf.us/advocacy/legal/BACT_LAER/Johnson_Letter.pdf. Nonetheless, EPA has not repudiated the approach embodied in the letter, leaving unresolved the issue of whether IGCC is BACT/LAER for purposes of PSD/NSR requirements.

- 116 These terms are included in the statutory definition of BACT and have been interpreted by EPA. See 42 U.S.C.A. § 7479 (definition of “best available control technology”) and 42 U.S.C.A. § 7501 (definition of “lowest achievable emission rate”).
- 117 See e.g., Steven Cook, “Appeals Board Decision Seen as Setback For Use of Coal Gasification Technology,” *Daily Environment Report*, September 14, 2006, at A-4; “Thoroughbred appealed over IGCC,” *Argus Air Daily*, May 15, 2006, at 4; “Ky rejects IGCC for BACT,” *Argus Air Daily*, April 12, 2006, at 1.
- 118 This approach is reflected in a draft bill widely circulated but not introduced by Senator Coleman of Minnesota on file with the authors. See Energy Info. Admin., Energy Market Impacts of a Clean Energy Portfolio Standard, at Appendix B (January 2007), available at [http://www.eia.doe.gov/oiaf/servicerpt/portfolio/pdf/sroiaf\(2007\)02.pdf](http://www.eia.doe.gov/oiaf/servicerpt/portfolio/pdf/sroiaf(2007)02.pdf)
- 119 Williams and Hawkins, Coal Low-Carbon Generation Obligation for U.S. Electricity. Review draft, August 7, 2005, available at <http://phys4.harvard.edu/~wilson/energypmp/Hawkins&Williams.doc>.
- 120 A version of this concept is reflected in section 709 (Low Carbon Generation Requirement) of the Sanders global warming bill (S. 309), under which an increasing percentage of generation from coal, lignite, coke, and biomass would need to meet a low carbon generation standard (250 pounds of CO₂ per MWh).
- 121 The low carbon commitment would start off at 0.5 percent in 2015 and increase to 5 percent by 2020. Subsequently, EPA could increase the commitment by up to 2 percent per year through 2025, and by up to 3 percent per year from 2026 through 2030.
- 122 In February 1993, soon after taking office, President Clinton proposed a broad-based energy tax for the United States as a means to tax the use of fossil fuels and decrease the nation’s reliance on foreign oil. The tax was to be levied on the energy content of fuels (i.e. the number of “BTUs” they contain), with a substantially higher rate for petroleum fuels than for coal and natural gas. The three reasons in addition to deficit reduction that the administration cited for the tax were the reduction of environmental damage, energy conservation, and the alleviation of U.S. dependence on foreign energy sources. The tax was carefully designed to spread the revenue burden evenly across the country’s diverse regions. The BTU tax would have reduced CO₂ emissions by encouraging greater efficiency in energy production, conservation, and use and by promoting development of renewable energy sources. Ultimately, the tax was defeated in the Senate, where the administration lost the support of several oil-state Democrats and failed to win over any moderate, pro-environment Republicans. The Senate chose a small increase in the gasoline tax as the alternative.
- 123 Nonetheless, legislation to impose a carbon tax has been proposed by Rep. Stark of California (H.R. 2069). This bill would initially tax coal, petroleum and natural gas at \$10 per ton of carbon content when these fuels are either extracted or imported.
- 124 Craig Hanson and James Hendricks, Jr., “Taxing Carbon to Finance Tax Reform”, Duke Energy and World Resources Institute Issue Brief at 3 (March 2006), available at http://pdf.wri.org/taxing_carbon_full.pdf.
- 125 Those are the goals set forth in the NETL Carbon Sequestration Roadmap and Program Plan—2006 and for the FutureGen project. See Roadmap, *supra* note 32 at 9; Fialka, *supra* note 61. Again, there might be some need to allow slight slippage of these goals.
- 126 S. 485 would amend the Clean Air Act so that each new coal power plant commencing construction on or after April 26, 2007 would be required to meet a standard of performance allowing the plant to produce no more than 285 pounds of CO₂ per MWh. CO₂ that is injected into a geological formation in a manner that prevents its release into the atmosphere would not be counted in applying this standard. The Kerry bill lacks some of the flexibility elements described in this paper, such as a phased schedule for actually capturing and sequestering CO₂.
- 127 The Energy Information Administration estimates that natural gas produces 1.314 pounds of CO₂ per kilowatt-hour, compared to 2.117 pounds per kilowatt-hour for coal. Energy Info. Admin., Carbon Dioxide Emissions from the Generation of Electric Power in the U.S., at 2 (July 2000), available at http://www.eia.doe.gov/cneaf/electricity/page/co2_report/co2report.html. In 2005, CO₂ emissions from natural gas plants were 318.9 million metric tons, representing 13 percent of total emissions from the electric power generation sector. The EIA 2006 Report, *supra* note 3, at 16.
- 128 Section 708 (Emission Standard for Electric Generation Units) of the Sanders global warming bill (S. 309) contains a somewhat similar provision under which all electricity generation units which begin operation in 2012 or later must meet, by 2016, an emission performance standard that is “not higher than the emission rate of a new combined cycle natural gas unit.” The standard would apply to all existing units by 2030, regardless of when they began operating.
- 129 See e.g. Testimony of Brian Hannegan, *supra* note 65 at 3.
- 130 Embodying a similar approach is a March 2007 settlement agreement between Kansas City Power and Light and the Sierra Club relating to the utility’s 850 megawatt coal-fired plant under construction in Missouri. The agreement requires Kansas City Power and Light to offset the 6 million tons of CO₂ emissions from the new plant by installing 400 megawatts of new wind power, implementing measures to save 300 megawatts of energy demand and closing or upgrading an older coal-fired plant. Steven Mufson, “Electric Utility, Sierra Club End Dispute: Kansas City Power & Light Agrees to Offset New Coal-Fired Plant’s Emissions,” *The Washington Post*, March 20, 2007, at D03.
- 131 The MIT Study, *supra* note 4, at 100. Consistent with the MIT report, federal financial support for IGCC units without CCS would be phased out because IGCC already has strong commercial backing and the adoption of an emission performance standard requiring CCS will change the economics of new coal plants in IGCC’s favor. *Id.*
- 132 Section 713 (Geologic Disposal of Global Warming Pollutants) of the Sanders utility-only bill, S. 1201, would authorize EPA to develop many of these program elements.

- 133 The performance standard could be implemented as a stand-alone provision (without a cap-and-trade program) if necessary to provide certainty to coal plant developers that uncontrolled plants will not be “grandfathered.” Section 716(c) of the Feinstein-Carper bill (S. 317), for example, provides that no allowances may be allocated to any coal-fired unit unless it entered operation before January 1, 2007 or is powered by “qualifying advanced clean coal technology.”
- 134 The MIT Report concludes that retrofits will be unlikely because of reductions in unit efficiency and output, unit downtime and increased on-site space requirements and that plant rebuilds to include capture technology appear more attractive, particularly if they upgrade low-efficiency PC units with high-efficiency technology. The MIT Study, *supra* note 4 at pages xiv, 28, 38 and 146–150. Nonetheless, AEP is investigating retrofit opportunities at two of its plants. AEP Press Release, *supra* note 36. Whatever the practical realities of retrofits, mandating them for existing plants (as is the approach under S. 309, which provides that all existing plants must meet emission performance standards by 2030) seems less desirable than a declining emissions cap, under which retrofits would be considered along with other options based on an analysis of cost-effectiveness.
- 135 Under existing Clean Air Act cap-and-trade programs for SO₂ and NO_x, utilities do not receive allowances for the emission reductions required to meet mandated limits on emissions except where such reductions exceed mandated levels. The same approach should be followed for greenhouse gases.
- 136 Put another way, the California Act requires reduction of 174 million tons of CO₂ per year by 2020. Assuming that California would permit its regulated companies to buy reductions from outside the state, this entire requirement could thus be met many times over by building new IGCC plants with CCS systems if credits for those plants (900 million tons on a nationwide basis) were permitted and business could otherwise continue as usual in California.
- 137 See The Wisconsin Report, *supra* note 63 at 32 (estimating that costs would increase to over \$75 per MWh of energy generated with carbon capture, compared to between \$50 and \$60 per MWh without carbon capture); The MIT Study, *supra* note 4, at 36 (estimating that the costs for IGCC with carbon capture will be 30 percent over that of SCPC without carbon capture and 25 percent to 40 percent higher than IGCC without carbon capture); The EPA Report, *supra* note 63, at 5–11 (estimating \$66 per MWh for IGCC with carbon capture versus \$48 per MWh for IGCC without capture and \$51 for SCPC without capture).
- 138 Michael L. Godec, Advanced Resources International, CO₂-EOR and Sequestration: Potential Opportunity for Coal Gasification (November 13, 2006) (unpublished PowerPoint presentation prepared for Pre-Conference Symposium: The Economics of Carbon Capture, Transport & Sequestration) (on file with authors).
- 139 EPRI estimates that the 30 percent energy efficiency penalty associated with CCS will be reduced to around 10 percent over the longer term. Testimony of Brian Hannegan, *supra* note 65 at 3.
- 140 David Hawkins of the National Resources Defense Council recently testified that a low-carbon generation obligation large enough to cover all forecasted new U.S. coal capacity by 2020 could be implemented with about a 2 percent increase in average U.S. electricity rates. Testimony of David Hawkins, *Carbon Capture and Sequestration—An Overview: Hearing Before the Subcommittee on Energy and Air Quality of the H. Comm. On Energy and Commerce*, 110th Cong. at 19 (March 6, 2007).
- 141 *Id.*
- 142 The estimate of 80 gigawatts assumes that some of the currently proposed 93 gigawatts of coal-fired plants would not have CCS systems but would offset their CO₂ emissions under the three-year alternative compliance option described in the text.
- 143 WEO 2006, *supra* note 5 at 148.
- 144 For example, under S. 280, the revenues for allowance auctions would be used to fund a Climate Change Credit Corporation, which must in turn support a climate technology challenge program. See S. 280, Title III. Similarly, S. 317 would use auction proceeds to fund a Climate Trust Fund which would in turn support innovative low and zero-emitting carbon generation technologies and clean coal technologies, among other activities. See S. 317, Section 717.
- 145 IPCC Fourth Assessment Report *supra* note 13 at 3.
- 146 The MIT Study, *supra* note 4, at 11.
- 147 Total electricity generation capacity in China increased by nearly a third in the last three years, and is expected to continue doubling each year for the next several years. See The MIT Study, *supra* note 4, at 63. India’s growth in coal consumption is currently projected at 6 percent per year; it is expected to reach current U.S. coal consumption levels by about 2020 and will match Chinese usage by about 2030. See The MIT Study, *supra* note 4, at 74.
- 148 See generally, The MIT Study, *supra* note 4, Chapter 5 (summarizing environmental regulation in China and to a lesser extent in India). See also, “Chinese energy reforms may surpass U.S.’s,” Greenwire, Apr 27, 2007, (stating that reforms adopted by China in 2001 are on track to cut 168 million tons (152 million metric tons) of greenhouse gases by 2010, and is focusing first on the dirtiest and largest energy consuming industries including coal-fired coal plants).
- 149 See The MIT Study, *supra* note 4, at 55 (stating that several small-scale sequestration studies are currently occurring in China and one small pilot project is underway in India, though concerted research and large-scale pilot projects are currently lacking).
- 150 See generally The Duke Study *supra* note 55. See also Figure 8 on page 15.

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